STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Mark J. Homick
General Manager, Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111
_______________________________/

Facility I.D. No. 0530233
DEP Permit No. PSD-FL-194F
Polk Power Station
Polk County

Enclosed is Final Permit Number 1050233-007-AC for the Polk Power Station IGCC unit, Emission Unit 001. This permit requires Tampa Electric Company to comply with a NO_X emission limit of 15 ppmvd @ 15% O_2 on a 30-day rolling average effective July 1, 2003. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

for C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 2/5/02 to the person(s) listed:

Mark J. Homick, TEC*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Mr. Jeff Spence, Polk County ESD
Buck Oven, DEP PPSO
Thomas W. Davis, P.E, ECT

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson February 5, 2002
(Clerk) (Date)

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

PERMITTEE

Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

Authorized Representative:
Mark J. Hornick, General Manager
Polk Power Station

DEP File No. 1050233-007-AC
Permit No. PSD-FL-194F
Emission Unit 001
NO_X Emissions Reduction
SIC No. 4911

PROJECT AND LOCATION

As per the original PSD permit: "*One month after the test period ends (estimated to be by June 1, 2001), the Permittee will submit to the Department a NO_X recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_X only and adjust the NO_X emission limits accordingly.*" Based upon the Department's review of the permittee's submittals, the Department has determined that the NO_X emission limits for Emission Unit 001 should be reduced.

The emission unit is located at the Polk Power Station, 9895 State Road 37 South, Mulberry, Polk County. The UTM coordinates are Zone 17, 402.45 km E and 3067.35 km N.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

ATTACHED APPENDIX MADE A PART OF THIS PERMIT

Appendix BD-2001

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management

FACILITY DESCRIPTION

Tampa Electric Company (TEC) Polk Power Station (PPS) Unit 1 located in Polk County, Florida is a nominal 260-megawatt (MW) electric generation facility. Major components of PPS Unit 1 include solid fuel handling and gasification systems, a sulfuric acid plant for processing of the solid fuel gasification system gas cleanup stream, an auxiliary boiler fired with No. 2 distillate fuel oil, and one integrated gasification combined cycle (IGCC) General Electric (GE) 7F combustion turbine (CT) fired with synthetic natural gas (syngas) or No. 2 distillate fuel oil. The unit is additionally authorized to burn syngas produced from the gasification of fuel blends of up to 60 percent petroleum coke.

REGULATORY CLASSIFICATION

This facility, TEC Polk Power Station, is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PERMIT SCHEDULE

- 05/23/01 Department published the Public Notice in the Tampa Tribune.
- 05/10/01 Department distributed initial Intent to Issue Permit.
- 02/15/01 Department received additional information; application deemed complete.
- 12/04/00 Department requested additional information.
- 11/17/00 Department received applicant's BACT submittal

RELEVANT DOCUMENTS

The documents listed below are the basis of the permit. They are specifically related to this permitting action. These documents are on file with the Department.

- Application received on November 17, 2000;
- Department's incompleteness letter dated December 4, 2000;
- TEC's response to Department's incompleteness letter received on February 15, 2001;
- Draft BACT Determination issued by the Department dated May 10, 2001;
- Department's Intent to Issue and Public Notice Package dated May 10, 2001;
- Additional submittals provided by TEC to Department subsequent to May 10, 2001;
- Permits PSD-FL-194, PSD-FL-194B, PSD- FL-194C, PSD-FL-194D and PSD-FL-194E.

PERMIT SPECIFIC CONDITIONS

This permit addresses the following emissions unit:

E.U. ID No.	Brief Description
-001	Integrated Gasification Combined Cycle Unit No. 1

1. The provisions of the Title V Operating Permit 1050233-001-AV remain in effect. However, an application shall be submitted to revise that permit consistent with the emission limit changes herein.
2. The provisions of air construction permits PSD-FL-194, PSD-FL-194A, PSD-FL-194C, PSD-FL-194D and PSD-FL-194E are incorporated into this air construction permit except for the changes to the NO$_X$ emission limit while firing syngas in the affected portions of Specific Condition H below.

H. Emission Limits

1. The maximum allowable emissions from the IGCC combustion turbine, when firing syngas and low sulfur fuel oil, in accordance with the BACT determination, shall not exceed the following:

EMISSIONS LIMITATIONS - 7F CT POST DEMONSTRATION PERIOD

POLLUTANT	FUEL	BASIS[a]	LB/HR*	TPY[b]
NO$_X$	Oil	42 ppmvd**	311	N/A
	Syngas	~~25~~ 15 ppmvd	~~222.5~~ 132	~~1,044~~ 620

(*) Emission limitations in lbs/hr are 30-day rolling averages, except for NO$_X$ while firing syngas, which as of July 1, 2003 is limited in ppmvd (at 15% oxygen) and complied with on a 30-day rolling average via CEMS. Pollutant emission rates may vary depending on ambient conditions and the CT characteristics. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review 120 days after the Siting Board approval of the site certification. Subject to approval by the Department, the manufacturer's curves may be used to establish pollutant emission rates over a range of temperatures for the purpose of compliance determination.

5. After the demonstration period, permittee shall operate the combustion turbine to achieve the lowest possible NO$_X$ emission limit but shall not exceed 25 ppmvd corrected to 15 percent oxygen and ISO conditions. Effective July 1, 2003, permittee shall operate the combustion turbine to achieve the lowest possible NO$_X$ emission limit but shall not exceed 15 ppmvd corrected to 15 percent oxygen and ISO conditions.

APPENDIX BD - 2001

Tampa Electric Company
Polk Power Station
PSD-FL-194 and PA92-32
Polk County, Florida

BACKGROUND

The applicant, Tampa Electric Company (TEC) is responsible for the operation of an existing facility known as the Polk Power Station. This facility is located at 9995 State Route 37 South, Mulberry, Polk County; UTM Coordinates: Zone 17, 402.45 km East and 3067.35 km North; Latitude: 27° 43' 43" North and Longitude: 81° 59' 23" West. The regulated emissions units at the coal gasification facility include a 260 megawatt (electric) combined cycle combustion turbine which fires syngas or No. 2 fuel oil; an auxiliary boiler which fires No. 2 fuel oil; a sulfuric acid plant; a solid fuel handling system; and a solid fuel gasification system.

As per the original PSD permit, (as well as the Site Certification and Title V permit) the combined cycle combustion turbine is now required to undergo an analysis for NO_X only. Specific Condition **H.7.** of the Site Certification document reads as follows: "*One month after the test period ends (estimated to be by June 1, 2001), the Permittee will submit to the Department a NO_X recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_X only and adjust the NO_X emission limits accordingly.*" Based upon existing permit conditions, the test period ended during November 2000.

PROPOSAL SUBMITTED BY APPLICANT:

TEC submitted a revised proposal on January 30, 2002 recommending an emission limits as follows:

POLLUTANT	CONTROL TECHNOLOGY	TEC PROPOSAL
NO_X	Syngas firing - N_2 diluent	15 ppmvd @ 15% O_2

This proposal would provide for a 40% reduction in the current (temporary) emission limit while firing syngas.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2. (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). Although this determination is required for NO_X only, the applicant's proposal is consistent with the NSPS, which allows NO_X emissions in the range of 110 ppmvd for the unit.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent determinations by states for combined cycle stationary gas turbine projects. This particular review has been limited to gas turbines in the United States which are permitted to combust coal or pet-coke produced syngas. The applicant's proposal is included for reference.

Best Available Copy

APPENDIX BD - 2001

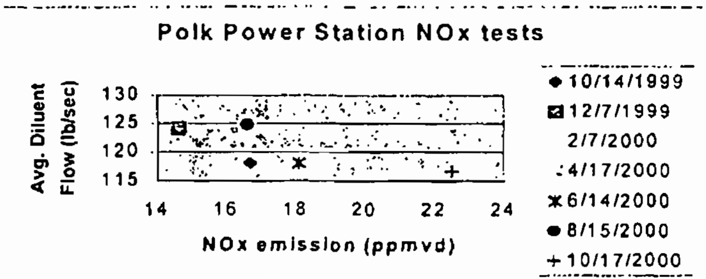
TABLE 1

RECENT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS WHICH COMBUST SYNGAS

Project Location	Power Output Megawatts	NO_X Emission Rate	Gasification Technology	Comments
Pinon Pine; Sierra Pacific, NV	100	0.07 lb/MMBtu	KRW air-blown pressurized fluidized bed	95% SO_2 removal
Wabash River; Terre Haute, IN	262	0.096 lb/MMBtu	Destec two-stage pressurized oxygen-blown entrained flow	
Kentucky Pioneer (proposed)	580	0.07 lb/MMBtu	British Gas / Lurgi slagging fixed bed	99% SO_2 removal
Motiva; Delaware City, DE	240	16 ppmvd	Texaco pressurized oxygen-blown entrained-flow	
TECO POLK; Polk County FL)	260	15 ppmvd (approx. equiv. 0.076 lb/MMBtu)	Texaco pressurized oxygen-blown entrained-flow	96% SO_2 removal

EVALUATION BY DEPARTMENT:

An analysis of the data gathered from the facility was conducted. Two sets of data exist: one which represents seven "full load tests" which were completed between October 1999 and October 2000, and the other is comprised of data from continuous emission monitoring systems (CEMS). Regarding the former, the data is represented on the chart below:



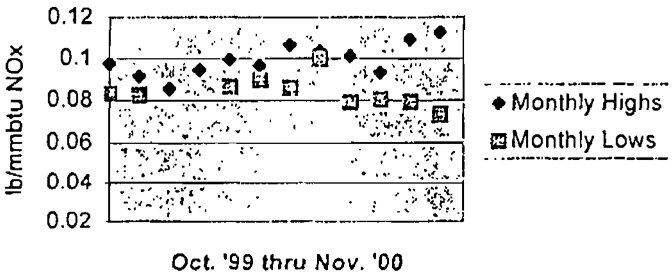
TEC has cautioned against an analysis of NO_X emissions as compared to diluent flow, noting that "*although the diluent flow is an important parameter for controlling NO_X emissions, a more appropriate measure is the ratio of diluent flow to syngas flow. On an overall basis, this ratio represents the proportional flows of NO_X controlling diluent and the syngas flow. Additional complicating factors that prevent a straightforward linear analysis of diluent flow rate or ratio and the NO_X emissions rate include the varying composition of the syngas, and the heating value of the fuel. Although these data are presented, TEC recommends against using these data to establish firm operating ranges due to the variability in other factors that significantly contribute to NO_X emissions from this combustion turbine.*" Since diluent flow will likely increase with generating load (up to some load point) and since syngas flow is directly proportional to unit load, it is likely that a measure of diluent flow to syngas flow (which the applicant purports is more appropriate) makes some sense, as in the case of reviewing the entire load range of a combustion turbine. However, the Department wishes to better understand the impact of diluent flow on NO_X emissions, given that the diluent is the control media for NO_X. Since the tests are at a similar load point, the syngas flow and its associated variability can be effectively ignored. This yields a chart similar to the one above, indicating some level of correlation (albeit with 7 data points) between the diluent flow and NO_X emissions. Given the very limited amount of tests, one initial conclusion which might be drawn is that NO_X emissions are likely to be less than 19 ppmvd if the diluent flow is held to 120 lb/sec or higher.

Regarding the latter set of data (from the CEMS), 14 months of data was reviewed, with the month of March 2000 ignored due to low operating time. In order to understand the range of data with respect to syngas NO_X emissions, only days where daily hours of operation firing syngas equaled 24 (all day) were analyzed. From this data set, the 5 highest and lowest daily average NO_X emission rates (in lb/MMBtu) were computed. This led to the chart below, with the lowest values during the months of December 1999 and January 2000 excluded due to calculated values around 0.01 lb/MMBtu. The following preliminary conclusions are drawn from this analysis:

1) There seems to be an increasing variability over the latter months, with highs increasing and lows decreasing.
2) The average of the monthly highs is just under 0.10 lb/MMBtu and the average of the monthly lows is just under 0.085 lb/MMBtu.
3) The facility should be able to easily comply with its current limit of 25 ppmvd (approximately 0.126 lb/MMBtu) and likely will operate closer to 0.09 lb/MMBtu (approximately 18 ppmvd) on a monthly average basis.

Each analysis of the facility data referred to herein suggests that a NO_X limit of 0.09 lb/MMBtu (approximately 18 ppmvd) would likely be reasonable, given that certain changes may be required.

CEMS DATA



DEPARTMENT DETERMINATION:

Although little incentive existed to maintain a NO_X limit below 25 ppm, the data shows that emissions can be maintained at much lower levels with minor changes.

POLLUTANT	DETERMINATION
NO_X (syngas - all operating modes)	15.0 ppmvd – 30-day rolling average via CEMS

The rationale is:

1) Polk IGCC is not a green-field unit, and additional controls effectively result in a retrofit
2) Other (similar) domestic IGCC units are able to comply with an emission limit of 15 ppmvd and
3) The process of gasification is likely to expand to renewable fuels, possibly complicating the application of more stringent controls.

APPENDIX BD - 2001

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E. Review Engineer
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	Approved By:
	Howard L Rhodes
for C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
2/4/02	2/4/02
Date:	Date:

TAMPA ELECTRIC

RECEIVED
MAY 02 2001
BUREAU OF AIR REGULATION

May 1, 2001

Mr. Clair Fancy
Florida Department of Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Via FedEx
Airbill No. 7909 2896 9447

Re: Tampa Electric Company (TEC) - Polk Power Station
Unit 1 NO_x BACT Determination
Notice of Waiver of 90-Day Period
FDEP Permit No. 1050233-001-AV

Dear Mr. Fancy:

With respect to the above referenced NO_x BACT Determination, Tampa Electric Company (the Company) is hereby granting a waiver of the 90-day period in which the Florida Department of Environmental Protection (Department) is required to act on a permit pursuant to Section 120.60(1), Florida Statutes. This waiver is granted to allow the Company to submit additional relevant information regarding this project, and will extend the period for Department action to and including July 1, 2001.

Please let me know if you have any questions. You can contact Shannon Todd or me at (813) 641-5125.

Sincerely,

Mark J Hornick

Mark J. Hornick
General Manager
Polk Power Station

EP\gm\SKT251

c: Mr. Al Linero - FDEP
Mr. Jerry Kissel - FDEP SW

Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Jeb Bush
Governor

David B. Struhs
Secretary

December 21, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Laura Crouch
Manager, Air Programs – Environmental Affairs
Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601

Re: Biomass Test Burn
Polk Power Station Unit 1
Facility ID No. 1050233

Dear Ms. Crouch:

The Department has reviewed the request from Tampa Electric Company received on October 25, 2001, and the supplementary information dated December 4 and December 21, 2001 concerning the gasification of a blend of coal/petcoke and biomass (eucalyptus, cottonwood and switch grass) in your IGCC unit located at the Polk Power Station, Polk County, Florida.

You are hereby authorized to conduct performance tests on these emissions units while gasifying and combusting a blend of up to 5 percent biomass by weight (eucalyptus, cottonwood and switch grass) for pollutants described herein, for a period not to exceed 28 days, and within 45 days from the first day biomass is gasified. Test results must include a material balance (fuels, emissions, gasifier slag, and boiler deposits) for each unique blend of fuels. All conditions of existing permits related to air pollution emission limits and control equipment remain in force during the test burn. This temporary permit shall expire on or before April 30, 2002.

The performance tests shall be conducted in order to gather data regarding air pollutant emissions, any operation limitations on gasifying a blend of up to 5 percent by weight biomass, to measure syngas characteristics and to determine the slag content from the gasifier and HRSG deposits. Unless otherwise specified, all test results shall be sent to the Department's Bureau of Air Regulation within 30 days of completion of the tests. Upon any requested change to allow permanent combustion of fuels not currently permitted for these emission units, the Department will evaluate the establishment of new or additional permit conditions resulting from either increases or improvements in emission quality or quantity.

The performance tests shall be subject to the following conditions:

1. The permittee shall notify the DEP Southwest District, and the Bureau of Air Regulation upon receipt of any biomass, 1 day prior to gasifying biomass and 7 days prior to commencement of any stack performance testing. Because of the end of the year tax credit, the permittee may give 1 day testing notification. A written final report shall be submitted to these offices within 45 days of completion of the last day that biomass is gasified.

2. While gasifying biomass, it shall be continuously fed so as to maintain a homogenous stream of syngas for combustion. The maximum biomass content shall not exceed 5 percent by weight of fuels gasified, as measured during each calendar day. A log shall be maintained at the facility demonstrating compliance with this condition, documenting the unique type of biomass being gasified (eucalyptus, cottonwood or switch grass) along with the unique blend of coal or petcoke. This log shall be available for inspection and submitted with the final test report. Performance testing (mass balance, syngas testing and stack testing) shall be conducted for each unique blend of biomass gasified with each unique blend of coal or petcoke.

3. Emissions due to biomass gasification shall not exceed any current limits in existing permits for all impacted emission units.

4. Representative samples of "as-burned" coal, petcoke and biomass shall be taken and analyzed for each unique blend of biomass gasified with each unique blend of coal or petcoke. All sample results shall be submitted with the final report.

5. As-burned (syngas) fuel samples shall be collected and analyzed as "refinery gas" (as has been done with past compliance tests) upon initial gasification of each unique blend of biomass gasified with each unique blend of coal or petcoke. Additionally, metals contents (fluorides, chromium, arsenic, cadmium, mercury, lead, and beryllium) phosphorous, amines and organic silicon compounds shall be measured for each unique blend of biomass gasified with each unique blend of coal or petcoke. Sample results shall be provided to the DEP Southwest District and the Bureau of Air Regulation within 14 days of sample collection.

6. To provide reasonable assurance that the ash generated from any fuel blend can be disposed of in a method to be proposed by TEC, as well as to ensure compliance with the solid and hazardous waste regulations, representative samples of the gasifier slag generated as the result of gasifying coal and petcoke with biomass shall be segregated, sampled and analyzed in accordance with the requirements set forth in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, EPA Publication SW-846, Third Edition."

7. A material balance of all measured syngas constituents shall be performed for each unique blend of biomass and coal or petcoke, based on all test/analytical data. Such material balances shall be provided with the final test report.

8. Stack gas emissions shall be conducted for each unique blend of biomass gasified with each unique blend of coal or petcoke and results reported for all measured syngas constituents as well as all currently regulated pollutants.

9. Performance tests shall be conducted using EPA Reference Methods, as contained in 40 CFR 60 (Standards of Performance for New Stationary Sources), 40 CFR 61 (National Emission Standards for Hazardous Air Pollutants), and 40 CFR 266, Appendix IX (Multi-metals), unless otherwise approved by the Department, in

writing, in accordance with Chapter 62-297, F.A.C. All performance testing shall be submitted with the final report.

10. Upon completion of the test burn period and upon the first unit shutdown, representative HRSG deposits shall be obtained. The Department's Southwest District, and the Bureau of Air Regulation shall be notified immediately upon such shutdown, as to the expected duration. TEC shall provide photographic evidence of the magnitude and location of such deposits upon conclusion of the unit shutdown. HRSG deposits shall be analyzed in a scanning electron microscope (SEM) using energy dispersive X-ray spectroscopy (EDS) to identify the elements present. The Southwest District and the Bureau of Air Regulation shall be provided with a copy of any and all sample analyses or results obtained for HRSG deposits upon receipt of any analyses or results, regardless of the purpose of such sample collection, analyses or results.

11. This test-burn shall not result in the release of objectionable odors pursuant to Rule 62-296.320(2). F.A.C.

12. Performance testing shall cease as soon as possible if the test results in any emissions, which are not in accordance with the conditions in existing permits, or this authorization protocol. Performance testing shall not resume until appropriate measures to correct the problem(s) have been implemented. The Southwest District shall be notified immediately upon such cessation and resumption.

13. This Department action is only to authorize the biomass blend performance testing of biomass consisting of eucalyptus, cottonwood and switch grass.

14. The Department's Southwest District, and the Bureau of Air Regulation shall be notified within 5 days, in writing, upon completion of the biomass test burn.

15. All testing series shall include emissions testing for emissions units operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the capacity allowed by existing permits.

This letter must be attached to permit No. PSD-FL-194 (current revision) and shall become a part of the permit.

Sincerely,

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/sms

cc: Mr. Jerry Kissel, FDEP/SW
Mr. A.A. Linero, FDEP – BAR
Mr. Gregg Worley, EPA-Region IV

SENDER: ***COMPLETE THIS SECTION***

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Laura Crouch
Manager, Air Programs -
Environmental Affairs
Tampa Electric Company
P. O. Box 111
Tampa, FL 33601

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* J. Spo

B. Date of Delivery

C. Signature

X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

DOWNTOWN STA TAMPA FL
DEC 31 2001

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 3048

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 2870 0000 7028 3048

Ms. Laura Crouch AL USE

Postage	$	
Certified Fee		
Return Receipt Fee (Endorsement Required)		Postmark Here 12/21/01
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Sent To
Tampa Electric Co.
Street, Apt. No.; or PO Box No.
P.O. Box 111
City, State, ZIP+4
Tampa, FL 33601

PS Form 3800, May 2000 **See Reverse for Instructions**

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

December 14, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Laura R. Crouch
Manager, Air Programs – Environmental Affairs
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601

Re: Proposed Biomass Test Burn
Polk Power Station Unit 1
Facility ID 1050233

Dear Ms. Crouch:

On October 25, 2001 the Department received your request to conduct a biomass test burn. On December 5, 2001 we received your responses to our November 20th request for additional information. Your request was for authorization to conduct a baseline test burn of 5% switch grass and/or eucalyptus/cottonwood to establish the representative emissions from Unit 1. Based upon those results, TEC might apply for a permit modification for the introduction of biomass into the gasifier on a more permanent basis. TEC has proposed to conduct a test burn for a period of 28 days to allow TEC to evaluate the impacts of the material on the fuel handling systems and other associated process equipment as well as evaluate the effects of firing syngas produced from a blend of biomass and other currently permitted fuels.

The Department finds that the request is yet incomplete. We understand that TEC wishes to pursue this test burn on a very fast track and we are endeavoring to provide a quick review. In order to continue processing your request, the Department will need the additional information below. Should your response to any of these items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application. The Department needs satisfactory written responses to these issues by **Tuesday, December 18th** in order to allow for the possibility of a test burn authorization by the end of this calendar year.

1. It remains unclear to the Department how the existing handling and feed systems will be utilized with the biomass fuel. For example, will the fuel be transported from the trucks to a storage pile? Where will the pile be located? Will the pile be covered, or open to atmospheric conditions? How will the fuel be ground, and how will it be moved to the grinding equipment? Will it be batch-fed or will an effort be made to maintain a continuous coal/biomass ratio (please be specific)? Will it be slurried directly with the coal? These questions are representative of level of description, which the Departments seeks, regarding storage, handling and feed systems.
2. Biomass fuels typically have higher water contents than coal. Please explain how moisture removal and disposal will be accommodated, or will the additional water end up in the syngas?
3. In the December response, TEC indicated that it is not aware of any other IGCC facility that has attempted to gasify a blend of 5% biomass and coal. Inasmuch as this appears to be the first attempt at such a venture, the Department's opinion is that this request is not identical to other requests it has received to combust biomass. Therefore, the Department maintains that it wishes written confirmation by the manufacturer of the gasifier, that it is currently capable of accommodating the proposed fuel mix of coal (and/or petcoke) and biomass.
4. As previously indicated, the Department is aware that one of the largest impediments to the widespread use of biomass is its tendency to form unmanageable ash deposits. In the event that TEC intends to ultimately combust the (beneficiated) slag, the Department will require TEC to segregate the "co-fired" gasifier slag and provide a protocol for analysis of the quantity and quality. Based upon these results, TEC may propose a method for disposal after the test burn.

5. The Department needs TEC to provide a protocol for syngas fuel analyses for each blend of biomass and coal/petcoke tested.
6. In order to have reasonable assurance that a PSD review and associated public notices are not triggered for the proposed co-firing, the Department requires a summary of the *estimated* emission increases/decreases. This should be done at TEC's proposed maximum blend for each biomass and coal/petcoke fuel to be combusted. All assumptions should be clearly stated.
7. The Department previously inquired as to TEC's expectations regarding the performance of an SCR in light of the fuel proposed within the test burn request. TEC responded that it does not expect the application of an SCR to be successful on any IGCC Unit that fires a sulfur bearing fuel, and that the gasification of a 5% biomass blend will not significantly change the composition of the resulting syngas, nor affect TEC's position regarding the application of an SCR. DOAH will soon hear the case concerning the Department's recent BACT Determination for this unit, which had required SCR.
8. The Department still maintains its position on SCR for this facility.

We have included the EPA and the National Park Service within this review. Should we receive written comments, we will forward them to you when received and they will comprise part of this completeness review.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature.

If you should have any questions, please call me at 850/921-9532 or Al Linero at 850/921-9523.

Sincerely,

Scott M. Sheplak, P.E.
Administrator
Title V Section

cc: Mr. Jerry Kissel, FDEP/SW
Mr. A.A. Linero, FDEP – BAR
Mr. Gregg Worley, EPA-Region IV

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1. Article Addressed to:

Ms. Laura R. Crouch
Manager, Air Programs - Environmental Affairs
Tampa Electric Company
PO Box 111
Tampa, FL 33601

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Florida
Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Jeb Bush
Governor

David Struhs
Secretary

FAX TRANSMITTAL SHEET

DATE: 12/14/01

TO: Laura R. Crouch, Manager, Air Programs with TECO

PHONE: 813-641-5376 FAX: 813-641-5081

FROM: Scott Sheplak, Title V Administator PHONE: 850-921-9532

Division of Air Resources Management FAX: 850.922.6979

RE: Polk Power Station Unit 1 - Proposed Biomass Test Burn

CC:

Total number of pages including cover sheet: 3

Message

For file

TECO
TAMPA ELECTRIC

MEETING AGENDA

INVITEES:

Greg Nelson, TEC	Howard Rhodes, FDEP
Laura Crouch, TEC	Clair Fancy, FDEP
Shannon Todd, TEC	Mike Halpin, FDEP

LOCATION: FDEP Offices, Tallahassee
DATE: Wednesday, July 11, 2001
TIME: 9:00 a.m.
RE: Polk Unit 1 NO_x BACT Determination

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1. Introductions
2. Overview of Project Status
3. Review of Additional Information Provided to FDEP
    a. May 10, 2001 – TEC's Additional Information Letter
        i. Original BACT Analysis
        ii. Refined Cost and Catalyst Quote
        iii. Kentucky Pioneer Completion
    b. June 5, 2001 - TEC's NOx BACT Comment Letter
4. Discuss Additional Issues
    a. Review Additional Information Provided by General Electric
    b. Review Kentucky Pioneer Permit Determination
    c. Review EPA Letter Dated June 13, 2001
5. Questions and Comments

ture dependency of the chemical reaction and catalyst life, SCR cannot be used in simple cycle configurations, except possibly in lower exhaust temperature systems. Other issues associated with SCR include exhaust emissions of ammonia (known as ammonia slip); concerns about accidental release of stored ammonia to the atmosphere, environmental concerns and costs of disposal of spent catalyst.

Ammonia Release

The use of ammonia in the SCR chemical process for NOx control presents several problems. Ammonia is on EPA's list of Extremely Hazardous Substances under Title III, Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Releases of ammonia to the atmosphere may occur due to unreacted ammonia going out the stack (known as ammonia "slip"), or it can be accidentally released during transport, transfer, or storage. In addition, ammonia is a PM-10 precursor emission (particulate matter smaller in diameter than 10 microns).

Some ammonia slip is unavoidable with SCR due to the non-uniform distribution of the reacting gases. Thus, some ammonia and unreacted NOx will pass through the catalyst and in fact some catalyst manufacturers recommend operating with excess ammonia to compensate for imperfect distribution. An ammonia slip of 10-20 ppm is generally permitted in a new system (although higher slip has been noted) and will increase with catalyst age. In the past, ammonia slip was not considered to be a problem by regulatory agencies because they felt that by releasing it from an elevated stack, the ground level concentration would be low. However, it has never appeared to be good environmental policy to allow ammonia to be released to the atmosphere in place of NOx and ammonia emissions are now of concern because of PM–2.5 considerations.

The Use of Sulfur-Bearing Fuels

The Problem – Distillate oil contains sulfur. There is no successful operating experience when SCR is used for NOx control while firing a gas turbine with sulfur bearing oil. However, some regulatory agencies require the use of SCR, even when distillate oil is used as a backup fuel. In most cases regulators have simply pointed to the many combined cycle plants with SCR permitted with oil as the backup fuel, ignoring the fact that most of those plants actually operate almost exclusively on gas and use little or no oil fuel. Those that have used oil have experienced significant problems.

The problems associated with the use of sulfur bearing fuels are due to the formation of the ammonium salts ammonium bisulfate, NH_4HSO_4, and ammonium sulfate, $(NH_4)SO_4$. These compounds are formed by the chemical reaction between the sulfur oxides in the exhaust gas and the ammonia injected for NOx control. Ammonium bisulfate causes rapid corrosion of boiler tube materials; and both ammonium compounds cause fouling and plugging of the boiler and an increase of PM–10 emissions.

Ammonium bisulfate forms in the lower temperature section of the HRSG where it deposits on the walls and heat transfer surfaces. These surface deposits can lead to rapid corrosion in the HRSG economizer and downstream metal surfaces resulting in increased pressure drop and reduced heat transfer (lower power output and cycle efficiency). While ammonium sulfate is not corrosive, its formation also contributes to plugging and fouling of the heat transfer surfaces (leading to reduced heat transfer efficiency) and higher particulate emissions. The increase in emissions of particulates due to the ammonium salts can be as high as a factor of five due to conversion of SO_2 to SO_3. Some of the SO_2 formed from the fuel sulfur is converted to SO_3 and it is the SO_3 that reacts with water and ammonia to form ammonium bisulfate and ammonium sulfate. The increase is a function of the amount of sulfur in the fuel, the ammonia slip (ammonia that does not react with NOx) and the temperature. It can also be increased by supplementary firing of the HRSG and by the use of a CO oxidizing catalyst (which significantly increases the conversion of SO_2 to SO_3).

The only effective way to inhibit the formation of ammonium salts appears to be to limit the sulfur content of the fuel to very low levels (or switch to a sulfur free fuel such as butane) and/or limit the excess ammonia available to react with the sulfur oxides. Pipeline quality natural gas usually has a sulfur content low enough that ammonium salt formation, while it is present, has not yet been a significant problem with natural gas-fired units. However, the sulfur content of even very low sulfur distillate oil (e.g., 0.05 percent) or liquid aviation fuel (Jet–A) may not be low enough to prevent enough formation of ammonium bisulfate to avoid the problems discussed above (ambient sulfates may also contribute). This potential is usually handled by a requirement to limit the operating time on the low sulfur distillate oil to a relatively few hundred hours between shutdowns and then clean the HRSG internals (although disposal of the deposits may be a problem due to the presence of hazardous materials). Lowering the ammonia slip or the sulfur concentration could lengthen the time between cleanings. Limiting the ammonia that is available to react with the sulfur oxides to negligible levels does not appear practical at NOx removal efficiencies above 80 percent because higher excess ammonia levels are required to achieve the higher NOx removal efficiencies. Limiting the excess ammonia may work at lower NOx removal efficiencies because the lower NH_3/NOx ratios required ensure that all the ammonia is consumed. However, when oil is to be used as the primary fuel, the experience would indicate that SCR should not be used, as there appears to be significant risk of equipment damage or failure, performance degradation and increased emissions of fine PM.]

Disposal of Spent Catalyst

SCR materials typically contain heavy metal oxides such as vanadium and/or titanium, thus creating a human health and environmental risk related to the handling and disposal of spent catalyst. Vanadium pentoxide, the most commonly used SCR catalyst, is on the EPA's list of Extremely Hazardous Materials. The quantity of waste associated with SCR is quite large, although the actual amount of active material in the catalyst bed is relatively small.

SCONOX

SCONOX is a post-combustion catalytic system that removes both NOx and CO from the gas turbine exhaust, but without ammonia injection. The catalyst is platinum and the active NOx removal reagent is potassium carbonate. At present, the only operating SCONOX system is being used with an LM2500 injected with steam to 25 ppm NOx at a facility in Vernon, CA. Stack NOx is maintained at 2 ppm or less and CO at less then 1 ppm.

How SCONOX Works

The exhaust gases from a gas turbine flow into the reactor and react with potassium carbonate which is coated on the platinum catalyst surface. The CO is oxidized to CO_2 by the platinum catalyst and the CO_2 is exhausted up the stack. NO is oxidized to NO_2 and then reacts with the potassium carbonate absorber coating on the catalyst to form potassium nitrites and nitrates at the surface of the catalyst. When the carbonate becomes saturated with NOx it must be regenerated. The effective operating temperature range is 280 to 750°F, with 500 to 700°F the optimum range for NOx removal. The optimum temperature range is approximately the same as that of SCR.

Regeneration is accomplished by passing a dilute hydrogen reducing gas (diluted to less than 4 percent hydrogen using steam) across the surface of the catalyst in the absence of oxygen. The sections of reactor catalyst undergoing regeneration are isolated from exhaust gases using sets of louvers on the upstream and downstream side of each reactor box. The Vernon LM2500 facility has 12 vertically stacked catalyst reactor boxes, nine of which are in the oxidation/absorption cycle at any given time, while three are in the regeneration cycle. When regen is completed in the three reactor boxes, the louvers open on those reactors and the louvers on three other reactors close and those reactors go into the regeneration cycle. Motor drives outside each box drive the shaft that opens and closes the louvers on each side of the box (inlet and outlet sides).

SCONOX Issues

There are several issues associated with the use of SCONOX. First, it is very sensitive to sulfur, even the small amount in pipeline natural gas. Second, the initial capital cost is about three times the cost of SCR, although this may come down once there are more in operation. Third, it has moving parts reliability and performance degradation due to leakage may be significant issues, especially on scale-up to bigger gas turbines (a 7FA would require 20 modules of 4 reactor boxes each vs. LM2500 using 3 modules of 4 reactor boxes). Last, use of any exhaust gas treatment technology (SCR or SCONOX) results in a pressure drop that reduces gas turbine efficiency. Thus, by adding a back-end cleanup system, more fuel must be burned to reduce NOx and SCONOX produces about twice the pressure drop of SCR.

The GE Dry Low NOx Combustor

GE began development of a dry low NOx combustor in 1973, primarily in response to increasingly stringent emission control requirements in California. The initial goal was a NOx level of 75 ppmvd at 15 percent oxygen, the NSPS requirement for utility gas turbines. An oil-fired combustor designed for a Frame 7 gas turbine achieved this goal in the laboratory in 1978. Field testing of the prototype dry low NOx combustor design demonstrated that the combustor was capable of meeting the NSPS. The design, tested at Houston Lighting and Power (HL and P) in 1980, has evolved into a system that is achieving a NOx level of 9 ppmvd at 15 percent oxygen in GE Frame 7EA, FA, and 6B gas turbines fired on natural gas.

DISCUSSION

Cost in $/ton of NOx Removed/Energy Output Reduction

The annual cost of reducing NOx using SCR from 9 ppm to 3.5 ppm for a GE Frame 7FA, 170 MW class gas turbine operating 8,000 hr/year is $8,000 to $12,000 per ton of NOx removed when a non sulfur bearing fuel is used and $15,000 to $30,000 if a sulfur bearing fuel is used. The cost will be the same or more than that with SCONOX, which in addition, cannot be used with sulfur bearing fuels without additional cost for sulfur removal. (The SCR cost effectiveness estimate with a sulfur bearing fuel is based on six year replacement of catalyst, 20 percent fixed charge rate and a vendor quote of 25 percent increase in HRSG cost for a redesigned economizer section to allow for cleaning of ammonium bisulfate. If a redesigned HRSG is not acceptable, the cost of periodic replacement of LP economizer tubes should be used in the BACT analysis.) Most gas turbine combined cycle or cogeneration systems today operate with natural gas as the primary fuel and fuel oil as the backup fuel. SCR operating and maintenance costs include continuous ammonia injection, periodic catalyst replacement, and the cost associated with a small decrease in power output (more than 650 kW for a 7FA). The output drop is due to power for auxiliaries associated with ammonia injection, catalyst pressure drop in the new and clean condition, which increases as ammonia-sulfur salts build up, and decrease in heat transfer as the salt buildup increases over time. This cost is considered too high for BACT in ozone attainment areas by most states. The decrease in output efficiency results in an increase in CO_2 emissions due to the need to burn more fuel to make up for the output reduction.

It is often argued that economics should not be considered at all in LAER determinations. There is, however, an implicit "reasonableness test" in all LAER determinations. Thus, no regulator has required that trains of multiple SCR be utilized to reduce NOx to zero (although this is technically possible) because the cost would be so high that we would conclude that it would not be "reasonable". This same rationale should apply to adding any emission control if the cost is unreasonably high, as is the case for adding SCR or SCONOX to a combustion system achieving 9 ppm NOx in a combined cycle.

Ammonia Slip/Ammonium-Sulfur Salts

The impact of slip on the environment may be at least as detrimental as if NOx were to be released. Where an ammonia emission limit is imposed, and there is often no such emission limit, slip is generally targeted at 10-20 ppm, although there are units operating with ammonia slip well below and well above that level. Most recent SCRs operate with 5 ppm slip or less, but slip is expected to be on the high side when the NOx level entering the catalyst bed is already very low. Unless there is perfect mixing, the ammonia molecules must "find" the fewer NOx molecules in order to react and this will require adding more excess ammonia. Thus, 20 ppm or more ammonia slip would be released in place of the reduction in NOx in going from 9 to 3.5 ppm. Table 1 shows that for a Frame 7FA with 20 ppm ammonia slip (base load, 8,000 hr/yr, 45°F ambient, natural gas) there are 24 tons per year (TPY) more ammonia emitted than NOx reduction by lowering NOx from 9 to 3.5 ppm with SCR. There also is an increase of 5 TPY in particulate matter emitted, or 36 TPY if a CO catalyst is also used. Note also that as the catalyst ages, ammonia slip increases as the efficiency of conversion decreases, until at the end of catalyst life the ammonia slip may be much higher than a new and clean catalyst. In fact that is one way that catalyst replacement is indicated. Some ammonia released to the atmosphere will be converted to NOx and ultimately to ozone. Finally, ammonia is on the SARA (Superfund) list of Extremely Hazardous Materials. Accident studies of transport and on-site storage of ammonia for use with SCR, performed for the Massachusetts DEP and California's South Coast AQMD, resulted in a change from anhydrous ammonia to aqueous ammonia. Aqueous ammonia has a lower ammonia concentration and lower storage pressure (resulting in a slower release rate) than anhydrous. Anhydrous ammonia was used until these studies revealed the potential public hazard in the event of catastrophic release. The hazard was reduced, but not eliminated.

GE Power Systems analysis of measurements of ammonia emissions on six plants with SCR showed a great deal of inconsistency (<1 ppm to 30 ppm). All of the tests were performed using different ammonia sampling methodologies. EPA Method 206 for ammonia was recently published for applicability to coal-fired plants. There is no specific method for gas turbine plants. The conclusion drawn from this study is that the ammonia slip on plants with SCR is not actually known with any accuracy.

Spent Catalyst

From a policy standpoint, the disposal of spent catalyst as hazardous waste, simply transfers an air problem (NOx) into a long-term solid waste disposal problem. This is not a good environmental tradeoff.

Use of Sulfur Bearing Fuels

It has been GE Power System's position for some time that SCR should not be used in gas turbine applications where a sulfur bearing fuel, such as distillate oil, is used. With the recent concern expressed by EPA through the promulgation of the National Ambient Air Quality Standards for fine particulate matter (PM 2.5), GE Power Systems feels even more strongly that the use of SCR should be avoided when such fuels are used. Unreacted ammonia from the SCR, and sulfur from the fuel react to form ammonium salts that are released as particulate matter, as previously discussed. EPA is very concerned with PM–2.5 (very fine, inhalable particulates) which would increase significantly. The example in Table 1 for a Frame 7FA shows an 8 TPY increase in PM with SCR and almost 50 TPY if a CO catalyst is also used, with only 400 hours per year of oil firing. Aside from the important health risks that EPA has indicated are posed by PM 2.5, the impact of the increase in fine particulates on regional haze should also be considered. A CO oxidizing catalyst, supplementary firing and noble metal catalysts will all result in much higher SO_2 to SO_2 conversion and greater sulfur salt formation. Note that particulate emission controls have never been used on gas turbines.

Although there are many gas turbine combined cycle plants using SCR that are permitted to use distillate oil as the backup fuel, GE Power Systems is not aware of ANY successful operation with this combination. Actual operating experience indicates that ammonium-sulfur salt formation and boiler damage occur without exception, when ANY sulfur bearing fuel is fired in the gas turbine and SCR is used for NOx control. This is not usually accounted for in BACT determinations, but adds significant cost and should be considered. Beside the down time associated with periodic cleaning, the added cost includes periodic replacement of the low pressure tube sections of the HRSG damaged by ammonium bisulfate corrosion, or the cost of an alternative design HRSG (which was used for the estimated cost in Section V.1). Reference 1 documents the damage done to the HRSGs on several representative plants.

State Example

The New York State Department of Environmental Conservation (DEC) Gas Turbine NOx Policy (93–AIR–39), allows a BACT NOx limit higher than normal when firing oil as a backup fuel, to either avoid the use of SCR, or to minimize ammonia slip. This is specifically stated to be in recognition of the increased particulate and ammonium bisulfate problems and concerns related to ammonia emissions. The NOx policy also states that the DEC "has determined that 6 ppmv (dry, corrected to 15 percent O) was the lowest emission limit for NOx which can be accurately measured in the stack, based on current monitoring/testing technology." This is the same finding as the ASME B133 Committee on emission measurements from gas turbines, Reference 2. Several other states also allow higher NOx levels if the use of SCR can be avoided to eliminate ammonia emissions. New Jersey has considered low sulfur kerosene for the backup fuel (rather than distillate oil) as BACT, when SCR is used for NOx control.

Measurement and Control of NOx

Recent regulatory agency actions in some states has resulted in excessively low NOx levels being required for gas turbines. Based on the performance of SCONOX at the single facility in California, NOx permit levels as low as 2 ppm are being required in some states. Even if such a level of NOx can be achieved, the question of how low a NOx level can be monitored and controlled has apparently not been addressed. Can we monitor and control on 2 ppm NOx? 40CFRPart 75 requires that a majority of readings be between 20 and 8 percent of the measurement range. A 10 ppm range is the lowest certified for a process NOx analyzer. With a 2 ppm NOx limit, the +/-10 percent of standard criterion is 0.2 ppm so that a CEMS would need to report no greater than 1.8 ppm NOx minus margin to insure not exceeding 2 ppm. The ASME B133 Committee study (Reference 2) concluded that if the reading is outside the 20 to 80 percent of scale range the error could be as high as 25%. Since the plant must actually operate below 2 ppm with a 2 ppm limit, EPA's Part 75 regulations are violated. Further, to insure not exceeding 2 ppm, a 7FA gas turbine would need to operate at:

- 1.5 ppm max to compensate for instrument error (25% of 2 ppm reading error)
- ~1.0 ppm max to compensate for combustion system operating variability
- Below 1.0 ppm (0 to 1 ppm) to compensate for ambient variability effects

The conclusion is that 2 ppm NOx is not a practical emission limit for gas turbines.

Environmental Impact of a Deregulated Electricity Market

The advent of electricity market deregulation is bringing in a new factor to consider for new power plants called "displacement". This process has been observed in the United Kingdom where deregulation is generally the furthest along among the mature industrialized nations. Parts of the USA are already seeing the development of new "merchant" power plants that will compete with traditional utility plants and non-utility power plants. The concept is that new combined cycle merchant plants will be added until the market price of electricity from the new merchant plants is at parity with the composite market price, including less environmentally friendly older plants. This in turn will force either reduced operation or shut down of the less competitive of these older plants, with a resultant net emissions reduction. However, if the cost of a new, cleaner plant is increased (by adding SCR) it becomes more difficult to compete with older plants and less displacement occurs. Figure 1 shows the environmental benefits of displacing a coal or oil-fired power plant meeting the 1979 NSPS with a new gas-fired combined cycle plant of the same MW output. Also shown is the impact of the incremental premium that must be paid for SCR on the ability of a plant to bid its power under the market clearing price (the highest price the market will pay for power). Figure 2 shows the relative costs for various control technologies, first as a function of the initial capital cost of the power plant and then as a life cycle cost, both as functions of the NOx emission level. DLN at 9 ppm NOx is a clear winner over SCR in this competitive market environment, where the cleanest total solution is one where the economics of reducing the usage of the older plants is a significant consideration.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

JUN 13 2001

4 APT-ARB

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BUREAU OF AIR REGULATION

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

This letter amends our recent comments on the draft prevention of significant deterioration (PSD) permit modification and associated draft best available control technology (BACT) determination dated May 10, 2001, for the Tampa Electric Company (TEC) Polk Power Station. The Polk Power Station is an existing facility consisting of an integrated gasification combined cycle (IGCC) combustion turbine system. The primary fuel burned in the combustion turbine is "syngas" produced from the gasification of coal and petroleum coke. The original permit for this facility provided for a deferral of a final BACT determination for nitrogen oxides (NO_x) until an initial "demonstration period" had been completed. The demonstration period has ended and the Florida Department of Environmental Protection (FDEP) has issued a draft BACT determination that, if finalized as proposed, would require use of selective catalytic reduction (SCR) to control NO_x emissions.

In our previous letter, we included Item 3. containing comments on the Motiva Enterprises IGCC project in Delaware. We have learned that those comments were based on incorrect information, and we are now deleting Item 3. in our previous letter. Our other comments remain unchanged and are reiterated as follows:

1. Because the TEC Polk Power Station PSD permit was issued under the Site Certification requirements of the Florida Power Plant Siting Act, the permit is considered an EPA-issued permit for purposes of federal law. This is because PSD permits for projects subject to the Site Certification process are issued under delegation from EPA and not under the FDEP SIP-approved PSD permit program that applies to all other types of projects in Florida. Our opinion is that FDEP has carried out the permit revision and BACT reassessment for the TEC Polk Power Station in accordance with the procedures appropriate to EPA-delegated PSD permits.

2. While recognizing TEC's concerns about the long-term feasibility of SCR with syngas combustion, we believe FDEP has arrived at a well-reasoned basis to support use of SCR as BACT for control of NO_x emissions. In particular, our opinion is that FDEP has developed an appropriate response to TEC's main concern about SCR - the deposition of ammonium salts in the heat recovery steam generator downstream of the SCR device.

We concur with FDEP that design and operational features can be applied to minimize ammonia slip and subsequent reaction of ammonia with sulfur oxides to form ammonium sulfate and bisulfate. Furthermore, the added cost of such design and operational features should not result in annualized costs that are prohibitive in comparison with SCR costs incurred with conventional fuel combined cycle combustion turbine facilities.

If you have any questions regarding this amendment to our previous letter, please call Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: M. Halpin
C. Holladay
M. Hornick, TEC
B. Oven, PPSO
B. Thomas, SWD
J. Spence, Polk Co. ESD
J. Davis, P.E. ECT
J. Bunyak, NPS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

JUN 05 2001

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JUN 11 2001
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4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

The Region 4 office of the U.S. Environmental Protection Agency (EPA) thanks you for sending the draft PSD permit modification and associated draft best available control technology (BACT) determination dated May 10, 2001, for the Tampa Electric Company (TEC) Polk Power Station. The Polk Power Station is an existing facility consisting of an integrated gasification combined cycle (IGCC) combustion turbine system. The primary fuel burned in the combustion turbine is "syngas" produced from the gasification of coal and petroleum coke. The original permit for this facility provided for a deferral of a final BACT determination for nitrogen oxides (NO_x) until an initial "demonstration period" had been completed. The demonstration period has now ended and the Florida Department of Environmental Protection (FDEP) has issued a draft BACT determination that, if finalized as proposed, would require use of selective catalytic reduction (SCR) to control NO_x emissions.

Based on our review of the draft PSD permit modification and draft BACT determination, we have the following comments:

1. Because the TEC Polk Power Station PSD permit was issued under the Site Certification requirements of the Florida Power Plant Siting Act, the permit is considered an EPA-issued permit for purposes of federal law. This is because PSD permits for projects subject to the Site Certification process are issued under delegation from EPA and not under the FDEP SIP-approved PSD permit program that applies to all other types of projects in Florida. Our opinion is that FDEP has carried out the permit revision and BACT reassessment for the TEC Polk Power Station in accordance with the procedures appropriate to EPA-delegated PSD permits.

2. While recognizing TEC's concerns about the long-term feasibility of SCR with syngas combustion, we believe FDEP has arrived at a well-reasoned basis to support use of SCR as BACT for control of NO_x emissions. In particular, our opinion is that FDEP has developed an appropriate response to TEC's main concern about SCR - the deposition of ammonium salts in the heat recovery steam generator downstream of the SCR device. We concur with FDEP that design and operational features can be applied to minimize ammonia slip and subsequent reaction of ammonia with sulfur oxides to form ammonium

sulfate and bisulfate. Furthermore, the added cost of such design and operational features should not result in annualized costs that are prohibitive in comparison with SCR costs incurred with conventional fuel combined cycle combustion turbine facilities.

3. We believe confusion may have arisen concerning a control technology assessment for another recent IGCC project, the Motiva Enterprises (Motiva) IGCC project in Delaware City, Delaware. Motiva uses diluent nitrogen to control NO_x emissions rather than an add-on control method such as SCR. Information obtained from EPA Region 3 indicates that the NO_x control method approved for the Motiva was not a lowest achievable emission rate (LAER) determination as we have seen referenced in some discussions. Rather, we understand Motiva was able to net out of major new source review for NO_x and a LAER determination was not required.

If you have any questions regarding the comments in this letter, please call Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: M. Halpin
C. Halladay
M. Hornick, TEC
B. Oven, DEP, PPSO
B. Thomas, SWD
J. Spence, Polk Co. ESD
T. Davis, P.E., ECT
J. Bunyak, NPS

TECO
TAMPA ELECTRIC

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JUN 06 2001
BUREAU OF AIR REGULATION

June 5, 2001

Mr. A. A. Linero, P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7915 7594 7432

Re: Tampa Electric Company (TEC) – Polk Power Station Unit 1
PSD Permit Modification and NO_x Recommended BACT Determination
DEP File No. PSD-FL-194F

Dear Mr. Linero:

Tampa Electric Company has received and reviewed the above referenced Draft PSD Permit Modification and oxides of nitrogen (NO_x) recommended Best Available Control Technology (BACT) Determination dated May 11, 2001 and offers the following comments for your review.

Comment 1 - Notice of Intent to Issue PSD Permit Modification

The fourth paragraph of this section indicates that

> *"No annual increases of regulated pollutants will occur as a result of the modification and emissions of NO_x will be reduced."*

This statement does not appear to be correct due to the fact that sulfuric acid mist emissions will increase due to the catalysis of sulfur dioxide (SO_2) to sulfur trioxide (SO_3) in the SCR. The magnitude of this increase is unknown because some of the SO_3 will be combined with excess ammonia to form ammonium sulfate and ammonium bisulfate. In addition, this statement may be misleading due to the fact that ammonia will be both introduced to the Polk Power Station and emitted from Unit 1 as "slip." TEC estimates that the requirement to install and operate a Selective Catalytic Reduction (SCR) system on Polk Unit 1 will generate approximately 72 tons of airborne ammonia emissions per year. This is compared to a NO_x reduction of approximately 495 tons per year assuming that the SCR system does not impact the availability of Polk Unit 1. These are significant issues, and TEC requests that the Department include it in its analysis of this project.

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Comment 2 - PSD Permit Modification, Page 1 of 4, Paragraphs 4 and 5

On May 10, 2001, TEC submitted additional information including a revised vendor quotation for a SCR system, a revised cost effectiveness analysis for the application of a SCR system to Polk Unit 1, an overview of the recently issued draft permit and EPA response with respect to the Kentucky Pioneer Project, and, most importantly, a proposal to work with the Department to reduce NO_x emissions from Polk Unit 1 through the implementation of a Continuous Improvement Plan (CIP). This letter was not referenced in either paragraph 4 or 5 on page 1 of 4, and TEC requests that the Department acknowledge the submittal of this document.

Comment 3 - Permit Modification, Page PM-3, Footnote

In the footnote, the Department has imposed an ammonia slip emissions limit of 5 ppmvd at the SCR exit. However, as found in specific condition 24 of the recently permitted Bayside Power Station PSD permit, ammonia slip emissions were limited to the following:

> "Additional Ammonia Slip Testing: *If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:*
>
> a. *Begin testing and reporting the ammonia slip for each subsequent calendar quarter;*
> b. *Take corrective actions before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen that lowers the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and*
> c. *Test and demonstrate that the ammonia slip is less than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.*
>
> *Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]"*

This provides TEC with the flexibility to operate a baseloaded unit through a peak generating season such as summer without being forced to remove the unit from service to replace SCR catalyst. If a SCR system is ultimately required to be installed on the Polk Unit 1 CT, TEC requests that the same language found in the Bayside Power Station air construction permit be included in the draft permit modification.

Comment 4 - BACT Determination, Page BD-1, Paragraph 3

The Department indicates that it received the original BACT submittal on 11/27/00. This contradicts the statement on page 1 of 4 of the PSD permit modification in which the Department indicates that it received the submittal on 11/17/00. TEC requests that the Department clarify this inconsistency.

Comment 5 - BACT Determination, Page BD-1, Paragraph 4

The Department indicates that it will consider a number of additional factors when making the final BACT Determination. The factors include:

- *Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.*
- *All scientific, engineering, and technical material and other information available to the Department.*
- *The emission limiting standards or BACT determination of any other state.*
- *The social and economic impact of the application of such technology.*

While it is fair to consider these factors under normal circumstances, the PSD and Title V permits governing the operation of Polk Unit 1 clearly mandate that this BACT Determination be made by considering:

> *"data gathered on this facility, other similar facilities, and the manufacturer's research."*

TEC feels that this BACT Determination is a special case, it should be carried out as defined by the above referenced permits.

Comment 6 - BACT Determination, Page BD-2, Second Bullet

The second bullet on Page BD-2 indicates that the Department would consider the emission limiting standards or BACT determinations of any other state when considering the appropriate NO_x limit for the Polk facility. Although TEC feels that this is outside of the defined scope of this particular BACT Determination, it is nonetheless important to note that if the Department takes this position, it would be prudent to await the issuance of the final Kentucky Pioneer PSD permit, since this is a new and clean IGCC facility. As the Department is aware, this permit currently exists in draft form and limits NO_x emissions to 15 ppmvd @ 15% O_2 through the use of steam injection. This limit is actually less stringent than the limit proposed by the Department.

Comment 7 - BACT Determination, Page BD-2, Paragraph 3

In paragraph 3, the Department identifies several recently permitted IGCC facilities and their NO_x emissions limits found in Table 1 on the same page. However, the Department does not specify the basis how each limit was established. Specifically, it is worth noting that the Delaware City Motiva project was permitted under a delegated Lowest Achievable Emission Rate (LAER) determination, and was not required to install SCR for NO_x control. TEC feels that this is a significant omission, and requests that the Department add a column to indicate the basis for each NO_x emission limit.

Comment 8 - BACT Determination, Page BD-2, Paragraph 3

The Department identifies SCR as the "typical BACT determination for pipeline natural gas fired combined cycle CT's" and states that:

> *"the application of SCR with an emission limit of 0.125 lb/MMBtu has been determined to represent BACT for a (conventional) Florida coal-fired unit."*

However, no reference is given to the typical (or recent) BACT determination for a syngas fired combined cycle CT. Since this project involves the permitting of a syngas fired combined cycle CT, TEC requests that the Department include this language in Paragraph 3 of Page BD-2 to complete the discussion.

Comment 9 - BACT Determination, Page BD-2, Table 1

As mentioned above, Table 1 lists five IGCC projects (including the Polk facility) and their representative NO_x emission limits. However, some of the limits are represented in units of lb/MMBtu, while the Delaware City Motiva project is listed in terms of ppmvd. In order to accurately compare the limits for each facility, they should be presented in equivalent units. For example, the permit governing the Wabash River Station facility contains the language below in condition D.2.3 limiting NO_x emissions:

> *"Pursuant to CP 167-2610-00021 (Issued May 27, 1993), the nitrogen oxides (NO_x) emissions from the gas turbine shall not exceed 25 ppmdv at 15 percent oxygen for syngas or natural gas combustion."*

It is unclear why the Department has represented the emissions limits in different units, but in order to make a complete and accurate comparison, TEC requests that all NO_x emissions limits found in this table be represented in terms of the same units.

Comment 10 - BACT Determination, Page BD-3, Paragraph 2

Paragraph 2 states that:

> *"The gasifier feedstock is more or less completely gasified to so-called synthesis gas (syngas)...."*

Although this is true in theory, this is not true for Polk Power Station. In fact, in most cases, the feedstock is not completely gasified, and some carbon exits the process as residual fuel material. The extent of gasification depends on the characteristics of the feedstock, the availability of pure oxygen for the reaction, and other reaction characteristics such as temperature and pressure. TEC requests that the description of the gasification process found on Page BD-3 be corrected to reflect site specific operation.

Comment 11 - BACT Determination, Page BD-4

The discussion found on Page BD-4 centers on the Texaco gasification process, and, specifically, identifies other facilities that use the Texaco gasification process to produce some end product.

These end products include ammonia, methanol, syngas, hydrogen, and electricity. While this discussion is interesting from a technical standpoint, it does not seem to be relevant to this project because the IGCC applications are completely unrelated and/or not similar to the Polk Power Station IGCC. Further, of the twelve facilities listed on Page BD-4, only five actually combust syngas for the purpose of power production. As such, the other seven listed projects should be stricken from the discussion because they are not relevant to this project.

Of the twelve projects listed on Page BD-4, only one domestic unit (Delaware City Motiva) uses the Texaco gasification process to produce syngas for firing in two GE 6FA combustion turbines. As noted previously, this unit was permitted under a LAER Determination and is limited to emit no more than 16 ppmvd NO_x @ 15% O_2. This facility uses steam injection for NO_x control and is one technical generation ahead of the Polk IGCC facility. This is the only domestic project (subject to the same Federal rules and regulations as the Polk facility) listed on Page BD-4 that utilizes the Texaco gasification process, and is the only project that should be considered within the scope of this project. This project was discussed in detail on page 8-2 and 8-3 of TEC original submittal. As noted in the submittal:

> *"An essential element of this design improvement is a relatively larger air separation plant than at Polk to provide additional diluent to the combustion turbine."*

In other words, even though the Delaware facility uses the Texaco gasification process to produce syngas for firing in two GE 6FA combustion turbines, there are significant technical differences between the facilities that prevent one from considering them to be 'similar' as applied to this project. In fact, the improved emissions performance of the Delaware facility was made possible by analyzing and improving on the process implemented at the Polk site. The discussion on Page BD-4 as it relates to the Delaware facility is interesting from a technological standpoint, but the Department should note that significant technical differences do exist between the Delaware and Polk IGCC facilities.

Comment 12 - BACT Determination, Pages BD-5, BD-6 and BD-7

On pages BD-5, BD-6 and BD-7, the Department lists several installations of GE CTs that fire syngas from various feedstocks. Of the units listed and discussed on these pages, only one (the Polk Unit 1 CT) is a GE 107FA unit, and many do not fire syngas produced from coal. Further, the Department gives a broad overview of each facility without providing any details regarding the NO_x emissions limits or the actual operating history. In many cases, the NO_x control strategy for a facility is not identified. Of those that are identified, none utilize a SCR system for NO_x control. As such, TEC requests that the Department add this critical detailed information for completeness.

The only unit identified on Pages BD-5, BD-6 or BD-7 that TEC believes can be considered similar for the purposes of this BACT Determination is the Wabash River IGCC facility located in Terre Haute, Indiana. This facility fires syngas derived from a coal feedstock in a GE 7FA combustion turbine and was discussed technically as well as identified as the only other IGCC facility that could be considered 'similar' for the purposes of this BACT Determination on Page

8-1 of the November 17, 2000 TEC BACT submittal. Although the technical discussion found on Pages BD-5, BD-6 and BD-7 is interesting, it is unclear how it applies to this special case. If the Department has provided this discussion to establish similarity between these units and the Polk IGCC facility, the reasoning and logic behind this conclusion should be discussed. Otherwise, since this discussion has no apparent relevance to this project, TEC requests that it be stricken from the BACT Determination.

Comment 13 - BACT Determination, Page BD-9, Paragraph 4

In Paragraph 4 of Page BD-9, the Department estimates that uncontrolled NO_x emissions from the Polk Unit 1 CT are as high as 200 ppmvd @ 15% O_2. TEC requests that the Department clarify how this estimate was arrived at.

Comment 14 - BACT Determination, Page BD-9, Paragraph 5

This paragraph discusses diluent injection as a means of NO_x control, indicating that the Polk facility utilizes advanced combustor design to reduce NO_x emissions to 25 ppmvd for gas firing. TEC requests that language be added to this section to specify that the fuel is syngas and the combustors are Multinozzle Quiet Combustors (MNQCs).

Comment 15 - BACT Determination, Page BD-10, Paragraph 3

A large portion of the Department's argument for the applicability of a SCR system to Polk Unit 1 centers on the fact that SCR systems are now being successfully applied to combined cycle units without the occurrence of sulfur poisoning due to the application of advanced catalysts. In the above referenced paragraph, the Department discusses the fact that SCR has been successfully applied to natural gas fired combined cycle CTs, oil fired boilers, and coal fired boilers. While this may be the case, there are significant technical differences between a syngas fired combined cycle CT and the three technologies cited above.

The main difference between a natural gas fired combined cycle CT and a syngas fired combined cycle CT lies in the composition of each fuel. According to the Department, when firing natural gas, a SCR system experiences inlet sulfur loading in the range of 0.0006 lb SO_2/MMBtu. Conversely, when firing syngas, the SCR experiences an inlet loading of 0.032 - 0.146 lb SO_2/MMBtu. This is in the range of (if not higher than) the diesel backup fuel fired in a combined cycle combustion turbine such as the one permitted by CPV Gulf Coast.

As the Department points out in paragraph 3 of Page BD-10, the CPV Gulf Coast facility would be <u>capable</u> of firing 0.05 % sulfur diesel oil for up to 30 days per year while emitting 10 ppmvd @ 15% O_2 of NO_x. The Polk NO_x BACT Determination, however, requires that Unit 1 utilize a SCR for NO_x control for up to 7,884 hours per year while accommodating an inlet sulfur loading as great or greater than that of the CPV Gulf Coast facility when firing distillate oil. Since, in the view of the Department, the CPV Gulf Coast facility is only capable of firing fuel oil for up to 30 days (equivalent to720 hours) per year while using a SCR for NO_x control, it seems inappropriate to expect that Polk Unit 1, with the same or greater SCR inlet sulfur loading would be capable of controlling NO_x through the use of a SCR for a period that is over ten times greater. TEC therefore requests that the Department provide further technical justification identifying why the Polk Unit 1 facility would be able to control NO_x through the use of SCR for up to 7,884 hours per year at an emission rate of 5 ppmvd @ 15% O_2 while the CPV Gulf Coast facility would only be capable of controlling NO_x for up to 720 hours per year at an emission rate of 10 ppmvd @ 15% O_2. This is a critical point, and should be addressed.

Additionally, in Paragraph 3 on Page BD-10, the Department asserts that SCR systems have been successfully applied to coal and oil fired utility boilers that experience high inlet SO_2 loading. Although this is an accurate statement, the fact that SCR can be successfully applied to coal and oil fired utility boilers does not necessarily mean that it can be successfully applied to a syngas fired combined cycle CT. The primary technical concern that TEC has raised regarding the application of a SCR system to Polk Unit 1 involves the formation of ammonium sulfate and ammonium bisulfate compounds in the HRSG section. Coal and oil fired boilers, however, do not share this technical concern for the following two reasons: (1) Most coal and oil fired boilers do not utilize HRSGs for additional heat transfer; and (2) The ammonia that reacts with SO_3 in a coal fired boiler is preferentially adsorbed onto the flyash. However, in a syngas fired combined cycle combustion turbine, there is not as much flyash in the flue gas stream. As such, the excess ammonia in a syngas fired combined cycle application is free to react with the sulfur compounds present in the flue gas stream.

In summary, it is inappropriate to conclude that because SCR has been successfully applied to coal and oil fired boilers, it can necessarily be successfully applied to a syngas fired combined cycle CT. The technologies are completely different, with different characteristics and different reaction mechanisms.

Comment 16 - BACT Determination, Page BD-10, Paragraph 4

This paragraph is an overview of recently permitted combined cycle CT projects in the State of Florida. Since the Bayside Power Station is a combined cycle CT application, TEC requests that it be included in this summary.

Comment 17 - BACT Determination, Page BD-11, Paragraph 1

In this paragraph, the Department indicates that SCR is the technology of choice for reducing NO_x emissions from F class combustion turbines. However, it is important to specify that the primary fuel in these applications is natural gas, not syngas. Due the significant fuel differences, this is an important distinction to make and TEC requests that the Department make this clear in its description.

Comment 18 - BACT Determination, Page BD-12, Paragraph 2

The Department indicates that, given the opportunity, it would be willing to reevaluate the cost effectiveness of the application of $SCONO_x$ control technology to Polk Unit 1. Since both the Department and TEC have rejected the $SCONO_x$ technology, there is no reason for the inclusion of this language, and TEC requests that it be stricken.

Comment 19 - BACT Determination, Page BD-13, Paragraph 3 and Table
In this paragraph, the Department indicates that it compared SCR inlet streams found in the associated table for various technologies to determine the chemical constituents for which the application of a SCR system to a syngas fired CT would be of possible concern. For the syngas inlet stream, the Department used values from TEC publications and the United States Environmental Protection Agency (USEPA) Acid Rain website to represent sulfur compound loading, and emission factors from the Kentucky Pioneer PSD permit application for all other constituents. This comparison seems to include several assumptions by the Department, which may be flawed or inappropriate when applied to the Polk IGCC facility.

First, by using the sulfur emission factor from the Polk IGCC facility and the metals emission factors from the Kentucky Pioneer PSD permit application, the Department has assimilated data from two different sources to arrive at a syngas composition that may not be representative of either facility. Each facility uses a different feed stock to produce syngas, which will ultimately affect the emissions from the combustion turbines. The Polk IGCC facility uses coal and, on occasion, a mixture of coal and up to 60% petcoke to produce the syngas fired in the CT. On the other hand, the Kentucky Pioneer IGCC facility will utilize a mixture of municipal solid waste and petcoke to produce the syngas fired in the CT. Clearly, since the two feedstocks are different, it can be concluded that the emissions resulting from firing each syngas would be different. In light of this, it is unclear why the Department assumed that it would be appropriate to combine the emissions data from each facility, and TEC requests that FDEP provide the reasoning behind this assumption.

Second, the Department has highlighted Cobalt and Nickel as constituents of concern when considering the application of a SCR system to a syngas fired unit. However, as discussed in the attached February 14, 2001 comment letter to FDEP, TEC feels that sulfur should be a significant concern also. TEC understands that SCR systems have been successfully applied to natural gas fired combined cycle units as well as coal and oil fired boilers. However, natural gas fired combined cycle units have a significantly lower sulfur inlet loading than do syngas fired combined cycle units, and the chemistry in coal and oil fired boilers is different than that in a syngas fired combined cycle application (see Comment 15). As such, TEC requests that the Department provide additional details regarding the exclusion of sulfur as a constituent of concern, as well as provide additional supporting data showing why cobalt and nickel are the only two constituents of concern for a syngas fired IGCC. Finally, TEC requests that the Department identify the algorithm or criteria used to determine which constituents are of concern.

Finally, as discussed in Comment 15, the technologies listed in the Table on Page BD-13 are all completely different for a variety of reasons. It is unclear why the Department has chosen to compare such a wide variety of technologies fired by such a diverse array of fuels. TEC feels that it would be prudent to identify the significant differences that exist between each of the technologies in the Table on Page BD-13, and requests that the Department either incorporate some discussion to that effect in the paragraph immediately preceding the Table, or eliminate the Table altogether.

Comment 20 - BACT Determination, Page BD-13, Paragraph 4

In Paragraph 4, the Department identifies several coal fired facilities and oil refineries that have applied SCR systems, but gives no indication of the operating history. In addition, FDEP indicates that a Polish IGCC facility which is currently proposed will be designed to gasify a variety of oils and refinery resids while controlling NO_x through the use of SCR. TEC feels that it is inappropriate to compare any of these units to the Polk IGCC facility because they either: (1) are completely different in technology and/or feedstock and (2) have no operating history from which to draw a reasonable evaluation of the effectiveness of SCR operation. TEC would like to take this opportunity to caution against making these types of comparisons. They are extremely risky due to the reasons discussed above and it is inappropriate to assume that because an IGCC facility is proposed to control NO_x emissions through the use of SCR that it will be successful in doing so.

Comment 21 - BACT Determination, Page BD-13, Paragraph 4

At the end of paragraph 4, the Department points out that TEC obtained SCR performance guarantees from Engelhard, which is accurate. However, due to the fact that TEC was constrained by a 30 day deadline after the last NO_x stack test to submit the BACT analysis, this quote was based on general information. Subsequently, TEC solicited additional bids from several catalyst vendors based on project and site specific data. Engelhard, which had previously offered general information used in this analysis, elected not to bid on the Polk IGCC project upon review of the site specific information. One catalyst vendor, Deltak, did offer a guarantee for this project of 5 ppmvd @ 15% O_2 NO_x emissions and 5 ppmvd @ 15% O_2 ammonia slip emissions. However, in the cover letter, Deltak stated:

> *"I would like to note one potential problem with retrofitting SCR into the subject HRSG. There is a rather high SO_2 loading in the exhaust gas stream due to the combustion of syn-gas in the combustion turbine. Approximately 5% of the SO_2 in the gas stream will oxidize to SO_3 across the catalyst. This additional SO_3 along with the unspecified level of SO_3 in the combustion turbine exhaust will combine with the injected ammonia (NH_3) to form ammonium salts (primarily ammonium bisulfate) that are likely to adhere to the tubing in the cooler HRSG sections causing both a thermal insulation effect and/or an increase in turbine back pressure. With the fuel that is being burned, and the potential for Fuel Oil back-up fuel, the potential for ammonium salt fouling will be quite significant."*

This letter was submitted to FDEP both by e-mail and Federal Express on May 10, 2001 and is enclosed. However, since the information was neither requested nor required to complete the project, it was not considered by the Department in this Determination. This information is significant, and TEC requests that the Department review it as part of this Determination.

Comment 22 - BACT Determination, Page BD-14, Paragraph 1

This paragraph is a paraphrase of a comment submitted to the Department as part of a letter submitted in response to a request for additional information. The response was submitted on

February 14, 2001 and contained several additional comments that have not been addressed by the Department. Furthermore, the comment addressed by the Department in this paragraph is not an accurate representation of the comment submitted by TEC. Specifically, the Department has omitted the first sentence from the original comment, which states:

> *"Although the November 8, 1999 letter from EPA Region IV established BACT for combined cycle combustion turbines as 3.5 ppm, this letter addressed natural gas fired combustion turbines, not syngas fired combustion turbines."*

It is unclear why this language was omitted, but TEC requests that it be reinserted into the BACT Determination to accurately reflect the intentions of TEC. The omitted language was meant to emphasize the fact that although BACT for combustion turbines had been established as 3.5 ppm, it was established for a combustion turbine that fired a fuel with very different characteristics than syngas.

Comment 23 - BACT Determination, Page BD-14, Paragraph 3

In this paragraph, the Department indicates that it has authored the PSD permit to allow for SCR induced, unscheduled shutdowns. Since the Polk CT is not designed for bypass operation in the event of a SCR induced, unscheduled shutdown, it is unclear which part or which condition of the permit is referred to in this section. TEC requests that the Department clarify this statement.

Comment 24 - BACT Determination, Page BD-15, Paragraph 1

This paragraph was part of the same comment addressed on Page BD-14, Paragraph 1. Again, it is unclear why the response has not been represented as written by TEC, and TEC requests that the Department present the response to its request for additional information as submitted to FDEP and respond to all of the material contained therein. TEC feels that there were several significant issues outlined in the response, and, for the record, TEC has enclosed the subject comment letter containing the complete text of its responses.

Comment 25 - BACT Determination, Page BD-15, Paragraph 2

This Paragraph reiterates the fact that SCR has been successfully applied to coal fired boilers. However, as found in previous sections of the BACT Determination, the Department has not considered the differences in technology or chemistry between coal fired boilers and syngas fired combined cycle CTs. TEC requests that the Department consider these differences before concluding that because SCR can be applied to a coal fired boiler, it can necessarily be applied to a syngas fired combined cycle CT.

Comment 26 - BACT Determination, Page BD-16, Paragraph 1

In this paragraph, the Department has presented portions of two separate paragraphs contained in the enclosed February 14, 2001 response to additional information as one comment. It is unclear why TEC's comments are misrepresented in this fashion, and for the record, the actual text submitted is presented below:

> *"The conclusion that SCR must be applied to Polk Unit 1 simply because the cost of* NO_x *control is lower than what the cost of* NO_x *control* ***might*** *be at the CPV Gulf Coast facility does not seem to take into account environmental, energy, and other costs as prescribed in the definition of BACT. In addition, this conclusion does not seem to consider the operation of 'other similar facilities' or 'manufacturer's research' as called for in Specific Condition A.50 of the Polk Power Station Title V Permit.*
>
> *Finally, the cost to control* NO_x *emissions through the use of an SCR system on Polk Unit 1 presented in the analysis submitted to FDEP was based on a limited number of estimated costs. Since SCR has not been required for any IGCC installation in the United States, it is not possible to compare the cost of installing an SCR at the Polk facility to the cost of installing an SCR at another IGCC facility. In fact, recent research developed by GE suggests that the cost to control* NO_x *emissions from a combined cycle combustion turbine that fires a sulfur bearing fuel may be much higher than originally anticipated. (see enclosed)"*

In combining the two paragraphs in the BACT Determination (in reverse order), the Department omitted the reference to the fact that "GE suggests that the cost to control NO_x emissions from a combined cycle combustion turbine that fires a sulfur bearing fuel may be much higher than originally anticipated." As noted in previous comments, TEC requests that the Department present TEC's responses to the request for additional information as written, to avoid confusion.

Comment 27 - BACT Determination, Page BD-16, Paragraph 3

The Department indicates in this paragraph that the portion of the SCR system costs due to replacing the power lost in the event that Polk Unit 1 cannot operate because of a SCR system malfunction are not appropriate in this evaluation. TEC does not feel that it is appropriate to strike these costs, as they are real and will be incurred by the Company when a forced outage due to a SCR system malfunction occurs. Furthermore, in determining this cost, TEC used the incremental cost of power generation; that is the difference between the cost of operating Polk Unit 1 and the cost of operating another typical unit within the TEC generating system rather than estimating the cost of purchasing the lost power during a peak generating period such as the summer months. This creates a cost analysis that is extremely conservative. As such, TEC requests that the Department include the cost of lost power generation due to SCR malfunction when estimating the cost effectiveness of a SCR system for Polk Unit 1.

Comment 28 - BACT Determination, Page BD-16, Paragraph 3

In the middle of the paragraph, the Department makes the statement:

> *"Since the basis of these costs was $0.04/kwh, the Department presumes that each cost was developed based upon some measure of lost revenue and not increased natural gas costs. Accordingly, the Department will reject these line items...."*

The Department should identify how it arrived at this presumption, as it may be inaccurate.

Comment 29 - BACT Determination, Page BD-17, Paragraph 1

The Department claims that:

> *"Since diluent flow will likely increase with generating load (up to some load point) and since syngas flow is directly proportional to unit load, it is likely that a measure of diluent flow to syngas flow (which the applicant purports is more appropriate) makes some sense, as in the case of reviewing the entire load range of a combustion turbine. However, the Department wishes to better understand the impact of diluent flow on NO_x emissions, given that the diluent is the control media for NO_x. Since the tests are at a similar load point, the syngas flow and its associated variability can be effectively ignored."*

The last sentence of this statement is inaccurate, since the variability of the syngas flow cannot be ignored any more than the variability of the associated feedstock can. The Polk facility uses a variety of fuels in the gasification process to produce the syngas fired in the CT. The variety of fuels fired produces a variety of syngases, each with different heat contents. This is a critical point to understand, as it explains why, in some cases, a syngas with a higher heat content can be fired at a lower flow rate than a syngas with a lower heat content, while still producing the same amount of power. Accordingly, as TEC pointed out in its original response to FDEP incompleteness issues, a better measure of evaluating the effectiveness of the Unit's ability to control NO_x is to examine the ratio of diluent flow to syngas flow. This allows one to determine whether or not the NO_x control system is being operated properly. If the Department wishes to better understand the impact of diluent flow on NO_x emissions, it must also consider the heat content of the syngas when making its evaluation. As such, TEC requests that the Department acknowledge the importance of the syngas variability when conducting its evaluation, and adjust its conclusions accordingly.

Comment 30 - BACT Determination, Page BD-21, Paragraph 2

The Department has rejected the costs due to HRSG modifications, claiming that they will not be necessary if the NO_x emissions are held to 5 ppmvd and the ammonia slip emissions are minimized. However, without any operational experience on any unit in the country, this is an assumption that cannot be made. In addition, based on the statement made by Deltak, (see Comment 21) it appears that there are significant concerns with respect to ammonium sulfate and ammonium bisulfate pluggage, indicating that the unit will, in fact, need to be cleaned. It is also important to note that this statement was made despite the fact that the quote guarantees 5 ppmvd NO_x @ 15% O_2 with an ammonia slip level of 5 ppmvd @ 15% O_2. This is the level of NO_x emissions and ammonia slip emissions that the Department claims will eliminate plugging and fouling concerns. Furthermore, since no operational experience exists regarding the operation of SCR on an IGCC system, failure to modify the HRSG in preparation for possible cleaning would be shortsighted. As such, TEC requests that the cost to install a SCR system should be adjusted to include the cost of modify the HRSG for cleaning.

Comment 31 - BACT Determination, Page BD-21, Paragraph 3

The Department indicates that, since data were not available for other IGCC facilities operating SCR systems, it has:

> *"...compensated for the shortage of IGCC specific data through a reasonable extrapolation of SCR and fuel data from utility units and refineries."*

This does not comport with the requirements of the permit to perform the analysis based on 'test data gathered at this facility, other similar facilities, and manufacturer's research.' The permit condition does not specify that it is appropriate to extrapolate data from other dissimilar facilities. Furthermore, as discussed extensively in this document, there are significant technical differences between 'utility units and refineries' that prevent 'reasonable extrapolation of SCR and fuel data.' Since FDEP used this as the basis for the BACT determination, the overall conclusion that SCR should be applied to Polk Unit 1 should be rejected.

Comment 32 - BACT Determination, General Comment

In general, it appears as though the Department has concluded that SCR technology should be applied to Polk Unit 1 based on data gathered from several other, technically different facilities. TEC has significant concerns with this approach, noting that although SCR has been successfully demonstrated on natural gas fired combined cycle facilities as well as coal and oil fired boilers, the differences between these facilities should not be discounted. In addition, due to these differences, it is not reasonable to conclude that because SCR technology was proven effective, it will necessarily be effective on a syngas fired IGCC. In addition, by comparing the Polk IGCC facility to dissimilar facilities such as coal and oil fired boilers and natural gas fired combined cycle combustion turbines, the Department seems to be violating the conditions of the PSD and Title V permits governing the facility. Specifically, both permits indicate that this BACT Determination must be carried out considering:

> *"data gathered on this facility, other similar facilities, and the manufacturer's research."*

Although it is somewhat unclear what the meaning of the word 'similar' is, TEC feels that it is not reasonable to consider coal and oil fired boilers as similar to the Polk IGCC facility because the technologies and fuels used to generate electricity are not comparable. Furthermore, it is not reasonable to consider a natural gas fired combined cycle combustion turbine as similar to the Polk Power Station syngas fired combustion turbine because of considerable differences in the fuel compositions. As indicated in the original BACT submittal received by the Department on November 17, 2000, TEC feels that the only facility that can be reasonably considered 'similar' in both technology and fuel fired is the Wabash River Station IGCC facility. This facility gasifies coal and fires the syngas in a GE 7FA combustion turbine.

The Department has addressed in this BACT Determination a number of responses by TEC to its original request for additional information. The Departments treatment of these responses was questionable due to the fact that the responses that were addressed were presented out of context, and in some cases, were misrepresented. In addition, TEC submitted several other responses that were not considered by FDEP, and TEC feels that they should be addressed in this Determination as well.

Finally, on May 10, 2001, TEC submitted additional information to the Department that was not considered in this Determination. This submittal included: (1) a revised SCR cost analysis, (2) a new site specific SCR quote from Deltak indicating that significant technical concerns exist for the application of SCR to the Polk IGCC facility, (3) confirmation that Engelhard, after reviewing the site specific information had chosen not to bid on this project, (4) an overview of the Kentucky Pioneer draft permit and, most importantly, (5) a request to work with the Department on implementing a continuous improvement program with the goal of reducing NO_x emissions from the Polk IGCC facility through the use of process optimization. This information was not considered in the current draft of the BACT Determination, and TEC requests that the Department reevaluate TEC's requests, as significant technical concerns still exist regarding the application of a SCR system to Polk Unit 1.

TEC appreciates the opportunity to provide comments in this matter, and if you have any questions, please telephone Shannon Todd or me at (813) 641-5125.

Sincerely,

Mark J Hornick

Mark J. Hornick
General Manager/Responsible Official
Polk Power Station

EP\gm\SKT258

Enclosures

c/enc: Mr. Michael Halpin – FDEP
Mr. Syed Arif - FDEP
Mr. Jerry Kissel - FDEP SW
Jim Little, EPA

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THE TAMPA TRIBUNE
Published Daily
Tampa, Hillsborough County, Florida

RECEIVED
MAY 29 2001
BUREAU OF AIR REGULATION

State of Florida }
County of Hillsborough } ss.

Before the undersigned authority personally appeared J. Rosenthal, who on oath says that she is Classified Billing Manager of The Tampa Tribune, a daily newspaper published at Tampa in Hillsborough County, Florida; that the attached copy of advertisement being a

LEGAL NOTICE

in the matter of

PUBLIC NOTICE OF INTENT

was published in said newspaper in the issues of MAY 23, 2001

Affiant further says that the said The Tampa Tribune is a newspaper published at Tampa in said Hillsborough County, Florida, and that the said newspaper has heretofore been continuously published in said Hillsborough County, Florida, each day and has been entered as second class mail matter at the post office in Tampa, in said Hillsborough County, Florida for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, this advertisement for publication in the said newspaper.

J Rosenthal

Sworn to and subscribed by me, this 24 day

of MAY, A.D. 20 01

Personally Known ✓ or Produced Identification ______
Type of Identification Produced ______

OFFICIAL NOTARY SEAL
SUSIE LEE SLATON
COMMISSION NUMBER
DD000060
MY COMMISSION EXP.
APRIL 16, 2005

Susie Lee Slaton

cc: M. Halpin
B. Thomas, SWD
J. Spence, Polk Co ESD
B. Oven, DEP
G. Worley, EPA
J. Bunyak, NPS

ISSUE PSD PERMIT
MODIFICATION
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 1050233-007-AC,
PSD-FL-194F
TEC Polk Power Station
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit modification for the TEC Polk Power Station (PPS) located in Polk County. The applicant's mailing address is: P.O. Box 111 Tampa, Florida 33601-0111. A Best Available Control Technology (BACT) Determination was required pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD).

This is an existing facility consisting of an integrated gasification combined cycle (IGCC) unit, referred to as Unit 1. Major components of PPS Unit 1 include solid fuel handling and gasification systems, a sulfuric acid plant for processing of the solid fuel gasification system gas cleanup stream, an auxiliary boiler fired with No. 2 distillate fuel oil, and one integrated gasification combined cycle (IGCC) General Electric (GE) 7F combustion turbine (CT) fired with synthetic natural gas (syngas) or No. 2 distillate fuel oil. The unit is additionally authorized to burn syngas produced from the gasification of fuel blends of up to 60 percent petroleum coke. The unit has a PSD Permit (1050233-001-AC) issued by the State of Florida.

In accordance with the conditions of the PSD permit, a determination of Best Available Control Technology (BACT) for Nitrogen Oxides (NOx) was required to be completed following a pre-defined "demonstration period". The permit condition reads as follows: "One month after the test period ends (estimated to be by June 1, 2001), the Permittee will submit to the Department a NOx recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NOx only and adjust the NOx emission limits accordingly." The Department has determined that the demonstration (test) period ended during November 2000. Based upon the Department's evaluation, PPS Unit 1 will be required to install an SCR unit in order to control NOx emissions from the IGCC unit as per the conditions outlined in the draft permit.

No annual increases of regulated pollutants will occur as a result of the modification and emissions of NOx will be reduced.

The Department will issue the Final permit modification in accordance with the referenced draft permit conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit Modification. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures emissions of NOx will be reduced.

The Department will issue the Final permit modification in accordance with the referenced draft permit conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit Modification. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material

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dicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
Suite 4, 111 S. Magnolia Drive
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Polk County Environmental Services
Natural Resources & Drainage Division
4177 Ben Durrance Road
Bartow, Florida 33830
Telephone: 941/534-7377
Fax: 941/534-7374

The complete project file includes the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Source Review Section, or the Department's reviewing engineer for this project, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

2651 5/23/01

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

May 10, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Mark J. Hornick
General Manager
Tampa Electric Company / Polk Power Station
P.O. Box 111
Tampa, Florida 33601-0111

Re: DEP File No. PSD-FL-194F
Polk Power Station
Unit 1 SCR Installation

Dear Mr. Hornick:

The Department is in receipt of your "Notice of Waiver of 90-Day Period" which was dated May 1. As indicated in our meeting of April 3rd, the Department has determined that the application was complete as of February 15th. Information received after this date has not been requested by the Department, but rather it has been offered by you, the applicant, as additional (late) information. The Department believes that ample information exists at this time to allow the issuance of the Draft BACT Determination.

Enclosed is one copy of the Draft PSD Permit Modification and Draft BACT Determination for the referenced project at the Polk Power Station located at 9995 State Route 37 South, Mulberry, Polk County. The Department's Intent to Issue PSD Permit Modification and the "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION" has been submitted by the Department for publishing in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section or me at the above letterhead address. If you have any questions, you may also call Michael Halpin, P.E. at 850/921-9519.

Sincerely,

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/mph

Enclosures

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Mark J. Hornick
General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* B. Date of Delivery

MAY 17 2001

C. Signature

X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1453 1934

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service

CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

7099 3400 0000 1453 1934

Article Sent To:

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark
Here

Mr. Mark J. Hornick
General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

See Reverse for Instructions

In the Matter of an
Application for Permit by:

Mr. Mark J. Hornick
General Manager, Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111
________________________________/

Facility I.D. No. 0530233
DEP Permit No. PSD-FL-194F
Polk Power Station
Polk County

INTENT TO ISSUE PSD PERMIT MODIFICATION

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit modification under the requirements for the Prevention of Significant Deterioration of Air Quality (copy of Draft PSD Permit Modification attached) for the proposed project, detailed in the application specified above, for the reasons stated below.

In accordance with the conditions of the existing PSD permit, a determination of Best Available Control Technology (BACT) for Nitrogen Oxides (NO_X) was required to be completed following a pre-defined "demonstration period". The permit condition reads as follows: "*One month after the test period ends (estimated to be by June 1, 2001), the Permittee will submit to the Department a* NO_X *recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for* NO_X *only and adjust the* NO_X *emission limits accordingly.*" The Department has determined that the demonstration (test) period ended during November 2000. Based upon the Department's evaluation, PPS Unit 1 will be required to install an SCR unit in order to control NO_X emissions from the IGCC unit as per the conditions outlined in the draft permit modification. The facility is located at 9995 State Route 37 South, Mulberry, Polk County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a permit under the provisions for the Prevention of Significant Deterioration (PSD) of Air Quality is required for the proposed work.

The Department intends to issue this PSD permit modification based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. and 40 CFR 52.21.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., the Department will publish the enclosed ""Public Notice of Intent to Issue PSD Permit Modification". The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place.

The Department will issue the final permit modification with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of "Public Notice of Intent to Issue PSD Permit Modification". Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes, which entitle the petitioner to relief; and (f) A demand for relief.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE PSD PERMIT MODIFICATION (including the PUBLIC NOTICE, Draft BACT Determination, and the DRAFT permit modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/11/01 to the person(s) listed:

Mark J. Hornick, TEC*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Mr. Jeff Spence, Polk County ESD
Buck Oven, DEP PPSO
Thomas W. Davis, P.E, ECT

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J Hayes 5/11/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1050233-007-AC, PSD-FL-194F

TEC Polk Power Station
Polk County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit modification for the TEC Polk Power Station (PPS) located in Polk County. The applicant's mailing address is: P.O. Box 111, Tampa, Florida 33601-0111. A Best Available Control Technology (BACT) Determination was required pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD).

This is an existing facility consisting of an integrated gasification combined cycle (IGCC) unit, referred to as Unit 1. Major components of PPS Unit 1 include solid fuel handling and gasification systems, a sulfuric acid plant for processing of the solid fuel gasification system gas cleanup stream, an auxiliary boiler fired with No. 2 distillate fuel oil, and one integrated gasification combined cycle (IGCC) General Electric (GE) 7F combustion turbine (CT) fired with synthetic natural gas (syngas) or No. 2 distillate fuel oil. The unit is additionally authorized to burn syngas produced from the gasification of fuel blends of up to 60 percent petroleum coke. The unit has a PSD Permit (1050233-001-AC) issued by the State of Florida.

In accordance with the conditions of the PSD permit, a determination of Best Available Control Technology (BACT) for Nitrogen Oxides (NO_X) was required to be completed following a pre-defined "demonstration period". The permit condition reads as follows: "*One month after the test period ends (estimated to be by June 1, 2001), the Permittee will submit to the Department a NO_X recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_X only and adjust the NO_X emission limits accordingly.*" The Department has determined that the demonstration (test) period ended during November 2000. Based upon the Department's evaluation, PPS Unit 1 will be required to install an SCR unit in order to control NO_X emissions from the IGCC unit as per the conditions outlined in the draft permit.

No annual increases of regulated pollutants will occur as a result of the modification and emissions of NO_X will be reduced.

The Department will issue the Final permit modification in accordance with the referenced draft permit conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 days from the date of publication of this Public Notice of Intent to Issue PSD Permit Modification. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the

Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
Suite 4, 111 S. Magnolia Drive
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Polk County Environmental Services
Natural Resources & Drainage Division
4177 Ben Durrance Road
Bartow, Florida 33830
Telephone: 941/534-7377
Fax: 941/534-7374

The complete project file includes the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Source Review Section, or the Department's reviewing engineer for this project, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

PERMITTEE

Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

Authorized Representative:
Mark J. Hornick, General Manager
Polk Power Station

DEP File No. 1050233-007-AC
Permit No. PSD-FL-194F
Unit No. 1 SCR Installation
SIC No. 4911
Expires: July 31, 2003

PROJECT AND LOCATION

Modified permit to require the installation of an SCR unit for Unit No. 1.

The unit is located at the Polk Power Station, 9895 State Road 37 South, Mulberry, Polk County. The UTM coordinates are Zone 17, 402.45 km E and 3067.35 km N.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

ATTACHED APPENDICES MADE A PART OF THIS PERMIT

Appendix BD-2001	BACT Determination for NO_X dated 05/xx/01
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources Management

FACILITY DESCRIPTION

Tampa Electric Company (TEC) Polk Power Station (PPS) Unit 1 located in Polk County, Florida is a nominal 260-megawatt (MW) electric generation facility. Major components of PPS Unit 1 include solid fuel handling and gasification systems, a sulfuric acid plant for processing of the solid fuel gasification system gas cleanup stream, an auxiliary boiler fired with No. 2 distillate fuel oil, and one integrated gasification combined cycle (IGCC) General Electric (GE) 7F combustion turbine (CT) fired with synthetic natural gas (syngas) or No. 2 distillate fuel oil, and fitted with an SCR unit. The unit is additionally authorized to burn syngas produced from the gasification of fuel blends of up to 60 percent petroleum coke.

REGULATORY CLASSIFICATION

This facility, TEC Polk Power Station, is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PERMIT SCHEDULE

- 05/xx/01 Department published the Public Notice in the Tampa Tribune.
- 05/10/01 Department distributed initial Intent to Issue Permit.
- 02/15/01 Department received additional information; application deemed complete.
- 12/04/00 Department requested additional information.
- 11/17/00 Department received applicant's BACT submittal

RELEVANT DOCUMENTS

The documents listed below are the basis of the permit. They are specifically related to this permitting action. These documents are on file with the Department.

- Application received on November 17, 2000;
- Department's incompleteness letter dated December 4, 2000;
- TEC's response to Department's incompleteness letter received on February 15, 2001;
- Draft BACT Determination issued by the Department dated May 10, 2001
- Department's Intent to Issue and Public Notice Package dated May 10, 2001 and
- Permits PSD-FL-194, PSD-FL-194B, PSD- FL-194C, PSD-FL-194D and PSD-FL-194E

PERMIT SPECIFIC CONDITIONS

This permit addresses the following emissions unit:

E.U. ID No.	**Brief Description**
-001	Integrated Gasification Combined Cycle Unit No. 1

1. The provisions of the Title V Operating Permit 1050233-001-AV remain in effect. However, an application shall be submitted to revise that permit upon completion of construction and satisfactory emissions performance testing of the Unit 1 SCR.
2. The provisions of air construction permits PSD-FL-194, PSD-FL-194A, PSD-FL-194C, PSD-FL-194D and PSD-FL-194E are incorporated into this air construction permit except for the changes that follow in Specific Conditions F, H, J and M below.

F. Fuel Consumption

Solid fuels input to the solid fuel gasification plant shall consist of coal or coal/petroleum coke blends containing a maximum of 60.0 percent petroleum coke by weight. The maximum input of solid fuels to the solid fuel gasification plant shall not exceed 2,325 tons per day, on a dry basis. The maximum weight of the petroleum coke blended shall not exceed 1,395 tons per day, on a dry basis. The maximum sulfur content of the blended fuel shall not exceed 3.5 percent by weight.

H. Emission Limits

1. **EMISSIONS LIMITATIONS - 7F CT POST DEMONSTRATION PERIOD**

POLLUTANT	FUEL	BASIS[a]	LB/HR*	TPY[b]
NO_X	Oil	9 ppmvd***	74.1	32.5
	Syngas	5 ppmvd***	44.1	206.6
VOC[c]	Oil	0.028	32 lb/MMBtu	N/A
	Syngas	0.0017	3 lb/MMBtu	38.5
CO	Oil	40 ppmvd	99	N/A
	Syngas	25 ppmvd	98	430.1
PM/PM$_{10}$[d]	Oil	0.009 lb/MMBtu	17	N/A
	Syngas	0.013 lb/MMBtu	17	74.5
Pb	Oil	5.30E-5 lb/MMBtu	0.101	N/A
	Syngas	2.41E-6 lb/MMBtu	0.0035	0.067
SO_2	Oil	0.048 lb/MMBtu	92.2	N/A
	Syngas	0.17 lb/MMBtu	357	1563.7
V.E.	Syngas	10 percent opacity		
	Oil	20 percent opacity.		

(*) Emission limitations in lbs/hr are 30-day rolling averages, except for NO$_X$, which is limited in ppmvd (at 15% oxygen) and complied with on a 24-hour block average via CEMS. Pollutant emission rates may vary depending on ambient conditions and the CT characteristics. ~~Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review 120 days after the Siting Board approval of the site certification.~~ Subject to approval by the Department, the manufacturer's curves may be used to establish pollutant emission rates over a range of temperatures for the purpose of compliance determination.

~~(**) The emission limit for NO$_x$ is adjusted as follows for higher fuel-bound nitrogen contents up to a maximum of 0.030 percent by weight:~~

~~**FUEL-BOUND NITROGEN (% by weight)**~~	~~**NO$_x$ EMISSION LEVELS (ppmvd @ 15% 0$_2$)**~~
~~0.015 or less~~	~~42~~
~~0.020~~	~~44~~
~~0.025~~	~~46~~
~~0.030~~	~~48~~

~~using the formula STD = 0.0042 + F where:~~

~~STD = allowable NO$_x$ emissions (% by volume at 15% 0$_2$ and on a dry basis).~~

~~F = NOx emission allowance for FBN defined by the following table:~~

~~**FUEL BOUND NITROGEN (% by weight)**~~	~~**F (NOx % by volume)**~~
~~0 < N < 0.015~~	~~0~~
~~015 < N < 0.03~~	~~0.04 (N-0.015)~~

~~N = nitrogen content of the fuel (% by weight).~~

~~NOx emissions are preliminary for the fuel oil specified in Condition XIII.C. The Permittee shall submit fuel bound nitrogen content data for the low sulfur fuel oil prior to commercial operation to the Bureau of Air Regulation in Tallahassee, and on each occasion that fuel oil is transferred to the storage tanks from any other source to the Southwest District office in Tampa. The percent FBN (Z) following each delivery of fuel shall be determined by the following equation:~~

~~x(Y) + m(n) = (x+m) (Z)~~
~~where x = amount fuel in storage tank~~
~~y = % FBN in storage tank~~
~~m = amount fuel added~~
~~n = % FBN of fuel added~~
~~Z = % FBN of composite~~

(***) Ammonia slip emission limitations of 5 ppmvd at SCR exit apply.

5. After the demonstration period and prior to the commissioning of the SCR unit, permittee shall operate the combustion turbine to achieve the lowest possible NO_X emission limit but shall not exceed 25 ppmvd corrected to 15 percent oxygen and ISO conditions. In the event that the SCR is required to be temporarily removed from service, it shall comply with the availability requirements specified in Specific Condition H.8. During this period of time, NO_X emissions from EU-001 shall be limited to 25 ppmvd (syngas) and 42 ppmvd (oil).

8. The installation of an SCR is required within 18 months of the date of issuance of this permit modification. It shall be designed and installed in order to ensure that EU-001 complies with all emission limits specified herein. The availability of the SCR shall be at least 98% as measured on a 12 month rolling average. Availability shall be computed each calendar month based upon the hours of operation during which EU-001 is complying with the specified NO_X emission limits (identified in Table H.1. as 5 ppmvd while firing syngas and 9 ppmvd while firing oil), divided by the hours of operation during which EU-001 is combusting any fuel. Each monthly calculation shall be averaged with the same calculation, which was determined during the prior eleven calendar months of operation. Periods where EU-001 combusts no fuel shall be excluded within the 12 month rolling average. Up to 2 hours in any 24-hour period may be excluded from this average for initial CT firing (i.e. firings of the CT while the steam turbine is off line) as required for startup of the combined cycle unit and placement of the SCR in service.

J. Performance Testing

1. l. The owner or operator shall determine compliance with the ammonia slip limit (of 5 ppmvd) using CTM-027, while simultaneously demonstrating annual compliance with the NO_X emission limit as per Specific Condition J.1.e. The ammonia test and analyses shall be conducted so that the minimum detection limit is 1 ppmvd (I, A)

M. Notification, Reporting, and Recordkeeping

To determine compliance with the syngas and fuel oil firing heat input limitation, the permittee shall maintain daily records of syngas and fuel oil consumption for the turbine and heating value for each fuel. All records shall be maintained for a minimum of five years after the date of each record and shall be made available to representatives of the Department upon request.

Daily records of all hourly NO_X emissions shall be maintained for a minimum of five years. These records may be maintained electronically in a manner, which shall be approved by the Department. Each monthly calculation of the SCR 12-month rolling average availability shall be submitted to the Department annually with the submittal of the AOR, in addition to being available on site at the Department's request.

Documentation verifying that the coal/petroleum coke blends input to the solid fuel gasification system have not exceeded the 60.0 percent (1,395 tons per day) maximum petroleum coke by weight limit and the blended fuel sulfur content of 3.5 percent by weight limit specified by Specific Condition F, shall be maintained and submitted to the Department's Southwest District Office with each annual report.

The permittee shall maintain and submit to the Department, on an annual basis for a period of five years from the date the unit begin firing syngas produced from blends of petroleum coke and coal, data demonstrating that the operational change associated with the use of petroleum coke did not result in a significant emission increase pursuant to 62-210.200(12)(d), F.A.C.

APPENDIX BD - 2001
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT) FOR NO_X

Tampa Electric Company
Polk Power Station
PSD-FL-194 and PA92-32
Polk County, Florida

BACKGROUND

The applicant, Tampa Electric Company (TEC) is responsible for the operation of an existing facility known as the Polk Power Station. This facility is located at 9995 State Route 37 South, Mulberry, Polk County; UTM Coordinates: Zone 17, 402.45 km East and 3067.35 km North; Latitude: 27° 43' 43" North and Longitude: 81° 59' 23" West. The regulated emissions units at the coal gasification facility include a 260 megawatt (electric) combined cycle combustion turbine which fires syngas or No. 2 fuel oil; an auxiliary boiler which fires No. 2 fuel oil; a sulfuric acid plant; a solid fuel handling system; and a solid fuel gasification system.

As per the original PSD permit, (as well as the Site Certification and Title V permit) the combined cycle combustion turbine is now required to undergo a BACT analysis for NO_X only. Specific Condition **H.7.** of the Site Certification document reads as follows: "*One month after the test period ends (estimated to be by June 1, 2001), the Permittee will submit to the Department a NO_X recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_X only and adjust the NO_X emission limits accordingly.*" Based upon existing permit conditions, the test period ended during November 2000.

BACT ANALYSIS:

A BACT analysis was prepared by the applicant's consultant, Environmental Consulting & Technology, Inc. (ECT) and received by the Department on November 27, 2000. The proposal is summarized below:

POLLUTANT	CONTROL TECHNOLOGY	BACT PROPOSAL
NO_X	Syngas firing - N_2 diluent	25 ppmvd @ 15% O_2
	Distillate oil firing – water injection	42 ppmvd @ 15% O_2

This proposal would allow the current (temporary) emission limit to become the BACT determined limit, i.e. would require no major change to the facility configuration.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.

- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Since SIP approval has not been given (by the EPA) to Florida for power plants which are subject to the Power Plant Siting Act (PPSA), the Florida Department of Environmental Protection (FDEP) is acting on behalf of the EPA.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2. (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). Although this BACT determination is required for NO_X only, the applicant's proposal is consistent with the NSPS, which allows NO_X emissions in the range of 110 ppmvd for the unit.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent determinations by states for combined cycle stationary gas turbine projects. This particular review has been limited to gas turbines in the United States which are permitted to combust coal or pet-coke produced syngas. The application of an SCR with a 3.5 ppmvd emission limit represents the typical BACT determination for pipeline natural gas fired combined cycle CT's. Additionally, the application of SCR with an emission limit of 0.125 lb/MMBtu has been determined to represent BACT for a (conventional) Florida coal-fired unit. The applicant's proposed BACT is included for reference.

TABLE 1

RECENT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS WHICH COMBUST SYNGAS

Project Location	Power Output Megawatts	NO_X Emission Rate	Gasification Technology	Comments
Pinon Pine; Sierra Pacific, NV	100	0.07 lb/MMBtu	KRW air-blown pressurized fluidized bed	95% SO_2 removal
Wabash River; Terre Haute, IN	262	0.096 lb/MMBtu	Destec two-stage pressurized oxygen-blown entrained flow	
Kentucky Pioneer **(proposed)**	580	0.07 lb/MMBtu	British Gas / Lurgi slagging fixed bed	99% SO_2 removal
Motiva; Delaware City, DE	240	16 ppmvd	Texaco pressurized oxygen-blown entrained-flow	
TECO POLK; Polk County FL)	260	25 ppmvd (equiv. 0.126 lb/MMBtu)	Texaco pressurized oxygen-blown entrained-flow	96% SO_2 removal

IGCC PLANT INFORMATION:

Many portions of this discussion are extracted from a paper prepared by Jürgen Karg and Günther Haupt, representing Siemens AG Power Generation. The main Features of an Oxygen-Blown Integrated-Gasification Combined Cycle (IGCC) plant are:

1) a gasification plant including preparation of the feedstock
2) raw gas heat recovery systems
3) a gas purification system with sulfur recovery
4) an air separation unit (only for oxygen-blown gasification)
5) a gas turbine-generator with heat-recovery steam generator
6) a steam turbine-generator

The gasifier feedstock is more or less completely gasified to so-called synthesis gas (syngas) with the addition of steam and either enriched oxygen or air. The known fixed-bed, fluidized-bed and entrained-flow gasifiers for coal are basically suited to integration in the combined cycle, as well as the well-proven entrained-flow systems for refinery residues. The selection of a specific gasifier type to achieve the best cost, efficiency and emission levels depends on the type of fuel and the particular application and must be investigated on a case-by-case basis.

In most gasifier systems applied to coal, the sensible heat of the hot raw gas is used in a syngas cooler to generate steam for the steam turbine. In some cases, considerable amounts of steam are generated in this way. This also cools the gas sufficiently that it can be led directly to the gas purification system. An alternative, primarily applied to the gasification of residues, is direct water quench for cooling the produced hot raw gas.

Dust, soot and heavy metal removal are key issues of the initial raw gas purification downstream of syngas cooler and quench system, respectively. Subsequently, chemical pollutants such as H_2S, COS, HCl, HF, NH_3 and HCN are removed, along with the remaining dust. The separated H_2S-rich gas stream, known as acid gas, is processed to recover saleable elemental sulfur. Downstream of the gas purification system, the clean gas is reheated, saturated with water if necessary (NO_X reduction) and supplied to the gas turbine combustion chamber. In this way, low-level heat can be used and gas turbine mass flow is increased. The air separation unit (ASU) generates the more or less enriched oxygen supply necessary for the gasification process. The inevitably (co-produced) nitrogen from the ASU is preferably used in the gas turbine cycle (e.g. diluent injection), and, in case of coal, smaller amounts for transportation of the solid fuels to the gasifier and for inerting purposes.

In addition to air for the combustion chambers, the compressor of the gas turbine-generator also supplies all or part of the air for the ASU. Nitrogen from the air separation unit is mixed with the purified gas to prevent temperature peaks in the low-NOx burners, and to increase the mass flow rate (including MW output) in the gas turbine. In the case of air-blown gasification, the extracted air is supplied directly to the gasifier following additional compression.

The hot exhaust gases from the gas turbine generate steam for the steam turbine in an unfired heat-recovery steam generator before they are discharged via the stack. The steam turbine is supplied with steam from the gas turbine heat-recovery steam generator (HRSG).

TEXACO GASIFIER INFORMATION:

Much of this information was obtained from a paper presented by William Preston of Texaco in October, 2000. The Texaco Gasification Process (TGP) is utilized for the conversion of heavy oils, petroleum coke, and other heavy petroleum streams, to valuable products. According to Texaco, in the year 2000, the commercial acceptance of the technology for the production of power, hydrogen, ammonia, and other chemicals reached a record number of startups and capacity additions. In all, twelve new commercial TGP plants were or will be started up in six countries. The feedstocks for these plants include coal, petroleum coke, natural gas, and a wide variety of low-valued heavy oil streams. The total syngas production capacity from these new projects totals 1375 million standard cubic feet per day, increasing the total operating capacity of the TGP around the world by more than fifty percent.

As noted, in the calendar year 2000, twelve projects using the TGP will (or did) startup. These break down geographically as follows: In Asia, two projects are in China, and two are in Singapore. In Europe, three projects are in Italy, and one is in Germany. Three projects are in the U. S., and the twelfth project is in Australia. Eight of the projects are fed by some type of heavy oil, three by coal or petroleum coke, and one by natural gas. Power and steam are the main products of five of the projects. Three of the projects mainly produce ammonia, two produce syngas for sale to a merchant chemicals market, one produces methanol and one produces hydrogen. In all, 1375 million standard cubic feet per day (MMscfd) of new syngas capacity will be added to the previously operating 2100 MMscfd capacity of TGP generated syngas worldwide. The eight new oil fed projects generate 1083 MMscfd, or 79%, of this syngas. Solid feeds such as coal or petroleum coke generate 262 MMscfd, or 19%. The remaining 2% is generated by a natural gas fed TGP unit.

The twelve TGP projects scheduled for year 2000 startups are listed below with pertinent information:

NAME	COUNTRY	OUTPUT	THRU-PUT	FEEDSTOCK
ISAB	Italy	500 MW	3174 sTPD	Deasphalter bottoms from the ISAB Sicily refinery in Priolo Gargallo, Siracusa
API	Italy	250 MW	1470 sTPD	Visbreaker residue from the API refinery in Falconara
Saras (Sarlux)	Italy	250 MW	3771 sTPD	Visbreaker residue from the Saras refinery in Sarroch, Cagliari.
DEA	Germany	methanol	600 sTPD	Heavy oil from the DEA refinery in Wesseling, Germany
Huainan	P.R. China	ammonia	990 sTPD	Coal
Nanjing	P.R. China	ammonia	850 sTPD	Heavy Oil
SSPL	Singapore	syngas	630 sTPD	Heavy Oil from local Caltex refinery
Exxon	Singapore	160 MW	1019 sTPD	Steam cracker tar
BOC	Australia	hydrogen	15 MMscfd	Natural gas
Baytown	USA (La.)	syngas	1213 sTPD	Deasphalter bottoms from the adjacent Exxon Mobil refinery
Farmland	USA (Kan.)	ammonia	1084 sTPD	Petcoke from Coffeyville refinery
Motiva	USA (Del.)	180	2300 sTPD	Petcoke from adjacent refinery

In addition to the above, Repsol and Iberdrola are planning to construct an IGCC facility in Spain, which will be based upon the Texaco gasifier with vacuum column residue feedstock. The planned 2004 startup of the 1654 MW (thermal) facility will represent the largest single generating facility based upon the TGP.

COMBUSTION TURBINE INFORMATION:

The combustion turbine utilized at the Polk Power Station is a General Electric 107FA. As a result, the Department has elected to incorporate pertinent portions of GE published information relative to their combustion turbine experience in the area of gasified fuels.

As of June 1998, General Electric had 10 units in operation on synthesis gas from the gasification of coal, petroleum coke and other low-grade fuels. According to GE, an additional twelve units for gasification applications were on order, or already shipped, with startup dates ranging from 1999 through 2001. These turbines include the full range of the GE products: one PGTIOB, one Frame 7E, two Frame 7FA's, five Frame 6B's six Frame 6FA's, six Frame 9E's, and one 9FA.

The IGCC projects include various levels of integration with the gasification plant, ranging from steamside integration only on many projects, to nitrogen return (Tampa, Motiva), and full steam and air integration including both air extraction and nitrogen return (EI Dorado, Pinon Pine). GE turbines are in operation on syngas from gasifier technologies by Texaco (solid fuels and oil), Destec (coal), GSP (coal and waste), Shell (oil), and operation with the Lurgi gasifier (biomass) is scheduled for operation in 2001.

In addition to synthesis gas applications, GE also has numerous turbines in operation on other special fuel gases, including refinery gases containing hydrogen, butane, propane, ethane, and blends of various process gases. These units include six Frame 3's, seventeen Frame 5's, 19 Frame 6's, and 15 Frame 7EA's.

The table below summarizes these applications, and is followed by a brief description of each project.

TABLE 2 - THE FOLLOWING IGCC POWER PLANTS ARE OPERATING, UNDER CONSTRUCTION OR ON ORDER:

Project	Location	COD	MW	Power Block	Fuel
Cool Water IGCC	Barstow, California	1984	120	107E	Coal
PSI Wabash River	Terre Haute, Indiana	1996	262	7FA	Coal
Tampa Electric	Polk, Florida	1996	250	107FA	Coal
Pinon Pine	Sparks, Nevada	1996	100	106FA	Coal
Texaco El Dorado	El Dorado, Kansas	1996	40	6B	Pet Coke
ILVA ISE	Taranto, Italy	1996	520	3xI09E	BFG/COG
SvZ	Schwarze Pumpe, Germany	1996	40	6B	Coal/Waste
Shell Pernis	Pemis, Netherlands	1997	120	206B	Oil
Fife Energy	Fife, Scotland	1999	109	106FA	Coal/Waste
Motiva Enterprises	Delaware City, Delaware	1999	180	2-6FA	Pet Coke
Sarlux	Sarroch, Italy	2000	550	3x109E	Oil
Fife Electric	Fife, Scotland	2000	350	109FA	Coal/Waste
Exxon Singapore	Jurong Island, Singapore	2000	173	2-6FA	Oil
IBIL Sanghai	Gujarat, India	2001	53	106B	Coal
Bioelettrica TEF	Cascina, Italy	2001	12	PGT10B/CC	Wood/Waste

Cool Water
The Cool Water Coal Gasification Program was the first commercial demonstration of integrated coal gasification combined cycle power generation. The gasification island included a 1200-ton per day, oxygen-blown Texaco gasifier with full heat recovery using both radiant and convective syngas coolers.

Wabash River (PSI)
The Wabash River Coal Gasification Repowering Project is a joint project between the U.S. Department of Energy and a Joint Venture formed in 1990 between Destec Energy Inc. and Public Service of Indiana (PSI). The gasification island includes a Destec two-stage, oxygen blown gasifier including full heat recovery steam integration with the power island.

Tampa Electric
The Tampa Electric Co. Polk Power coal gasification project is partially funded by the U.S. Department of Energy, and includes a Texaco oxygen blown gasifier with full heat recovery using both radiant and convective syngas coolers. Process syngas, steam, and nitrogen are integrated with the GE STAG-107FA power block.

Pinon Pine
The Pinon Pine Power Project - Undertaken by Sierra Pacific Power Company at its Tracy station in Sparks, Nevada, with support from the U.S. Department of Energy, includes a KRW air-blown fluidized bed gasifier with hot gas cleanup. Air extraction from the GE 6FA gas turbine is integrated with the process island to produce high temperature low Btu syngas for the 100 MW combined cycle power block.

Texaco El Dorado
The El Dorado gasification facility, developed by Texaco Alternative Energy Inc., is fully commercial without government subsidies. The project incorporates a Texaco oxygen blown quench type gasifier fired on a mixture of petroleum coke (approx. 166 tpd), and about 15 tpd of waste streams provided from the Texaco refinery site in El Dorado, Kansas. A 35 MW GE MS6001B gas turbine is co-fired with syngas and natural gas to meet the refinery's total internal power needs.

ILVA- ISE
The ILVA Sistemi Energia (ISE) cogeneration project is located at the ILVA steelworks in Taranto, Italy. Three GE 109E combined cycle units operate on a variable mixture of compressed steel mill recovery gases (coke oven gas, blast furnace gas, and LD furnace gas), which normally combine to an equivalent low heating value fuel (140 Btu/scf-LHV). The combined facility output is 520 MW, with 150 tons/hr of steam feed to the steel mill. Each gas turbine generator unit is directly coupled to a centrifugal fuel gas compressor in a single shaft lineup with a separate steam turbine generator unit.

Schwarze Pumpe
The Sekundarrohstoff-Verwertungszentrum Schwarze Pumpe GmbH (SVZ) is a waste utilization facility, established and privatized in 1995. The facility contains seven fixed bed gasifiers, which gasify a mixture of waste combustibles with the help of oxygen and hydrogen. The synthesis gases from these facilities are used for methanol production and to fuel a combined cycle plant built around a MS6001B gas turbine provided by Thomassen under GE license. The turbine also combusts purge gas from the methanol plant and operates on distillate as backup and startup fuel.

Shell Pernis
The PER+ project is an upgrade of the existing Shell Pernis refinery. A new hydrocracker unit was added for the conversion of heavy, high-sulfur crudes into light low-sulfur fuels. Hydrogen required for the conversion process is supplied by the Shell Gasification Hydrogen Process plant, which gasifies heavy residues with oxygen and water to yield syngas. Most of the hydrogen is then removed to feed the hydrocracker, and the depleted syngas is then used as fuel in a combined cycle cogeneration facility. The syngas is blended with LPG and/or natural gas when the heating value in combination with the amount of

the syngas is insufficient for the desired load of the turbines. The turbines can also fire 100% natural gas, which is used for startup and as backup fuel.

Fife Energy

Global Energy Inc., as owner of the Westfield Development Center in Fife, Scotland is developing a new Advanced Fuel Technology (AFT)-IGCC power project (Fife Energy), at an existing gasification test facility. The 109 MW GE 106FA combined cycle power block is fueled by syngas produced from the oxygen-blown British Gas/Lurgi staging gasifier and natural gas. A wide variety of organic waste feedstocks including MSW and MSP, which can be mixed with petroleum coke or coal, are compressed into briquettes that are gasified under pressure to produce a medium Btu syngas.

Motiva Enterprises

The Motiva IGCC project is a cogeneration project located at the Star refinery at Delaware City, Delaware. This gasification system incorporates the Texaco oxygen-blown high-pressure quench process design, using petroleum coke from the refinery as feedstock. The 180 MW net power block output is produced from two GE 6FA gas turbine units operating on syngas, with nitrogen return for NO_X control. Power production services the internal IGCC loads, with surplus power being sold into the Delmarva utility system.

Sarlux

The Sarlux IGCC project company will own and operate a 550 MW cogeneration project to be sited at the Saras oil refinery located in Sarroch Italy, on the island of Sardinia. Three Texaco oxygen blown low-pressure quench gasifiers are used to produce a dry medium Btu syngas from vacuum visbroken residue (tar) feedstock, for the co-production of power and hydrogen. Three GE 109E single-shaft combined cycle units each gross 186 MW of power on moisturized syngas at 77F, and provide 285-tons/hr total process steam to the refinery.

Fife Electric

Global Energy Inc., is expanding their Environmental Energy Park at the Westfield site to include another Advanced Fuel Technology-IGCC project called Fife Electric, which will provide an additional 350 MW to the facility. Power block will be fueled by a mixture of natural gas and syngas produced from additional new oxygen-blown British Gas/Lurgi slagging gasifiers. The combined cycle plant co-fires a mixture of dry syngas, nitrogen, and natural gas, and uses steam injection for NO_X control.

Exxon Singapore

The Exxon Singapore IGCC project uses the Texaco oil-gasification process as part of a major expansion program for the existing refinery, to produces syngas feeding two GE 6FA gas turbines coupled with single-pressure supplementary-fired HRSGs. When natural gas becomes available at the site, the units will be converted to use natural gas for startup, co-firing, and backup fuel operation. The gas turbines will normally be fired on a combination of the backup fuel and syngas, and the amount of syngas will vary depending on the hydrogen demand of the refinery.

IBIL Sanghi

The project is based on the air blown pressurized fluidized bed gasification of lignite, with hot gas cleanup, and a GE 106B combined cycle system. Air supply to the gasifier is first extracted from the gas turbine and increased in pressure using a boost compressor. Raw product gas is cooled after the cyclone separator by a fire tube heat recovery boiler producing high-pressure steam for use in the steam turbine.

Bioelettrica (TEF)

This is a biomass IGCC project initiated by the European Commission in 1994. This net 12.1 MW project incorporates a Lurgi atmospheric, air blown circulating, fluidized-bed (CFB) gasifier, integrated with a Nuovo Pignone PGTIOB single-shaft, heavy-duty gas turbine. Fuel supply to the gasifier is a combination of short rotation forestry (SRF) wood, and agricultural and forestry residues.

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, some of the key information reviewed by the Department includes:

- Noell SCR Training Manual for OUC Stanton Energy Center Unit 2
- "Improved SCR Control to Reduce Ammonia Slip", K. Zammit (EPRI), A. Engelmeyer (OUC) 2000
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island 3
- Polk Power Station reports to DOE (various)
- Pinon Pine reports to DOE (various)
- Wabash River reports to DOE (various)
- E & A Associates report on the application of zinc titanium pellets for coal gasifiers
- Technical reports (several) concerning coal gasification, prepared by Dr. H. Christopher Frey, Associate Professor, North Carolina State University
- Study reviewing a Texaco based IGCC power plant (published in U.K.)
- "Repowering Conventional Coal Plants with Texaco Gasification", Cynthia Caputo, Paul Wallace and Leslie Bazzoon
- Review of Claus process prepared for the USEPA
- "Status of IGCC" Adapted from a paper presented by Lowe, Benyon, and O'Neill, dated January 1998
- 1999 EPRI Gasification Technologies Conference
- "A Membrane Reactor for H_2S Decomposition", D. Edlund
- "Phillips Sorbent Development for Tampa Electric...", Phillips Petroleum Company
- "Development of Disposable Sorbents for Chloride Removal from High Temperature Coal-Derived Gases"; SRI, Research Triangle and GE
- "Wabash River Coal Gasification Repowering Project", E.J. Troxclair and Jack Stultz
- "Clean Coal Technology Evaluation Guide – Final Report", December 1999, DOE
- "Microbial Sweetening of Low Quality Sour natural Gas", Charanjit Rai, Texas A & M University
- "Technical Guidance – Oil and Gas Processes", published by U.K. Environment Agency
- BACT proposal prepared for Kentucky Pioneer Energy
- Mitsubishi Documentation on SCR applications
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Kennedy Plant Project
- "Oil & Gas Journal", several issues.
- TNRCC NOx Rule Log No. 2000-011H-117

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion. Fuel NO_X is formed when fuels containing bound nitrogen are burned.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions as high as 200 ppmvd @15% O_2 for the subject TEC combustion turbine. The proposed NO_X control (diluent injection) reduces these emissions significantly.

NO_X Control Techniques

Diluent Injection

Water, steam (or in this case nitrogen) is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NO_X emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Nitrogen and steam injection use the same principle, excluding the heat required to vaporize the water. Therefore, much more diluent is required (on a mass basis) than water to achieve the same level of NO_X control (e.g. approximately 6000 TPD at this facility). However, there is a physical limit to the amount of any diluent that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Advanced combustor designs with injection can achieve NO_X emissions of 25/42 ppmvd for gas/oil firing, resulting in 60% to 80% control efficiencies. This is the technology recommended by the applicant.

Combustion Controls

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% and 100% of base load and provides the lowest NO_X emissions. Due to the intricate air and fuel staging necessary for dry low-NO_X combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date outside of California. SCR units are typically used in combination with diluent injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming commonplace and have recently been specified for CPV Gulf Coast (PSD-FL-300). In that review, the Department determined that SCR was cost effective for reducing NO_X emissions from 9 ppmvd to 3.5 ppmvd on a General Electric 7FA unit burning natural gas in combined cycle mode. This review additionally concluded that the unit would be capable of combusting 0.05%S diesel fuel oil for up to 30 days per year while emitting 10 ppmvd of NO_X. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan. These newer catalysts (versus the older alumina-based catalysts) are resistant to sulfur fouling at temperatures below 770°F (EPRI). In fact, Mitsubishi reports that as of 1998, SCR's were installed on 61 boilers which combust residual oil (40 of which are utility boilers) and another 70 industrial boilers, which fire diesel oil. Likewise, B & W reports satisfactory results with the installation of SCR to several large Taiwan Power Company utility boilers, which fire a wide range of coals, as well as heavy fuel oil with sulfur contents up to 2.0% and 50 ppm vanadium. Catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) currently employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project and Kissimmee Utility Authority will install SCR on newly permitted Cane Island Unit 3. New combined cycle combustion turbine projects in Florida are normally considered to be prime candidates for SCR and today are routinely permitted as such (as noted on page 2).

Figure B is a photograph of FPC Hines Energy Complex. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. Figure C below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems, where the temperature requirements for conventional SCR can be met.

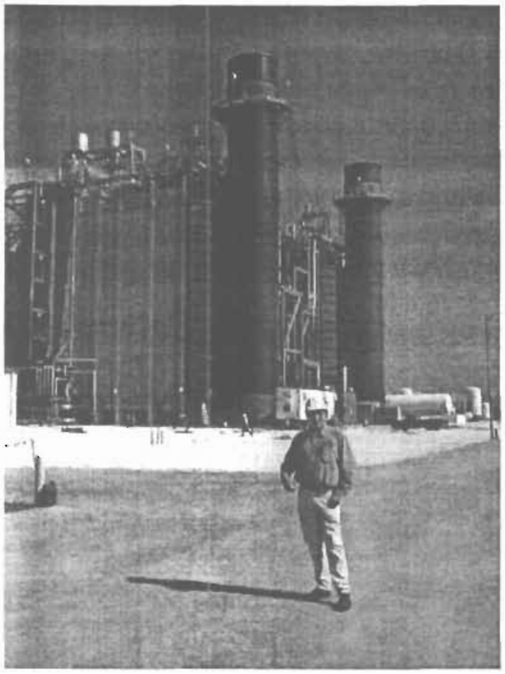


Figure B

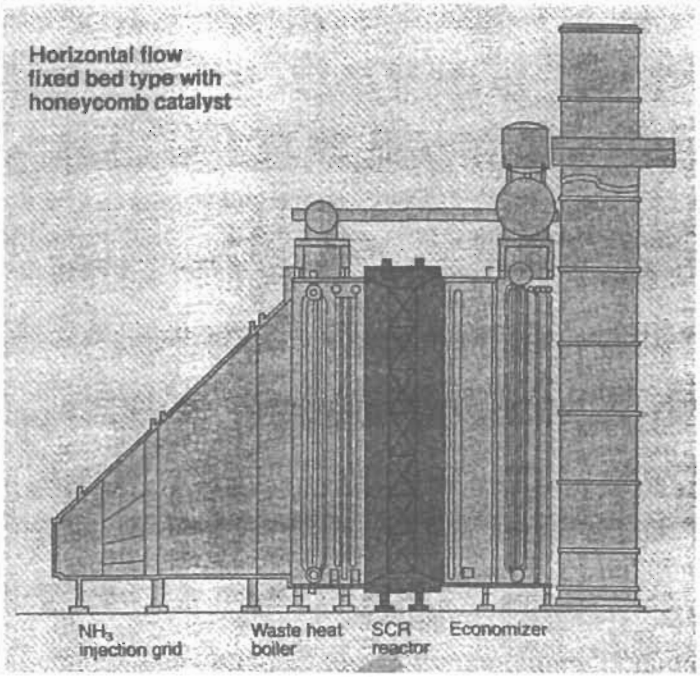


Figure C

Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country. Permit BACT limits of 3.5 ppmvd NO_X are being routinely specified using SCR for F Class projects (with large in-line duct burners) in the Southeast and even lower limits in the southwest. This technology will be further reviewed for this specific application.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) reduction works on the same principal as SCR. The differences are that it is applicable to hotter streams than conventional SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market an SNCR for NO_X control within the temperature ranges for which this project will operate (700 – 1400°F). The process also requires a low oxygen content in the exhaust stream in order to be effective. Although SNCR may be applicable for this project, a top-down review requires a further evaluation of more stringent technologies.

Emerging Technologies: SCONOx^{TM} and XONON^{TM}

SCONOx^{TM} is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts. California regulators and industry sources have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx ^{TM}. The overall project includes several more 250 MW blocks with SCR for control. According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E has been approved to install SCONOx^{TM} on two F frame units at Otay Mesa, approximately 15 miles S.E. of San Diego, California. Additionally, USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system.

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include (in addition to the reduction of NO_X) the elimination of ammonia and the control of VOC and CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently only due to cost considerations. The Department is interested in seeing this technology implemented in Florida and intends to continue to work with applicants seeking an opportunity to demonstrate ammonia-free emissions on a large unit. The applicant estimates that the application of this control technology to the Polk Power Station results in cost-effectiveness of $10,820 per ton of NO_X removed. Although there are specific items within the applicant's analysis that the Department does not support, on balance the Department concurs with the conclusion that $SCONO_X$ is likely not cost-effective for this project. However, given the applicant's concerns for ammonia bisulfate formation (see pages that follow) the Department believes that it may very well be an appropriate control technology for this application and is not opposed to reconsidering the cost effectiveness, given the opportunity.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as SCONOx™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

On February 8, 2001, Catalytica Energy Systems, Inc. announced that its XONON™ Cool Combustion system had successfully completed an evaluation process by the U.S. Environmental Protection Agency (EPA), which verified the ultra-low emissions performance of a XONON™-equipped gas turbine operating at Silicon Valley Power. The performance results gathered through the EPA's Environmental Technology Verification (ETV) Program provide high-quality, third party confirmation of XONON™ 's ability to deliver a near-zero emissions solution for gas turbine power production. The verification, which was conducted over a two-day period on a XONON™-equipped Kawasaki M1A-13A (1.4 MW) gas turbine operating at Silicon Valley Power, recorded nitrogen oxides (NO_X) emissions of less than 2.5 parts per million (ppm) and ultra-low emissions of carbon monoxide and unburned hydrocarbons.

The XONON™-equipped Kawasaki M1A-13A gas turbine has operated for over 7400 hours at Silicon Valley Power (SVP), a municipally owned utility, supplying essentially pollution-free power to the residents of the City of Santa Clara, California, with NO_X levels averaging under 2.5 ppm. Enron Energy Services North America, Kawasaki and Catalytica recently signed contracts for the installation of three XONON™-equipped 1.4MW Kawasaki GPB15X gas turbines in Massachusetts, at a healthcare facility of a U.S. Government agency. These turbines will enter service in late 2001.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. However, the technology cannot (at this time) be recommended for the attendant project.

PLANT SPECIFIC ANALYSIS

Based upon the information presented thus far, an initial BACT determination for a new IGCC facility would likely result in either the application of an SCR or the imposition of a NO_X emission rate between 0.07 lb/MMBtu and 0.096 lb/MMBtu (approximately 14 ppmvd and 19 ppmvd respectively). Either of these outcomes is more stringent than what the applicant had proposed. The following arguments have been made by the applicant in support of its conclusion to reject the use of an SCR on this project.

Applicant Comment: Although EPA has established BACT for NO_X emissions on combined cycle combustion turbines as 3.5 ppmvd, Polk Unit 1 fires syngas. The fuel differences are adequately significant to consider Polk as a separate and unique facility.

Department Response:. A review of the estimated differences for SCR inlet streams follows (based upon one 1760 MMBtu/hr turbine). Shaded areas represent those parameters where syngas emissions appear to be an area of possible concern for the application of an SCR when compared to other fuels:

Pollutant	Syngas [a]	Natural gas [b,c]	Refinery Gas [f]	#2 Fuel Oil [b,d]	Coal [e]
SO_2 – lb/MMBtu	0.032 – 0.146	0.0006	0.029 – 3.31	0.051	3.5
H_2S, SO_2 or SO_3	40 ppm $S0_2$	< 4 ppmvd H_2S	< 200 ppmvd H_2S		25 ppmvd SO_3[g]
Trace metal	**10^6 lb/MMBtu**	**10^6 lb/MMBtu**	**10^6 lb/MMBtu**	**10^6 lb/MMBtu**	**10^6 lb/MMBtu**
Arsenic	6.0	0.20	0.85	11	16
Beryllium	0.60	0.012	0.257	0.31	0.81
Cadmium	5.0	1.1	0.99	4.8	2.0
Chromium	1.1	1.4	2.17	11	10
Cobalt	12	0.08	ND	ND	3.8
Lead	10	ND	4.89	14	16
Manganese	4.0	0.37	6.81	790	19
Mercury	0.70	0.25	0.18	1.2	3.2
Nickel	310	2.1	9.42	52	11
Selenium	1.4	0.024	0.012	ND	50

a Emission factors from Kentucky Pioneer PSD permit application; sulfur compounds obtained from TEC publications and Acid Rain website
b Emission factors from AP-42, Section 3.1
c Trace Metal emission factors from AP-42, Section 1.4
d Sulfur Factor was multiplied by sulfur wt% in fuel (0.05); Nickel emission factor from
MEMORANDUM: HAP Emission Control Technology for New Stationary Combustion Turbines
e Factors from AP-42 Section 1.1: PC, dry-bottom, tangentially fired, sub-bituminous, pre-NSPS and from DOE Conference on SCR, May 1997
f Factors from CARB report dated August 14, 1998; SO_2 and H_2S factors from reports by the European Environment Agency;
g Obtained from OUC Stanton Energy Center: not a fuel quality, but represents SO_3 design-basis at SCR inlet

The Department finds that fuel differences do exist, yet predominantly in the area of nickel and (perhaps) cobalt. However, SCR has been applied to coal facilities (Indiantown Cogeneration and Orlando Utilities Stanton Energy Center) as well as to the combustion of refinery gas where BAAQMD has set SCR as BACT (re: Tosco Refining Co., Wilmington, CA; Mobil Oil refinery, Torrance, CA; Scanraff refinery, Lysekil Sweden, and at least 7 Japanese refineries). In fact, an IGCC facility with SCR is currently proposed at a Polish refinery (Gdansk) with a varied feedstock of oils and refinery resids. It is noteworthy that BP Amoco is sponsoring a project to investigate next generation LNB technology, as SCR is one of the few control technologies that can reduce refinery NO_X emissions to levels required in the Houston-Galveston area. This review suggests that the application of an SCR cannot be rejected purely on technical grounds. This has been confirmed (and reconfirmed at the Department's request) by the ability of TEC to obtain performance guarantees from at least one manufacturer (Engelhard).

Applicant Comment: Other collateral environmental impacts should be considered for this installation when performing a BACT evaluation. Draft guidance from John S. Seitz, director of the Office of Air Quality Planning and Standards dated August 4, 2000 allows for the consideration of collateral environmental impacts associated with the use of SCR on dry low NO_X natural gas fired combined cycle combustion turbines. Although Polk Unit 1 is a syngas fired combined cycle combustion turbine utilizing multinozzle quiet combustors, TEC feels that collateral environmental impacts should also be considered for this installation when performing a BACT evaluation. Several parties have commented on this draft guidance including the Department of Energy (DOE) and the Utility Air Regulatory Group (UARG). In an enclosed written opinion, DOE supports the draft guidance noting that, among other things, the establishment of the use of SCR as BACT for natural gas fired combined cycle facilities will:

1) Slow research and development of efficiency and performance improvement in advanced combustion turbines;
2) Slow the development of other non-ammonia based NO_X control technologies; and
3) Create a situation in which the units containing SCR become more expensive to operate, thus lowering their position in a system dispatch order and allowing dirtier plants to operate higher in the dispatch order. This will have the effect of increasing overall emissions despite the use of SCR on an already relatively clean unit.

Integrated Gasification Combined Cycle (IGCC) Technology is still in the early stages of development and provides a mechanism for the combustion of coal while minimizing air emissions. In fact, Polk Unit 1 was constructed as part of the Department of Energy's Clean Coal Technology program. If SCR is established as BACT for Polk Unit 1, it could impact the further development of this technology. Furthermore, if SCR becomes BACT for this type of installation, it could slow the development of further advances in combustion technology for clean coal facilities such as Polk Unit 1 by increasing the cost of an already high cost technology. In addition, although SCR has never been applied to a domestic IGCC facility, there is no evidence or operating experience that indicates that the application of SCR to an IGCC facility can be successfully accomplished as described in Section 8 of the BACT Analysis. If this occurs, Tampa Electric Company could be forced to operate other coal fired units in lieu of Polk Unit 1, resulting in an actual overall increase in NO_X emissions in the Tampa Bay area.

Department Response: Concerning the draft guidance and related comments, the Department offers no review within this BACT determination. However, in response to those issues raised in the final paragraph (which are specific to Polk), the Department has the following responses.

(1) Under the presumption that the application of SCR to the Polk Station offers no technical issues beyond those encountered at other facilities, added cost would have the most likely potential to impact the development of IGCC technology. To evaluate the cost impacts that would result from the installation of SCR as BACT, the Department will utilize TEC's estimated costs minus the "annual electrical loss penalty", which the Department believes is inappropriate.
Capital Cost impact: Approximately 1.5% ($4.5M as compared to $303M)
Production Cost impact: < 3.0% (4.58 cents/kWh as compared to 4.46 cents/kWh)
Although these are not insignificant, the Department believes that the increases are not likely to represent a major impediment in the further deployment of the technology.

(2) TEC suggests that the application of an SCR may result in it being forced to operate other coal-fired units in lieu of Polk 1, causing an overall increase in NO_X emissions in the Tampa Bay area. Although the Department's analysis does not support this conclusion, the most likely cause of this occurrence would seem to be SCR-induced, unscheduled shutdowns. In order to accommodate TEC's concern, the permit conditions will be structured to allow for this type of unexpected problem.

Applicant Comment: It is extremely important to draw the distinction between a natural gas fired combustion turbine and a syngas fired combustion turbine when applying the EPA determination; as the fuels are completely different. While natural gas is mainly composed of methane and almost completely free of sulfur and sulfur containing compounds, syngas is mostly composed of hydrogen and carbon monoxide, and also contains some carbonyl sulfide as well as hydrogen sulfide. Upon combustion, these sulfur-containing compounds are oxidized to form SO_2, and upon passage through an SCR system, most of the SO_2 is further oxidized to SO_3. When combined with water and the excess ammonia required by the SCR system for optimal NO_X removal, the sulfur oxides in the exhaust gas form ammonium bisulfate and ammonium sulfate. According to a paper authored by General Electric (within the TEC submittal), these compounds are responsible for plugging in the HRSG, tube fouling, and increased emissions of PM.

Department Response: Although these concerns are understandable, they are the similar in nature to past concerns related to coal firing. During the mid-1990's, DOE sponsored testing such as "Demonstration of SCR Technology for the Control of NO_X Emissions from High-Sulfur Coal-fired Utility Boilers" for the combustion of coals with sulfur contents ranging from 2.5 – 3.0%. Currently, the actual field use of SCR's for high-sulfur coal has been able to show that with a careful examination of catalyst characteristics suited to the specific application, the technology may be properly applied. In fact, with respect to catalyst SO_2 oxidation, W.S. Hinton & Associates have concluded that in practice, all SCR suppliers would likely be able to meet a customer's specific SO_2 oxidation requirements.

Given that an SCR supplier has proposed guarantees for this project, there is little reason for the Department to question the ability of the equipment to reduce NO_X to a limit of 3.5 ppmvd at the Polk Power Station. Of remaining concern is the applicant's contention (supported by a paper from General Electric) that the use of sulfur bearing fuels in conjunction with SCR may lead to fouling of downstream components such as the back passes (lower temperature regions) of the HRSG (walls and associated heat transfer surfaces). According to the GE paper, the cause of this is due to ammonium bisulfate formation, which is supported by the aforementioned DOE work as well as actual practice.

In order for ammonium bisulfate to form, excess ammonia (referred to as slip) must be present in conjunction with sulfur compounds. Minimization of NH_3 slip is also a major operational and design concern in the application of SCR to coal-fired boilers, as U.S. high-sulfur coal may form much more SO_3 in the boiler. The condensation of NH_4HSO_4 is a sticky, corrosive material that can cause corrosion problems. Factors that contribute to NH_4HSO_4 formation are the temperature, catalyst composition and the concentration of NH_3 and NO_X in the flue gas. The influence of temperature and catalyst composition is interdependent. The amount of SO_3 present is due to two factors: the amount formed in the boiler itself and the amount that formed by the catalytic oxidation of SO_2 to SO_3 in the SCR unit. Higher flue gas SO_2 content will likely cause more SO_2 to be converted to SO_3 in the SCR reactor, thereby aggravating the NH_4HSO_4 formation problems. Of course, if there is no ammonia slip, the compound may not form. According to the GE paper cited by TEC, "The only effective way to limit the formation ammonia salts appears to be to limit the sulfur content of the fuel to very low levels (or switch to a sulfur free fuel such as butane) and/or limit the excess ammonia available to react with the sulfur oxides." The paper additionally suggests that "Limiting the ammonia that is available to react with the sulfur oxides to negligible levels does not appear practical at NO_X removal efficiencies above 80%...(but) may work at lower NO_X removal efficiencies". Since Mitsubishi reports that SCR's are in use on 40 utility boilers firing residual oil (with average sulfur content > 1%), the latter GE recommendation appears more logical for Polk Power Station. In consideration of these concerns, the Department will restrict the ammonia slip to < 5ppm, and set the NO_X emission limit at 80% removal (5 ppmvd syngas and 9 ppmvd oil).

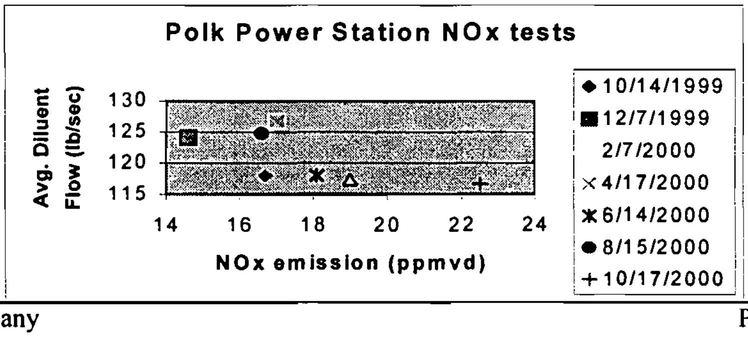
Applicant Comment: The cost to control NO_X emissions through the use of an SCR system on Polk Unit 1 presented in the analysis submitted to FDEP was based on a limited number of estimated costs. Since SCR has not been required for any IGCC installation in the United States, it is not possible to compare the cost of installing an SCR at the Polk facility to the cost of installing an SCR at another IGCC facility. The conclusion that SCR must be applied to Polk Unit 1 simply because the cost of NO_X control is lower than what the cost of NO_X control might be at the CPV Gulf Coast facility does not seem to take into account environmental, energy, and other costs as prescribed in the definition of BACT. In addition, this conclusion does not seem to consider the operation of 'other similar facilities' or 'manufacturer's research' as called for in Specific Condition A.50 of the Polk Power Station Title V Permit.

Department Response: It does not seem unreasonable to review the cost of applying an SCR to TEC's Polk Unit 1 (an IGCC unit) as it compares to the cost of applying an SCR to a gas/oil fired combined cycle unit. In fact, such a review leads to an initial conclusion that there is little difference in these costs.

TEC has submitted an analysis concluding that the annualized cost of applying SCR to Polk Power Station is $4,061,000. As mentioned earlier in this Determination of BACT, one line item within that analysis lists an annualized cost of $1,934,400 for "Unscheduled Outages". According to the submittal, the majority of this figure ($1,814,400) is attributable to replacement power costs of $20/MWH for an assumed 12 days annually of unscheduled outages. Two similar line items exist ($363,000 each) for lost power costs due to the pressure drop across the catalyst in a clean configuration and an additional cost for when the catalyst is assumed to be fouled. Although it is appropriate to calculate the costs of using additional natural gas to compensate for the power consumption resulting from pressure drops across the catalyst bed, lost revenue should not be included in the analysis and should be omitted. Since the basis of these costs was $0.04/kwh, the Department presumes that each cost was developed based upon some measure of lost revenue and not increased natural gas costs. Accordingly, the Department will reject these line items, as inappropriate, which is consistent with EPA comments on previous analyses and in line with the Department's view in calculating cost effectiveness. The resulting annualized cost of applying SCR to Polk Unit 1 ($1,520,600) yields a cost effectiveness of under $2,000 per ton of NO_X removed. This is less than similar recent analyses submitted by other applicants for other projects (approximately $2500/ton for OUC's Stanton new combined cycle unit and $4,400/ton for JEA's Brandy Branch "repowering"). According to Polk Power Station's Title V permit (Specific Condition **A.50.**):

A.50. *One month after the test period ends (estimated to be by June 1, 2001), the permittee shall submit to the Department a NO_X recommended BACT Determination as if it were a new source, using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination of BACT for NO_X only and adjust the NO_X emission limits accordingly.*

Lastly then, an analysis of the data gathered from the facility is in order. Two sets of data exist: one which represents seven "full load tests" which were completed between October 1999 and October 2000, and the other is comprised of data from continuous emission monitoring systems (CEMS). Regarding the former, the data is represented on the chart below:



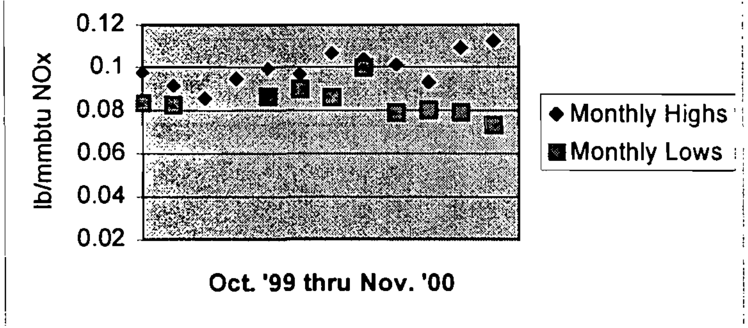
TEC has cautioned against an analysis of NO_X emissions as compared to diluent flow, noting that "*although the diluent flow is an important parameter for controlling NO_X emissions, a more appropriate measure is the ratio of diluent flow to syngas flow. On an overall basis, this ratio represents the proportional flows of NO_X controlling diluent and the syngas flow. Additional complicating factors that prevent a straightforward linear analysis of diluent flow rate or ratio and the NO_X emissions rate include the varying composition of the syngas, and the heating value of the fuel. Although these data are presented, TEC recommends against using these data to establish firm operating ranges due to the variability in other factors that significantly contribute to NO_X emissions from this combustion turbine.*" Since diluent flow will likely increase with generating load (up to some load point) and since syngas flow is directly proportional to unit load, it is likely that a measure of diluent flow to syngas flow (which the applicant purports is more appropriate) makes some sense, as in the case of reviewing the entire load range of a combustion turbine. However, the Department wishes to better understand the impact of diluent flow on NO_X emissions, given that the diluent is the control media for NO_X. Since the tests are at a similar load point, the syngas flow and its associated variability can be effectively ignored. This yields a chart similar to the one above, indicating some level of correlation (albeit with 7 data points) between the diluent flow and NO_X emissions. Given the very limited amount of tests, one initial conclusion which might be drawn is that NO_X emissions are likely to be less than 19 ppmvd if the diluent flow is held to 120 lb/sec or higher.

Regarding the latter set of data (from the CEMS), 14 months of data was reviewed, with the month of March 2000 ignored due to low operating time. In order to understand the range of data with respect to syngas NO_X emissions, only days where daily hours of operation firing syngas equaled 24 (all day) were analyzed. From this data set, the 5 highest and lowest daily average NO_X emission rates (in lb/MMBtu) were computed. This led to the chart below, with the lowest values during the months of December 1999 and January 2000 excluded due to calculated values around 0.01 lb/MMBtu. The following preliminary conclusions are drawn from this analysis:

1) There seems to be an increasing variability over the latter months, with highs increasing and lows decreasing.
2) The average of the monthly highs is just under 0.10 lb/MMBtu and the average of the monthly lows is just under 0.085 lb/MMBtu.
3) The facility should be able to easily comply with its current limit of 25 ppmvd (approximately 0.126 lb/MMBtu) and likely will operate closer to 0.09 lb/MMBtu (approximately 18 ppmvd) on a monthly average basis.

Each analysis of the facility data referred to herein suggests that a NO_X limit of 0.09 lb/MMBtu (approximately 18 ppmvd) via full load testing or monthly average would likely be reasonable (given that certain operational changes may be required), even if the Department had alternately concluded that more stringent controls should be rejected. Barring these operational changes, 25 ppmvd may be reasonable.

CEMS DATA



Additional SCR-related cost information received from the applicant after the application was complete:

As noted above, the application was received by the Department on November 27, 2000. Within the applicant's submittal was a cost analysis for the installation of an SCR, which included a vendor quote (Engelhard) dated October 25, 2000. The vendor quoted the SCR system cost at $1,738,000 with a three-year catalyst life guaranty, an expected life of 5-7 years and a 3.5 ppmvd NO_X output. TEC annualized the NO_X removal costs at $4660 per ton of NO_X removed, which is discussed in more detail above.

On December 4th, 2000 the Department requested additional information from TEC. Included within this request was a confirmation that Engelhard had provided a guarantee for the catalyst life at 3 years, and expected the catalyst life to be 5 to 7 years. Additionally, the Department stated that the application of an SCR (even with cost effectiveness costs as high as $6000 per ton) would "represent the Department's determination for this project, unless Tampa Electric Company can demonstrate to the Department's satisfaction (absent fuel quality issues) why this installation is significantly different". On February 15th, 2001 the Department received the requested information (which has been analyzed in the foregoing pages), including the requested Engelhard confirmation. The application was deemed complete that day.

On April 3rd, 2001 FDEP officials met with TEC officials at the request of the applicant. TEC indicated that the purpose of the meeting was to ensure that FDEP's questions were satisfactorily answered and to understand FDEP's intentions. At the prompting of TEC officials, FDEP indicated a *very preliminary* intention (pending the detailed review as required by a BACT Determination) to require SCR for the attendant project, although it may be at some control level above 3.5 ppmvd of NO_X. FDEP additionally noted that certain costs (such as replacement power) contained within the TEC cost analysis (see page 16 above) would likely be rejected, improving the cost effectiveness below the $4660/ ton value. At the meeting conclusion, TEC indicated a desire to provide additional submittals to the Department, and FDEP officials indicated that TEC was welcome to do so, however that no additional information was either requested or required by the Department in order to complete the BACT Determination. [Note: As can be seen herein, the Department had estimated that the annualized cost of an SCR was likely less than $2M].

On April 16th, 2001 FDEP received a voice-mail from the applicant indicating that TEC had contacted several catalyst vendors and expected responses by the week of April 23rd. TEC stated that they would be sending additional information to FDEP by the first week in May. No indication was provided as to the intent or the reasoning behind the forthcoming submittals. A follow-up phone call was received on April 24th at approximately 1:15 p.m., with the applicant indicating that the nature of the submittals was related to the applicant's concern over the formation of ammonia sulfates and that the information would be forthcoming soon. The applicant additionally inquired as to the Determination status, requesting to know whether the conclusion reached within the Department's BACT Determination (albeit unfinished) had changed in any way.

Although a draft BACT Determination would normally be issued well before day 74, the Department awaited the TEC submittal for several additional days. On May 2nd, 2001 (Day 76 on the DEP permit clock), the Department received a "Notice of Waiver of 90-Day Period" from TEC. This waiver was offered by the applicant as a means to allow more time for the additional information, which the applicant wished to submit. Inasmuch as this additional information was not requested by the Department in order to take action, the Department had no reason to accept TEC's waiver to be allowed until July 1st to submit the additional (unrequested) information.

EPA Comments regarding Kentucky Pioneer:

EPA commented adversely over Kentucky's Draft BACT Determination, which would authorize Kentucky Pioneer to emit NO_X at 15 ppmvd. TEC's submittal requests a BACT Determination at 25 ppmvd NO_X.

The best available control technology (BACT) question of most concern to us is BACT for the control of NO_x *emissions from the combined cycle combustion turbines... The* NO_x *emission rates proposed as BACT for the combined cycle combustion turbines are an emission rate of 15 ppmvd (at 15% oxygen) when burning syngas and an emission rate of 25 ppmvd (at 15% oxygen) when burning natural gas (and a weighted average when burning both fuels simultaneously). All of the recent combined cycle combustion turbine projects throughout the U.S. that are known to us and that involve large natural gas-fired combustion turbines comparable in size to the Kentucky Pioneer Energy turbines have been permitted with a* NO_x *emission rate for natural gas combustion of 3.5 ppmvd or less to be achieved by a combination of combustor design and use of post-combustion controls. While we recognize that IGCC combustion turbines differ from standard natural gas-fired combined cycle combustion turbines, we are still concerned that the* NO_x *BACT levels proposed for Kentucky Pioneer Energy are four to seven times higher than the emission rates approved for all other recently permitted natural gas-fired combined cycle combustion turbines of comparable size.*

EPA was not persuaded by Kentucky's argument that ammonia bisulfate salts would "cause serious plugging, loss of heat transfer and corrosion in the downstream portions of the heat recovery steam generator". What follows are selected EPA comments about this issue.

The sulfur content of syngas is much less than the sulfur content of post-combustion air streams in coal-fired boilers where SCR technology has been successfully applied despite initial concerns that the technology would not be feasible in the high-sulfur environment of such air streams

Most recent dual-fuel (natural gas and No. 2 fuel oil) combined cycle combustion turbine projects have been permitted to require use of SCR for NO_x *control when burning fuel oil as well as when burning natural gas. The typical sulfur content of the fuel oil proposed for such projects is 0.05 percent by weight, which should yield exhaust gas sulfur compound concentrations comparable to those resulting from combustion of syngas.*

Furthermore, in conventional SCR systems, proper operation of the ammonia feed system along with proper sizing and selection of the catalyst components can serve to minimize the amount of ammonia that slips through the SCR reaction zone. We recommend that the applicant or KDAQ investigate means of reducing residual ammonia before concluding that SCR is not a technically feasible option due to formation of ammonium bisulfate salts.

EPA did not accept the cost figures provided for the Kentucky project, which formed the basis of SCR being rejected at cost effectiveness values of $8516/ton or higher.

The preliminary determination and the original permit application contain two SCR cost evaluations, one based on a U.S. Environmental Protection Agency (EPA) publication (Alternative Control Techniques Document - NO_x *Emissions from Stationary Gas Turbines, 1993) and one based on Engelhard vendor data with additional costs to allow for modifications of the HRSG to counteract the potential harmful effects of ammonium bisulfate salts. We have concerns about both evaluations.... The cost estimate ... appears to be based on a procedure in the 1993 EPA document cited above, a document that we have indicated is out of date.*

The purchased equipment cost based on the Engelhard quote is a total of approximately $12,000,000 for both combustion turbines, or about $6,000,000 for each turbine. This cost is far higher than the typical equipment costs reported in other permit applications for F-class combustion turbines.

In summary, we have serious concerns about the cost evaluations for SCR. A further evaluation of costs coupled with use of a higher "uncontrolled" baseline emission rate is likely to show that the cost of SCR for the Kentucky Pioneer Energy combustion turbines is within the range of NO_x *control costs considered acceptable for recent combined cycle combustion turbine projects involving combustion of conventional fuels.*

It seems clear that EPA is not in agreement with the Draft BACT proposed by Kentucky. That Draft BACT rejects the application of an SCR for the proposed IGCC facility based upon costs. The excessive costs cited, find root in the applicant's concern that ammonia bisulfate formation will be a significant issue, which would affect the project. EPA does not accept the premise that ammonia bisulfate is a serious issue for the Kentucky project, nor do they accept the conclusion that SCR is not cost-effective, indicating a notion that the cost effectiveness is likely closer to that of a natural gas fired combined cycle unit.

Department analysis of related concerns as they may apply to TEC Polk:

A further review of concerns related to ammonia sulfate and ammonia bisulfate for this specific project follows. Much of the information presented is derived from published reports, which are itemized. From an October 1998 article in Pollution Engineering, written by Michael Sandell:

There is a concern about the use of SCR with high-sulfur fuels because sticky ammonium bisulfate can be deposited on the catalyst, air heater and other downstream surfaces. This compound is formed through the reaction of ammonia with SO_3*, which in turn is formed primarily through the oxidation of* SO_2 *by the SCR catalyst. By minimizing ammonia slip and suppressing the oxidation of sulfur dioxide, the amount of ammonium bisulfate may be kept to a level that does not affect boiler operation. Ammonia slip, the emission of unreacted ammonia, is caused by the incomplete reaction of injected ammonia with* NO_x *present in the flue gas. A system designed to achieve good distribution and mixing of the injected ammonia with the flue gas, as well as proper catalyst sizing and selection, will ensure ammonia slip is controlled to levels low enough that effects on plant operation, ash properties and health will be insignificant.*

From an article entitled "Properly Apply Selective Catalytic Reduction for NO_X Removal" authored by Dr. Soung M. Cho, January 1994 Chemical Engineering (note the specific references to industrial gas and low sulfur oil, which the author relates as being similar to natural gas):

...The other important reason for limiting the ammonia slip to a low value is to reduce the chances of forming ammonium sulfates in the presence of SO_3*. Sulfur containing fuels produce* SO_2 *and a small quantity of* SO_3*. A small fraction of* SO_2 *is also converted to* SO_3 *by the SCR catalyst. When combined with excess ammonia and water vapor,* SO_2 *may form ammonium sulfates. Ammonium sulfate* $(NH_4)_2SO_4$ *is powdery and contributes to the quantity of particulates in the flue gas. Ammonium bisulfate* NH_4HSO_4 *is a sticky substance that can deposit in the catalyst layers and/or downstream equipment, causing flow blockage and equipment deterioration. Temperature is an extremely important factor in the formation of sulfates. The lower the temperature, the higher the probability of sulfate formation. When natural or industrial gas or low sulfur oil is used as the combustion fuel, the deteriorating effects discussed above are not likely to occur if the ammonia slip is limited to less than 10 ppm and the* SO_3 *concentration is less than 5 ppm (unless the gas temperature is very low).*

From a March 1998 paper "Estimating Sulfuric Acid Aerosol Emissions from Coal-Fired Power Plants" authored by R. Hardman, R. Stacy (of Southern Company Services) and E. Dismukes (SRI):

...In the literature, varying and sometimes conflicting estimates exist regarding the conversion of SO_2 *to* SO_3*. For example, in one publication the conversion rate is estimated to vary from 3 to 5 percent, from 1.25 to 5 percent, and from 1 to 4 percent, depending on the section of the book being read. In other reports, which focus on the performance of cold-side ESP's, the ratio of* SO_2 *to* SO_3 *at the air heater are presented. These ratios are lower since a portion of the* SO_3 *generated during the coal combustion process condenses onto the cold sections of the air heater baskets as the flue gas temperature drops. For example, in one evaluation average flue gas* SO_3 *concentrations dropped from 25 ppm to 11 ppm (56 percent) across a hot-side ESP and an air heater. Other reports (such as an EPA-documented* SO_2 *to* SO_3 *ratio of 0.4 percent) confirm these pilot scale results. The same EPA study reports that the* SO_3 *levels from six different power stations vary from undetectable levels to 0.67 percent of the* SO_2 *concentration. Other full-scale experimental results based on measurements during 16 field tests showed concentrations from 0.1 to 0.41 percent of the* SO_2 *levels. In both of these examples, the* SO_3 *concentrations when burning western coals were lower than the* SO_3 *concentrations when burning eastern coals. Laboratory results have confirmed the direct proportional relationship between the* SO_2 *to* SO_3 *conversion rate and the sulfur content of the fuel.*

EPA's Acid Rain information system shows that typical flue gas SO_2 values for this emissions unit are less than 40 ppm. Therefore, according to the technical literature above, it is extremely likely that the amount of SO_3, which will be converted from the available SO_2, will be less than 2 ppm (5% of 40 ppm), and may very well be less than 1 ppm. This published information (referred to above) supports the conclusion that a well-designed ammonia injection system along with proper catalyst selection will minimize or eliminate concerns related to ammonia bisulfate formation, given a low ammonia slip level and low SO_3 values. It additionally supports EPA's comments on Kentucky: "*...proper operation of the ammonia feed system along with proper sizing and selection of the catalyst components can serve to minimize the amount of ammonia that slips through the SCR reaction zone. We recommend that the applicant or KDAQ investigate means of reducing residual ammonia before concluding that SCR is not a technically feasible option due to formation of ammonium bisulfate salts.*"

Accordingly, HRSG modifications and additional costs proposed for an IGCC project such as Polk are also deemed to be unwarranted costs and are rejected. The Department concludes that the cost effectiveness for installation of an SCR is less than $4,660 per ton and is within the range of reasonableness for prior natural gas combined cycle determinations. This value should be ample to ensure that the SCR will be designed with the proper catalyst sizing and selection, as well as to provide for an ammonia injection system capable of achieving good distribution and mixing of the injected ammonia, with a resulting low level of slip.

DEPARTMENT BACT DETERMINATION:

In summary, the application of SCR to the subject Polk generating unit *as if it were a new source* cannot be rejected based upon technical, economic, energy or environmental impacts. The determination that a control alternative is inappropriate involves a demonstration that unusual circumstances exist that distinguishes the source from other sources where the technology may have been required. The applicant has failed to meet this test. In this case, the Department has compensated for the shortage of IGCC specific data through a reasonable extrapolation of SCR and fuel data from utility units and refineries. Accordingly, SCR is deemed to be BACT. Following are the BACT limits determined for the Polk Power project for NO_X corrected to 15% O_2.

POLLUTANT	CONTROL TECHNOLOGY	BACT DETERMINATION
NO_X (syngas - all operating modes) NO_X (oil - all operating modes)	SCR	5.0 ppmvd (SCR) – 24 hour block average 9.0 ppmvd (SCR) – 24 hour block average 5 ppm ammonia slip at SCR outlet
POLLUTANT	**COMPLIANCE PROCEDURE**	
NO_X 24-hr block average	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed	
NO_X (performance)	Annual Method 20 or 7E	
Ammonia Slip	CTM-027 initial and annual (The test and analyses shall be conducted so that the minimum detection limit is 1 ppmvd).	

APPENDIX BD - 2001
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT) FOR NO_X

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E. Review Engineer
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	Approved By:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date:	Date:

TECO
TAMPA ELECTRIC

RECEIVED
MAY 11 2001
BUREAU OF AIR REGULATION

May 10, 2001

Mr. Michael Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Via Fed Ex
Airbill No. 7900 4812 1562

Re: Polk Power Station Unit 1
Syngas Fired Combustion Turbine NO_x BACT Determination

Dear Mr. Halpin:

Tampa Electric Company (TEC) would like to take this opportunity to submit additional information regarding the Best Available Control Technology (BACT) determination for Polk Power Station Unit 1. This information is submitted as a follow up to our meeting of April 3, 2001, and subsequent communications via telephone. This submittal is comprised of three main elements, an overview of the original BACT evaluation, a refined BACT cost analysis, and information regarding a recently permitted syngas fired Combustion Turbine (CT) installation. Furthermore, if deemed acceptable, TEC would like to work with the Florida Department of Environmental Protection (FDEP) in developing a continuous improvement program (CIP) to reduce NO_x emissions from Polk Unit 1 through the use of process optimization and equipment upgrades.

The Original BACT Evaluation

In the course of developing the original BACT evaluation, TEC was required to consider "data gathered on this facility, other similar facilities, and manufacturer's research." In taking this approach, TEC determined that a NO_x limit of 25 ppmvd @15% O_2 was appropriate as an emission limit. This would allow TEC to continue firing its present array of fuels while generating safe and reliable electricity to serve its customers.

In subsequent discussions with FDEP, TEC has come to understand that the Department may be considering the application of a selective catalytic reduction (SCR) system to Polk Unit 1 as BACT. In the original BACT submittal, TEC outlined several technical concerns with the application of this technology to an Integrated Gasification Combined Cycle (IGCC) facility, and, based on discussions with several catalyst vendors, these overriding technical concerns remain. The most significant of these concerns is the formation of ammonium sulfate and ammonium bisulfate compounds. These compounds, when formed in the Heat Recovery Steam Generator (HRSG) will cause significant plugging and fouling of heat transfer equipment, which could require several additional outages per year to allow for the cleaning of this equipment.

Since the manufacturer of the combustion turbine, General Electric, believes that SCR is not applicable to this unit, no other IGCC in the United States currently employs SCR technology, and the testing performed at the Polk facility demonstrated that 25 ppmvd @15% O_2 is a reasonable limit, TEC feels that based on the criteria established by the Department for this evaluation, a SCR system can clearly be eliminated as a BACT recommended technology for Polk Unit 1.

Refined BACT Cost Analysis

Due to the fact that the original submittal was required within 30 days of the completion of the test program, TEC based the original SCR cost analysis on vendor quotes for other facilities that did not fire syngas as a primary fuel. Since that time, TEC has solicited additional input from four SCR equipment vendors to refine the cost analysis presented in the initial submittal. Of the four vendors contacted, two vendors submitted no-bid responses, one of whom was Englehard. This point is important as the original submittal was based on an Englehard quote for a facility that was not an IGCC. The SCR quote that is used in this current analysis was provided by Deltak. The quote is enclosed as Attachment 1 to this letter and serves as a basis for the cost analysis performed in this submittal.

The Deltak quote specifies an outlet NO_x concentration from the SCR of 5 ppmvd corrected to 15% oxygen. Because this quote is based on this exit concentration, the 5 ppmvd value is used as the controlled NO_x value when estimating cost effectiveness, and the baseline for NO_x emissions remains at 25 ppmvd. The baseline emissions from oil firing (i.e., back up fuel firing) is 42 ppmvd, and the SCR system is expected to have the same 80% control for the NO_x emissions when firing oil as when controlling syngas firing. Therefore, the associated controlled NO_x emission rate during oil firing would be 10.5 ppmvd. Although oil is only fired for a maximum of 10% of the total allowable operation, the emissions reductions from the oil case represent approximately 21% of the total emissions reductions. Thus, because the maximum allowable back up fuel firing load is used in the estimation of cost effectiveness, the cost effectiveness calculations tend to be conservative in nature (i.e., will tend to under estimate the cost per ton of pollutant removed because back up fuel is typically fired in considerably less quantities than the allowable limit).

The Deltak quote includes the following statement on the first page regarding concerns with ammonia sulfate and ammonia bisulfate deposition and plugging. The fact that two vendors elected not to bid on this project coupled with the placement of this concern on the cover page of the Deltak quote lends credence to the overall priority that equipment vendors place on this concern.

> *I would like to note one potential problem with retrofitting SCR into the subject HRSG. There is a rather high SO_2 loading in the exhaust gas stream due to the combustion of syn-gas in the combustion turbine. Approximately 5% of the SO_2 in the gas stream will oxidize to SO_3 across the catalyst. This additional SO_3 along with the unspecified level of SO_3 in the combustion turbine exhaust will combine with the injected ammonia (NH_3) to form ammonium salts (primarily ammonium bisulfate) that are likely to adhere to the tubing in the cooler HRSG sections causing both a thermal insulation effect and/or an increase in turbine back pressure. With the fuel that is being burned, and the potential for Fuel Oil back-up fuel, the potential for ammonium salt fouling will be quite significant.*

Based on this concern, TEC estimates that the HRSG and down stream exhaust ductwork will need to be cleaned three times per year, at a minimum. The cost estimate includes two entries to account for these costs. The first entry is the annualized costs of HRSG maintenance that is expected to occur with increased degradation and corrosion of the heat transfer media. These estimates were prepared by plant personnel, taking into account the anticipated increased tube replacement costs that will be incurred starting in the third year after the installation of the SCR unit. These costs were estimated through ten years, then converted to an annualized recurring cost using engineering economic accounting methods.

In addition to the HRSG maintenance costs, contract labor costs are included for performing the anticipated cleanings. One cleaning will be performed during a scheduled outage, and two cleanings will be performed during unscheduled outages. The contract labor costs involved with the cleaning will be incurred by TEC during each of the outages. The estimated cleaning cost is $60,000 per occurrence.

During the scheduled outage, there are no additional costs that are incurred by TEC. However, during the unscheduled outages that are performed solely to address the plugging, TEC will incur costs associated with the loss of generating capacity. During these unscheduled outages, TEC will need to replace the electricity that would otherwise be generated by the Polk facility (i.e., 315 MW). The basis for estimating the incremental replacement cost of $20 per MW-hour is presented on page 6-22 of the November 2000 submittal.

TEC believes the incremental costs to replace the electrical power that would otherwise be generated by the Polk facility to be a real and valid cost that is associated with an unscheduled outage. During the meeting between FDEP and TEC, the Department had indicated that additional supporting information for the use of this cost estimate is warranted, especially as it related to United States Environmental Protection Agency (USEPA) guidance on accounting for lost power generation capacity during plant outages. TEC understands USEPA guidance to state that during scheduled outages, or those events that can reasonably take place during scheduled outages, it is not appropriate to account for the lost generation capacity. As such, costs for events such as catalyst replacement and one cleaning of the catalyst per year are estimated without the additional costs of replacing the power that would otherwise be generated by the facility.

However, because the Polk facility is a base load unit on TEC's system and has a current overall availability commitment of 86.5%, any unscheduled outages will incur considerable costs to TEC, especially if these unscheduled outages will affect the ability of the Polk facility to meet this availability commitment. TEC believes the estimated incremental cost for electrical generation or purchase to be a real cost that would be incurred by the facility during any unscheduled outage, regardless of the reason for the outage. This cost is one of the reasons that unscheduled outages get prompt attention of engineering and maintenance staff, including subcontractors, to return the facility to normal operational mode.

TEC believes that the cost of replacing the power generation capacity lost during an unscheduled outage is a real and justifiable cost that must be included in the performance of the economic analysis of control options. To provide a complete analysis to FDEP, TEC has provided the information on cost effectiveness analysis for both cases, with and without the incremental cost for power replacement Attachment 2.

The revised cost effectiveness estimate for the SCR control of NO_x is $5,737 per ton of NO_x removed, as summarized in Table 1. This cost takes into account the incremental cost of replacing power during two unscheduled outages per year. Table 2 presents the cost effectiveness of $3,499 per ton, which does not take into account the incremental cost for replacing power during the outage. Tables 3 through 5 contain supporting information regarding costs estimates used for this analysis. This analysis follows the same approach that was used in the November 2000 submittal, hence is not described in further detail.

The incremental cost of replacing the lost power generating capacity is approximately 40% of the total cost associated with the SCR. TEC has serious concerns regarding the fouling, plugging and corrosion of components downstream of the SCR in the high sulfur environment, and believes these cost estimates to be conservatively low. Because there is a shortage of practical experience of CT SCR performance in high sulfur environments, these estimates are based on expected performance, not actual data. TEC is aware of predictions by equipment vendors (e.g., General Electric) that account for considerably more difficulties and associated costs that TEC is taking into account in this cost analysis.

Recent Syngas Fired CT BACT Determination

The Kentucky Pioneer Energy LLC facility proposed for Trapp, Kentucky is currently undergoing the public review of its draft Prevention of Significant Deterioration (PSD) permit. This permit proposes NO_x BACT of 15 ppmvd for syngas firing, and 25 ppmvd for back up fuel (i.e., natural gas) firing. The NO_x control technology selected for this facility is steam injection. The subject equipment includes two CTs which are GE 7FA CTs, each rated at 197 MW without the associated HRSG.

Discussions with Mr. Donald Newell, the Commonwealth of Kentucky permit engineer, indicate that no questions were raised to date by the public regarding the proposed BACT emissions limit. The questions raised by the public concerned other items, such as the placement of lights at the facility to minimize light pollution, the need to keep the public informed of what is happening at the facility, mercury emissions and the impacts of burning municipal solid waste on rainwater.

The USEPA has questioned certain aspects of the BACT determination for the facility, but has not determined that add-on controls (e.g., an SCR) are cost effective or technically feasible. The questions from the USEPA are included as Attachment 3. The questions raised in this letter regard specific aspects of the BACT determination for the facility, and ask for supporting information to validate the concerns regarding the implementation of SCR on an IGCC CT. For example, regarding validation of the plugging concerns, the USEPA states:

> *We would be more persuaded if the applicant were to provide information directly from one or more HRSG vendors discussing why ammonium bisulfate salts pose a greater problem for combined cycle combustion turbine HRSG's than for coal-fired boilers.*

Additional concerns raised by the USEPA address other aspects of the BACT determination, such as cost data and the survey of other similar facilities conducted to support the permit application. Mr. Newell indicated that he is in the process of collecting additional information to support his determination of steam injection meeting BACT, and will be responding to USEPA comments. Mr. Newell expressed concerns with reliability and clogging of equipment as a result of using an SCR system.

Until a final determination of the BACT is made for this Kentucky facility, TEC feels it is inappropriate to use the fact that questions are being raised by USEPA as a justification for requiring SCR as BACT for the Polk facility. First, the BACT process is interactive in nature, allowing for all concerned parties (e.g., citizen groups, USEPA, and affected Class I area managers) to provide their input and comments. The final BACT determination takes into account these comments, as well as other factors that are reviewed by the permitting agency. Additionally, many of the questions raised by the USEPA regarding the Kentucky BACT determination either do not apply to the Polk facility, or already were addressed by TEC in prior submittals.

Additionally, the CT at the Polk facility, although similar to the CTs proposed for the Kentucky facility, is approximately two generations in technological advances behind the CTs that will be installed in Kentucky. This point is further discussed in the November 2000 submittal. Thus, because the CT at the Kentucky facility is expected to achieve 15 ppmvd NO_x emissions, it is not appropriate to expect the Polk CT to achieve the same level of emissions.

Conclusions

Through the use of a CIP, TEC is willing to work with the Department to reduce NO_x emissions from the Polk facility. This program would investigate the use of process optimization and the addition of hardware where applicable to minimize the formation of NO_x rather than remove it from the flue gas stream. This is a prudent approach to the minimization of NO_x emissions from Unit 1, and does not carry with it the significant technical concerns associated with the addition of a post combustion control technology such as SCR.

TEC has considerable technical concerns with the use of an SCR system at this facility because of the high sulfur content of the exhaust gas, and these concerns are shared by several SCR vendors. Although TEC has tried to incorporate the costs associated with these concerns into the cost effectiveness analysis, the costs are based on estimated difficulties, not on data from similar facilities because there are no similar IGCC facilities that operate an SCR unit. Since the control cost effectiveness evaluation was conservative in nature, TEC believes the cost effectiveness value of $5,737 per ton of NO_x removed to be a lower bound of the cost, and actual costs of an SCR may be substantially higher. Based on this analysis, TEC believes the SCR control option to be both technically and economically infeasible.

Thank you in advance for your consideration of this matter. If you have any questions regarding the information contained in this submittal, please feel free to telephone Shannon Todd or me at (813) 641-5125.

Sincerely,

Laura R. Crouch for

Gregory M. Nelson, P.E.
Director
Environmental Affairs

EA/gm/SKT253

Attachments

c: Mr. A.A. Linero – FDEP
Mr. Jerry Kissel - FDEP SW
M. Halpin
G. Worley, EPA

ATTACHMENT 1

DELTAK

April 19, 2001

Mr. Stirling Robertson
Environmental Consulting & Technology, Inc.
1901 S. Harbor City Blvd., Suite 600
Melbourne, FL 32901

FAX: 321-733-1303
E-Mail: srobertson@ectinc.com

Ref: **Request for SCR Quote**
Deltak Ref: Budgetary Proposal B22707

Dear Mr. Robertson,

The purpose of this letter is to respond to your request for quotation fo the retrofit of an SCR system into an existing HRSG.

The information supplied in your Request for Quote was not sufficient for me to go through the actual design process of an SCR retrofit. However, I am able to offer you some rough information based upon past SCR retrofit projects that have been completed by Deltak. This information, including rough budgetary pricing is included below. This budgetary proposal assumes that there is an existing spool duct in the HRSG for the addition of SCR catalyst.

I would like to note one potential problem with retrofitting SCR into the subject HRSG. There is a rather high SO_2 loading in the exhaust gas stream due to the combustion of syn-gas in the combustion turbine. Approximately 5% of the SO_2 in the gas stream will oxidize to SO_3 across the catalyst. This additional SO_3 along with the unspecified level of SO_3 in the combustion turbine exhaust will combine with the injected ammonia (NH_3) to form ammonium salts (primarily ammonium bisulfate) that are likely to adhere to the tubing in the cooler HRSG sections causing both a thermal insulation effect and/or an increase in combustion turbine back pressure. With the fuel that is being burned, and the potential for Fuel Oil back-up fuel, the potential for ammonium salt fouling will be quite significant.

Page 2 of your Request for Quotation outlined the specific information that you wished Deltak to provide. Below is a repeat of your required information outline with information provided.

1. Equipment Included

The following equipment and services have been assumed to be required, and are included in this budgetary proposal:

1. SCR Spool Duct Modifications:

- a) Add bolted access hatches to duct roof for catalyst access.
- b) Remove existing liner and insulation, as needed, for installation of catalyst frame components to duct casing walls.
- c) Structural steel engineering and floor modifications/reinforcement to support the catalyst system.
- d) Add insulation and liner necessary to transition between the catalyst frame and the existing liner and insulation.
- e) Add 12 test ports (3 upstream, 3 downstream of the catalyst on each side wall). Each port to be a 2.5" minimum pipe penetrating the HRSG casing, insulation and liner with flange and blind on the outside.

2. Catalyst Frame:
   - a) Frame designed to support catalyst modules from Catalyst vendor
   - b) Frame designed to fit inside existing SCR spool duct.
   - c) The frame components will be lowered inside the duct and attached to the duct floor, sidewalls and structural steel as required for proper support.
   - d) The frame will include space for expansion of the catalyst bed depth by no less than 50%.

3. Catalyst Modules:
   - a) Multiple catalyst modules will be supplied by the selected Catalyst supplier. Each module will be supplied so they can be lowered inside the catalyst frames.
   - b) The modules can be lifted out of the catalyst frame when fresh modules are required.

4. Ammonia Injection Grid (AIG) Lances
   - a) AIG Location: The grid will be designed for installation into an existing HRSG access lane.
   - b) Ammonia Injection Lances. Each lance will span the width of the HRSG, and be supported by the sidewalls. The lance material will be SS304.
   - c) The appropriate number of lances, nozzles and nozzle sizes will be provided to assure uniform distribution of ammonia in the exhaust stream. Ammonia will be fed into the HRSG from one sidewall.
   - d) Lance Casing Penetration Sleeves & Guides. Each lance will be supplied with a flanged casing penetration on one sidewall, and a support guide penetrating the opposite wall.
   - e) AIG Lance Liner: 10ga. carbon steel liner and insulation to fit around AIG lance penetrations.

5. AIG Distribution Piping
   - a) Distribution piping between the ammonia "distribution header" and the AIG lances. Each distribution pipe will supply vaporized ammonia to four AIG lances.
   - b) Pipe supports.
   - c) Insulation and lagging. (Insulation and lagging to be 2" mineral wool with .020 aluminum with vapor barrier.)

6. AIG Distribution Manifold Header
    a) Header assembly to distribute vaporized ammonia to the distribution pipes. The 12" SA106B header will be located adjacent to one sidewall of the SCR spool duct.
    b) Distribution pipe flow adjustment trim: Each of the manifold's distribution pipe stubs will include the following shop installed trim: flow element, pressure differential gauge with sensing lines, manual butterfly valve.
    c) Manifold header pressure tap and gage.
    d) Insulation and lagging. (Insulation and lagging to be 2" mineral wool with .020 aluminum with vapor barrier.)

7. Aqueous Ammonia Dilution Skid: This shop fabricated and prewired skid will include the following:
    a) Dilution Air Fans: Two (2) fans, 100% capacity each. (≈ 15 Hp, 460VAC/60Hz/3ph)
    b) Dilution Air Heater (Approximate Rating = 180 kW)
    c) Deltak assumes that existing "spare cabinets" in a motor control center would be used to house the new buckets required for the skid motors and heater.
    d) Aqueous Ammonia Vaporizer Tank
    e) Shop installed interconnecting piping and wiring which will be brought to connection points at the skid boundary, ready for instrument air, ammonia supply piping, and wiring connections.
    f) Panel mounted system controls for vaporizer (on/off/temp indicator/reset), fans (on/off/flow indicators), system pressure indicators, air/ammonia flow indicator and controller, main power disconnect switch.
    g) Skid mounted PLC controller.

8. Aqueous Ammonia Storage Tank and Unloading Station
    a) 15,000 gallon capacity, horizontal storage tank 10 feet OD x 24 feet, 25 psig internal pressure (no vacuum rating) with 18" manway, constructed in accordance with ASME Section VIII, Division 1.
    b) Liquid fill and vapor return lines.
    c) Tank Trim: liquid level gauging device, pressure and vacuum relief valve, four ammonia leak detectors mounted on posts and one ammonia sensor mounted on a panel.
    d) Aqueous Ammonia Injection Pumps: Two (2) 100% capacity skid mounted NH_3 injection pumps to deliver ammonia from the storage tank to the dilution skid. Skid to be located inside storage tank containment basin. (Pump Size: ≈ 1 hp, 120 VAC)
    e) Truck unloading pump not included and assumed to be provided on delivery truck, which is typical.

  - f) Containment Dike: concrete containment consisting of floor & sidewalls for containment of ammonia storage tank leak/spill containment. The dike will be capable of holding at least the tank capacity volume plus 10%.
  - g) Sump well and electric pump for draining containment dike. Pump discharge piping to be supplied to top of containment wall. Piping from containment wall to collection point by others. (Pump Size: 1 hp, 120 VAC).

9. Aqueous & Vaporized Ammonia Piping Between Tank and AIG Manifold
   - a) Storage tank to Injection pumps (2" SA106B - aqueous).
   - b) Injection pumps to Ammonia dilution skid (3/4" SA106B - aqueous).
   - c) Dilution skid to the Ammonia distribution manifold (8" SA106B - vaporized).
   - d) Pipe supports.
   - e) Insulation & lagging for vaporized flows. (Insulation and lagging to be 2" mineral wool with .020 aluminum with vapor barrier.)

10. Civil Engineering:
    - a) Design: Ammonia vaporizer skid pad & foundations; Ammonia injection pump skid pad & foundations; Aqueous ammonia storage tank foundations and containment basin;
    - b) General: Stamped Drawings

11. Electrical Engineering and Equipment:
    - a) Power wiring between the Skid Mounted Equipment, MCC's and existing power supplies.
    - b) Control wiring between the Skid Mounted Equipment, MCC's and existing power supplies.
    - c) MCC's for the two injection pumps, one trolley hoist, and the vaporization heater.
    - d) Electrical Classification Plan (NEC Code)

12. Controls Engineering:
    - a) Develop and supply the necessary control logic diagram and information for the SCR system. The information and diagrams will be sufficient to permit the controls integration into the existing plant DCS.

13. Deltak Documentation:
    - a) Operations & Maintenance Manuals: Five (5) copies will be provided.
    - b) Arrangement drawings of the system.

14. Installation Services:
    - a) Equipment, materials and labor to install all Deltak supplied equipment.

2. Equipment Excluded

The following equipment and/or services are excluded from the proposed scope of supply:

1. Catalyst loading monorail and electric hoist.
2. Performance test procedures, test equipment, test personnel or test results analysis.
3. Stack Continuous Emissions Monitor System (CEMS), or NOx analyzers.
4. NOx sample probe, sampling lines and analyzers for detecting NOx.
5. Stack modifications for NOx sampling.
6. Safety eye wash station and/or shower.
7. Fire protection system modifications.
8. Engineering and/or evaluation to update existing plant procedures and policies.
9. Modification of existing foundation.
10. Shipping of equipment to the, as yet, unknown plant site.

3. Mechanical Warranty

Typically the mechanical warranty statement for a catalyst system would be as follows:

> The sole, and exclusive, remedies for breach of these warranties shall be that Deltak will repair or replace defective or nonconforming equipment or parts thereof free of charge, F.O.B. point of shipment; provided the defect or nonconformance is due to its fault and is not the result of abuse, misuse, accident, or other event outside Deltak's control and provided that the user of the equipment gives written notice of any defect or nonconformance within ten days of discovery thereof. In no event shall Seller have any responsibility for the cost of creating adequate access to the equipment for the purpose of repair or replacement thereof. Deltak's obligation hereunder, shall cease, in the case of equipment manufactured by it 18 months from date of shipment or 12 months from date of start-up, whichever occurs first. Thereafter, Deltak shall have no further obligation.
>
> With respect to auxiliaries and accessories furnished by Deltak, but manufactured by others, the warranties shall be limited in all respects, including duration and available remedies, to the warranty of the respective equipment manufacturer. Deltak shall not have any liability with respect to such equipment not manufactured by it except only to the assignment of whatever rights Deltak has against the manufacturer of such equipment and such rights are hereby assigned.
>
> The user agrees that the above conditions precedent are reasonable limitations, and waives any right of recovery if it fails to comply with them or the defect or failure of performance does not occur within the stated time.

4. Performance Guarantee

The subject Request for Quote did not specify a required NOx reduction, or NH_3 slip requirements. This budgetary proposal is based upon the following assumption:

Inlet NOx – 25 ppmvd @ 15% O_2 Max.
Outlet NOx – 5 ppmvd @ 15% O_2 (80% NOx reduction)
NH_3 Slip – 5 ppmvd @ 15% O_2

Outlet NOx and NH_3 slip would be guaranteed for a period of three years from first introduction of combustion turbine exhaust gas into the catalyst.

5. Expected Catalyst Life

A. Guarantee Life – Typically an SCR catalyst is guaranteed for a three (3) year life. A three (3) year life has been assumed in this budgetary proposal.

B. Typical Lifetime – Actual catalyst life depends upon the service environment and the care that is taken to not subject the catalyst to poisons and large amounts of water. In Deltak's experience, SCR catalyst life is typically in the five (5) to eight (8) year range.

6. Budget Pricing

Budgetary pricing for this inquiry is based upon the scope of supply and assumptions outlined in this proposal. The budgetary price for the supply and installation of the proposed SCR catalyst is $3,110,000.00.

7. NH_3 Slip (ppm)

The budgetary design for the proposed SCR system assumes a maximum NH_3 slip of 5 ppmvd @ 15% O_2.

8. Express any concerns you have about catalyst poisoning and ammonia bisulfate deposition.

Catalyst Poisoning: The following contaminants and compounds are known catalyst deactivators and contribute to shortened catalyst life:

Heavy and Base Metals: Antimony, Arsenic, Chrome, Copper, Lead, Mercury, Nickel, Tin, Zinc
Alkali Metals: Cesium, Francium, Lithium, Potassium, Rubidium and Sodium, Alkaline Earth
Metals: Calcium, Magnesium, Barium, Strontium, Silica Compounds: Silicone and Siloxane
Phosphorous: Particularly from oil or turbine cleaning detergents.

It is the responsibility of Owner to notify Deltak if the catalyst will be exposed to these poisons. Deltak is not responsible for the shortening of catalyst life due to poisons, unless properly advised of the potential poisons before the catalyst is designed. The catalyst will accommodate exposure to combustion turbine oil firing exhaust with the ammonia injection system off. The catalyst suitability with the ammonia injection system on is yet to be determined because the turbine exhaust analysis is unknown.

Ammonia Salts Deposition

The referenced specification did not state the expected SO_3 levels in the exhaust gas stream. However, considering the levels of SO_2 in the exhaust gas, it is assumed that SO_3 levels are significant. Additionally, approximately 5% of the SO_2 will be oxidized to SO_3 across the catalyst. Ammonia salts are formed by the reaction of SO_3 and NH_3 in the exhaust stream. The salts once formed, deposit on cool HRSG surfaces. It should be assumed significant ammonia salt fouling of the cool end of the subject HRSG will occur.

I trust that this information is satisfactory for your needs at this time. If you require additional information, I can be reached at 763-557-7457, or by E-Mail at **rmeyer@dletak.com**.

Sincerely,

Ronald J. Meyer, PE
Aftermarket Product Manager

c: Em Mohammed – RME Associates, Inc.

ATTACHMENT 2

Table 1. Cost-Effectiveness Summary, 25 to 5 ppm, Including Electrical Costs of Unscheduled Outages

CT No.	Scenario No.	No. of CTs	Annual Operation (hrs/yr)	NO_x Emission Rates								Economic Impacts	
				Baseline			Outlet - SCR Control System				Decrease	Annualized Cost	Cost-Effectiveness Over Baseline
				(ppmvd)	(lb/hr)	(tpy)	(Eff. - %)	(ppmvd)	(lb/hr)	(tpy)	(tpy)	($)	($/ton)
Unit 1	Natural Gas	1	7,884	25.0	222.5	877.1	80.0	5.0	44.5	175.4	701.7		
Unit 1	Oil	1	876	42.0	311.0	136.2	80.0	8.4	62.2	27.2	109.0		
		Totals	**8,760**	**N/A**	**N/A**	**1,013.3**	**N/A**	**N/A**	**N/A**	**202.7**	**810.7**	**4,650,600**	**5,737**

Table 2. Cost-Effectiveness Summary, 25 to 5 ppm, Excluding Electrical Costs of Unscheduled Outages

CT No.	Scenario No.	No. of CTs	Annual Operation (hrs/yr)	NO$_x$ Emission Rates								Economic Impacts	
				Baseline			Outlet - SCR Control System				Decrease (tpy)	Annualized Cost ($)	Cost-Effectiveness Over Baseline ($/ton)
				(ppmvd)	(lb/hr)	(tpy)	(Eff. - %)	(ppmvd)	(lb/hr)	(tpy)			
Unit 1	Natural Gas	1	7,884	25.0	222.5	877.1	80.0	5.0	44.5	175.4	701.7		
Unit 1	Oil	1	876	42.0	311.0	136.2	80.0	8.4	62.2	27.2	109.0		
		Totals	8,760	N/A	N/A	1,013.3	N/A	N/A	N/A	202.7	810.7	2,836,200	3,499

Table 3. Capital Cost Summary (Both Cases)

Direct Costs	($)	OAQPS Factor
Purchased Equipment (PE)		
SCR Control System	3,110,000	Deltak Quote 4/19/01
Aqueous Ammonia Storage Tank	0	Included with SCR System
Purchased Equipment Total	3,110,000	A
Instrumentation	311,000	0.10 * A
Sales Tax	186,600	0.06 * A
Freight	155,500	0.05 * A
HRSG Modifications	300,000	ngineering Estimate, allows for cleanin
Total Purchased Equipment	4,063,100	B
Installation		
Foundations & Supports	325,000	0.08 * B
Handling & Erection	568,800	0.14 * B
Electrical	162,500	0.04 * B
Piping	81,300	0.02 * B
Insulation For Ductwork	40,600	0.01 * B
Painting	40,600	0.01 * B
Total Installation Cost	1,218,800	
Total Direct Cost	5,281,900	TDC
Indirect Costs	($)	OAQPS Factor
Engineering	406,300	0.10 * B
Construction & Field Expenses	203,200	0.05 * B
Contractor Fees	406,300	0.10 * B
Start-up	81,300	0.02 * B
Performance Test	40,600	0.01 * B
Contingency	121,900	0.03 * B
Total Indirect Cost	1,259,600	TIC
Total Capital Investment	**6,541,500**	TCI

Source: ECT, 2001.

Table 4. Operating Cost Summary, Including Electrical Costs of Unscheduled Outages

Direct Costs	($)	OAQPS Factor
Labor & Material Costs		
Operator	12,000	A
Supervisor	1,800	0.15 * A
Maintenance		
Labor	12,000	B
Material	12,000	1.0 * B
Total Labor & Material Costs	37,800	C
Catalyst Costs		
Replacement (materials)	823,600	
Replacement (labor)	20,000	
Disposal	138,600	
Total Catalyst Cost	982,200	
Annualized Catalyst Cost	239,500	
Aqueous Ammonia	285,300	113/ton
Electricity Costs	78,500	
Scheduled Outage	60,000	
Unscheduled Outage	1,934,400	
HRSG Maintenance	129,600	
Energy Penalties		
Turbine Backpressure - control system	403,700	0.50%
Turbine Backpressure - plugging	403,700	
Total Energy Penalties	807,400	
Total Direct Cost	3,572,500	TDC
Indirect Costs	**($)**	**OAQPS Factor**
Overhead	22,700	0.60 * C
Administrative Charges	130,800	0.02 * TCI
Property Taxes	65,400	0.01 * TCI
Insurance	65,400	0.01 * TCI
Capital Recovery	814,100	
Total Indirect Cost	1,098,400	
Emission Fee Credit	(20,300)	$25/ton
Total Annual Cost	**4,650,600**	

Source: ECT, 2000.

Table 5. Operating Cost Summary, Excluding Electrical Costs of Unscheduled Outages

Direct Costs	($)	OAQPS Factor
Labor & Material Costs		
Operator	12,000	A
Supervisor	1,800	0.15 * A
Maintenance		
Labor	12,000	B
Material	12,000	1.0 * B
Total Labor & Material Costs	37,800	C
Catalyst Costs		
Replacement (materials)	823,600	
Replacement (labor)	20,000	
Disposal	138,600	
Total Catalyst Cost	982,200	
Annualized Catalyst Cost	239,500	
Aqueous Ammonia	285,300	113/ton
Electricity Costs	78,500	
Scheduled Outage	60,000	
Unscheduled Outage	120,000	
HRSG Maintenance	129,600	
Energy Penalties		
Turbine Backpressure - control system	403,700	0.50%
Turbine Backpressure - plugging	403,700	
Total Energy Penalties	807,400	
Total Direct Cost	1,758,100	TDC
Indirect Costs	**($)**	**OAQPS Factor**
Overhead	22,700	0.60 * C
Administrative Charges	130,800	0.02 * TCI
Property Taxes	65,400	0.01 * TCI
Insurance	65,400	0.01 * TCI
Capital Recovery	814,100	
Total Indirect Cost	1,098,400	
Emission Fee Credit	(20,300)	$25/ton
Total Annual Cost	**2,836,200**	

Source: ECT, 2001.

ATTTACHMENT 3

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

May 1, 2001

4APT-ARB

John E. Hornback, Director
Division for Air Quality
Department for Environmental Protection
Natural Resources and Environmental
Protection Cabinet
803 Schenkel Lane
Frankfort, Kentucky 40601-1403

Dear Mr. Hornback:

Thank you for sending the draft PSD/Title V permit and preliminary determination and statement of basis for the proposed Kentucky Pioneer Energy facility in Clark County, Kentucky (Permit No. V-00-049). The project operator will be Kentucky Pioneer Energy LLC, a subsidiary of Global Energy USA. The project will consist of an integrated gasification combined cycle (IGCC) combustion turbine electric power generating station with two combustion turbines. The primary fuel for the combustion turbines will be a synthetic gas (syngas) generated on site by gasification of coal and municipal waste. Based on the applicant's emission estimates, the facility will be a major source under prevention of significant deterioration (PSD) and title V permitting regulations. Also based on the applicant's estimates, the facility is subject to PSD review for the following pollutants: nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM and PM_{10}), volatile organic compounds (VOC), beryllium, municipal solid waste metals, and municipal solid waste acid gases.

This letter provides Region 4's comments on the PSD components of the draft permit and on federal new source performance standards (NSPS) applicable to municipal waste combustors and stationary gas turbines. We will send a separate letter commenting on the title V components. Our PSD and NSPS comments are as follows:

1. The best available control technology (BACT) question of most concern to us is BACT for the control of NO_x emissions from the combined cycle combustion turbines. The applicant's proposed NO_x BACT, which as of this time has been accepted by the Kentucky Department for Air Quality (KDAQ), is a combination of combustor design plus use of diluent water/steam to minimize NO_x formation, without use of a post-combustion NO_x control method such as selective catalytic reduction (SCR) or

SCONOx™. Our concerns regarding this approach are discussed in the following items.

a. The NO_x emission rates proposed as BACT for the combined cycle combustion turbines are an emission rate of 15 ppmvd (at 15% oxygen) when burning syngas and an emission rate of 25 ppmvd (at 15% oxygen) when burning natural gas (and a weighted average when burning both fuels simultaneously). All of the recent combined cycle combustion turbine projects throughout the U.S. that are known to us and that involve large natural gas-fired combustion turbines comparable in size to the Kentucky Pioneer Energy turbines have been permitted with a NO_x emission rate for natural gas combustion of 3.5 ppmvd or less to be achieved by a combination of combustor design and use of post-combustion controls. While we recognize that IGCC combustion turbines differ from standard natural gas-fired combined cycle combustion turbines, we are still concerned that the NO_x BACT levels proposed for Kentucky Pioneer Energy are four to seven times higher than the emission rates approved for all other recently permitted natural gas-fired combined cycle combustion turbines of comparable size.

b. The applicant's (and KDAQ's) primary concern about use of SCR as a NO_x control method appears to be the potential for reaction of residual ammonia downstream of the SCR device with syngas sulfur to form ammonium bisulfate salts. These salts could in turn "cause serious plugging, loss of heat transfer and corrosion in the downstream portions of the heat recovery steam generator." [Quote from applicant's revised NO_x BACT analysis dated August 2, 2000.] Our response to this concern is as follows:

    - The sulfur content of syngas is much less than the sulfur content of post-combustion air streams in coal-fired boilers where SCR technology has been successfully applied despite initial concerns that the technology would not be feasible in the high-sulfur environment of such air streams. The applicant addresses this consideration by saying that formation and deposition of ammonium bisulfate salts within coal-fired boiler air preheaters is a less serious concern because air preheaters can be cleaned more easily than the surfaces within a heat recovery steam generator (HRSG) and because such deposition has a lesser effect on heat transfer in coal-fired boilers. We would be more persuaded if the applicant were to provide information directly from one or more HRSG vendors discussing why ammonium bisulfate salts pose a greater problem for combined cycle combustion turbine HRSG's than for coal-fired boilers.

    - Most recent dual-fuel (natural gas and No. 2 fuel oil) combined cycle combustion turbine projects have been permitted to require use of SCR for NO_x control when burning fuel oil as well as when burning natural gas. The typical sulfur content of the fuel oil proposed for such projects is 0.05 percent by weight, which should yield exhaust gas sulfur compound concentrations comparable to those resulting from combustion of syngas. We recognize that fuel oil is generally proposed only as a backup fuel for combined cycle combustion turbine projects and not as the primary fuel. Accordingly, intermittent combustion of fuel oil may not pose the same potential for HRSG contamination as continuous combustion of syngas. Nevertheless, we would be interested in the applicant's explanation of why SCR can be used with fuel oil combustion in combined cycle combustion turbines but not with syngas combustion.

- We are aware of at least one SCR vendor (Huntington Environmental Systems) that also provides a component for residual ammonia scavenging to minimize plugging and corrosion of equipment downstream of the SCR device. Furthermore, in conventional SCR systems, proper operation of the ammonia feed system along with proper sizing and selection of the catalyst components can serve to minimize the amount of ammonia that slips through the SCR reaction zone. We recommend that the applicant or KDAQ investigate means of reducing residual ammonia before concluding that SCR is not a technically feasible option due to formation of ammonium bisulfate salts.

c. Although acknowledging the technical feasibility concerns of SCR, KDAQ's preliminary determination also includes a cost effectiveness evaluation for SCR as a technically feasible option. The comparison point for this cost evaluation is an uncontrolled baseline emission rate. Table A-5 (page 29) in the preliminary determination (and information in the original permit application on which Table A-5 is based) lists a NO_x emissions rate of 15 ppmvd as the "uncontrolled" emissions rate. We have two concerns about this baseline rate. (1) Using an emission rate of 15 ppmvd as the uncontrolled level overlooks the contribution of natural gas combustion at an emission rate of 25 ppmvd. By the terms of the draft permit, natural gas combustion can equal approximately 12 percent of the total heat input to the combustion turbines after the first two years of operation (during which natural gas use can be even higher). We recognize that the applicant's revised NO_x BACT evaluation dated August 2, 2000, contains a weighted average "uncontrolled" NO_x emission rate of 16.6 ppmvd to adjust for natural gas use. (2) We question whether 15 ppmvd (or 16.6 ppmvd) is truly the uncontrolled baseline rate. This rate represents the level achieved with use of diluent water/steam injection. Unless the turbines can not be run without diluent water/steam injection, then the emission rate without diluent injection should be estimated and used as the uncontrolled baseline. Use of a higher baseline emission rate would result in a lower cost effectiveness value (lower dollars per ton removed).

d. The preliminary determination and the original permit application contain two SCR cost evaluations, one based on a U.S. Environmental Protection Agency (EPA) publication (*Alternative Control Techniques Document - NO_x Emissions from Stationary Gas Turbines*, 1993) and one based on Englehard vendor data with additional costs to allow for modifications of the HRSG to counteract the potential harmful effects of ammonium bisulfate salts.. We have concerns about both evaluations, as follows. (1) The EPA document is generic in nature and may not be appropriate for every project. More importantly, it does not reflect the substantial improvements and cost reductions in SCR technology for large combined cycle combustion turbines that have occurred since the time that the EPA document was written in the early 1990's. (2) The purchased equipment cost based on the Engelhard quote is a total of approximately \$12,000,000 for both combustion turbines, or about \$6,000,000 for each turbine. This cost is far higher than the typical equipment costs reported in other permit applications for F-class combustion turbines. A possible justification for this high cost is that more than half of the equipment cost is due to the estimated additional cost for HRSG improvements. However, we did not find any information directly from a HRSG vendor in the draft permit package that would support this additional cost. (3) A revised BACT analysis from the applicant dated August 2, 2000, contains another SCR vendor quote, this one from Cormetech. The equipment cost in the Cormetech quote is \$1,394,000 for two units, or approximately \$700,000 for each combustion turbine. The quote also contains a statement that "Based on discussions with an HRSG company, Cormetech estimates that the balance of the SCR equipment would cost an additional \$500,000 to \$600,000." If this "additional" amount is not accounted for in the Cormetech quote of \$1,394,000 for two units, adding it to the quote would boost the total equipment cost to about \$1,000,000 per turbine. This is much lower than the equipment cost based on the Engelhard quote. (4) The cost effectiveness analysis for SCR based on the Englehard quote (page 34 of the preliminary determination) contains a "Maintenance labor and materials" cost of \$518,300 per year for both turbines combined. This cost appears excessive compared to cost estimates for the same item in other recent combustion turbine permit applications. The cost estimate for this item appears to be based on a procedure in the 1993 EPA document cited above, a document that we have indicated is out of date. (5) In summary, we have serious concerns about the cost evaluations for SCR. A further evaluation of costs coupled with use of a higher "uncontrolled" baseline emission rate is likely to show that the cost of SCR for the Kentucky Pioneer Energy combustion turbines is within the range of NO_x control costs considered acceptable for recent combined cycle combustion turbine projects involving combustion of conventional fuels.

e. Appendix C of the draft permit/preliminary determination package contains a list of selected simple cycle combustion turbine NO_x BACT determinations from 1995 to present. We are not exactly sure why a list of simple cycle projects is included since the combustion turbine projects at the Kentucky Pioneer Energy facility will be combined cycle combustion turbines. Assuming this list has some relevance, we offer the following observations. (1) The list does not impart the reality that essentially all recently permitted simple cycle combustion turbine projects have NO_x BACT levels in the 9 ppmvd to 15 ppmvd range when firing natural gas, much lower than the 25 ppmvd proposed for the Kentucky Pioneer Energy facility when firing natural gas. (2) The list includes the Enron Calvert City project in Kentucky that was eventually canceled and that had a proposed NO_x BACT level of 25 ppmvd (for natural gas combustion) with which we strongly disagreed.

f. In the preliminary determination, KDAQ states that the SCONOx™ technology for control of NO_x emissions from combined cycle combustion turbines "is not yet commercialized for combustion turbines larger than 100 MW." Our understanding is that SCONOx™ is commercially available for large combustion turbines from ALSTOM Power, and, in fact, that ALSTOM Power is the sole licensee of the technology for turbines of this size. This is not to say that SCONOx™ should be required as BACT for the Kentucky Pioneer Energy facility, but we request that your final BACT determination take into account the presumption that SCONOX™ is commercially available.

g. Table A-1 (page 19-20) in the preliminary determination contains a "snapshot" of projects that for the most part are pre-1996 projects that do not necessarily reflect current technology.

h. Page 25 of the preliminary determination is a copy of a letter from General Electric (GE) stating in essence that GE's Dry Low NO_x (DLN) product line is not available for combustion turbines firing syngas fuels. This letter is dated October 19, 1999. We request that KDAQ check with GE to confirm that the position stated in this letter is still valid.

i. On page 22 of the preliminary determination, KDAQ refers to Tampa Electric Company's (TECO's) IGCC facility (Polk Power Station), and cites the NO_x limit of 25 ppmvd for this facility. Please note that this was an interim limit to be confirmed or replaced pending a final BACT determination to be made at a later date. In fact, the Florida Department of Environmental Protection is currently assessing the appropriate BACT for the TECO facility. Therefore, KDAQ should not assume that 25 ppmvd has been accepted as BACT for the TECO facility.

2. We are confused concerning whether the NO_x emissions listed in KDAQ's preliminary determination and draft permit are consistent with the most recent emissions estimates provided by the applicant. The annual NO_x emission rate listed on page 9 of the preliminary determination for the entire project is 1060.1 tons per year (tpy), whereas the annual NO_x emissions rate listed in the applicant's revised emissions estimates dated August 3, 2000, for the two combustion turbines alone range from 1,337 tpy for the first year of operation to 1,187 tpy for operation after the first two years of operation. More importantly, the combustion turbine NO_x emissions limit in the draft permit for synthetic fuel combustion is 0.072 pounds per million Btu (lb/MMBtu), but the estimate in the applicant's August 3, 2000, application revision is 0.0735 lb/MMBtu. We request that KDAQ review the preliminary determination and draft permit to confirm that they are based on the most recent information for the project.

3. The applicant and KDAQ have identified two options for minimization of SO_2 emissions from the combustion turbines, as summarized on pages 40 to 42 of the preliminary determination. The top two control methods are identified as amine-based acid gas cleanup (which is the applicant's choice) and flue gas desulfurization (FGD). Another option that would provide an even greater level of control than either of these methods individually is a combination of the two, that is, amine-based acid gas cleanup to remove sulfur prior to combustion and FGD to remove SO_2 after combustion. Although this combination might be prohibitively expensive, we request that KDAQ consider acid gas cleanup combined with FGD as the "top" technically feasible option when arriving at a final BACT determination.

4. Section B.4. of the draft permit excludes startup and shutdown periods from compliance with emissions limits. We consider periods of startup and shutdown to be part of normal source operation, and we recommend that KDAQ consider including more specific BACT requirements for startup and shutdown in the final PSD permit. Startup and shutdown control options that could be considered include (but are not limited to) the following: limitations on the number of startups and shutdowns in any 12-month period; limitations on the number of hours allowed in any 24-hour period for excess NO_x and CO emissions due to startup and shutdown conditions; mass emission limits for NO_x and CO emissions during any 24-hour period to include emissions during startup and shutdown; and future establishment of startup and shutdown BACT emission limits for NO_x derived from test results during the first few months of commercial operation. At a minimum, the final permit should include a definition of the words startup and shutdown in terms of the observable operating conditions that indicate a period of startup and a period of shutdown.

5. We direct your attention to a possible discrepancy in the averaging period to be used for assessment of compliance with SO_2 emissions limits. Section B.2.c) of the draft permit states that the SO_2 emissions limit is based on "any rolling three-hour average period." Section B.4.h) states that "... if any 24-hour rolling average sulfur dioxide value exceeds ...." We request that you review these two permit conditions and make revisions if needed.

6. In terms of the air quality impact assessment, our review comments on the PSD permit application and KDAQ preliminary determination are provided below. Because the modeling computer files were not available, they were not included in our review.

   a. Alternate Operational Scenarios - Only one operational scenario was modeled in the application. To ensure the worst-case ambient impact is considered in the modeling, other possible operational scenarios (e.g., independent partial load for each of the two combined-cycle turbines) should be considered, or each combustion turbine should be limited to nearly full load operation.

b. Modeling Receptor Grid - The receptor grid spacing of 1.0 km is not sufficient to identify the maximum concentration close to the facility (e.g., within 5 km of the facility). Confirmation is needed that the refined 100-m grids were of sufficient size to ensure adequate coverage of the area between coarse grid points. To ensure identification of maximum concentrations for 100-m grid modeling, smaller grid spacings (e.g., 200-500 meters) are needed within the first few kilometers of the site boundary.

c. Site Boundary - A figure in the permit application indicates the site boundary as the rail loop about the facility. The application indicates a 100-m interval receptor grid was placed about the fenceline. Confirmation is needed that the modeled site boundary is an actual fence containing property owned or controlled by Kentucky Pioneer Energy. If this is different from the rail loop about the site, the fenceline should be identified.

d. Class I Area Analysis - The PSD class I area analysis provided in the application does not follow the modeling guidance provided by EPA and the class I area federal land managers (FLMs): (1) the ISCST3 model is not appropriate beyond 50 km; (2) improper class I PSD significant impact levels were used; and (3) the visibility assessments beyond 50 km from the facility should be for regional haze. The preliminary determination indicates the federal land manager of the nearest class I area (National Park Service) has performed a CALPUFF screening assessment for all air quality related values and found no significant adverse impacts. The maximum CALPUFF ambient concentrations in the Class I area should be provided to confirm that they are less than the appropriate PSD Class I significant impact levels.

e. Air Toxics Impact Assessment - The procedure used to assess the ambient impacts of non-criteria toxic emissions was reviewed by the Kentucky Division of Environmental Services. Their comments, provided in a memo dated September 29, 2000, need to be resolved.

7. We have the following comments related to NSPS for municipal waste combustor (MWC) units in 40 C.F.R. part 60, subpart Eb and for stationary gas turbines in 40 C.F.R. part 60, subpart GG:

Section B, Part 1, Operating Limitations

In Condition #1g, line 5, change to read - "...of this section, **a fully certified shift supervisor, or a provisionally certified shift supervisor who is scheduled to take the full certification exam according to the schedule specified in paragraph (b) of this section.**" [reference §60.54b(c)]

In Condition #1g, add the requirements of §60.54b(c)(2) - "**If one of the persons listed**

in paragraph (c) of this section must leave the affected facility during their operating shift, a provisionally certified control room operator, who is onsite at the affected facility may fulfill the requirement in paragraph (c) in this section."

In Condition #1h, the second sentence should be changed to include all of the elements outlined in §60.54b(e)(1) through (e)(11).

In Condition #1h, add the requirements of §60.54b(g) - "**The operating manual required by paragraph (e) of this section shall be kept in a readily accessible location for all persons required to undergo training under paragraph (f) of this section. The operating manual and records of training shall be available for inspection by the EPA or Kentucky DAQ.**"

In Condition #1i, change the condition to read - "Pursuant to **40 C.F.R. 60.57b(a) and (b), a preliminary and draft final materials separation plan and a siting analysis plan shall be prepared for the facility**." These applicable NSPS requirements are listed in the draft permit, however, compliance with the requirements for preparation of the preliminary and draft final materials separation plan and the siting analysis plan must be completed before the final construction permit can be issued. Information to fulfill the requirements of §60.57b(b)(1) and (b)(2) for preparing the siting analysis plan can be taken from the PSD permit application. Preparation of the materials separation plan for the facility and its service area must include the information required by §60.57b(a)(2)(iii)(A) through (H) and may not be available in the PSD permit application. A public meeting to accept comments on the preliminary draft materials separation plan and siting analysis must be conducted as outlined in §60.57b(a) and (b).

<u>Section B, Part 2, Emission Limitations</u>

In Condition #2c, line 2, the emission limitation for sulfur dioxide is listed as 0.032 lb/MMBtu with no corresponding parts per million (ppm) basis. Condition #2c should also list the §60.52b(b)(1) limit for sulfur dioxide of "**30 ppm by volume or 20 percent of the potential sulfur dioxide emission concentration (80 percent reduction by weight or volume), corrected to 7% oxygen (dry basis), whichever is less stringent.**"

In Condition #2j, line 2, change to read - "...shall not exceed 0.080 milligrams per dry standard cubic meter **or 15 percent of the potential mercury emission concentration (85 percent reduction by weight), corrected to 7% oxygen, whichever is less stringent.**"

In Condition #2k, verify that the hydrogen chloride limit is correctly stated as "0.2 ppm, corrected to 15% oxygen." The limit from §60.52b(b)(2) is "25 ppm by volume or 5 percent of the potential hydrogen chloride emission concentration (85 percent reduction by weight or volume), corrected to 7% oxygen (dry basis), whichever is less stringent."

In Condition #21, verify that the dioxin/furan limit of "0.01 nanograms per dry standard cubic meter, corrected to 7% oxygen," is measured as toxic equivalency or total mass and annotate that measure in the permit condition. The dioxin/furan total mass emissions limit from §60.52b(c)(2) is "13 nanograms per dry standard cubic (total mass), corrected to 7% oxygen."

<u>Section B, Part 3, Testing Requirements</u>

In Condition #3a, line 3, change "40 C.F.R. 60.335" to "**40 C.F.R. 60.335(f)**."

Add Condition #3b as a new condition and, after other revisions, renumber after b, to read as follows - "**Pursuant to Regulation 40 C.F.R. 60.58b, in conducting performance tests required by 40 C.F.R. 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of Part 60, except as provided for in 40 C.F.R. 60.8(b).**" This will ensure that alternatives to test methods are approved by the appropriate EPA Region 4 authority or KDAQ authority, depending on the minor, intermediate, or major change to a test method under consideration as an alternative.

In Condition #3b, change to read - "Pursuant to Regulation 401 KAR 50:045 **and 40 C.F.R. 60.58b,** ...." [reference §60.58b(h)]

In Condition #3c, change to read - "Pursuant to Regulation 401 KAR 50:045 **and 40 C.F.R. 60.58b,** ...." [reference §60.58b(e)]

In Condition #3d, line 2, change to read - "...carbon monoxide, in accordance with General Condition G(d)(5)."

In Condition #3e, line 2, change to read - "...particulate matter, in accordance with General Condition G(d)(5)."

Condition #3h should be deleted, since it is repeated verbatim in the General Conditions as G(d)(6).

In Condition #3i, line 2, change to read - "...cadmium, lead and mercury using EPA Reference Method 29, in accordance with General Condition G(d)(5)."

In Condition #3j, line 2, change to read - "...hydrogen chloride using EPA Reference Method 26 or 26A, in accordance with General Condition G(d)(5)."

In Condition #3k, line 2, change to read - "...dioxins and furans using EPA Reference

Method 23, in accordance with General Condition G(d)(5)."

Section B, Part 5, Specific Recordkeeping Requirements

Add Condition #5g as a new condition, to read as follows - **"Pursuant to Regulation 40 C.F.R. 60.59b, the permittee shall maintain records of the information specified in paragraphs (d)(1) through (d)(15) of this section, as applicable, for this facility for a period of at least 5 years."** [reference §60.59b(d)]

Section B, Part 6, Specific Reporting Requirements

In Condition #6p, line 3, change to read - "...fuels planned for use **in the unit,** the unit capacity...

Add Condition #6q as a new condition, to read as follows - **"Pursuant to Regulation 40 C.F.R. 60.59b, the owner or operator shall submit to the Division's Frankfort Regional Office the preliminary and final draft materials separation plan information specified in paragraphs (a)(1) through (a)(4) of this section."** [reference §60.59b(a)]

Section B, Emissions Unit: 05 (05) - Vitrified Frit Handling Operations

In Testing Requirements, first sentence, change to read - "Pursuant to Regulation 40 C.F.R. 60.55b **and 60.58b**, the owner or operator shall conduct initial and annual performance tests for fugitive particulate emissions using EPA Reference Method 22, in accordance with General Condition G(d)(5)." [reference §60.58b(k)] See comment regarding new Condition #3b for additional information.

Section D, Source Emission Limitations and Testing Requirements

Renumber Condition #3 to #2.

If you have any questions concerning the comments in this letter, please contact Jim Little of the EPA Region 4 staff at (404) 562-9118.

Sincerely,

/s/

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides, and Toxics

From: Shannon Todd [sktodd@tecoenergy.com]
Sent: Thursday, May 10, 2001 4:18 PM
To: Halpin, Mike
Cc: Laura Crouch
Subject: Polk NOx BACT

halpin1_.doc

Mike,

Attached is the letter with additional information on the Polk NOx BACT Determination for your consideration. This letter will be sent today via FedEx and should arrive tomorrow. If you have any questions, feel free to call me at (813) 641-5125.

-Shannon

May 10, 2001

Mr. Michael Halpin, P.E.
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Via Fed Ex
Airbill No. 7900 4812 1562

Re: Polk Power Station Unit 1
Syngas Fired Combustion Turbine NO_x BACT Determination

Dear Mr. Halpin:

Tampa Electric Company (TEC) would like to take this opportunity to submit additional information regarding the Best Available Control Technology (BACT) determination for Polk Power Station Unit 1. This information is submitted as a follow up to our meeting of April 3, 2001, and subsequent communications via telephone. This submittal is comprised of three main elements, an overview of the original BACT evaluation, a refined BACT cost analysis, and information regarding a recently permitted syngas fired Combustion Turbine (CT) installation. Furthermore, if deemed acceptable, TEC would like to work with the Florida Department of Environmental Protection (FDEP) in developing a continuous improvement program (CIP) to reduce NO_x emissions from Polk Unit 1 through the use of process optimization and equipment upgrades.

The Original BACT Evaluation

In the course of developing the original BACT evaluation, TEC was required to consider "data gathered on this facility, other similar facilities, and manufacturer's research." In taking this approach, TEC determined that a NO_x limit of 25 ppmvd @15% O_2 was appropriate as an emission limit. This would allow TEC to continue firing its present array of fuels while generating safe and reliable electricity to serve its customers.

In subsequent discussions with FDEP, TEC has come to understand that the Department may be considering the application of a selective catalytic reduction (SCR) system to Polk Unit 1 as BACT. In the original BACT submittal, TEC outlined several technical concerns with the application of this technology to an Integrated Gasification Combined Cycle (IGCC) facility, and, based on discussions with several catalyst vendors, these overriding technical concerns remain. The most significant of these concerns is the formation of ammonium sulfate and ammonium bisulfate compounds. These compounds, when formed in the Heat Recovery Steam Generator (HRSG) will cause significant plugging and fouling of heat transfer equipment, which could require several additional outages per year to allow for the cleaning of this equipment.

Since the manufacturer of the combustion turbine, General Electric, believes that SCR is not applicable to this unit, no other IGCC in the United States currently employs SCR technology, and the testing performed at the Polk facility demonstrated that 25 ppmvd @15% O_2 is a reasonable limit, TEC feels that based on the criteria established by the Department for this evaluation, a SCR system can clearly be eliminated as a BACT recommended technology for Polk Unit 1.

Refined BACT Cost Analysis

Due to the fact that the original submittal was required within 30 days of the completion of the test program, TEC based the original SCR cost analysis on vendor quotes for other facilities that did not fire syngas as a primary fuel. Since that time, TEC has solicited additional input from four SCR equipment vendors to refine the cost analysis presented in the initial submittal. Of the four vendors contacted, two vendors submitted no-bid responses, one of whom was Englehard. This point is important as the original submittal was based on an Englehard quote for a facility that was not an IGCC. The SCR quote that is used in this current analysis was provided by Deltak. The quote is enclosed as Attachment 1 to this letter and serves as a basis for the cost analysis performed in this submittal.

The Deltak quote specifies an outlet NO_x concentration from the SCR of 5 ppmvd corrected to 15% oxygen. Because this quote is based on this exit concentration, the 5 ppmvd value is used as the controlled NO_x value when estimating cost effectiveness, and the baseline for NO_x emissions remains at 25 ppmvd. The baseline emissions from oil firing (i.e., back up fuel firing) is 42 ppmvd, and the SCR system is expected to have the same 80% control for the NO_x emissions when firing oil as when controlling syngas firing. Therefore, the associated controlled NO_x emission rate during oil firing would be 10.5 ppmvd. Although oil is only fired for a maximum of 10% of the total allowable operation, the emissions reductions from the oil case represent approximately 21% of the total emissions reductions. Thus, because the maximum allowable back up fuel firing load is used in the estimation of cost effectiveness, the cost effectiveness calculations tend to be conservative in nature (i.e., will tend to under estimate the cost per ton of pollutant removed because back up fuel is typically fired in considerably less quantities than the allowable limit).

The Deltak quote includes the following statement on the first page regarding concerns with ammonia sulfate and ammonia bisulfate deposition and plugging. The fact that two vendors elected not to bid on this project coupled with the placement of this concern on the cover page of the Deltak quote lends credence to the overall priority that equipment vendors place on this concern.

> *I would like to note one potential problem with retrofitting SCR into the subject HRSG. There is a rather high SO_2 loading in the exhaust gas stream due to the combustion of syn-gas in the combustion turbine. Approximately 5% of the SO_2 in the gas stream will oxidize to SO_3 across the catalyst. This additional SO_3 along with the unspecified level of SO_3 in the combustion turbine exhaust will combine with the injected ammonia (NH_3) to form ammonium salts (primarily ammonium bisulfate) that are likely to adhere to the tubing in the cooler HRSG sections causing both a thermal insulation effect and/or an increase in turbine back pressure. With the fuel that is being burned, and the potential for Fuel Oil back-up fuel, the potential for ammonium salt fouling will be quite significant.*

Based on this concern, TEC estimates that the HRSG and down stream exhaust ductwork will need to be cleaned three times per year, at a minimum. The cost estimate includes two entries to account for these costs. The first entry is the annualized costs of HRSG maintenance that is expected to occur with increased degradation and corrosion of the heat transfer media. These estimates were prepared by plant personnel, taking into account the anticipated increased tube replacement costs that will be incurred starting in the third year after the installation of the SCR unit. These costs were estimated through ten years, then converted to an annualized recurring cost using engineering economic accounting methods.

In addition to the HRSG maintenance costs, contract labor costs are included for performing the anticipated cleanings. One cleaning will be performed during a scheduled outage, and two cleanings will be performed during unscheduled outages. The contract labor costs involved with the cleaning will be incurred by TEC during each of the outages. The estimated cleaning cost is \$60,000 per occurrence.

During the scheduled outage, there are no additional costs that are incurred by TEC. However, during the unscheduled outages that are performed solely to address the plugging, TEC will incur costs associated with the loss of generating capacity. During these unscheduled outages, TEC will need to replace the electricity that would otherwise be generated by the Polk facility (i.e., 315 MW). The basis for estimating the incremental replacement cost of \$20 per MW-hour is presented on page 6-22 of the November 2000 submittal.

TEC believes the incremental costs to replace the electrical power that would otherwise be generated by the Polk facility to be a real and valid cost that is associated with an unscheduled outage. During the meeting between FDEP and TEC, the Department had indicated that additional supporting information for the use of this cost estimate is warranted, especially as it related to United States Environmental Protection Agency (USEPA) guidance on accounting for lost power generation capacity during plant outages. TEC understands USEPA guidance to state that during scheduled outages, or those events that can reasonably take place during scheduled outages, it is not appropriate to account for the lost generation capacity. As such, costs for events such as catalyst replacement and one cleaning of the catalyst per year are estimated without the additional costs of replacing the power that would otherwise be generated by the facility.

However, because the Polk facility is a base load unit on TEC's system and has a current overall availability commitment of 86.5%, any unscheduled outages will incur considerable costs to TEC, especially if these unscheduled outages will affect the ability of the Polk facility to meet this availability commitment. TEC believes the estimated incremental cost for electrical generation or purchase to be a real cost that would be incurred by the facility during any unscheduled outage, regardless of the reason for the outage. This cost is one of the reasons that unscheduled outages get prompt attention of engineering and maintenance staff, including subcontractors, to return the facility to normal operational mode.

TEC believes that the cost of replacing the power generation capacity lost during an unscheduled outage is a real and justifiable cost that must be included in the performance of the economic analysis of control options. To provide a complete analysis to FDEP, TEC has provided the information on cost effectiveness analysis for both cases, with and without the incremental cost for power replacement Attachment 2.

The revised cost effectiveness estimate for the SCR control of NO_x is \$5,737 per ton of NO_x removed, as summarized in Table 1. This cost takes into account the incremental cost of replacing power during two unscheduled outages per year. Table 2 presents the cost effectiveness of \$3,499 per ton, which does not take into account the incremental cost for replacing power during the outage. Tables 3 through 5 contain supporting information regarding costs estimates used for this analysis. This analysis follows the same approach that was used in the November 2000 submittal, hence is not described in further detail.

The incremental cost of replacing the lost power generating capacity is approximately 40% of the total cost associated with the SCR. TEC has serious concerns regarding the fouling, plugging and corrosion of components downstream of the SCR in the high sulfur environment, and believes these cost estimates to be conservatively low. Because there is a shortage of practical experience of CT SCR performance in high sulfur environments, these estimates are based on expected performance, not actual data. TEC is aware of predictions by equipment vendors (e.g., General Electric) that account for considerably more difficulties and associated costs that TEC is taking into account in this cost analysis.

Recent Syngas Fired CT BACT Determination

The Kentucky Pioneer Energy LLC facility proposed for Trapp, Kentucky is currently undergoing the public review of its draft Prevention of Significant Deterioration (PSD) permit. This permit proposes NO_x BACT of 15 ppmvd for syngas firing, and 25 ppmvd for back up fuel (i.e., natural gas) firing. The NO_x control technology selected for this facility is steam injection. The subject equipment includes two CTs which are GE 7FA CTs, each rated at 197 MW without the associated HRSG.

Discussions with Mr. Donald Newell, the Commonwealth of Kentucky permit engineer, indicate that no questions were raised to date by the public regarding the proposed BACT emissions limit. The questions raised by the public concerned other items, such as the placement of lights at the facility to minimize light pollution, the need to keep the public informed of what is happening at the facility, mercury emissions and the impacts of burning municipal solid waste on rainwater.

The USEPA has questioned certain aspects of the BACT determination for the facility, but has not determined that add-on controls (e.g., an SCR) are cost effective or technically feasible. The questions from the USEPA are included as Attachment 3. The questions raised in this letter regard specific aspects of the BACT determination for the facility, and ask for supporting information to validate the concerns regarding the implementation of SCR on an IGCC CT. For example, regarding validation of the plugging concerns, the USEPA states:

> *We would be more persuaded if the applicant were to provide information directly from one or more HRSG vendors discussing why ammonium bisulfate salts pose a greater problem for combined cycle combustion turbine HRSG=s than for coal-fired boilers.*

Additional concerns raised by the USEPA address other aspects of the BACT determination, such as cost data and the survey of other similar facilities conducted to support the permit application. Mr. Newell indicated that he is in the process of collecting additional information to support his determination of steam injection meeting BACT, and will be responding to USEPA comments. Mr. Newell expressed concerns with reliability and clogging of equipment as a result of using an SCR system.

Until a final determination of the BACT is made for this Kentucky facility, TEC feels it is inappropriate to use the fact that questions are being raised by USEPA as a justification for requiring SCR as BACT for the Polk facility. First, the BACT process is interactive in nature, allowing for all concerned parties (e.g., citizen groups, USEPA, and affected Class I area managers) to provide their input and comments. The final BACT determination takes into account these comments, as well as other factors that are reviewed by the permitting agency. Additionally, many of the questions raised by the USEPA regarding the Kentucky BACT determination either do not apply to the Polk facility, or already were addressed by TEC in prior submittals.

Additionally, the CT at the Polk facility, although similar to the CTs proposed for the Kentucky facility, is approximately two generations in technological advances behind the CTs that will be installed in Kentucky. This point is further discussed in the November 2000 submittal. Thus, because the CT at the Kentucky facility is expected to achieve 15 ppmvd NO_x emissions, it is not appropriate to expect the Polk CT to achieve the same level of emissions.

Conclusions

Through the use of a CIP, TEC is willing to work with the Department to reduce NO_x emissions from the Polk facility. This program would investigate the use of process optimization and the addition of hardware where applicable to minimize the formation of NO_x rather than remove it from the flue gas stream. This is a prudent approach to the minimization of NO_x emissions from Unit 1, and does not carry with it the significant technical concerns associated with the addition of a post combustion control technology such as SCR.

TEC has considerable technical concerns with the use of an SCR system at this facility because of the high sulfur content of the exhaust gas, and these concerns are shared by several SCR vendors. Although TEC has tried to incorporate the costs associated with these concerns into the cost effectiveness analysis, the costs are based on estimated difficulties, not on data from similar facilities because there are no similar IGCC facilities that operate an SCR unit. Since the control cost effectiveness evaluation was conservative in nature, TEC believes the cost effectiveness value of $5,737 per ton of NO_x removed to be a lower bound of the cost, and actual costs of an SCR may be substantially higher. Based on this analysis, TEC believes the SCR control option to be both technically and economically infeasible.

Thank you in advance for your consideration of this matter. If you have any questions regarding the information contained in this submittal, please feel free to telephone Shannon Todd or me at (813) 641-5125.

Sincerely,

Gregory M. Nelson, P.E.
Director
Environmental Affairs

EA/gm/SKT253

Attachments

c: Mr. A.A. Linero – FDEP
Mr. Jerry Kissel - FDEP SW

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May 1, 2001

Mr. Clair Fancy
Florida Department of Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Via FedEx
Airbill No. 7909 2896 9447

Re: Tampa Electric Company (TEC) - Polk Power Station
Unit 1 NO_x BACT Determination
Notice of Waiver of 90-Day Period
FDEP Permit No. 1050233-001-AV

Dear Mr. Fancy:

With respect to the above referenced NO_x BACT Determination, Tampa Electric Company (the Company) is hereby granting a waiver of the 90-day period in which the Florida Department of Environmental Protection (Department) is required to act on a permit pursuant to Section 120.60(1), Florida Statutes. This waiver is granted to allow the Company to submit additional relevant information regarding this project, and will extend the period for Department action to and including July 1, 2001.

Please let me know if you have any questions. You can contact Shannon Todd or me at (813) 641-5125.

Sincerely,

Mark J Hornick

Mark J. Hornick
General Manager
Polk Power Station

EP\gm\SKT251

c: Mr. Al Linero - FDEP
Mr. Jerry Kissel - FDEP SW

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April 6, 2001

Mr. Clair Fancy
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7915 2139 2472

Re: Tampa Electric Company (TEC) – Polk Power Station Title V Permit BACT Determination for Syngas Combustion Turbine – Test #7

Dear Mr. Fancy:

During the review of the Polk Power Station NO_x BACT Determination, it was discovered that the turbine summary data table titled "Polk Power Station Unit 1 BACT #7" found in Appendix B of the seventh test report contained data for October 18, 2000 rather than October 17, 2000; the actual test date. The enclosed table corrects this error and contains the turbine data for October 17, 2001. Please replace the original data table with the one enclosed.

If you have any questions, please feel free to contact me at (813) 641-5125.

Sincerely,

Shannon K. Todd
Engineer
Environmental Affairs

EP\gm\SKT247

Enclosures

c/enc: Mr. Al Linero – FDEP
Mr. Mike Halpin - FDEP
Mr. Jerry Kissel - FDEP SW

POLK POWER STATION UNIT 1 BACT #7

10/17/2000	1MIN	Gas Flow lb/sec	Load Watts	Gen Watts	Heating Content, BTU/IB	N2 Flow	Inlet Temp, Deg,F	Bar, Press
10/17/2000	Date:Time	1TSYFI910	1PWRJI900	1GMLJI962	1TSYJYI910	NITFI920	1TMSTI922M	1TMSPI909
Polk 1	17-Oct-00 10:30:00	99.62400818	191.873138	192.6472	174.954071	111.581	73.12463379	29.857426
	17-Oct-00 10:31:00	100.0039673	191.578033	192.66579	174.954071	111.295	73.71014404	29.857327
	17-Oct-00 10:32:00	100.1067505	192.141251	192.68437	174.954071	110.502	74.47385406	29.857227
	17-Oct-00 10:33:00	99.42021179	192.040085	192.70297	174.954071	111.324	74.69023895	29.857128
	17-Oct-00 10:34:00	99.86873627	192.213745	192.72156	174.954071	112.134	73.8343811	29.857031
	17-Oct-00 10:35:00	99.87377167	191.852097	192.67868	174.954071	111.283	73.22729492	29.856932
	17-Oct-00 10:36:00	99.87773895	191.811249	192.582	174.954071	111.173	73.63794708	29.856833
	17-Oct-00 10:37:00	99.96877289	191.794754	192.48532	174.954071	111.363	74.54411316	29.856733
	17-Oct-00 10:38:00	99.90661621	191.866409	192.45126	174.954071	111.745	74.72731781	29.856636
	17-Oct-00 10:39:00	99.9093399	191.938065	192.472	174.954071	112.344	74.78911591	29.856537
	17-Oct-00 10:40:00	99.75204468	191.739304	192.49275	174.954071	112.059	74.85092163	29.856438
	17-Oct-00 10:41:00	99.80929565	192.039337	192.51349	174.954071	111.492	74.91271973	29.856339
	17-Oct-00 10:42:00	99.88878632	191.749359	192.53423	174.954071	111.791	74.97451782	29.856239
	17-Oct-00 10:43:00	100.1504593	191.787338	192.55498	174.954071	111.418	74.65851593	29.856142
	17-Oct-00 10:44:00	100.1126938	191.634247	192.57571	174.954071	111.704	74.59712219	29.856043
	17-Oct-00 10:45:00	99.96179199	191.491318	192.59645	174.954071	110.625	74.53572845	29.855944
	17-Oct-00 10:46:00	100.0699005	191.643158	192.6172	174.954071	111.106	74.47432709	29.855844
	17-Oct-00 10:47:00	99.92645264	191.795013	192.63794	174.954071	110.913	74.41293335	29.855747
	17-Oct-00 10:48:00	99.94142914	192.319717	192.65868	174.954071	111.501	74.6337738	29.855648
	17-Oct-00 10:49:00	99.75979614	191.563446	192.67943	174.954071	112.142	74.94226074	29.855549
	17-Oct-00 10:50:00	99.77153015	191.728546	192.70016	174.954071	111.781	74.78952026	29.85545
	17-Oct-00 10:51:00	99.8414917	191.893646	192.7209	174.954071	111.994	74.79803467	29.855352
	17-Oct-00 10:52:00	99.59534454	191.69278	192.69728	174.954071	111.104	74.88529968	29.855253
	17-Oct-00 10:53:00	99.85980988	191.886398	192.63736	174.954071	111.562	75.31647491	29.855154
	17-Oct-00 10:54:00	99.79956818	191.517166	192.60939	174.954071	111.434	75.31647491	29.855055
	17-Oct-00 10:55:00	100.1811523	191.375793	192.60939	174.954071	111.489	75.08163452	29.854958
	17-Oct-00 10:56:00	100.09552	191.565598	192.60939	174.954071	111.89	74.37712097	29.854858
	17-Oct-00 10:57:00	100.0772095	191.639496	192.60939	174.954071	112.093	74.4938736	29.854759
	17-Oct-00 10:58:00	99.88398743	191.650452	192.60939	174.954071	111.643	74.89753723	29.85466
	17-Oct-00 10:59:00	99.83202362	191.766586	192.60939	174.954071	111.939	75.88339996	29.854561
	17-Oct-00 11:00:00	99.80254364	191.718292	192.60939	174.954071	111.063	75.57968903	29.854464
	17-Oct-00 11:01:00	99.75766754	191.610229	192.60939	174.954071	111.757	75.35697174	29.854364

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 11:02:00	100.0191498	191.827911	192.60939	174.954071	110.915	75.66068268	29.854265
17-Oct-00 11:03:00	99.92171478	192.185211	192.60939	174.954071	111.039	75.92369843	29.854166
17-Oct-00 11:04:00	99.95223999	191.905579	192.60939	174.954071	111.428	75.82047272	29.854069
17-Oct-00 11:05:00	100.074707	191.936096	192.60939	174.954071	111.808	75.71723938	29.85397
17-Oct-00 11:06:00	99.90463257	191.804001	192.60939	174.954071	112.538	75.57902527	29.85387
17-Oct-00 11:07:00	99.79013824	191.979248	192.60939	174.954071	111.731	75.00335693	29.853771
17-Oct-00 11:08:00	99.91147614	191.809082	192.60939	174.954071	111.808	75.06539917	29.853674
17-Oct-00 11:09:00	100.0402908	191.638916	192.60939	174.954071	112.102	75.91377258	29.853575
17-Oct-00 11:10:00	100.0140076	191.605927	192.60939	174.954071	111.723	75.61006165	29.853476
17-Oct-00 11:11:00	99.63607788	191.692978	192.60939	174.954071	111.88	75.32629395	29.853376
17-Oct-00 11:12:00	99.78009796	191.780029	192.60939	174.954071	111.118	75.62089539	29.853277
17-Oct-00 11:13:00	99.80437469	191.805222	192.60939	174.954071	111.166	75.31647491	29.85318
17-Oct-00 11:14:00	99.89753723	191.835388	192.60939	174.954071	111.573	75.62089539	29.853081
17-Oct-00 11:15:00	99.90746307	191.552734	192.60939	174.954071	111.804	75.75574493	29.852982
17-Oct-00 11:16:00	99.97499847	191.937271	192.60939	174.954071	111.239	76.20246887	29.852882
17-Oct-00 11:17:00	99.96238708	191.804886	192.60939	174.954071	111.572	76.15524292	29.852785
17-Oct-00 11:18:00	100.1427994	191.813492	192.60939	174.954071	111.752	76.05313873	29.852686
17-Oct-00 11:19:00	99.96963501	191.770065	192.80276	174.954071	113.338	75.95103455	29.852587
17-Oct-00 11:20:00	99.76781464	191.943146	192.81082	174.954071	111.931	75.84893036	29.852488
17-Oct-00 11:21:00	100.0164413	191.532928	192.50868	174.954071	112.311	75.74682617	29.85239
17-Oct-00 11:22:00	99.73769379	191.735291	192.36769	174.954071	112.062	75.64472198	29.852291
17-Oct-00 11:23:00	99.95539856	191.903488	192.36769	174.954071	110.75	76.10101318	29.852192
17-Oct-00 11:24:00	99.88525391	191.887787	192.36769	174.954071	112.379	76.36519623	29.852093
17-Oct-00 11:25:00	100.056427	191.872101	192.36769	174.954071	111.563	76.51919556	29.851994
17-Oct-00 11:26:00	100.3948059	191.8564	192.36769	174.954071	111.766	77.01197052	29.851896
17-Oct-00 11:27:00	100.019989	191.869263	192.36769	174.954071	111.025	76.65778351	29.851797
17-Oct-00 11:28:00	99.92891693	191.685837	192.36769	174.954071	112.376	76.66635132	29.851698
17-Oct-00 11:29:00	99.93255615	191.915604	192.36769	174.954071	111.736	76.82161713	29.851599
17-Oct-00 11:30:00	99.95391083	191.787125	192.36769	174.954071	112.824	76.76044464	29.851501
17-Oct-00 11:31:00	99.97364807	191.705383	192.36769	174.954071	112.546	77.66661835	29.851402
17-Oct-00 11:32:00	99.64261627	192.077011	192.36769	174.954071	111.33	77.55012512	29.851303
17-Oct-00 11:33:00	100.0031281	191.625717	192.36769	174.954071	111.726	77.05303955	29.851204
17-Oct-00 11:34:00	99.7379303	191.66832	192.46437	174.954071	111.416	77.01197052	29.851107
17-Oct-00 11:35:00	100.0520325	191.710922	192.64565	174.954071	110.732	76.85250092	29.851007
17-Oct-00 11:36:00	100.031662	191.753525	192.69586	174.954071	112.143	76.87337494	29.850908

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 11:37:00	99.70114899	191.796127	192.63141	174.954071	111.815	76.56025696	29.850809
17-Oct-00 11:38:00	100.0153732	191.647079	192.56696	174.954071	111.523	76.69371796	29.850712
17-Oct-00 11:39:00	99.89013672	191.522415	192.51883	174.954071	110.644	77.11463928	29.850613
17-Oct-00 11:40:00	99.81169891	192.193176	192.485	174.954071	111.905	76.96063995	29.850513
17-Oct-00 11:41:00	99.697258	191.49585	192.45116	174.954071	112.06	77.14324951	29.850414
17-Oct-00 11:42:00	99.88671112	191.905273	192.41731	174.954071	111.96	77.0394516	29.850315
17-Oct-00 11:43:00	99.67871857	191.859985	192.38348	174.954071	111.716	76.93565369	29.850218
17-Oct-00 11:44:00	99.98565674	192.206696	192.40636	174.954071	112.086	76.78611755	29.850119
17-Oct-00 11:45:00	99.81109619	191.96814	192.47887	174.954071	112.549	77.0769043	29.850019
17-Oct-00 11:46:00	99.76637268	191.507462	192.55138	174.954071	112.009	76.98117065	29.84992
17-Oct-00 11:47:00	99.84021759	191.636978	192.62389	174.954071	111.889	77.1708374	29.849823
17-Oct-00 11:48:00	99.82670593	191.449631	192.65451	174.954071	111.2	77.94404602	29.849724
17-Oct-00 11:49:00	99.95635986	191.914795	192.64847	174.954071	111.115	77.58311462	29.849625
17-Oct-00 11:50:00	99.81594086	191.600235	192.64243	174.954071	112.195	77.73060608	29.849525
17-Oct-00 11:51:00	100.0169144	191.594833	192.63638	174.954071	111.145	77.42262268	29.849428
17-Oct-00 11:52:00	99.97146606	191.771896	192.63034	174.954071	112.814	77.32791138	29.849329
17-Oct-00 11:53:00	99.31424713	192.0159	192.6243	174.954071	114.825	77.81273651	29.84923
17-Oct-00 11:54:00	99.7056427	191.711731	192.61826	174.954071	116.004	77.81273651	29.849131
17-Oct-00 11:55:00	99.55458832	191.897949	192.61221	174.954071	116.37	77.70836639	29.849031
17-Oct-00 11:56:00	99.9710083	192.011719	192.60939	174.954071	116.905	77.21195984	29.848934
17-Oct-00 11:57:00	99.35849762	191.930664	192.60939	174.954071	116.397	77.36470032	29.848835
17-Oct-00 11:58:00	99.55181122	191.849609	192.60939	174.954071	116.74	77.5714798	29.848736
17-Oct-00 11:59:00	99.53305054	191.76857	192.60939	174.954071	116.77	78.110466	29.848637
17-Oct-00 12:00:00	99.34428406	191.565506	192.60939	174.954071	117.88	77.95646667	29.848539
17-Oct-00 12:01:00	99.4318924	191.889099	192.60939	174.954071	117.453	77.5304184	29.84844
17-Oct-00 12:02:00	99.50956726	191.618942	192.60939	174.954071	115.947	77.81273651	29.848341
17-Oct-00 12:03:00	99.42259216	191.735855	192.60939	174.954071	116.628	77.81273651	29.848242
17-Oct-00 12:04:00	99.89511108	192.096283	192.60939	174.954071	117.241	77.81273651	29.848145
17-Oct-00 12:05:00	99.7309494	191.932083	192.60939	174.954071	117.978	77.48934937	29.848045
17-Oct-00 12:06:00	99.52472687	191.767883	192.60939	174.954071	118.168	77.19693756	29.847946
17-Oct-00 12:07:00	99.46226501	191.824249	192.60939	174.954071	119.315	77.79186249	29.847847
17-Oct-00 12:08:00	99.57975769	191.967331	192.60939	174.954071	118.954	77.21730042	29.847748
17-Oct-00 12:09:00	99.88806152	191.717636	192.60939	174.954071	119.358	77.91201782	29.847651
17-Oct-00 12:10:00	99.26657104	191.661865	192.60939	174.954071	119.131	78.67572784	29.847551
17-Oct-00 12:11:00	99.4341507	191.700668	192.60939	174.954071	118.566	78.19772339	29.847452

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 12:12:00	99.55519104	191.555527	192.60939	174.954071	119.552	77.00074768	29.847353
17-Oct-00 12:13:00	99.60112	191.646469	192.60939	174.954071	119.131	77.98213196	29.847256
17-Oct-00 12:14:00	99.51071167	191.322662	192.60939	174.954071	118.398	78.34807587	29.847157
17-Oct-00 12:15:00	99.63084412	191.997406	192.62233	174.954071	118.374	78.4389801	29.847057
17-Oct-00 12:16:00	99.22039032	191.725571	192.64658	174.954071	119.054	77.681427	29.846958
17-Oct-00 12:17:00	99.57975769	191.694046	192.67082	174.954071	118.637	77.74600983	29.846861
17-Oct-00 12:18:00	99.36605835	191.493164	192.69508	174.954071	118.397	78.05400085	29.846762
17-Oct-00 12:19:00	99.53359985	191.452423	192.71933	174.954071	118.617	77.88973236	29.846663
17-Oct-00 12:20:00	99.06906128	192.06601	192.70815	174.954071	118.45	78.04373169	29.846563
17-Oct-00 12:21:00	99.08981323	191.874542	192.66797	174.954071	118.476	77.82801056	29.846464
17-Oct-00 12:22:00	99.24888611	192.026733	192.62781	174.954071	118.647	78.28623962	29.846367
17-Oct-00 12:23:00	99.31063843	191.957993	192.58763	174.954071	118.238	78.23023224	29.846268
17-Oct-00 12:24:00	99.60352325	191.822906	192.54745	174.954071	118.58	78.53650665	29.846169
17-Oct-00 12:25:00	99.55939484	191.68782	192.50729	174.954071	119.071	78.61790466	29.846069
17-Oct-00 12:26:00	99.50401306	191.905624	192.4944	174.954071	118.907	78.41145325	29.845972
17-Oct-00 12:27:00	99.47111511	191.852036	192.50539	174.954071	118.683	78.20500183	29.845873
17-Oct-00 12:28:00	99.43632507	191.798447	192.51637	174.954071	118.841	78.34915161	29.845774
17-Oct-00 12:29:00	99.59399414	192.07663	192.52736	174.954071	119.04	78.19515228	29.845675
17-Oct-00 12:30:00	99.59777069	191.921814	192.53835	174.954071	119.24	78.04116058	29.845577
17-Oct-00 12:31:00	99.51114655	191.965073	192.54933	174.954071	119.022	77.88716888	29.845478
17-Oct-00 12:32:00	99.47102356	191.996841	192.56032	174.954071	118.931	78.0873642	29.845379
17-Oct-00 12:33:00	99.50498962	191.859421	192.5713	174.954071	119.398	78.01036835	29.84528
17-Oct-00 12:34:00	99.52383423	191.991486	192.58229	174.954071	119.081	77.93336487	29.845182
17-Oct-00 12:35:00	99.6908493	191.968643	192.59328	174.954071	118.764	77.85636902	29.845083
17-Oct-00 12:36:00	99.3259201	191.621567	192.60426	174.954071	118.7	77.88002014	29.844984
17-Oct-00 12:37:00	99.04317474	191.759155	192.63087	174.954071	118.199	78.03528595	29.844885
17-Oct-00 12:38:00	99.22940826	191.522873	192.67116	174.954071	119.056	78.37837982	29.844786
17-Oct-00 12:39:00	99.23970795	191.994537	192.71144	174.954071	118.807	78.75209808	29.844688
17-Oct-00 12:40:00	99.92614746	192.043213	192.6817	174.954071	118.241	78.75209808	29.844589
17-Oct-00 12:41:00	99.32321167	192.134766	192.59068	174.954071	119.461	78.42871094	29.84449
17-Oct-00 12:42:00	99.24910736	191.990891	192.49966	174.954071	118.737	77.96800232	29.844391
17-Oct-00 12:43:00	99.38737488	191.781921	192.40865	174.954071	119.284	78.43379974	29.844294
17-Oct-00 12:44:00	99.61485291	191.572937	192.37244	174.954071	118.601	78.65294647	29.844194
17-Oct-00 12:45:00	99.55984497	191.655701	192.38107	174.954071	119.043	78.33982086	29.844095
17-Oct-00 12:46:00	99.47626495	191.343414	192.38971	174.954071	119.164	78.02670288	29.843996

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 12:47:00	99.62333679	191.528	192.39833	174.954071	119.065	78.18403625	29.843899
17-Oct-00 12:48:00	99.83000946	192.019272	192.40697	174.954071	119.415	78.38935852	29.8438
17-Oct-00 12:49:00	99.5973053	191.932068	192.4156	174.954071	119.257	78.59468079	29.8437
17-Oct-00 12:50:00	99.02432251	191.784882	192.42422	174.954071	118	78.53998566	29.843601
17-Oct-00 12:51:00	99.60913086	191.794037	192.43286	174.954071	119.374	77.96672821	29.843502
17-Oct-00 12:52:00	99.51480103	191.531799	192.4415	174.954071	118.934	78.73670197	29.843405
17-Oct-00 12:53:00	99.39767456	191.607727	192.45013	174.954071	118.76	79.32615662	29.843306
17-Oct-00 12:54:00	99.65354919	191.539566	192.45876	174.954071	118.847	78.65970612	29.843206
17-Oct-00 12:55:00	99.68502808	191.482193	192.46739	174.954071	119.043	78.24707031	29.843107
17-Oct-00 12:56:00	99.68205261	191.583359	192.47603	174.954071	118.61	79.06521606	29.84301
17-Oct-00 12:57:00	99.534935	191.840897	192.48465	174.954071	118.675	78.79059601	29.842911
17-Oct-00 12:58:00	99.55369568	191.600281	192.49329	174.954071	119.325	79.25257874	29.842812
17-Oct-00 12:59:00	99.450737	191.821213	192.50192	174.954071	118.943	79.66065979	29.842712
17-Oct-00 13:00:00	99.47309875	191.770172	192.51056	174.954071	118.416	79.06521606	29.842615
17-Oct-00 13:01:00	99.46032715	191.719131	192.51918	174.954071	118.616	79.06521606	29.842516
17-Oct-00 13:02:00	99.70298004	191.718735	192.52782	174.954071	118.864	78.44924927	29.842417
17-Oct-00 13:03:00	99.63597107	191.799789	192.53645	174.954071	118.311	78.4389801	29.842318
17-Oct-00 13:04:00	99.71877289	191.880844	192.54507	174.954071	119.299	78.4389801	29.842218
17-Oct-00 13:05:00	99.63614655	191.563156	192.55371	174.954071	118.487	78.98822021	29.842121
17-Oct-00 13:06:00	99.5535202	191.507034	192.56235	174.954071	118.053	78.78289795	29.842022
17-Oct-00 13:07:00	99.80727386	191.709671	192.57098	174.954071	119.214	79.3157196	29.841923
17-Oct-00 13:08:00	99.9223938	191.85376	192.57961	174.954071	119.574	79.46798706	29.841824
17-Oct-00 13:09:00	99.67345428	191.822235	192.58824	174.954071	119.367	79.29011536	29.841726
17-Oct-00 13:10:00	99.3509903	191.747635	192.59688	174.954071	119.125	79.18631744	29.841627
17-Oct-00 13:11:00	99.72815704	191.618927	192.6055	174.954071	119.352	79.08251953	29.841528
17-Oct-00 13:12:00	99.35170746	191.571121	192.60464	174.954071	119.126	79.37834167	29.841429
17-Oct-00 13:13:00	99.63479614	191.640915	192.59601	174.954071	118.914	78.97180176	29.841331
17-Oct-00 13:14:00	99.62123871	191.710709	192.58737	174.954071	120.061	78.45281982	29.841232
17-Oct-00 13:15:00	99.59638977	191.780502	192.57875	174.954071	117.805	77.93383026	29.841133
17-Oct-00 13:16:00	99.69275665	191.853958	192.57011	174.954071	119.157	78.89350891	29.841034
17-Oct-00 13:17:00	99.73628235	191.480301	192.56148	174.954071	117.961	79.94197845	29.840937
17-Oct-00 13:18:00	99.18778992	192.198013	192.55286	174.954071	119.487	79.8693924	29.840837
17-Oct-00 13:19:00	99.91943359	191.577805	192.54422	174.954071	119.026	79.46833801	29.840738
17-Oct-00 13:20:00	99.62593079	191.709473	192.53558	174.954071	118.764	78.69631958	29.840639
17-Oct-00 13:21:00	99.62033081	191.841125	192.52695	174.954071	119.435	78.71274567	29.84054

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 13:22:00	99.50823975	191.745911	192.51833	174.954071	119.291	79.12339783	29.840443
17-Oct-00 13:23:00	99.41762543	191.646851	192.50969	174.954071	119.615	79.53404236	29.840343
17-Oct-00 13:24:00	99.63353729	191.637543	192.50105	174.954071	119.892	79.37834167	29.840244
17-Oct-00 13:25:00	99.8739624	191.646851	192.49243	174.954071	119.505	78.8393631	29.840145
17-Oct-00 13:26:00	99.73725891	191.408203	192.55501	174.954071	118.724	78.56934357	29.840048
17-Oct-00 13:27:00	99.72750092	191.526459	192.67586	174.954071	118.728	78.79938507	29.839949
17-Oct-00 13:28:00	99.69020081	191.699615	192.72285	174.954071	118.492	79.0294342	29.839849
17-Oct-00 13:29:00	99.5293808	191.872772	192.70943	174.954071	118.903	79.25948334	29.83975
17-Oct-00 13:30:00	99.63673401	191.633636	192.696	174.954071	119.238	79.23069	29.839653
17-Oct-00 13:31:00	99.81790924	191.989807	192.68257	174.954071	118.173	78.92520905	29.839554
17-Oct-00 13:32:00	99.4289093	191.928467	192.66914	174.954071	119.073	79.0147171	29.839455
17-Oct-00 13:33:00	99.50244141	191.57251	192.65572	174.954071	118.776	79.2530899	29.839355
17-Oct-00 13:34:00	99.41557312	191.50441	192.64229	174.954071	118.917	79.31160736	29.839256
17-Oct-00 13:35:00	99.69541931	191.834457	192.62886	174.954071	119.367	79.34090424	29.839159
17-Oct-00 13:36:00	99.21149445	191.573303	192.61543	174.954071	118.812	79.23880005	29.83906
17-Oct-00 13:37:00	99.54718018	191.792435	192.5695	174.954071	118.77	79.13668823	29.838961
17-Oct-00 13:38:00	99.41918945	191.674316	192.49699	174.954071	118.332	79.20365906	29.838861
17-Oct-00 13:39:00	99.62574005	191.752365	192.42448	174.954071	118.628	79.66514587	29.838764
17-Oct-00 13:40:00	99.70195007	191.830414	192.35197	174.954071	119.32	79.82377625	29.838665
17-Oct-00 13:41:00	99.71320343	191.591019	192.27945	174.954071	119.082	79.40557098	29.838566
17-Oct-00 13:42:00	99.76226044	191.64505	192.29648	174.954071	118.835	79.50767517	29.838467
17-Oct-00 13:43:00	99.81785583	192.009949	192.38673	174.954071	118.94	79.60977936	29.838369
17-Oct-00 13:44:00	99.53131104	191.673187	192.47701	174.954071	119.045	79.50666809	29.83827
17-Oct-00 13:45:00	99.75554657	191.857803	192.56726	174.954071	119.15	78.8374939	29.838171
17-Oct-00 13:46:00	99.41793823	191.66156	192.63087	174.954071	119.433	79.30329132	29.838072
17-Oct-00 13:47:00	99.17041016	191.787491	192.67116	174.954071	119.153	79.46798706	29.837973
17-Oct-00 13:48:00	99.53403473	191.948273	192.71144	174.954071	118.956	79.9603653	29.837875
17-Oct-00 13:49:00	99.67631531	191.961197	192.68703	174.954071	119.112	79.46840668	29.837776
17-Oct-00 13:50:00	99.75676727	191.752365	192.60602	174.954071	118.123	80.29864502	29.837677
17-Oct-00 13:51:00	99.58639526	191.672791	192.52499	174.954071	119.25	80.14337921	29.837578
17-Oct-00 13:52:00	99.41191101	191.801163	192.48439	174.954071	118.739	80.288414	29.837481
17-Oct-00 13:53:00	99.45313263	191.92955	192.47685	174.954071	118.97	79.69817352	29.837381
17-Oct-00 13:54:00	99.4974823	191.908905	192.4693	174.954071	118.856	79.89954376	29.837282
17-Oct-00 13:55:00	99.25626373	191.681824	192.46176	174.954071	118.373	80.100914	29.837183
17-Oct-00 13:56:00	99.60951233	191.723404	192.45421	174.954071	117.979	80.30228424	29.837086

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 13:57:00	99.57862091	191.764984	192.44667	174.954071	119.313	79.40936279	29.836987
17-Oct-00 13:58:00	99.67521667	191.752304	192.43912	174.954071	118.945	79.50003815	29.836887
17-Oct-00 13:59:00	99.44698334	191.543457	192.43158	174.954071	119.369	79.95774078	29.836788
17-Oct-00 14:00:00	99.51654816	191.8172	192.42403	174.954071	119.142	79.71682739	29.836691
17-Oct-00 14:01:00	99.64922333	191.924377	192.41649	174.954071	119.793	80.51704407	29.836592
17-Oct-00 14:02:00	99.5896759	191.95723	192.40894	174.954071	119.471	80.35005951	29.836493
17-Oct-00 14:03:00	99.80339813	191.557739	192.4014	174.954071	118.395	80.5716095	29.836393
17-Oct-00 14:04:00	99.6203537	191.542648	192.39384	174.954071	119.379	79.85928345	29.836294
17-Oct-00 14:05:00	99.62693787	191.527557	192.38631	174.954071	118.765	79.87759399	29.836197
17-Oct-00 14:06:00	99.44517517	192.048874	192.37875	174.954071	118.866	80.1055069	29.836098
17-Oct-00 14:07:00	99.52577972	191.584656	192.37122	174.954071	118.924	80.3334198	29.835999
17-Oct-00 14:08:00	99.56907654	191.7901	192.56105	174.954071	119.105	80.56134033	29.835899
17-Oct-00 14:09:00	99.87120819	191.995544	192.68727	174.954071	119.69	80.51100922	29.835802
17-Oct-00 14:10:00	99.7151947	191.692871	192.6067	174.954071	119.373	80.3595047	29.835703
17-Oct-00 14:11:00	99.44319153	191.381577	192.52614	174.954071	118.49	79.70857239	29.835604
17-Oct-00 14:12:00	99.31707001	192.08342	192.48854	174.954071	118.719	79.44371796	29.835505
17-Oct-00 14:13:00	99.50392914	191.806244	192.48854	174.954071	119.06	79.54694366	29.835407
17-Oct-00 14:14:00	99.39597321	191.482056	192.48854	174.954071	119.456	79.65016937	29.835308
17-Oct-00 14:15:00	99.36907959	191.992661	192.48854	174.954071	118.858	80.5348587	29.835209
17-Oct-00 14:16:00	99.40771484	191.862839	192.48854	174.954071	118.696	80.41166687	29.83511
17-Oct-00 14:17:00	99.46244049	191.549423	192.48854	174.954071	118.603	79.99588013	29.835011
17-Oct-00 14:18:00	99.42948914	191.843323	192.48854	174.954071	118.891	79.99588013	29.834913
17-Oct-00 14:19:00	99.68572998	191.843323	192.48854	174.954071	118.089	80.29889679	29.834814
17-Oct-00 14:20:00	99.66896057	191.843323	192.48854	174.954071	119.327	80.19493103	29.834715
17-Oct-00 14:21:00	99.64079285	191.843323	192.48854	174.954071	118.612	79.62158966	29.834616
17-Oct-00 14:22:00	99.45051575	191.802643	192.48854	174.954071	119.341	79.46632385	29.834518
17-Oct-00 14:23:00	99.06460571	191.787567	192.48854	174.954071	118.184	79.25437164	29.834419
17-Oct-00 14:24:00	99.65239716	191.649109	192.48854	174.954071	119.879	79.70835876	29.83432
17-Oct-00 14:25:00	99.63065338	191.629883	192.48854	174.954071	119.65	80.05188751	29.834221
17-Oct-00 14:26:00	99.34634399	191.665909	192.48854	174.954071	119.383	80.20462799	29.834124
17-Oct-00 14:27:00	99.8777771	191.70192	192.48854	174.954071	119.71	80.21147156	29.834024
17-Oct-00 14:28:00	99.78303528	191.552399	192.49365	174.954071	118.741	80.08981323	29.833925
17-Oct-00 14:29:00	99.41680908	191.94133	192.50294	174.954071	119.04	79.99588013	29.833826
17-Oct-00 14:30:00	99.32293701	191.815262	192.51225	174.954071	119.094	79.99588013	29.833727
17-Oct-00 14:31:00	99.21557617	191.638657	192.52155	174.954071	118.485	79.99588013	29.83363

POLK POWER STATION UNIT 1 BACT #7

17-Oct-00 14:32:00	99.64376831	191.548691	192.53084	174.954071	118.869	80.38085938	29.83353
17-Oct-00 14:33:00	99.47538757	191.411301	192.54013	174.954071	118.683	80.81204987	29.833431
17-Oct-00 14:34:00	99.39189911	191.549744	192.54942	174.954071	119.372	80.29027557	29.833332
17-Oct-00 14:35:00	99.44776917	191.601852	192.55873	174.954071	119.005	80.18817902	29.833235
17-Oct-00 14:36:00	99.15962219	191.835159	192.56802	174.954071	118.964	80.08607483	29.833136
17-Oct-00 14:37:00	99.27793121	191.778427	192.57732	174.954071	119.197	80.01384735	29.833036
17-Oct-00 14:38:00	99.40542603	191.72171	192.58661	174.954071	119.261	80.16783905	29.832937
17-Oct-00 14:39:00	99.39246368	191.942673	192.59592	174.954071	119.378	80.28333282	29.83284
17-Oct-00 14:40:00	99.30020905	191.801926	192.60521	174.954071	119.103	80.30389404	29.832741
17-Oct-00 14:41:00	99.74098969	191.589218	192.60497	174.954071	119.013	80.20178986	29.832642
17-Oct-00 14:42:00	99.80532074	191.876144	192.59691	174.954071	119.352	80.09968567	29.832542
17-Oct-00 14:43:00	99.30700684	191.782349	192.58885	174.954071	118.73	79.99758148	29.832443
17-Oct-00 14:44:00	99.45106506	191.726425	192.5808	174.954071	118.454	80.14730835	29.832346
17-Oct-00 14:45:00	99.55841827	191.766312	192.57274	174.954071	119.476	80.30130005	29.832247
17-Oct-00 14:46:00	99.53462982	191.757553	192.56468	174.954071	119.447	80.01641083	29.832148
17-Oct-00 14:47:00	99.56907654	191.572937	192.55663	174.954071	118.248	80.57078552	29.832048
17-Oct-00 14:48:00	99.42173767	191.563477	192.54857	174.954071	118.548	80.79291534	29.831951
17-Oct-00 14:49:00	99.48210144	192.144394	192.54051	174.954071	119.507	80.63764191	29.831852
17-Oct-00 14:50:00	99.76439667	192.139648	192.53246	174.954071	118.576	79.81154633	29.831753
17-Oct-00 14:51:00	99.64479828	192.246826	192.5244	174.954071	118.637	79.69145966	29.831654
17-Oct-00 14:52:00	99.54906464	192.293442	192.51634	174.954071	118.706	80.73134613	29.831556
17-Oct-00 14:53:00	99.49267578	191.555893	192.50829	174.954071	118.761	80.62211609	29.831457
17-Oct-00 14:54:00	99.61943054	192.016571	192.50023	174.954071	119.083	79.87759399	29.831358
17-Oct-00 14:55:00	99.45882416	191.995682	192.49217	174.954071	119.337	80.23593903	29.831259
17-Oct-00 14:56:00	99.54896545	191.974777	192.48412	174.954071	119.072	80.07668304	29.831161
17-Oct-00 14:57:00	99.43504333	191.953888	192.47606	174.954071	119.017	80.33466339	29.831062
17-Oct-00 14:58:00	99.53016663	191.430878	192.468	174.954071	119.217	80.79664612	29.830963
17-Oct-00 14:59:00	99.72592926	191.528931	192.45995	174.954071	118.992	80.40452576	29.830864
17-Oct-00 15:00:00	99.27587891	191.660583	192.45189	174.954071	119.01	80.57078552	29.830765
Averages	**99.65**	**191.77**	**192.55**	**174.95**	**116.61**	**78.12**	**29.84**

Suggested Agenda and Discussion Topics

Location: FDEP Offices Tallahassee, FL
Date: April 3, 2001
Time: 9:00 am
Subject: Polk Unit 1 NO_x BACT Determination

Tampa Electric Company requested this meeting to discuss any outstanding issues associated with the Polk Unit 1 NO_x BACT Determination. Below is a suggested list of discussion topics for this meeting.

1. Review of the last correspondence
   A. Additional questions
   B. Submittal completion status

2. Polk Power Station overview
   A. Coal plant
   B. Technology has not matured
   C. Process is variable by nature
   D. Clean Coal Demonstration Project

3. Review of BACT Submittal
   A. Existing operation
   B. Add on controls

Department of
Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

February 23, 2000 2001

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region IV
61 Forsyth Street
Atlanta, Georgia 30303

Re: Tampa Electric Company, Polk Power Station

Dear Mr. Worley:

We have supplied, under separate cover, a submittal from Tampa Electric Company (TEC) concerning their Polk Power Station. That facility incorporates an IGCC electrical generating unit (GE 7FA), which combusts synthetic gas. As a result of the original permitting which was done, the BACT Determination for NO_X (only) was to be executed after the facility was operating for a period of time, such that test data was available. We are now commencing our review of this project.

The applicant's recently submitted BACT Review concluded that the initial (temporary) permit limit (25 ppmvd @ 15% O_2) is appropriate for use in the future. This review rejected the use of SCR for multiple reasons, many of which can be seen from the attached 3 pages, representing a portion of TEC's responses to our questions of that BACT Review.

We would appreciate your review and comments on TEC's responses, and your specific comments regarding the application of SCR to this emissions unit. If necessary, additional information can be provided to assist in your review. Your comments can be forwarded to my attention at the letterhead address or faxed to me at (850) 922-6979. Please be aware that our review time of 30 days expires on March 21, provided that we have no further questions of TEC. If you have any questions, please contact Mike Halpin at (850) 921-9519.

Sincerely,

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/mph

w/ enclosures

FDEP Comment 3
In a November 8, 1999 letter, EPA Region IV established that BACT for combined cycle turbines is 3.5 ppm NO_x. (Note: EPA wrote the letter after the Florida Department of Environmental Protection proposed a 6 ppm NO_X limit for a GE combined cycle Frame 7 turbine with SCR). Recently (on November 17, 2000) the Department issued a draft permit and BACT Determination for CPV Gulf Coast (PSD-FL-300). In that review, the Department determined that SCR was cost effective for reducing NO_X emissions from 9 ppmvd to 3.5 ppmvd on a General Electric 7FA unit burning natural gas in combined cycle mode. This review additionally concluded that the unit would be capable of combusting 0.05%S diesel fuel oil for up to 30 days per year while emitting 10 ppmvd of NO_X. This determination was made under the assumption that cost of NO_X control by SCR might be as high as $6,000 per ton (with ammonia emissions held to 5 ppmvd), which represents a NO_X control cost significantly higher than that offered in TECO's submittal.

a) Accordingly, this will represent the Department's determination for this project, unless Tampa Electric Company can demonstrate to the Department's satisfaction (absent fuel quality issues) why this installation is significantly different.

b) The Department notes (in reviewing the records for this project), that although the final BACT Determination for NO_X (while firing syngas) was set at 25 ppmvd through the test period, that the initial draft (1993) of the BACT evaluation had concluded that a NO_X emission limit of 12.5 ppmvd was appropriate, even if the application of an SCR was required.

TEC Response
Although the November 8, 1999 letter from EPA Region IV established BACT for combined cycle combustion turbines as 3.5 ppm, this letter addressed natural gas fired combustion turbines, not syngas fired combustion turbines. In addition, subsequent draft guidance from John S. Seitz, director of the Office of Air Quality Planning and Standards dated August 4, 2000 (see enclosed) allows for the consideration of collateral environmental impacts associated with the use of SCR on dry low NO_x natural gas fired combined cycle combustion turbines. Although Polk Unit 1 is a syngas fired combined cycle combustion turbine utilizing multinozzle quiet combustors, TEC feels that collateral environmental impacts should also be considered for this installation when performing a BACT evaluation. Several parties have commented on this draft guidance including the Department of Energy (DOE) and the Utility Air Regulatory Group (UARG). In an enclosed written opinion, DOE supports the draft guidance noting that, among other things, the establishment of the use of SCR as BACT for natural gas fired combined cycle facilities will:

1. *Slow research and development of efficiency and performance improvement in advanced combustion turbines;*
2. *Slow the development of other non-ammonia based NO_x control technologies; and*
3. *Create a situation in which the units containing SCR become more expensive to operate, thus lowering their position in a system dispatch order and allowing dirtier plants to operate higher in the dispatch order. This will have the effect of increasing overall emissions despite the use of SCR on an already relatively clean unit.*

Integrated Gasification Combined Cycle (IGCC) Technology is still in the early stages of development and provides a mechanism for the combustion of coal while minimizing air emissions. In fact, Polk Unit 1 was constructed as part of the Department of Energy's Clean Coal Technology program. If SCR is established as BACT for Polk Unit 1, it could impact the further development of this technology. Furthermore, if SCR becomes BACT for this type of installation, it could slow the development of further advances in combustion technology for clean coal facilities such as Polk Unit 1 by increasing the cost of an already high cost technology. In addition, although SCR has never been applied to a domestic IGCC facility, there is no evidence or operating experience that indicates that the application of SCR to an IGCC facility can be successfully accomplished as described in Section 8 of the BACT Analysis. If this occurs, Tampa Electric Company could be forced to operate other coal fired units in lieu of Polk Unit 1, resulting in an actual overall increase in NO_x emissions in the Tampa Bay area.

UARG also supports the draft guidance in a September 18, 2000 letter (enclosed) to Ms. Ellen Brown of the USEPA and states, in part, "The Clean Air Act as well as EPA's regulations make it abundantly clear that a BACT determination must be based upon a case-by-case, site-specific balancing of energy, environmental, and economic impacts and other costs, and mandate that this balancing be done by the appropriate State permitting authority." This supports the position that BACT is determined on a case by case basis, and is not a limit to be applied to all units at all times. As such, TEC believes that fuel and associated technical differences must be considered when evaluating BACT and other similar facilities. The fact that SCR was deemed to be BACT for NO_x at the CPV Gulf Coast natural gas fired facility does not necessarily mean that SCR is BACT for the Polk Unit 1 syngas fired IGCC facility.

Additionally, it is extremely important to draw the distinction between a natural gas fired combustion turbine and a syngas fired combustion turbine when applying the EPA determination; as the fuels are completely different. While natural gas is mainly composed of methane and almost completely free of sulfur and sulfur containing compounds, syngas is mostly composed of hydrogen and carbon monoxide, and also contains some carbonyl sulfide as well as hydrogen sulfide. Upon combustion, these sulfur-containing compounds are oxidized to form SO_2, and upon passage through an SCR system, most of the SO_2 is further oxidized to SO_3. When combined with water and the excess ammonia required by the SCR system for optimal NO_x removal, the sulfur oxides in the exhaust gas form ammonium bisulfate and ammonium sulfate. According to a paper authored by General Electric (enclosed), these compounds are responsible for plugging in the HRSG, tube fouling, and increased emissions of particulate matter.

Furthermore, it should be noted that the Specific Condition A.50 of the Polk Power Station Title V Permit directs Tampa Electric Company to conduct a BACT evaluation for NO_x based on "data gathered on this facility, other similar facilities, and the manufacturer's research." (Underline emphasis added) In the Department's letter dated December 4, 2000, references are made to BACT determinations for NO_x on other natural gas fired combined cycle facilities. Since Polk Unit 1 fires syngas, it is TEC's position that this Unit is similar to a natural gas fired facility only in that it fires a gaseous fuel. In fact, during the recent EPA Mercury Information Collection Request, Unit 1 was classified as a coal fired facility. Syngas is a sulfur containing fuel and, to date, there is no evidence of a successful SCR installation on a combined cycle combustion turbine that fires a sulfur containing fuel. To compare Unit 1 to a truly similar facility, one must look to the PSI Destec Wabash River Station in Vigo County, Indiana. This facility operates a syngas fired combustion turbine of similar design and vintage as the Unit found at Polk Power Station and does not operate an SCR for NO_x control. In addition, the somewhat similar and recently permitted Star Delaware IGCC facility is required to meet a NO_x limit of 15 ppmvd @ 15% O_2 using through the use of advanced combustors as a result of a LAER determination. As described in the original BACT Analysis, this facility was not required to install an SCR system. This is significant, because a LAER determination does not consider cost effectiveness in the analysis. This facility utilizes advanced burner technology that cannot be effectively applied to the Polk facility due to limited nitrogen diluent production at Polk Power Station.

In the December 4, 2000 comment letter, FDEP indicated that the CPV Gulf Coast facility was required to install an SCR for NO_x control although the cost of control might be as high at \$6,000 per ton of NO_x removed. Since TEC submitted a NO_x control cost lower than \$6,000 the application of SCR on Polk Unit 1 would be deemed economically feasible and, therefore, determined to be BACT. According to 40 CFR 52.21(b)(12), BACT is defined as:

"An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, ***on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs****, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.* ***If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be***

prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results." (bold emphasis added)

The conclusion that SCR must be applied to Polk Unit 1 simply because the cost of NO_x control is lower than what the cost of NO_x control might be at the CPV Gulf Coast facility does not seem to take into account environmental, energy, and other costs as prescribed in the definition of BACT. In addition, this conclusion does not seem to consider the operation of 'other similar facilities' or 'manufacturer's research' as called for in Specific Condition A.50 of the Polk Power Station Title V Permit.

Finally, the cost to control NO_x emissions through the use of an SCR system on Polk Unit 1 presented in the analysis submitted to FDEP was based on a limited number of estimated costs. Since SCR has not been required for any IGCC installation in the United States, it is not possible to compare the cost of installing an SCR at the Polk facility to the cost of installing an SCR at another IGCC facility. In fact, recent research developed by GE suggests that the cost to control NO_x emissions from a combined cycle combustion turbine that fires a sulfur bearing fuel may be much higher than originally anticipated. (see enclosed)

Based on the above discussion, TEC believes that it would be presumptuous for FDEP to consider the application of SCR to Polk Unit 1 as BACT without considering the severe technical consequences of installing such a control to an IGCC facility. As mentioned above, it appears that FDEP has concluded that SCR is applicable to Polk Unit 1 based on the operating experience of natural gas fired combined cycle facilities as well as recent BACT determinations for such facilities. In fact, an IGCC facility is considerably different than a natural gas fired combined cycle facility, and any BACT determination for such a facility should consider the energy, environmental, economic, and other costs as mandated by 40 CFR 52.21(b)(12). Furthermore, in this special case, the BACT analysis must consider the data gathered during the bimonthly stack tests, other similar facilities, and manufacturer's research. As such, the initial draft of the BACT evaluation performed in 1993 that concluded that a NO_x emission limit of 12.5 ppm was appropriate must not be considered in this determination. This was a preliminary limit and was subsequently rejected based on further analysis.

TEC has provided the Department with all of the above information and believes that a NO_x emission limit of 25 ppm @15% O_2 continues to be appropriate for this facility. This is consistent with the Wabash River Station, the statistical results of the individual stack tests performed in support of this analysis, and the research of GE, the original equipment manufacturer.

TECO
TAMPA ELECTRIC

RECEIVED
FEB 15 2001
BUREAU OF AIR REGULATION

February 14, 2001

Mr. A.A. Linero, P.E.
Administrator - New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7926 5766 4183

Re: Polk Power Station Unit 1
Syngas Fired Combustion Turbine NO_x BACT Determination

Dear Mr. Linero:

TEC has received your letter dated December 4, 2000 regarding the NO_x BACT Determination for Unit 1 at the Polk Power Station and offers the following responses to the issues raised by FDEP.

FDEP Comment 1

Please provide 30 day rolling average NO_X emissions data for calendar months October 1999 through November 2000. This submittal should include actual NO_X emissions (tons) for each calendar month, as well as the following related data:

- **a) each calendar month summary should include each daily average NO_X emission value in lb/hr (and ppm corrected to 15% O_2), as well as the total daily heat input by fuel type (e.g. synfuel, natural gas or oil), heating value and daily hours of operation on each fuel; the average daily MW output (from the CT) and average daily SO_2 emission (CEM) rates should also be shown**
- **b) provide the ultimate analysis of the "as-fired" coal for each calendar month listed above where synfuel was fired in the combustion turbine**
- **c) if available, provide data on gasifier H_2S and COS removal, as compared to the coal feedstock used**

TEC Response

Other than NO_x emissions corrected to 15% O_2, the data requested above are enclosed. Due to the varying nature of the fuels gasified at Polk Power Station, the heat content of the syngas fired in the combustion turbine fluctuates and is generally between 250 and 275 Btu/SCF (HHV). The heat content of the distillate oil fired in the combustion turbine is typically about 138,000 Btu/gallon of oil fired.

Currently, Polk Power Station demonstrates compliance with the limit of 25 ppm @ 15% O_2 by monitoring NO_x emissions on a lb/hr basis.

TAMPA ELECTRIC COMPANY
P. O. BOX 111 TAMPA, FL 33601-0111
(813) 228-4111

CUSTOMER SERVICE:
HILLSBOROUGH COUNTY (813) 223-0800
OUTSIDE HILLSBOROUGH COUNTY 1 (888) 223-0800

AN EQUAL OPPORTUNITY COMPANY
HTTP://WWW.TECOENERGY.COM

For clarity, it is important to emphasize that although the request in paragraph a) calls for a total daily heat input when firing natural gas, this unit has never fired natural gas, nor is it capable of doing so. Unit 1 is designed to accommodate syngas as the primary fuel and distillate oil as the backup fuel. Paragraph c) requests the gasifier H_2S and COS removal, but these data are not monitored or limited by a permit condition and are, therefore, not available. However, based on plant operating experience, between 60% and 90% of the incoming COS is removed in the process. This removal efficiency is highly dependent on several process parameters such as ambient temperature and feed stock. Hence the removal efficiency is variable. The facility monitors SO_2 emissions to assure environmental compliance.

FDEP Comment 2

Please provide the average nitrogen diluent flow delivered to the CT during each of the seven NO_X BACT tests identified on page 4-1 of the submitted BACT analysis.

TEC Response

The requested data are presented below. Although the diluent flow is an important parameter for controlling NO_x emissions, a more appropriate measure is the ratio of diluent flow to syngas flow. On an overall basis, this ratio represents the proportional flows of NO_x controlling diluent and the syngas flow. Additional complicating factors that prevent a straightforward linear analysis of diluent flow rate or ratio and the NO_x emissions rate include the varying composition of the syngas, and the heating value of the fuel. Although these data are presented, TEC recommends against using these data to establish firm operating ranges due to the variability in other factors that significantly contribute to NO_x emissions from this combustion turbine.

The table below summarizes the ratio of nitrogen diluent flow to syngas flow during each test as compared to the NO_x emissions. As the data in the table demonstrates, although the nitrogen flow and the syngas flow vary from test to test, the ratio is reasonably consistent.

Test Date	Average Nitrogen Diluent Flow (lb/sec)	Average Syngas flow rate (lb/sec)	Average Nitrogen Diluent/Syngas Ratio	Average NOx Emissions Result (ppmvd, 15% O2, ISO)
October 14, 1999	118.0	102.8	1.1	16.7
December 7, 1999	124.1	103.8	1.2	14.6
February 7, 2000	117.3	102.7	1.1	19.0
April 17, 2000	126.8	102.1	1.2	17.0
June 14, 2000	118.0	101.0	1.2	18.1
August 15, 2000	124.7	100.2	1.2	16.6
October 17, 2000	116.6	99.7	1.2	22.5

These data, presented graphically in the enclosed Figure 1, show no strong correlation between diluent/syngas flow rate and NOx emissions rate. A linear regression analysis demonstrated a large error in fitting the data, with a regression coefficient of 0.14 thus, it may be concluded that factors other than the diluent/syngas flow ratio considerably affect the emissions performance of the combustion turbine.

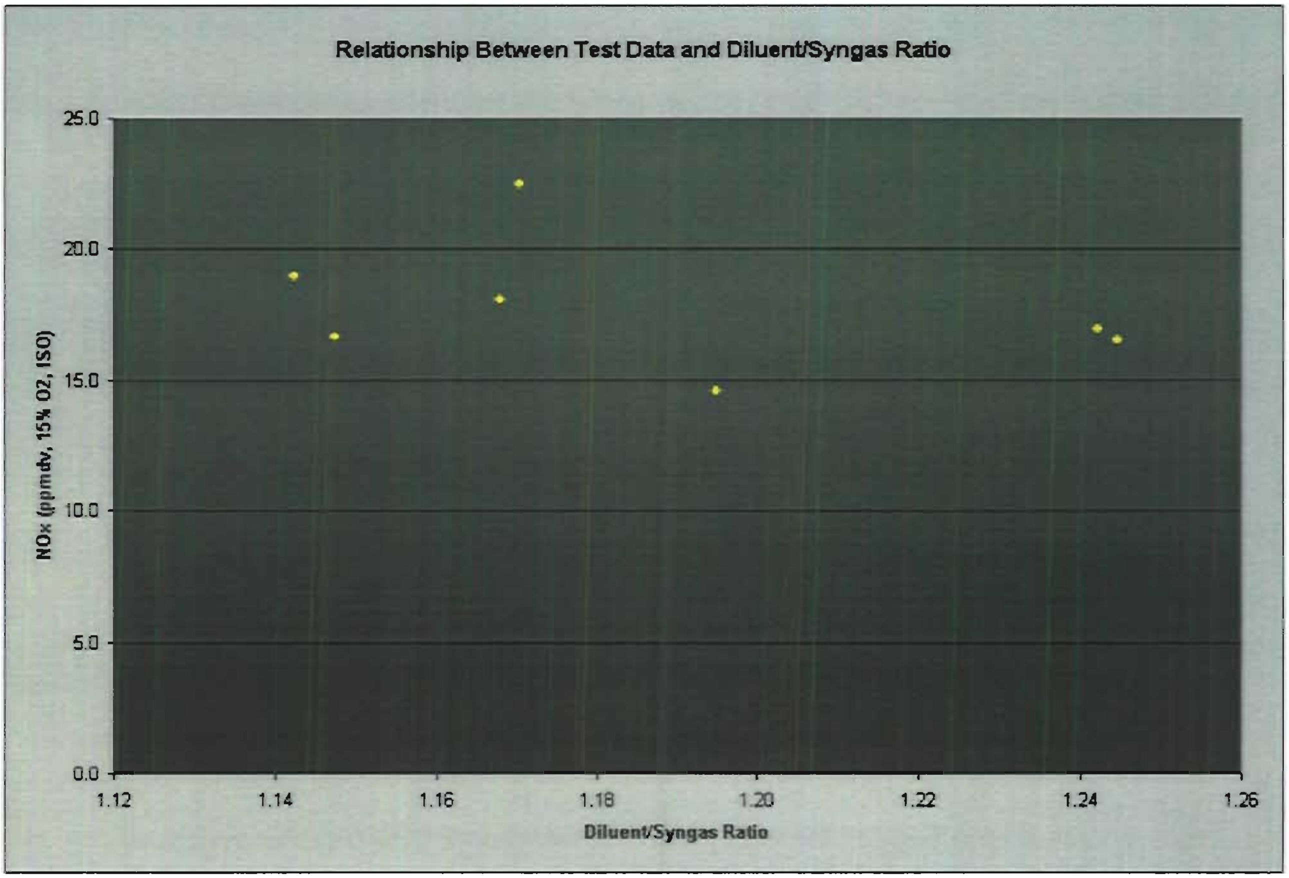

Figure 1

FDEP Comment 3

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Furthermore, it should be noted that the Specific Condition A.50 of the Polk Power Station Title V Permit directs Tampa Electric Company to conduct a BACT evaluation for NO_x based on "data gathered on this facility, <u>other similar facilities</u>, and the manufacturer's research." (Underline emphasis added) In the Department's letter dated December 4, 2000, references are made to BACT determinations for NO_x on other <u>natural gas fired</u> combined cycle facilities. Since Polk Unit 1 fires syngas, it is TEC's position that this Unit is similar to a natural gas fired facility only in that it fires a gaseous fuel. In fact, during the recent EPA Mercury Information Collection Request, Unit 1 was classified as a coal fired facility. Syngas is a sulfur containing fuel and, to date, there is no evidence of a successful SCR installation on a combined cycle combustion turbine that fires a sulfur containing fuel. To compare Unit 1 to a truly similar facility, one must look to the PSI Destec Wabash River Station in Vigo County, Indiana. This facility operates a syngas fired combustion turbine of similar design and vintage as the Unit found at Polk Power Station and does not operate an SCR for NO_x control. In addition, the somewhat similar and recently permitted Star Delaware IGCC facility is required to meet a NO_x limit of 15 ppmvd @ 15% O_2 using through the use of advanced combustors as a result of a LAER determination. As described in the original BACT Analysis, this facility was not required to install an SCR system. This is significant, because a LAER determination does not consider cost effectiveness in the analysis. This facility utilizes advanced burner technology that cannot be effectively applied to the Polk facility due to limited nitrogen diluent production at Polk Power Station.

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> *" An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator,* ***on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs****, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.* ***If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology.*** *Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results." (bold emphasis added)*

The conclusion that SCR must be applied to Polk Unit 1 simply because the cost of NO_x control is lower than what the cost of NO_x control <u>might</u> be at the CPV Gulf Coast facility does not seem to take into account environmental, energy, and other costs as prescribed in the definition of BACT. In addition, this conclusion does not seem to consider the operation of 'other similar facilities' or 'manufacturer's research' as called for in Specific Condition A.50 of the Polk Power Station Title V Permit.

Finally, the cost to control NO_x emissions through the use of an SCR system on Polk Unit 1 presented in the analysis submitted to FDEP was based on a limited number of estimated costs. Since SCR has not been required for any IGCC installation in the United States, it is not possible to compare the cost of installing an SCR at the Polk facility to the cost of installing an SCR at another IGCC facility. In fact, recent research developed by GE suggests that the cost to control NO_x emissions from a combined cycle combustion turbine that fires a sulfur bearing fuel may be much higher than originally anticipated. (see enclosed)

Based on the above discussion, TEC believes that it would be presumptuous for FDEP to consider the application of SCR to Polk Unit 1 as BACT without considering the severe technical consequences of installing such a control to an IGCC facility. As mentioned above, it appears that FDEP has concluded that SCR is applicable to Polk Unit 1 based on the operating experience of natural gas fired combined cycle facilities as well as recent BACT determinations for such facilities. In fact, an IGCC facility is considerably different than a natural gas fired combined cycle facility, and any BACT determination for such a facility should consider the energy, environmental, economic, and other costs as mandated by 40 CFR 52.21(b)(12). Furthermore, in *this special case, the BACT analysis must consider the data gathered during the bimonthly stack tests, other similar facilities, and manufacturer's research. As such, the initial draft of the BACT evaluation performed in 1993 that concluded that a* NO_x *emission limit of 12.5 ppm was appropriate must not be considered in this determination. This was a preliminary limit and was subsequently rejected based on further analysis.*

TEC has provided the Department with all of the above information and believes that a NO_x *emission limit of 25 ppm @15%* O_2 *continues to be appropriate for this facility. This is consistent with the Wabash River Station, the statistical results of the individual stack tests performed in support of this analysis, and the research of GE, the original equipment manufacturer.*

FDEP Comment 4

Please estimate schedule requirements, which would be necessary to procure and install an SCR for the subject unit. Additionally, please confirm that Engelhard Corporation expects the catalyst life to be 5 to 7 years and will guarantee same for 3 years of operation.

TEC Response

Below are the schedule requirements necessary to procure and install an SCR system, if required.

Step	Description	Time Required (weeks)
1	Develop specification package	6
2	Solicit bids	4
3	Review bids/select vendor	2
4	Contract negotiations	4
5	Design/build/delivery	40
6	Site Prep and Installation	8
7	Startup/debug	6
	Total	**70 weeks**

According to Englehard Corporation, catalyst life is expected to be 5-7 years with a 3 year guarantee.

TEC appreciates the opportunity to respond to the Department's comments and looks forward to working with FDEP to ensure that a reasonable BACT determination for NO_x on Polk Unit 1 is arrived at. TEC is confident that this determination will benefit the environment while encouraging the development of future NO_x reduction technologies as well as the advancement of clean coal technologies.

If you have any questions, please feel free to telephone Shannon Todd or me at (813) 641-5125.

Sincerely,

Mark J Hornick

Mark J. Hornick
General Manager/Responsible Official
Polk Power Station

EP\gm\SKT233

Enclosure

c/enc: Mr. Michael Halpin – FDEP
Mr. Syed Arif - FDEP
Mr. Jerry Kissel - FDEP SW
J. Little, EPA
B. Worley, EPA
J. Bunyak, NPS

Comment 1 Enclosures

OCTOBER 1999	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
	Synfuel	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs / hr)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	174.8	201.3	212.3	24:00	0:00	48,638.2	0.0	191.00	146.4	26.7
2	176.2	201.3	207.1	24:00	0:00	47,571.9	0.0	184.96	153.7	26.7
3	175.8	205.2	173.0	21:00	3:00	37,180.9	5,311.6	154.46	156.4	27.3
4	175.8	204.9	7.1	0:00	0:15	0.0	0.0	0.00	156.4	26.7
5	175.8	201.4	2.7	0:00	1:30	0.0	0.1	0.13	156.4	26
6	175.8	207.6	9.9	0:00	1:15	0.0	1.0	1.04	156.4	26.6
7	175.8	210.9	237.2	0:00	16:45	0.0	76.1	76.13	156.4	26.4
8	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
9	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
10	180.3	229.1	355.8	7:00	8:30	9,753.6	11,843.6	71.83	153.3	25.5
11	180.3	229.1	183.3	24:00	0:00	48,099.3	0.0	188.29	152.5	25.5
12	180.8	229.1	186.0	24:00	0:00	47,755.1	0.0	188.96	155.1	25.5
13	181.5	229.1	183.3	24:00	0:00	48,036.5	0.0	190.83	161.8	25.5
14	182.1	229.1	182.7	24:00	0:00	48,158.9	0.0	191.00	170.3	25.5
15	182.2	229.1	166.5	24:00	0:00	47,141.4	0.0	187.42	178.4	25.5
16	182.4	229.1	175.8	24:00	0:00	47,942.5	0.0	191.00	182.1	25.5
17	182.7	229.1	176.3	24:00	0:00	48,057.1	0.0	191.00	188.6	25.5
18	182.9	229.1	173.9	24:00	0:00	48,116.6	0.0	190.71	193.7	25.5
19	183.4	229.1	181.6	24:00	0:00	46,815.2	0.0	185.50	197.9	25.5
20	183.7	229.1	164.3	24:00	0:00	45,616.4	0.0	179.83	206.1	25.5
21	183.1	229.1	166.3	24:00	0:00	46,708.2	0.0	186.54	210.9	25.5
22	182.8	229.1	168.3	24:00	0:00	47,372.7	0.0	191.00	215.7	25.5
23	182.1	229.1	164.5	24:00	0:00	47,115.5	0.0	189.00	221	25.5
24	182	229.1	164.0	24:00	0:00	47,330.4	0.0	190.13	226.6	25.5
25	181.5	229.1	165.9	24:00	0:00	47,635.0	0.0	190.54	232.5	25.5
26	180.9	229.1	166.0	24:00	0:00	47,237.2	0.0	188.79	241	25.5
27	180.3	229.1	165.8	24:00	0:00	47,061.7	0.0	187.25	247.3	25.5
28	179.8	229.1	163.1	24:00	0:00	47,962.0	0.0	188.50	249.9	25.5
29	179.5	229.1	163.3	24:00	0:00	48,050.0	0.0	189.29	251	25.5
30	179.1	229.1	166.4	24:00	0:00	48,391.0	0.0	189.46	248.6	25.5
31	179.2	229.1	166.5	24:00	0:00	48,637.6	0.0	190.29	246.3	25.5

Total Actual NO_x Emissions for the month (tons) :	57.9

NOVEMBER	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
1999	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	179.1	229.1	169.0	24:00	0:00	48,727.1	0.0	190.96	247.8	25.5
2	178.8	229.1	162.8	24:00	0:00	48,210.2	0.0	191.00	249.5	25.5
3	178.6	229.1	167.0	24:00	0:00	48,093.3	0.0	190.67	244.8	25.5
4	177.5	229.1	95.1	15:45	0:00	29,572.6	0.0	114.08	245.6	25.5
5	177.5	225.8	53.6	0:00	8:15	0.0	19.5	19.46	245.6	24.9
6	177.7	222.6	169.8	20:45	1:00	37,508.9	6.9	149.92	241.8	24.4
7	176.4	222.6	174.1	24:00	0:00	47,911.3	0.0	189.04	237.9	24.4
8	175.3	222.6	174.4	24:00	0:00	48,381.2	0.0	189.17	233.2	24.4
9	175.6	222.6	177.2	24:00	0:00	48,894.8	0.0	186.00	234.5	24.4
10	171.7	227.5	182.4	17:15	1:00	32,257.8	6.6	121.17	240.4	23.5
11	171.8	227.5	203.0	24:00	0:00	49,369.2	0.0	186.33	249.7	23.5
12	170.9	225.3	217.2	18:00	6:00	34,098.9	37.6	150.38	253.1	22.8
13	170.9	225.3	200.8	24:00	0:00	49,444.8	0.0	191.00	252.9	22.8
14	170.8	225.3	201.8	24:00	0:00	49,696.8	0.0	191.00	248.4	22.8
15	171.3	225.3	200.0	24:00	0:00	49,495.2	0.0	191.00	247.5	22.8
16	170.8	225.3	171.9	24:00	0:00	45,860.4	0.0	185.83	250.2	22.8
17	170.4	225.3	164.4	24:00	0:00	45,022.7	0.0	191.00	252.6	22.8
18	170	225.3	163.3	24:00	0:00	44,781.5	0.0	188.63	254.9	22.8
19	169.3	225.3	160.5	24:00	0:00	45,013.4	0.0	190.46	258.2	22.8
20	169.4	225.3	163.6	24:00	0:00	44,391.1	0.0	190.54	259.2	22.8
21	169.2	225.3	159.7	24:00	0:00	44,244.3	0.0	190.75	263.9	22.8
22	168.6	225.3	159.5	24:00	0:00	44,176.6	0.0	190.50	267.9	22.8
23	168.3	225.3	154.0	24:00	0:00	44,381.4	0.0	189.29	267	22.8
24	167.9	225.3	152.8	24:00	0:00	43,981.0	0.0	187.92	267.8	22.8
25	167.6	225.3	153.4	24:00	0:00	44,476.4	0.0	189.21	272.9	22.8
26	167.5	225.3	161.5	24:00	0:00	44,792.2	0.0	191.00	274.6	22.8
27	167.1	225.3	156.0	24:00	0:00	44,806.4	0.0	191.00	277	22.8
28	166.7	225.3	150.9	24:00	0:00	44,536.7	0.0	191.00	275.9	22.8
29	166.4	225.3	153.3	24:00	0:00	44,956.4	0.0	191.00	277.2	22.8
30	165.8	225	149.6	23:00	1:00	41,042.5	7.7	184.13	282.3	22.3

Total Actual NO_X Emissions for the month (tons) :	59.11

DECEMBER	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
1999	Synfuel	Oil		Synfuel	Oil	Synfuel	Oil		Synfuel	Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	165	222.9	148.5	19:00	5:00	29,763.7	7,832.6	159.13	293.1	23.2
2	164.8	222.9	163.9	24:00	0:00	43,798.6	0.0	191.00	295	23.2
3	164.7	222.9	156.8	24:00	0:00	43,585.4	0.0	191.00	294.6	23.2
4	164.3	222.9	156.9	24:00	0:00	43,610.4	0.0	191.00	293.4	23.2
5	164.8	222.9	156.1	24:00	0:00	43,993.6	0.0	191.00	287.4	23.2
6	163.7	222.9	157.4	24:00	0:00	44,053.9	0.0	190.50	290.9	23.2
7	162.7	222.9	145.8	24:00	0:00	44,220.8	0.0	189.38	296.4	23.2
8	161.5	222.9	138.1	24:00	0:00	43,524.1	0.0	184.54	299.5	23.2
9	160.4	222.9	137.8	24:00	0:00	44,486.1	0.0	190.00	302.7	23.2
10	158.6	222.9	140.2	24:00	0:00	44,427.3	0.0	188.29	308.2	23.2
11	157.6	222.9	154.7	24:00	0:00	45,949.2	0.0	190.58	308.4	23.2
12	157.6	225	165.0	21:00	2:30	36,318.1	4,323.6	161.04	303.9	23.8
13	0.0	0.0	1.9	0:00	0:00	0.0	0.0	0.00	0.0	0.0
14	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
15	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
16	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
17	157.6	224.2	88.7	0:00	11:30	0.0	14,788.5	52.04	303.9	24.2
18	157.6	220.9	171.9	0:00	24:00	0.0	33,080.1	113.58	303.9	24
19	155.2	217.2	129.2	12:00	12:00	16,106.7	16,106.7	130.13	318.2	23.7
20	153	217.2	116.0	24:00	0:00	42,477.3	0.0	190.50	325.1	23.7
21	148.7	217.2	72.6	24:00	0:00	40,405.7	0.0	189.58	325	23.7
22	144.1	217.2	25.2	24:00	0:00	39,573.1	0.0	189.17	324.5	23.7
23	139.4	217.2	25.3	24:00	0:00	40,327.3	0.0	189.46	324.9	23.7
24	134.5	217.2	17.6	24:00	0:00	39,620.4	0.0	189.42	324	23.7
25	129.7	217.2	14.7	24:00	0:00	39,696.1	0.0	190.21	321.7	23.7
26	125.1	217.2	22.5	24:00	0:00	39,228.1	0.0	190.83	318	23.7
27	120.7	217.2	28.5	24:00	0:00	39,306.0	0.0	189.88	314.3	23.7
28	116	217.2	19.8	24:00	0:00	38,939.6	0.0	187.21	313.3	23.7
29	111.9	217.2	31.3	24:00	0:00	39,585.0	0.0	190.71	311.6	23.7
30	108.2	217.2	38.9	24:00	0:00	39,222.9	0.0	190.92	312.7	23.7
31	103.5 **********	210.4 ***********	24.0	17:30	3:00	20,873.6	3,578.3	114.88	307.5	22.5

Total Actual NO_x Emissions for the month (tons) :	31.8

JANUARY	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
2000	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	99.1	203.2	29.9	15:30	6:00	19,164.2	7,418.4	124.75	298.3	21.2
2	94.3	203.2	18.1	24:00	0:00	37,425.2	0.0	182.79	297.5	21.2
3	89.8	197.7	36.8	16:00	8:00	20,555.4	10,277.7	146.38	299.6	20.1
4	85.3	197.7	17.6	24:00	0:00	39,212.2	0.0	191.00	302.8	20.1
5	80.7	197.7	13.0	24:00	0:00	38,903.2	0.0	189.42	306.3	20.1
6	76.5	197.4	17.9	24:00	0:00	38,964.4	0.0	190.71	300.6	20.1
7	72	197.4	27.0	24:00	0:00	38,906.9	0.0	191.00	301.9	20.1
8	67.6	197.4	26.0	24:00	0:00	38,849.9	0.0	191.00	300.8	20.1
9	63.2	197.4	24.0	24:00	0:00	38,910.4	0.0	191.00	310.4	20.1
10	58.6	197.4	23.7	24:00	0:00	38,986.2	0.0	191.00	318.3	20.1
11	54.3	197.4	27.1	24:00	0:00	38,566.7	0.0	190.88	319.9	20.1
12	50.2	197.4	22.3	24:00	0:00	39,139.9	0.0	191.00	320.8	20.1
13	46.4	190.1	24.6	24:00	0:00	39,245.3	0.0	191.00	317.4	19.9
14	42.5	190.1	19.8	24:00	0:00	39,539.1	0.0	191.00	313.3	19.9
15	38.8	190.1	30.8	24:00	0:00	39,782.2	0.0	191.00	312.2	19.9
16	34.7	190.1	30.0	24:00	0:00	39,568.4	0.0	191.00	310	19.9
17	30.3	190.1	30.9	24:00	0:00	38,690.0	0.0	187.13	313.9	19.9
18	29.3	190.1	65.2	24:00	0:00	33,890.7	0.0	165.75	291.4	19.9
19	30.3	190.1	140.1	24:00	0:00	37,710.8	0.0	183.63	288.6	19.9
20	32.9	190.1	128.2	24:00	0:00	43,380.3	0.0	187.79	293.5	19.9
21	36.2	190.1	135.0	24:00	0:00	42,992.9	0.0	185.33	298	19.9
22	36.6	190.1	177.9	24:00	0:00	48,265.2	0.0	187.71	295.3	19.9
23	37.3	190.1	190.0	24:00	0:00	47,870.2	0.0	190.33	295.5	19.9
24	41.2	197.9	136.5	13:45	6:00	20,623.0	8,999.1	112.96	291.2	20.7
25	45.8	197.9	154.0	24:00	0:00	43,961.5	0.0	190.58	291.1	20.7
26	50.5	197.9	165.2	23:00	0:00	43,738.3	0.0	191.54	294.3	20.7
27	56.3	197.9	187.9	24:00	0:00	44,653.7	0.0	190.58	293.5	20.7
28	61.2	197.9	169.1	24:00	0:00	41,676.1	0.0	180.33	297	20.7
29	63.8	197.9	24.1	3:15	0:00	5,238.8	0.0	21.08	290.3	20.7
30	68.6	204.1	98.9	8:15	8:30	10,295.1	10,607.0	79.29	284	21.8
31	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0

Total Actual NO_x Emissions for the month (tons) :	26.3

FEBRUARY 2000	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
	Synfuel	Oil		Synfuel	Oil	Synfuel	Oil		Synfuel	Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	69.2	199.4	15.2	1:30	2:00	819.6	1,092.7	4.42	281.3	21.7
2	69.2	195.2	124.3	0:00	24:00	0.0	21,978.2	60.67	281.3	22
3	73.6	192.5	143.0	21:00	3:00	34,209.8	4,887.1	162.25	278.4	22
4	79.1	188.5	137.9	8:00	16:00	9,261.6	18,523.1	97.33	275.2	21.8
5	83	187.9	133.0	15:00	9:00	21,279.1	12,767.4	135.29	275.2	22.1
6	88.9	187.9	178.0	24:00	0:00	44,068.7	0.0	191.00	272.5	22.1
7	94.7	187.9	181.3	24:00	0:00	44,439.6	0.0	191.00	270.2	22.1
8	99.6	187.9	116.7	16:45	0:00	32,469.8	0.0	133.83	270.3	22.1
9			0.0	0:00	0:00	0.0	0.0	0.00		
10	99.6	181.4	13.4	0:00	3:15	0.0	1,904.8	3.67	270.3	21.4
11	102.6	171.7	128.4	10:00	14:00	12,656.3	17,718.8	108.42	272.2	21.1
12	106.8	171.7	139.4	24:00	0:00	43,140.0	0.0	179.75	268.5	21.1
13	110.8	170.3	132.6	17:00	7:00	24,403.4	10,048.5	134.92	261.6	21.4
14	115.4	170.3	156.0	24:00	0:00	42,396.0	0.0	178.13	259	21.4
15	120.4	170.3	161.2	24:00	0:00	43,981.3	0.0	182.50	256.5	21.4
16	126.5	170.3	195.2	24:00	0:00	45,067.0	0.0	189.71	254.9	21.4
17	132.6	171.6	178.2	18:00	6:00	28,125.6	9,375.2	151.50	251.4	21.9
18	138.3	171.6	189.9	24:00	0:00	45,563.9	0.0	191.00	245	21.9
19	143.9	171.6	190.6	24:00	0:00	46,241.8	0.0	191.00	238.3	21.9
20	149.4	171.6	184.6	24:00	0:00	45,188.4	0.0	191.00	231.6	21.9
21	152.8	171.6	176.5	24:00	0:00	44,897.5	0.0	191.00	233.2	21.9
22	154.2	171.6	183.7	24:00	0:00	45,008.1	0.0	191.00	225.3	21.9
23	155.1	171.6	158.3	24:00	0:00	46,015.0	0.0	190.54	216.3	21.9
24	156.7	171.6	170.5	24:00	0:00	44,912.0	0.0	191.00	207.4	21.9
25	157	171.6	167.1	24:00	0:00	43,157.9	0.0	182.46	206.5	21.9
26	157	165.4	12.2	0:00	1:00	0.0	440.8	0.42	206.5	20.6
27	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
28	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
29	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0

Total Actual NO_x Emissions for the month (tons) :	42.76

MARCH	30-Day Rolling Average NO$_X$ Emissions		Average NO$_X$ Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO$_2$ Emission	
2000	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
2	0.0	0.0	0.0	0:30	0:00	0.0	0.0	0.00	0.0	0.0
3	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
4	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
5	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
6	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
7	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
8	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
9	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
10	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
11	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
12	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
13	157	160.3	5.1	0:00	2:45	0.0	810.8	0.08	206.5	20.2
14	157	163.8	34.3	0:00	5:15	0.0	3,844.3	4.13	206.5	21.9
15	157	160.3	14.1	0:00	3:15	0.0	2,076.6	4.50	206.5	21.9
16	155.7	154.3	150.4	16:00	8:00	26,127.5	13,063.7	151.75	208.4	21.5
17	155.8	154.3	53.5	10:15	0:00	14,620.9	0.0	60.13	208.5	21.5
18	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
19	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
20	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
21	155.8	127.3	2.5	0:00	1:15	0.0	295.3	0.17	208.5	20.9
22	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
23	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
24	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
25	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
26	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
27	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
28	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
29	155.8	128.2	51.7	0:00	7:15	0.0	8,411.7	24.92	208.5	21.4
30	155.8	135.9	75.3	0:00	11:15	0.0	12,402.8	38.08	208.5	23.1
31	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0

Total Actual NO$_x$ Emissions for the month (tons) :	4.6

APRIL 2000	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
	Synfuel	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	155.8	134.8	27.2	0:00	4:45	0.0	3,495.1	8.79	208.5	23
2	155.8	135.8	45.7	0:00	6:15	0.0	5,684.2	16.54	208.5	23.1
3	155.2	136.9	138.4	20:00	4:00	30,445.8	6,089.2	159.29	213.2	23.4
4	154.7	136.9	153.9	24:00	0:00	41,216.1	0.0	181.63	213.3	23.4
5	153.9	136.9	151.7	24:00	0:00	39,131.2	0.0	179.54	213.5	23.4
6	153.8	136.9	134.1	19:45	0:00	32,621.6	0.0	144.38	214.8	23.4
7	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
8	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
9	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
10	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
11	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
12	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
13	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
14	153.8	129.9	29.7	0:00	5:00	0.0	3,519.0	8.96	214.8	129.9
15	154.9	130	154.9	20:00	4:00	31,708.4	6,341.7	162.25	222.2	130
16	155.1	130	166.0	24:00	0:00	48,653.2	0.0	191.00	229.8	130
17	159.4	130	170.8	23:45	0:00	46,949.8	0.0	191.00	237.1	130
18	160.4	130	168.6	23:45	0:00	45,575.8	0.0	190.88	234.5	130
19	160.7	130	171.8	24:00	0:00	45,248.8	0.0	191.00	232	130
20	161.8	130	155.2	24:00	0:00	39,721.4	0.0	169.13	226.8	130
21	161.3	130	5.1	6:00	0:00	1,920.4	0.0	0.17	223.6	130
22	160.5	127.1	142.0	18:00	2:00	29,469.7	3,274.4	124.00	221.1	127.1
23	160.3	127.1	207.3	24:00	0:00	44,478.9	0.0	186.08	216.1	127.1
24	162.3	127.1	189.9	24:00	0:00	45,362.3	0.0	191.00	212.1	127.1
25	163.3	127.1	163.8	24:00	0:00	45,146.6	0.0	190.58	208	127.1
26	164.7	127.1	163.4	24:00	0:00	44,308.5	0.0	191.00	210.1	127.1
27	165	127.1	169.0	24:00	0:00	44,667.3	0.0	190.54	209.7	127.1
28	165.2	127.1	172.9	24:00	0:00	45,266.1	0.0	190.50	206.7	127.1
29	163.7	127.1	161.9	24:00	0:00	45,290.3	0.0	189.96	209.5	127.1
30	162.2	127.1	162.3	24:00	0:00	45,002.7	0.0	189.96	214.7	127.1

Total Actual NO_x Emissions for the month (tons) :	38.5

MAY 2000	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
	Synfuel	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	160.7	127.1	157.5	24:00	0:00	45,289.8	0.0	189.58	216.9	21.7
2	159.1	127.1	154.7	24:00	0:00	45,218.4	0.0	187.33	221.5	21.7
3	157.9	127.1	155.5	24:00	0:00	43,918.4	0.0	188.83	228.7	21.7
4	156.7	127.1	159.9	24:00	0:00	43,404.6	0.0	191.00	233.6	21.7
5	154.2	127.1	143.9	23:30	0:00	41,436.9	0.0	182.08	236.1	21.7
6	154.3	127.1	158.6	24:00	0:00	42,215.9	0.0	191.00	234.1	21.7
7	153.8	127.1	157.2	24:00	0:00	41,827.6	0.0	188.33	237	21.7
8	153.5	127.1	157.3	24:00	0:00	40,640.9	0.0	187.67	240.2	21.7
9	155.7	127.1	152.8	24:00	0:00	41,715.4	0.0	186.92	235.4	21.7
10	157.2	127.1	151.8	24:00	0:00	41,203.5	0.0	183.33	238.6	21.7
11	158.7	127.1	162.3	24:00	0:00	41,909.8	0.0	186.29	231.4	21.7
12	160.2	127.1	172.3	24:00	0:00	40,902.9	0.0	185.00	223.8	21.7
13	161.3	127.1	174.4	24:00	0:00	41,297.4	0.0	185.71	223	21.7
14	161.7	127.1	175.3	24:00	0:00	41,145.2	0.0	183.63	221.6	21.7
15	162.9	127.1	167.2	24:00	0:00	40,314.6	0.0	180.54	219.3	21.7
16	163.2	127.1	159.1	24:00	0:00	39,809.2	0.0	179.46	220.2	21.7
17	162.1	127.1	153.2	24:00	0:00	39,240.8	0.0	177.54	218.1	21.7
18	161.3	127.1	154.0	24:00	0:00	38,945.8	0.0	175.92	219.4	21.7
19	160	127.1	152.8	24:00	0:00	38,837.2	0.0	174.83	219.7	21.7
20	158.6	127.1	136.7	24:00	0:00	38,090.6	0.0	168.50	220.9	21.7
21	161.4	127.1	216.2	24:00	0:00	40,569.5	0.0	187.08	212.9	21.7
22	162.5	127.1	184.0	24:00	0:00	41,836.3	0.0	191.00	208.9	21.7
23	163.2	127.1	176.6	24:00	0:00	41,811.0	0.0	191.00	204.4	21.7
24	163.4	127.1	164.7	24:00	0:00	40,812.5	0.0	190.46	201.8	21.7
25	163.7	127.1	173.4	24:00	0:00	42,118.9	0.0	191.00	209	21.7
26	163.7	127.1	158.2	24:00	0:00	40,921.8	0.0	190.33	230.6	21.7
27	163.6	127.1	160.6	24:00	0:00	40,896.8	0.0	186.17	237	21.7
28	162.2	127.1	128.1	24:00	0:00	39,455.5	0.0	173.79	234.6	21.7
29	161.7	127.1	148.9	24:00	0:00	39,782.8	0.0	177.08	232.1	21.7
30	161.7	127.1	159.9	24:00	0:00	40,603.7	0.0	182.21	229.2	21.7
31	161.9	127.1	166.9	24:00	0:00	41,481.7	0.0	185.88	228	21.7

Total Actual NO_x Emissions for the month (tons) : 60.0

JUNE	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
2000	Synfuel	Oil		Synfuel	Oil	Synfuel	Oil		Synfuel	Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	162	127.1	161.7	24:00	0:00	39,184.6	0.0	181.04	228.1	21.7
2	161.9	127.1	135.6	24:00	0:00	33,544.9	0.0	188.38	230.5	21.7
3	162.4	127.1	128.4	24:00	0:00	30,967.7	0.0	190.00	230.5	21.7
4	163.3	127.1	169.4	24:00	0:00	41,775.1	0.0	190.17	233.2	21.7
5	163.6	127.1	163.8	24:00	0:00	39,875.0	0.0	187.71	234.8	21.7
6	163.9	127.1	147.8	24:00	0:00	36,562.5	0.0	188.88	235.2	21.7
7	163.9	127.1	36.4	5:45	0:00	6,420.2	0.0	28.21	235.7	21.7
8	164.9	127.1	132.7	24:00	0:00	30,833.8	0.0	189.17	239.9	21.7
9	165.7	127.1	175.5	24:00	0:00	42,046.2	0.0	190.63	244.5	21.7
10	166.5	127.1	188.1	24:00	0:00	42,259.4	0.0	190.71	245.6	21.7
11	166.9	127.1	180.1	24:00	0:00	41,830.4	0.0	191.00	247.9	21.7
12	166.6	127.1	134.2	24:00	0:00	31,692.1	0.0	191.00	246.7	21.7
13	166.3	127.1	161.0	24:00	0:00	43,666.5	0.0	188.75	244.8	21.7
14	166.3	127.1	184.1	24:00	0:00	45,516.9	0.0	188.75	242	21.7
15	166.5	127.1	198.9	24:00	0:00	44,720.0	0.0	191.00	239.6	21.7
16	167	127.1	195.9	24:00	0:00	44,715.0	0.0	189.88	241.9	21.7
17	167.6	127.1	184.1	24:00	0:00	44,496.5	0.0	189.29	243.8	21.7
18	168.2	127.1	188.2	24:00	0:00	43,549.4	0.0	186.54	244.5	21.7
19	169.7	127.1	190.2	24:00	0:00	43,500.8	0.0	184.38	244.7	21.7
20	167.7	127.1	66.4	7:45	0:00	11,677.4	0.0	40.79	253	21.7
21	165.4	127.1	157.1	23:00	0:00	36,186.1	0.0	142.38	257.5	21.7
22	164	127.1	148.6	24:00	0:00	36,577.1	0.0	161.00	263.9	21.7
23	163.7	127.1	159.5	24:00	0:00	37,416.9	0.0	166.79	272.2	21.7
24	163.5	127.1	166.7	24:00	0:00	37,924.0	0.0	169.71	269.4	21.7
25	163.1	127.1	154.2	24:00	0:00	38,127.2	0.0	168.67	251.3	21.7
26	162.4	123.5	122.7	19:00	1:30	26,932.5	2,126.3	124.96	242.1	21.4
27	162.4	118.9	0.3	0:00	0:30	0.0	107.9	0.04	242.1	20.8
28	162.4	117.8	4.7	0:00	1:15	0.0	481.8	0.54	242.1	21.1
29	162.4	122	47.9	0:00	6:00	0.0	6,936.8	21.25	242.1	22.4
30	162.4	120.1	0.8	0:00	0:45	0.0	184.9	0.00	242.1	22.7

Total Actual NO_x Emissions for the month (tons) :	49.0

JULY	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
2000	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	162.4	122	111.3	9:00	9:30	11,107.8	11,724.8	86.04	248.9	23
2	163.5	122.6	170.6	23:00	1:00	37,643.4	1,636.7	169.46	252	23.2
3	165.2	124	192.4	22:00	2:00	37,715.5	3,428.7	175.50	264.4	23.7
4	166.3	124	191.2	24:00	0:00	44,242.6	0.0	190.96	274.7	23.7
5	167.7	124	193.1	24:00	0:00	43,679.3	0.0	190.58	281.8	23.7
6	169.1	124	190.7	24:00	0:00	43,606.0	0.0	190.71	287.3	23.7
7	169.3	124	175.5	24:00	0:00	43,379.8	0.0	191.00	296.8	23.7
8	168.8	124	160.6	24:00	0:00	43,339.7	0.0	191.00	297.5	23.7
9	168.5	124	162.1	24:00	0:00	43,346.1	0.0	191.00	301.5	23.7
10	168.2	124	160.0	24:00	0:00	42,149.2	0.0	185.38	306.5	23.7
11	167.9	125.6	155.3	21:00	3:00	33,997.9	4,856.8	166.83	310.8	24.1
12	167.1	125.6	168.8	24:00	0:00	43,361.8	0.0	190.71	313	24.1
13	166.7	125.6	167.0	24:00	0:00	43,183.2	0.0	190.17	312.8	24.1
14	165.2	125.6	156.9	24:00	0:00	43,037.1	0.0	191.00	314.5	24.1
15	163.5	125.6	146.2	24:00	0:00	42,719.3	0.0	191.00	312.5	24.1
16	162.6	125.6	144.0	24:00	0:00	43,069.7	0.0	190.13	308.8	24.1
17	162.3	125.6	156.0	24:00	0:00	43,197.1	0.0	191.00	305.1	24.1
18	162.4	125.6	165.0	24:00	0:00	43,208.4	0.0	191.00	301.9	24.1
19	162.5	125.6	163.5	24:00	0:00	43,001.7	0.0	190.92	299.2	24.1
20	162.4	125.6	160.2	24:00	0:00	42,773.5	0.0	190.79	294.8	24.1
21	162.4	125.6	162.9	24:00	0:00	42,566.6	0.0	190.75	290.8	24.1
22	162.5	125.6	166.1	24:00	0:00	42,890.5	0.0	191.00	287.3	24.1
23	162.4	125.6	158.0	24:00	0:00	43,138.9	0.0	191.00	285.2	24.1
24	162	125.6	150.1	24:00	0:00	42,974.7	0.0	191.00	285.5	24.1
25	162	125.6	135.0	24:00	0:00	43,214.9	0.0	189.42	290.3	24.1
26	161.8	125.6	143.6	24:00	0:00	43,413.4	0.0	190.83	291.1	24.1
27	161.2	125.6	140.6	24:00	0:00	43,463.6	0.0	190.67	291.2	24.1
28	160.7	125.6	153.7	24:00	0:00	42,839.4	0.0	189.33	287.1	24.1
29	160.9	125.6	157.6	24:00	0:00	42,997.3	0.0	191.00	285.6	24.1
30	161	125.6	150.6	24:00	0:00	42,954.1	0.0	191.00	289.6	24.1
31	161.7	125.6	150.6	24:00	0:00	43,156.2	0.0	191.00	291.2	24.1

Total Actual NO_x Emissions for the month (tons) :	59.6

AUGUST	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
2000	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	160.4	125.6	133.3	24:00	0:00	42,603.6	0.0	187.63	293.7	24.1
2	158.5	125.6	137.9	24:00	0:00	42,883.1	0.0	189.29	289.5	24.1
3	157.1	125.6	148.2	24:00	0:00	42,631.5	0.0	189.04	282.8	24.1
4	155.6	125.6	149.9	24:00	0:00	43,466.0	0.0	191.00	279.4	24.1
5	154.4	125.6	153.1	24:00	0:00	43,304.1	0.0	190.50	275.3	24.1
6	153.6	125.6	151.8	24:00	0:00	43,467.1	0.0	191.00	274.2	24.1
7	153.4	125.6	153.0	24:00	0:00	42,404.5	0.0	187.25	276.4	24.1
8	153.1	125.6	155.3	24:00	0:00	42,863.9	0.0	189.83	276.8	24.1
9	153.2	125.6	160.9	24:00	0:00	42,672.7	0.0	190.92	275.4	24.1
10	153.2	125.6	153.9	24:00	0:00	42,775.2	0.0	190.67	274.2	24.1
11	152.9	125.6	160.2	24:00	0:00	42,929.6	0.0	190.96	270.8	24.1
12	152.6	125.6	158.7	24:00	0:00	42,510.0	0.0	191.00	267.9	24.1
13	153.2	125.6	172.2	24:00	0:00	42,662.3	0.0	191.00	264.7	24.1
14	153.9	125.6	167.8	24:00	0:00	42,653.9	0.0	191.00	264	24.1
15	154.4	125.6	158.6	24:00	0:00	42,852.5	0.0	191.00	265.5	24.1
16	154.6	125.6	163.2	24:00	0:00	42,774.7	0.0	191.00	268	24.1
17	154.6	125.6	165.2	24:00	0:00	42,551.9	0.0	191.00	269.3	24.1
18	154.5	125.6	159.2	24:00	0:00	42,674.1	0.0	190.21	271.7	24.1
19	154.1	125.6	148.6	24:00	0:00	42,896.2	0.0	188.54	277	24.1
20	153.8	125.6	154.4	24:00	0:00	42,601.1	0.0	188.79	280.9	24.1
21	153.6	125.6	159.6	24:00	0:00	42,846.8	0.0	190.13	284.8	24.1
22	153.5	125.6	155.1	24:00	0:00	43,243.2	0.0	191.00	287.8	24.1
23	153.7	125.6	157.6	24:00	0:00	43,226.8	0.0	191.00	289.6	24.1
24	154.5	125.6	157.3	24:00	0:00	43,176.3	0.0	191.00	289.5	24.1
25	154.9	125.6	155.4	24:00	0:00	43,023.7	0.0	190.58	293.4	24.1
26	155.4	125.6	155.3	24:00	0:00	42,737.6	0.0	190.21	293	24.1
27	155.3	125.6	152.4	24:00	0:00	43,044.1	0.0	190.21	298.2	24.1
28	154.3	124.9	53.2	8:30	0:15	9,942.9	292.4	42.67	294.5	24
29	0.0	0.0	0.0	0:00	0:00	0.0	0.0	0.00	0.0	0.0
30	149.4	124.9	0.1	0:30	0:00	24.2	0.0	0.00	283.9	24
31	146.5	133.6	120.8	1:45	8:00	1,491.9	6,820.0	25.25	272.2	24.8

Total Actual NO_x Emissions for the month (tons) :	52.5

SEPTEMBER 2000	30-Day Rolling Average NO_X Emissions		Average NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
	Synfuel	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	146.5	138.1	265.1	0:00	24:00	0.0	37,913.4	133.29	272.2	26.1
2	147.8	142.7	201.3	9:00	15:00	12,215.1	20,358.4	127.88	267.2	27.2
3	148.3	146.7	186.7	16:00	8:00	24,679.8	12,339.9	155.38	266	28.1
4	150.1	147.7	191.1	17:00	7:00	27,531.1	11,336.4	167.00	267.3	29.1
5	151.8	147.7	202.7	24:00	0:00	42,478.4	0.0	188.83	269.3	29.1
6	152.6	151.6	182.2	22:00	2:00	35,050.6	3,186.4	168.25	265.3	30.2
7	153.8	154	187.5	19:00	5:00	30,149.6	7,934.1	161.63	261.4	31.1
8	155	154	189.3	24:00	0:00	42,891.6	0.0	190.88	262.2	31.1
9	155.9	154	183.0	24:00	0:00	42,931.2	0.0	190.88	263.7	31.1
10	157	154	193.5	24:00	0:00	43,088.3	0.0	190.83	263.2	31.1
11	158.1	154	184.8	24:00	0:00	43,354.5	0.0	191.00	262.3	31.1
12	158.8	154	182.9	24:00	0:00	43,391.9	0.0	191.00	263.4	31.1
13	159.5	154	180.5	24:00	0:00	43,203.3	0.0	191.00	264	31.1
14	160.3	154	196.2	24:00	0:00	42,860.8	0.0	191.00	265.1	31.1
15	161.1	154	189.8	24:00	0:00	42,438.4	0.0	191.00	266.9	31.1
16	161.3	154	165.9	24:00	0:00	42,302.4	0.0	191.00	266.2	31.1
17	161.4	154	167.2	24:00	0:00	42,206.9	0.0	191.00	263.2	31.1
18	161.6	154	169.0	24:00	0:00	42,244.8	0.0	191.00	261	31.1
19	161.6	154	161.9	24:00	0:00	42,357.6	0.0	191.00	256.4	31.1
20	161.6	158.6	136.5	13:30	7:00	18,921.9	9,811.4	121.42	249.9	32.7
21	163.1	158.6	198.9	24:00	0:00	43,002.9	0.0	190.42	249	32.7
22	163.1	158.6	160.8	24:00	0:00	42,680.2	0.0	191.00	248.3	32.7
23	163.3	158.6	160.9	24:00	0:00	42,922.8	0.0	191.00	245.4	32.7
24	163.3	158.6	157.4	24:00	0:00	41,987.0	0.0	189.54	243.9	32.7
25	162.6	158.6	136.4	24:00	0:00	42,682.7	0.0	191.00	246.3	32.7
26	161.7	158.6	130.9	24:00	0:00	42,554.8	0.0	191.00	246.7	32.7
27	161.1	158.6	134.9	24:00	0:00	42,500.0	0.0	191.00	245.4	32.7
28	160.5	161.6	170.9	6:30	15:00	10,532.5	24,305.9	132.21	240.7	33
29	160.1	164.7	161.9	5:00	19:00	6,490.3	24,663.1	112.50	239.3	34.1
30	164.7	164.7	140.6	24:00	0:00	42,871.9	0.0	190.96	245.6	34.1

Total Actual NO_x Emissions for the month (tons) :	63.2

OCTOBER	30-Day Average NO_X Emissions		NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
2000	Synfuel	Oil		Synfuel	Oil	Synfuel	Oil		Synfuel	Oil
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	167.5	164.7	145.4	24:00	0:00	42,681.6	0.0	191.00	256.9	34.1
2	166.5	164.7	142.9	24:00	0:00	42,118.6	0.0	191.00	264.3	34.1
3	165.7	164.7	131.0	24:00	0:00	42,513.8	0.0	191.00	266.5	34.1
4	163.3	164.7	130.6	24:00	0:00	42,808.0	0.0	191.00	269.1	34.1
5	161	164.7	132.6	24:00	0:00	43,124.3	0.0	191.00	269.1	34.1
6	159.5	164.7	129.7	24:00	0:00	43,164.4	0.0	191.00	275.3	34.1
7	157.6	164.7	133.2	24:00	0:00	42,825.4	0.0	191.00	280.1	34.1
8	155.7	164.7	131.1	24:00	0:00	43,110.7	0.0	191.00	280.4	34.1
9	154.3	164.7	142.1	24:00	0:00	42,516.0	0.0	191.00	278	34.1
10	153.5	164.7	166.5	24:00	0:00	42,894.5	0.0	191.00	277.2	34.1
11	153.2	164.7	176.1	24:00	0:00	43,185.7	0.0	191.00	278.7	34.1
12	152.7	164.7	167.4	24:00	0:00	43,281.7	0.0	191.00	277.9	34.1
13	152	164.7	160.2	24:00	0:00	42,955.8	0.0	187.75	274.6	34.1
14	151.3	164.7	177.7	24:00	0:00	43,325.8	0.0	191.00	270.3	34.1
15	151.5	164.7	193.0	24:00	0:00	42,955.0	0.0	191.00	265.3	34.1
16	152.6	164.7	199.3	24:00	0:00	42,939.7	0.0	191.00	265.9	34.1
17	153.3	164.7	189.2	24:00	0:00	42,798.1	0.0	191.00	270.2	34.1
18	153.7	164.7	179.8	24:00	0:00	43,194.3	0.0	191.00	275.3	34.1
19	154.7	164.7	181.1	24:00	0:00	43,303.0	0.0	191.00	280.5	34.1
20	156.4	164.7	194.2	24:00	0:00	43,179.4	0.0	191.00	284.9	34.1
21	155.7	164.7	177.7	24:00	0:00	43,077.5	0.0	191.00	284.5	34.1
22	156.4	164.7	182.0	24:00	0:00	43,198.0	0.0	191.00	283.5	34.1
23	157.1	164.7	180.5	24:00	0:00	43,131.6	0.0	191.00	284	34.1
24	157.3	166.9	220.4	7:00	17:00	12,088.7	29,358.4	161.96	280.7	35.3
25	157.3	173.4	229.2	0:00	24:00	0.0	37,062.2	133.17	280.7	37.1
26	160.1	174	161.9	8:45	10:15	11,887.2	13,925.1	101.71	269.7	37.4
27	163.1	174	222.7	24:00	0:00	43,023.7	0.0	191.00	262.7	37.4
28	165.1	174	196.3	24:00	0:00	43,014.8	0.0	191.00	261.1	37.4
29	167.2	174	197.1	24:00	0:00	43,192.7	0.0	191.00	262.3	37.4
30	169.7	174	190.3	24:00	0:00	42,998.6	0.0	191.00	271.5	37.8
31	171.5	174	197.0	24:00	0:00	42,829.8	0.0	191.00	273.8	37.8

Total Actual NO_x Emissions for the month (tons) :	64.4

NOVEMBER	30-Day Average NO_X Emissions		NO_X Emissions	Daily Hours of Operation		Total Daily Heat Input		Daily Average MW Output	30-Day Rolling Average SO_2 Emission	
2000	**Synfuel**	**Oil**		**Synfuel**	**Oil**	**Synfuel**	**Oil**		**Synfuel**	**Oil**
	(lbs)		(lb / hr)	(hr)		(MMBTU / day)		(MW)	(lbs)	
1	173.1	174	191.2	24:00	0:00	42,972.8	0.0	191.00	270.1	37.8
2	174.9	174	197.4	24:00	0:00	42,621.5	0.0	191.00	267.6	37.8
3	176.6	174	180.7	24:00	0:00	40,822.8	0.0	183.29	266.8	37.8
4	178.1	173.2	174.3	22:00	2:00	35,440.6	3,221.9	169.42	266.5	40.6
5	179.5	173.2	175.8	24:00	0:00	42,462.6	0.0	191.00	266.2	40.6
6	180.8	173.2	169.3	24:00	0:00	42,687.4	0.0	191.00	264.3	40.6
7	182	173.2	168.4	24:00	0:00	42,892.1	0.0	191.00	261.8	40.6
8	183.5	173.2	175.9	24:00	0:00	42,727.5	0.0	191.00	259.7	40.6
9	184.7	173.2	176.8	24:00	0:00	42,552.6	0.0	191.00	261.3	40.6
10	184.4	173.2	159.1	24:00	0:00	41,129.1	0.0	183.21	257.3	40.6
11	183.9	173.2	163.1	24:00	0:00	38,954.0	0.0	174.88	248.6	40.6
12	183.9	173.2	167.5	24:00	0:00	38,899.0	0.0	174.79	241.6	40.6
13	183.8	173.2	156.6	24:00	0:00	39,057.9	0.0	174.83	240.7	40.6
14	183	173.2	153.1	24:00	0:00	38,890.4	0.0	174.71	244.3	40.6
15	182.1	173.2	165.3	24:00	0:00	38,938.1	0.0	174.75	250.4	40.6
16	180.3	174.2	149.2	23:00	1:00	34,465.5	1,498.5	157.67	252.4	42
17	178.9	174.2	145.7	24:00	0:00	39,534.5	0.0	174.83	250.8	42
18	177.6	174.2	141.9	24:00	0:00	39,614.2	0.0	174.88	249	42
19	175.9	174.2	139.1	24:00	0:00	39,616.0	0.0	174.83	247.8	42
20	174.2	174.2	148.7	24:00	0:00	39,587.2	0.0	174.71	249.3	42
21	173.9	174.2	167.2	24:00	0:00	39,708.5	0.0	174.92	245.7	42
22	174	174.2	183.2	24:00	0:00	40,356.9	0.0	178.42	243.1	42
23	173.7	174.2	174.3	24:00	0:00	39,487.3	0.0	174.88	239.3	42
24	173.7	174.2	164.6	24:00	0:00	39,554.4	0.0	174.92	238	42
25	171.4	174.2	148.1	24:00	0:00	39,718.7	0.0	174.88	242.1	42
26	169.1	174.2	152.3	24:00	0:00	39,527.6	0.0	174.83	245.9	42
27	167.9	174.2	161.9	24:00	0:00	39,663.3	0.0	174.79	247.9	42
28	167.3	174.2	178.3	24:00	0:00	39,538.0	0.0	174.83	247.4	42
29	166.2	175.5	166.2	19:00	5:00	28,636.6	7,536.0	152.75	244.8	43.1
30	164.9	175.5	157.5	24:00	0:00	37,662.2	0.0	164.92	242.3	43.1

Total Actual NO_x Emissions for the month (tons) :	59.5

October 1999

Mine: **Ohio #11** **Coal Blend:** **54%**

Coal Analysis - As Received	Result	Units
Ash, as Received	6.81	%
BTU, as Received	11841	BTU/Lb
Sulfur, as Received	2.88	%
Volatiles, as Received	37.49	%
Fixed Carbon, as Received	44.30	%
Carbon, as Received	65.27	%
Hydrogen, as Received	4.48	%
Nitrogen as Received	1.34	%
Oxygen, as Received	7.72	%

Mine: **Camp** **Coal Blend:** **46%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.22	%
BTU, as Received	11664	BTU/Lb
Sulfur, as Received	2.93	%
Volatiles, as Received	35.51	%
Fixed Carbon, as Received	44.77	%
Carbon, as Received	65.25	%
Hydrogen, as Received	4.47	%
Nitrogen as Received	1.38	%
Oxygen, as Received	6.17	%

November 1999

Mine: Camp

Coal Blend: 100%

Coal Analysis - As Received	Result	Units
Ash, as Received	9.22	%
BTU, as Received	11664	BTU/Lb
Sulfur, as Received	2.93	%
Volatiles, as Received	35.51	%
Fixed Carbon, as Received	44.77	%
Carbon, as Received	65.25	%
Hydrogen, as Received	4.47	%
Nitrogen as Received	1.38	%
Oxygen, as Received	6.17	%

December 1999

Mine: **Camp** **Coal Blend:** **100%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.12	%
BTU, as Received	11629	BTU/Lb
Sulfur, as Received	2.89	%
Volatiles, as Received	35.61	%
Fixed Carbon, as Received	44.67	%
Carbon, as Received	64.91	%
Hydrogen, as Received	4.55	%
Nitrogen as Received	1.38	%
Oxygen, as Received	6.43	%

January 2000

Mine: **Camp**

Coal Blend: **100%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.21	%
BTU, as Received	11456	BTU/Lb
Sulfur, as Received	2.92	%
Volatiles, as Received	35.04	%
Fixed Carbon, as Received	44.35	%
Carbon, as Received	63.71	%
Hydrogen, as Received	4.34	%
Nitrogen as Received	1.39	%
Oxygen, as Received	6.94	%

February 2000

Mine: **Camp** **Coal Blend:** **47%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11501	BTU/Lb
Sulfur, as Received	2.95	%
Volatiles, as Received	35.19	%
Fixed Carbon, as Received	44.55	%
Carbon, as Received	64.12	%
Hydrogen, as Received	4.72	%
Nitrogen as Received	1.44	%
Oxygen, as Received	6.41	%

Mine: **Petcoke** **Coal Blend:** **21%**

Coal Analysis - As Received	Result	Units
Ash, as Received	0.403	%
BTU, as Received	14558	BTU/Lb
Sulfur, as Received	5.00	%
Volatiles, as Received	11.44	%
Fixed Carbon, as Received	83.72	%
Carbon, as Received	84.28	%
Hydrogen, as Received	3.62	%
Nitrogen as Received	1.67	%
Oxygen, as Received	0.557	%

Mine: **Pitt** **Coal Blend:** **33%**

Coal Analysis - As Received	Result	Units
Ash, as Received	7.11	%
BTU, as Received	13290	BTU/Lb
Sulfur, as Received	1.50	%
Volatiles, as Received	35.18	%
Fixed Carbon, as Received	52.57	%
Carbon, as Received	74.75	%
Hydrogen, as Received	4.89	%
Nitrogen as Received	1.50	%
Oxygen, as Received	4.97	%

March 2000

Mine: Camp **Coal Blend:** 100%

Coal Analysis - As Received	Result	Units
Ash, as Received	8.74	%
BTU, as Received	11499	BTU/Lb
Sulfur, as Received	2.61	%
Volatiles, as Received	34.93	%
Fixed Carbon, as Received	44.93	%
Carbon, as Received	64.08	%
Hydrogen, as Received	4.39	%
Nitrogen as Received	1.43	%
Oxygen, as Received	7.22	%

April 2000

Mine: Camp **Coal Blend:** 62%

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

Mine: Petcoke **Coal Blend:** 22%

Coal Analysis - As Received	Result	Units
Ash, as Received	0.402	%
BTU, as Received	14072	BTU/Lb
Sulfur, as Received	5.64	%
Volatiles, as Received	9.174	%
Fixed Carbon, as Received	83.27	%
Carbon, as Received	81.67	%
Hydrogen, as Received	3.48	%
Nitrogen as Received	1.54	%
Oxygen, as Received	0.058	%

Mine: Pitt **Coal Blend:** 16%

Coal Analysis - As Received	Result	Units
Ash, as Received	7.29	%
BTU, as Received	13276	BTU/Lb
Sulfur, as Received	1.46	%
Volatiles, as Received	35.27	%
Fixed Carbon, as Received	52.34	%
Carbon, as Received	74.29	%
Hydrogen, as Received	4.87	%
Nitrogen as Received	1.51	%
Oxygen, as Received	5.36	%

May 2000

Mine: **Camp** **Coal Blend:** **69%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

Mine: **Petcoke** **Coal Blend:** **3%**

Coal Analysis - As Received	Result	Units
Ash, as Received	0.486	%
BTU, as Received	13743	BTU/Lb
Sulfur, as Received	4.15	%
Volatiles, as Received	10.69	%
Fixed Carbon, as Received	78.82	%
Carbon, as Received	79.80	%
Hydrogen, as Received	2.94	%
Nitrogen as Received	2.02	%
Oxygen, as Received	0.564	%

Mine: **Pitt** **Coal Blend:** **28%**

Coal Analysis - As Received	Result	Units
Ash, as Received	7.29	%
BTU, as Received	13276	BTU/Lb
Sulfur, as Received	1.46	%
Volatiles, as Received	35.27	%
Fixed Carbon, as Received	52.34	%
Carbon, as Received	74.29	%
Hydrogen, as Received	4.87	%
Nitrogen as Received	1.51	%
Oxygen, as Received	5.36	%

June 2000

Mine: Camp

Coal Blend: 100%

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

July 2000

Mine: Camp **Coal Blend:** 100%

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

August 2000

Mine: Camp

Coal Blend: 100%

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

September 2000

Mine: **Camp** **Coal Blend:** **48%**

Coal Analysis - As Received	Result	Units
Ash, as Received	9.26	%
BTU, as Received	11510	BTU/Lb
Sulfur, as Received	2.94	%
Volatiles, as Received	34.99	%
Fixed Carbon, as Received	44.75	%
Carbon, as Received	64.26	%
Hydrogen, as Received	4.49	%
Nitrogen as Received	1.42	%
Oxygen, as Received	6.53	%

Mine: **Pitt** **Coal Blend:** **52%**

Coal Analysis - As Received	Result	Units
Ash, as Received	7.70	%
BTU, as Received	13103	BTU/Lb
Sulfur, as Received	2.52	%
Volatiles, as Received	36.53	%
Fixed Carbon, as Received	49.62	%
Carbon, as Received	73.32	%
Hydrogen, as Received	4.90	%
Nitrogen as Received	1.46	%
Oxygen, as Received	3.87	%

October 2000

Mine: **Pitt**

Coal Blend: **100%**

Coal Analysis - As Received	Result	Units
Ash, as Received	7.84	%
BTU, as Received	13090	BTU/Lb
Sulfur, as Received	2.33	%
Volatiles, as Received	36.43	%
Fixed Carbon, as Received	49.73	%
Carbon, as Received	72.77	%
Hydrogen, as Received	4.79	%
Nitrogen as Received	1.45	%
Oxygen, as Received	4.74	%

October 2000

Mine: Pitt

Coal Blend: 100%

Coal Analysis - As Received	Result	Units
Ash, as Received	7.62	%
BTU, as Received	13251	BTU/Lb
Sulfur, as Received	2.66	%
Volatiles, as Received	37.06	%
Fixed Carbon, as Received	49.96	%
Carbon, as Received	73.68	%
Hydrogen, as Received	4.88	%
Nitrogen as Received	1.45	%
Oxygen, as Received	4.27	%

Comment 3 Enclosures

GER 4172

GE Power Generation

Gas Turbine NOx Emissions Approaching Zero – Is it Worth the Price?

Marvin M. Schorr, Consulting Engineer
Joel Chalfin, Manager, Environmental Engineering
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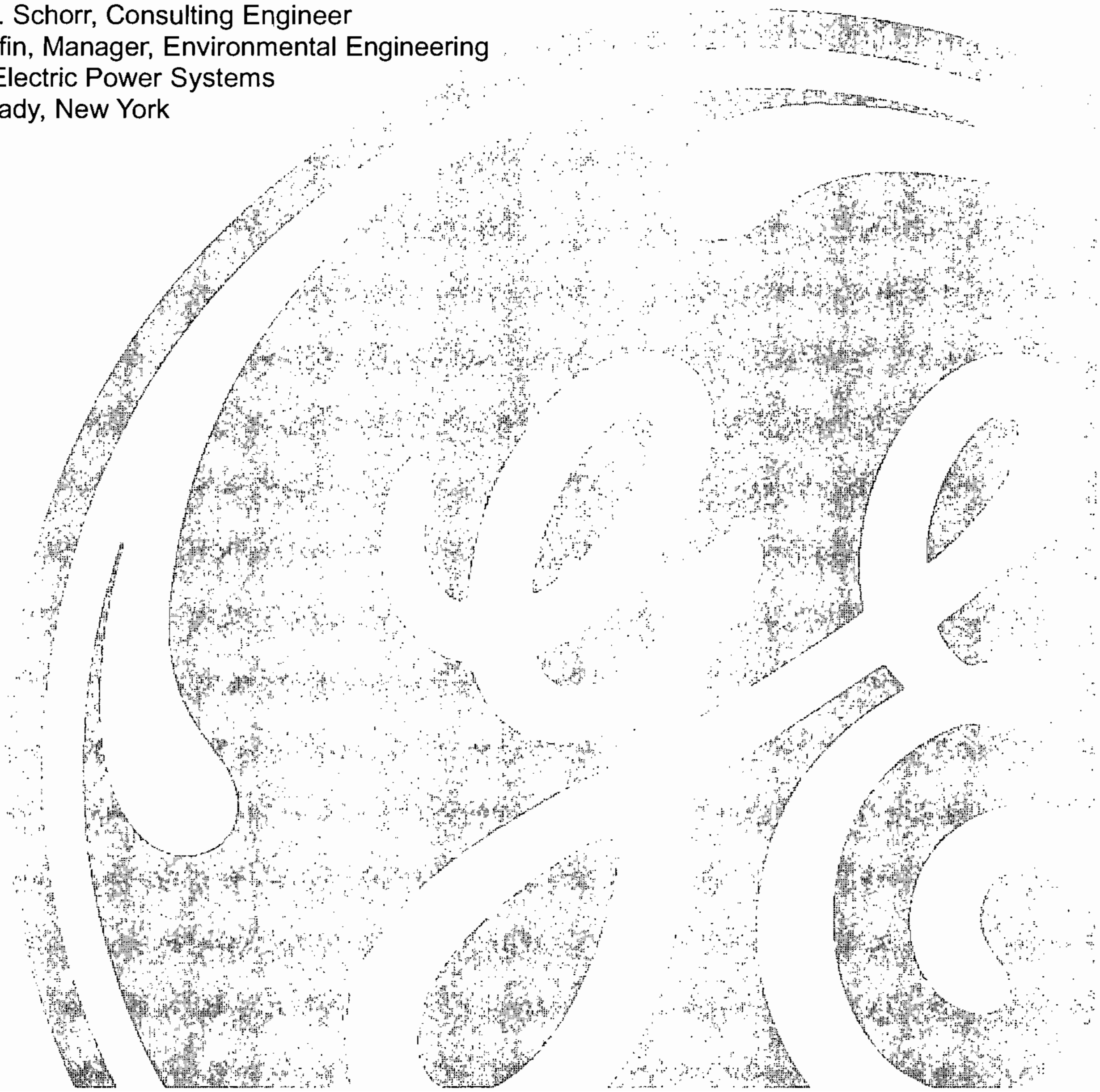

GAS TURBINE NOx EMISSIONS APPROACHING ZERO - IS IT WORTH THE PRICE?

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ABSTRACT

The requirement for gas turbines to meet ever lower NOx emission levels results from a regulatory approach developed before combustion systems existed that are capable of achieving single digit NOx. Dry low NOx (DLN) combustors for GE Frame 7FAs, 7EAs and 6Bs are now demonstrating 9 ppm NOx. This paper compares the energy, environmental and economic impacts of requiring add-on emission controls to achieve a lower level of NOx, with a gas turbine combustion system that is already capable of achieving single digit NOx. The conclusion reached is that ratcheting NOx down to lower and lower levels through the use of add-on emission controls reaches the point of diminishing return when the gas turbine combustion system is capable of achieving single digit NOx. The cost of add-on emission controls to achieve a lower NOx level becomes excessive, the heat rate increases and the overall environmental impacts are actually worsened. The recommendation is made for the U.S. EPA to amend the regulatory process to allow permit authorities to consider conflicting environmental, energy and economic impacts in nonattainment areas, as they now can in attainment areas, in cases where add-on emission controls will result in only a small reduction in emissions.

INTRODUCTION

The current regulatory process for permitting gas turbines is the product of a regulatory approach that does not seem to have anticipated gas turbine combustion systems capable of achieving single digit NOx without add-on controls (such as selective catalytic reduction, SCR). The technology forcing approach of the Clean Air Act New Source Review process has been especially successful with respect to gas turbine combustion system emissions through the use of Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) requirements. Allowable NOx emissions have been ratcheted down from an New Source Performance Standards (NSPS) level of 75 ppm (plus heat rate correction) to less than 10 ppm (when firing natural gas) in about 12 years. However, the point of diminishing returns appears to have been reached, at least for GE gas turbine combustion systems that are now achieving single digit NOx without the use of post combustion, add-on emission controls. The response of gas turbine manufacturers to the technology forcing programs of the Clean Air Act has been truly impressive.

Dry low NOx (DLN) combustors for GE Frame 7FAs, 7EAs and 6Bs are now operating at 9 ppm NOx and even lower levels are likely to be achieved in the next few years. The cost of add-on emission controls to achieve a NOx level below 9 ppm becomes excessive and the overall environmental impacts may actually be worsened when the gas turbine combustion system is capable of achieving single digit NOx. The recommendation is made for the U.S. EPA to amend the regulatory process to allow permit authorities to consider conflicting environmental, energy and economic impacts in nonattainment areas, as they now can in attainment areas, in cases where add-on emission controls will result in only a marginal reduction in emissions.

REGULATORY BACKGROUND

The decade of the 1980s was one of rapid change for both gas turbine emission control regulations and the technologies used to meet those regulations. The primary pollutant of concern from gas turbines has been, and continues to be, oxides of nitrogen. The Gas Turbine New Source Performance Standards (NSPS), issued in 1979, did not regulate the emissions of carbon monoxide or unburned hydrocarbons from gas turbines because the levels are very low at base load. However, in December 1987, EPA's "top-down approach" for determining the Best Available Control Technology (BACT) became a requirement. This ratcheted allowable gas turbine NOx emission levels down to levels significantly lower than the NSPS. As the allowable NOx levels decreased, with steam or water injection the primary technology used for NOx control, carbon monoxide emissions started to become more of a concern. Increases in CO levels resulted from massive amounts of steam or water being injected to control NOx to the lower levels and part load operation in cogeneration applications. As a result, advances in dry low NOx combustion technology and new add-on emission controls allowed gas turbine operators to achieve very low levels of NOx without injection. The Clean Air Act Amendments of 1990 have resulted in new emission control requirements, not only for NOx, but also for CO and VOCs in ozone non-attainment areas.

GAS TURBINE EMISSIONS

Potential pollutant emissions from gas turbines include oxides of nitrogen (NO and NO2, collectively referred to as NOx), carbon monoxide (CO), unburned hydrocarbons (UHC, usually expressed as equivalent methane), oxides of sulfur (SO2 and SO3) and particulate matter (PM). Unburned hydrocarbons are made up of volatile organic compounds (VOCs), which contribute to the formation of ground level atmospheric ozone, and compounds such as methane and ethane, that do not contribute to ozone formation. SO2, UHC and PM are generally considered negligible when burning natural gas. Thus, NOx and possibly CO are the only emissions of significance when combusting natural gas in combustion turbines.

The NOx production rate falls sharply as either the combustion temperature decreases, or as the fuel-air ratio decreases, due to an exponential temperature effect. Therefore, the introduction of a small amount of any diluent into the combustion zone will decrease the rate of thermal NOx production. This is the physics behind the injection of water or steam and of lean combustors. Because the diluent effect is a thermal one, the higher specific heat of steam means that less steam needs to be introduced than air and less water than steam to achieve the equivalent NOx reduction. However, the introduction of steam or water to the gas turbine combustor is a thermodynamic loss, whereas redistributing combustor airflow splits (combustion vs. dilution/cooling) has no impact on the cycle efficiency. As a result, the use of very lean combustors to achieve the lower NOx levels is more desirable than steam/water injection.

NO$_X$ CONTROL TECHNOLOGIES

The "front-end" technologies that are available for the control of NOx emissions from gas turbines include: (1) injection of water or steam into the combustion zone, a control technology that lowers flame temperature, (2) dry low NOx combustion (DLN), a technology that uses staged combustion and lean-premixed fuel-air mixtures, and (3) catalytic combustion, a new technology that holds the promise of achieving extremely low emission levels. "Back-end" exhaust gas clean-up systems include (4) selective catalytic reduction (SCR) and (5) SCONOXTM, a new catalytic technology.

Water/Steam Injection

Most of the experience base with gas turbine NOx emission control prior to 1990 was with diluent injection into the combustion zone. The injected diluent provides a heat sink that lowers the combustion zone temperature, which is the primary parameter affecting NOx formation. As the combustion zone temperature decreases, NOx production decreases exponentially.

Manufacturers continue to develop machines having higher firing temperatures as a way to increase the overall thermodynamic efficiency. However, higher firing temperatures mean higher combustion temperatures, which produce more NOx, resulting in the need for more diluent injection to achieve the same emission levels of NOx. There has also been a reduction of allowable NOx emissions and lower NOx levels require even more injection. The increased injection rate lowers the thermodynamic efficiency, seen as an increase in heat rate (fuel use), due to taking some of the energy from combustion gases to heat the water or steam. Furthermore, as injection increases, dynamic pressure oscillation activity (i.e., noise) in the combustor also increases, resulting in increased wear of internal parts. Carbon monoxide, which may be viewed as a measure of the inefficiency of the combustion process, also increases as the injection rate increases. Basically, as more and more water or steam is injected into the combustor to lower the combustion temperature, flame stability is affected until, if it were increased sufficiently, the water would literally put out the flame. Thus, a design dichotomy exists whereby increasing firing temperature to increase the efficiency of the combustion process, unfortunately produces more NOx, requiring more injection, which lowers the thermodynamic efficiency, producing more CO and also decreasing parts life. Increased injection to meet lower NOx emission limits simply exacerbates the problems associated with increased injection. The lowest practical NOx levels achieved with injection are generally 25 ppm when firing natural gas and 42 ppm when firing oil.

Selective Catalytic Reduction, SCR

In the SCR process, ammonia (NH) injected into the gas turbine exhaust gas stream as it passes through the heat recovery steam generator (HRSG), reacts with nitrogen oxides (NOx) in the presence of a catalyst to form molecular nitrogen and water. Based on experience, SCR works best in base loaded combined cycle gas turbine applications where the fuel is natural gas. The reasons for that relate to the temperature dependency of the catalytic NOx-ammonia reaction and the catalyst life, and to major problems associated with the use of sulfur bearing (liquid) fuels. The reaction takes place over a limited temperature range, 600-750°F, and above approximately 850°F the catalyst is damaged irreversibly. In addition, because of the temperature dependency of the chemical reaction and catalyst life, SCR cannot be used in simple cycle configurations, except possibly in lower exhaust temperature systems. Other issues associated with SCR include exhaust emissions of ammonia (known as ammonia slip); concerns about accidental release of stored ammonia to the atmosphere, environmental concerns and costs of disposal of spent catalyst.

Ammonia Release

The use of ammonia in the SCR chemical process for NOx control presents several problems. Ammonia is on EPA's list of Extremely Hazardous Substances under Title III, Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Releases of ammonia to the atmosphere may occur due to unreacted ammonia going out the stack (known as ammonia "slip"), or it can be accidentally released during transport, transfer, or storage. In addition, ammonia is a PM-10 precursor emission (particulate matter smaller in diameter than 10 microns).

Some ammonia slip is unavoidable with SCR due to the non-uniform distribution of the reacting gases. Thus, some ammonia and unreacted NOx will pass through the catalyst and in fact some catalyst manufacturers recommend operating with excess ammonia to compensate for imperfect distribution. An ammonia slip of 10-20 ppm is generally permitted in a new system (although higher slip has been noted) and will increase with catalyst age. In the past, ammonia slip was not considered to be a problem by regulatory agencies because they felt that by releasing it from an elevated stack, the ground level concentration would be low. However, it has never appeared to be good environmental policy to allow ammonia to be released to the atmosphere in place of NOx and ammonia emissions are now of concern because of PM–2.5 considerations.

The Use of Sulfur-Bearing Fuels

The Problem – Distillate oil contains sulfur. There is no successful operating experience when SCR is used for NOx control while firing a gas turbine with sulfur bearing oil. However, some regulatory agencies require the use of SCR, even when distillate oil is used as a backup fuel. In most cases regulators have simply pointed to the many combined cycle plants with SCR permitted with oil as the backup fuel, ignoring the fact that most of those plants actually operate almost exclusively on gas and use little or no oil fuel. Those that have used oil have experienced significant problems.

The problems associated with the use of sulfur bearing fuels are due to the formation of the ammonium salts ammonium bisulfate, NH_4HSO_4, and ammonium sulfate, $(NH_4)SO_4$. These compounds are formed by the chemical reaction between the sulfur oxides in the exhaust gas and the ammonia injected for NOx control. Ammonium bisulfate causes rapid corrosion of boiler tube materials; and both ammonium compounds cause fouling and plugging of the boiler and an increase of PM–10 emissions.

Ammonium bisulfate forms in the lower temperature section of the HRSG where it deposits on the walls and heat transfer surfaces. These surface deposits can lead to rapid corrosion in the HRSG economizer and downstream metal surfaces resulting in increased pressure drop and reduced heat transfer (lower power output and cycle efficiency). While ammonium sulfate is not corrosive, its formation also contributes to plugging and fouling of the heat transfer surfaces (leading to reduced heat transfer efficiency) and higher particulate emissions. The increase in emissions of particulates due to the ammonium salts can be as high as a factor of five due to conversion of SO_2 to SO_3. Some of the SO_2 formed from the fuel sulfur is converted to SO_3 and it is the SO_3 that reacts with water and ammonia to form ammonium bisulfate and ammonium sulfate. The increase is a function of the amount of sulfur in the fuel, the ammonia slip (ammonia that does not react with NOx) and the temperature. It can also be increased by supplementary firing of the HRSG and by the use of a CO oxidizing catalyst (which significantly increases the conversion of SO_2 to SO_3).

The only effective way to inhibit the formation of ammonium salts appears to be to limit the sulfur content of the fuel to very low levels (or switch to a sulfur free fuel such as butane) and/or limit the excess ammonia available to react with the sulfur oxides. Pipeline quality natural gas usually has a sulfur content low enough that ammonium salt formation, while it is present, has not yet been a significant problem with natural gas-fired units. However, the sulfur content of even very low sulfur distillate oil (e.g., 0.05 percent) or liquid aviation fuel (Jet–A) may not be low enough to prevent enough formation of ammonium bisulfate to avoid the problems discussed above (ambient sulfates may also contribute). This potential is usually handled by a requirement to limit the operating time on the low sulfur distillate oil to a relatively few hundred hours between shutdowns and then clean the HRSG internals (although disposal of the deposits may be a problem due to the presence of hazardous materials). Lowering the ammonia slip or the sulfur concentration could lengthen the time between cleanings. Limiting the ammonia that is available to react with the sulfur oxides to negligible levels does not appear practical at NOx removal efficiencies above 80 percent because higher excess ammonia levels are required to achieve the higher NOx removal efficiencies. Limiting the excess ammonia may work at lower NOx removal efficiencies because the lower NH_3/NOx ratios required ensure that all the ammonia is consumed. However, when oil is to be used as the primary fuel, the experience would indicate that SCR should not be used, as there appears to be significant risk of equipment damage or failure, performance degradation and increased emissions of fine PM.

Disposal of Spent Catalyst

SCR materials typically contain heavy metal oxides such as vanadium and/or titanium, thus creating a human health and environmental risk related to the handling and disposal of spent catalyst. Vanadium pentoxide, the most commonly used SCR catalyst, is on the EPA's list of Extremely Hazardous Materials. The quantity of waste associated with SCR is quite large, although the actual amount of active material in the catalyst bed is relatively small.

SCONOX

SCONOX is a post-combustion catalytic system that removes both NOx and CO from the gas turbine exhaust, but without ammonia injection. The catalyst is platinum and the active NOx removal reagent is potassium carbonate. At present, the only operating SCONOX system is being used with an LM2500 injected with steam to 25 ppm NOx at a facility in Vernon, CA. Stack NOx is maintained at 2 ppm or less and CO at less then 1 ppm.

How SCONOX Works

The exhaust gases from a gas turbine flow into the reactor and react with potassium carbonate which is coated on the platinum catalyst surface. The CO is oxidized to CO_2 by the platinum catalyst and the CO_2 is exhausted up the stack. NO is oxidized to NO_2 and then reacts with the potassium carbonate absorber coating on the catalyst to form potassium nitrites and nitrates at the surface of the catalyst. When the carbonate becomes saturated with NOx it must be regenerated. The effective operating temperature range is 280 to 750°F, with 500 to 700°F the optimum range for NOx removal. The optimum temperature range is approximately the same as that of SCR.

Regeneration is accomplished by passing a dilute hydrogen reducing gas (diluted to less than 4 percent hydrogen using steam) across the surface of the catalyst in the absence of oxygen. The sections of reactor catalyst undergoing regeneration are isolated from exhaust gases using sets of louvers on the upstream and downstream side of each reactor box. The Vernon LM2500 facility has 12 vertically stacked catalyst reactor boxes, nine of which are in the oxidation/absorption cycle at any given time, while three are in the regeneration cycle. When regen is completed in the three reactor boxes, the louvers open on those reactors and the louvers on three other reactors close and those reactors go into the regeneration cycle. Motor drives outside each box drive the shaft that opens and closes the louvers on each side of the box (inlet and outlet sides).

SCONOX Issues

There are several issues associated with the use of SCONOX. First, it is very sensitive to sulfur, even the small amount in pipeline natural gas. Second, the initial capital cost is about three times the cost of SCR, although this may come down once there are more in operation. Third, it has moving parts reliability and performance degradation due to leakage may be significant issues, especially on scale-up to bigger gas turbines (a 7FA would require 20 modules of 4 reactor boxes each vs. LM2500 using 3 modules of 4 reactor boxes). Last, use of any exhaust gas treatment technology (SCR or SCONOX) results in a pressure drop that reduces gas turbine efficiency. Thus, by adding a back-end cleanup system, more fuel must be burned to reduce NOx and SCONOX produces about twice the pressure drop of SCR.

The GE Dry Low NOx Combustor

GE began development of a dry low NOx combustor in 1973, primarily in response to increasingly stringent emission control requirements in California. The initial goal was a NOx level of 75 ppmvd at 15 percent oxygen, the NSPS requirement for utility gas turbines. An oil-fired combustor designed for a Frame 7 gas turbine achieved this goal in the laboratory in 1978. Field testing of the prototype dry low NOx combustor design demonstrated that the combustor was capable of meeting the NSPS. The design, tested at Houston Lighting and Power (HL and P) in 1980, has evolved into a system that is achieving a NOx level of 9 ppmvd at 15 percent oxygen in GE Frame 7EA, FA, and 6B gas turbines fired on natural gas.

DISCUSSION

Cost in $/ton of NOx Removed/Energy Output Reduction

The annual cost of reducing NOx using SCR from 9 ppm to 3.5 ppm for a GE Frame 7FA, 170 MW class gas turbine operating 8,000 hr/year is $8,000 to $12,000 per ton of NOx removed when a non sulfur bearing fuel is used and $15,000 to $30,000 if a sulfur bearing fuel is used. The cost will be the same or more than that with SCONOX, which in addition, cannot be used with sulfur bearing fuels without additional cost for sulfur removal. (The SCR cost effectiveness estimate with a sulfur bearing fuel is based on six year replacement of catalyst, 20 percent fixed charge rate and a vendor quote of 25 percent increase in HRSG cost for a redesigned economizer section to allow for cleaning of ammonium bisulfate. If a redesigned HRSG is not acceptable, the cost of periodic replacement of LP economizer tubes should be used in the BACT analysis.) Most gas turbine combined cycle or cogeneration systems today operate with natural gas as the primary fuel and fuel oil as the backup fuel. SCR operating and maintenance costs include continuous ammonia injection, periodic catalyst replacement, and the cost associated with a small decrease in power output (more than 650 kW for a 7FA). The output drop is due to power for auxiliaries associated with ammonia injection, catalyst pressure drop in the new and clean condition, which increases as ammonia-sulfur salts build up, and decrease in heat transfer as the salt build-up increases over time. This cost is considered too high for BACT in ozone attainment areas by most states. The decrease in output efficiency results in an increase in CO_2 emissions due to the need to burn more fuel to make up for the output reduction.

It is often argued that economics should not be considered at all in LAER determinations. There is, however, an implicit "reasonableness test" in all LAER determinations. Thus, no regulator has required that trains of multiple SCR be utilized to reduce NOx to zero (although this is technically possible) because the cost would be so high that we would conclude that it would not be "reasonable". This same rationale should apply to adding any emission control if the cost is unreasonably high, as is the case for adding SCR or SCONOX to a combustion system achieving 9 ppm NOx in a combined cycle.

Ammonia Slip/Ammonium-Sulfur Salts

The impact of slip on the environment may be at least as detrimental as if NOx were to be released. Where an ammonia emission limit is imposed, and there is often no such emission limit, slip is generally targeted at 10-20 ppm, although there are units operating with ammonia slip well below and well above that level. Most recent SCRs operate with 5 ppm slip or less, but slip is expected to be on the high side when the NOx level entering the catalyst bed is already very low. Unless there is perfect mixing, the ammonia molecules must "find" the fewer NOx molecules in order to react and this will require adding more excess ammonia. Thus, 20 ppm or more ammonia slip would be released in place of the reduction in NOx in going from 9 to 3.5 ppm. Table 1 shows that for a Frame 7FA with 20 ppm ammonia slip (base load, 8,000 hr/yr, 45°F ambient, natural gas) there are 24 tons per year (TPY) more ammonia emitted than NOx reduction by lowering NOx from 9 to 3.5 ppm with SCR. There also is an increase of 5 TPY in particulate matter emitted, or 36 TPY if a CO catalyst is also used. Note also that as the catalyst ages, ammonia slip increases as the efficiency of conversion decreases, until at the end of catalyst life the ammonia slip may be much higher than a new and clean catalyst. In fact that is one way that catalyst replacement is indicated. Some ammonia released to the atmosphere will be converted to NOx and ultimately to ozone. Finally, ammonia is on the SARA (Superfund) list of Extremely Hazardous Materials. Accident studies of transport and on-site storage of ammonia for use with SCR, performed for the Massachusetts DEP and California's South Coast AQMD, resulted in a change from anhydrous ammonia to aqueous ammonia. Aqueous ammonia has a lower ammonia concentration and lower storage pressure (resulting in a slower release rate) than anhydrous. Anhydrous ammonia was used until these studies revealed the potential public hazard in the event of catastrophic release. The hazard was reduced, but not eliminated.

GE Power Systems analysis of measurements of ammonia emissions on six plants with SCR showed a great deal of inconsistency (<1 ppm to 30 ppm). All of the tests were performed using different ammonia sampling methodologies. EPA Method 206 for ammonia was recently published for applicability to coal-fired plants. There is no specific method for gas turbine plants. The conclusion drawn from this study is that the ammonia slip on plants with SCR is not actually known with any accuracy.

Spent Catalyst

From a policy standpoint, the disposal of spent catalyst as hazardous waste, simply transfers an air problem (NOx) into a long-term solid waste disposal problem. This is not a good environmental tradeoff.

Use of Sulfur Bearing Fuels

It has been GE Power System's position for some time that SCR should not be used in gas turbine applications where a sulfur bearing fuel, such as distillate oil, is used. With the recent concern expressed by EPA through the promulgation of the National Ambient Air Quality Standards for fine particulate matter (PM 2.5), GE Power Systems feels even more strongly that the use of SCR should be avoided when such fuels are used. Unreacted ammonia from the SCR, and sulfur from the fuel react to form ammonium salts that are released as particulate matter, as previously discussed. EPA is very concerned with PM–2.5 (very fine, inhalable particulates) which would increase significantly. The example in Table 1 for a Frame 7FA shows an 8 TPY increase in PM with SCR and almost 50 TPY if a CO catalyst is also used, with only 400 hours per year of oil firing. Aside from the important health risks that EPA has indicated are posed by PM 2.5, the impact of the increase in fine particulates on regional haze should also be considered. A CO oxidizing catalyst, supplementary firing and noble metal catalysts will all result in much higher SO_2 to SO_2 conversion and greater sulfur salt formation. Note that particulate emission controls have never been used on gas turbines.

Although there are many gas turbine combined cycle plants using SCR that are permitted to use distillate oil as the backup fuel, GE Power Systems is not aware of ANY successful operation with this combination. Actual operating experience indicates that ammonium-sulfur salt formation and boiler damage occur without exception, when ANY sulfur bearing fuel is fired in the gas turbine and SCR is used for NOx control. This is not usually accounted for in BACT determinations, but adds significant cost and should be considered. Beside the down time associated with periodic cleaning, the added cost includes periodic replacement of the low pressure tube sections of the HRSG damaged by ammonium bisulfate corrosion, or the cost of an alternative design HRSG (which was used for the estimated cost in Section V.1). Reference 1 documents the damage done to the HRSGs on several representative plants.

State Example

The New York State Department of Environmental Conservation (DEC) Gas Turbine NOx Policy (93–AIR–39), allows a BACT NOx limit higher than normal when firing oil as a backup fuel, to either avoid the use of SCR, or to minimize ammonia slip. This is specifically stated to be in recognition of the increased particulate and ammonium bisulfate problems and concerns related to ammonia emissions. The NOx policy also states that the DEC "has determined that 6 ppmv (dry, corrected to 15 percent O) was the lowest emission limit for NOx which can be accurately measured in the stack, based on current monitoring/testing technology." This is the same finding as the ASME B133 Committee on emission measurements from gas turbines, Reference 2. Several other states also allow higher NOx levels if the use of SCR can be avoided to eliminate ammonia emissions. New Jersey has considered low sulfur kerosene for the backup fuel (rather than distillate oil) as BACT, when SCR is used for NOx control.

Measurement and Control of NOx

Recent regulatory agency actions in some states has resulted in excessively low NOx levels being required for gas turbines. Based on the performance of SCONOX at the single facility in California, NOx permit levels as low as 2 ppm are being required in some states. Even if such a level of NOx can be achieved, the question of how low a NOx level can be monitored and controlled has apparently not been addressed. Can we monitor and control on 2 ppm NOx? 40CFRPart 75 requires that a majority of readings be between 20 and 8 percent of the measurement range. A 10 ppm range is the lowest certified for a process NOx analyzer. With a 2 ppm NOx limit, the +/-10 percent of standard criterion is 0.2 ppm so that a CEMS would need to report no greater than 1.8 ppm NOx minus margin to insure not exceeding 2 ppm. The ASME B133 Committee study (Reference 2) concluded that if the reading is outside the 20 to 80 percent of scale range the error could be as high as 25%. Since the plant must actually operate below 2 ppm with a 2 ppm limit, EPA's Part 75 regulations are violated. Further, to insure not exceeding 2 ppm, a 7FA gas turbine would need to operate at:

- 1.5 ppm max to compensate for instrument error (25% of 2 ppm reading error)
- ~1.0 ppm max to compensate for combustion system operating variability
- Below 1.0 ppm (0 to 1 ppm) to compensate for ambient variability effects

The conclusion is that 2 ppm NOx is not a practical emission limit for gas turbines.

Environmental Impact of a Deregulated Electricity Market

The advent of electricity market deregulation is bringing in a new factor to consider for new power plants called "displacement". This process has been observed in the United Kingdom where deregulation is generally the furthest along among the mature industrialized nations. Parts of the USA are already seeing the development of new "merchant" power plants that will compete with traditional utility plants and non-utility power plants. The concept is that new combined cycle merchant plants will be added until the market price of electricity from the new merchant plants is at parity with the composite market price, including less environmentally friendly older plants. This in turn will force either reduced operation or shut down of the less competitive of these older plants, with a resultant net emissions reduction. However, if the cost of a new, cleaner plant is increased (by adding SCR) it becomes more difficult to compete with older plants and less displacement occurs. Figure 1 shows the environmental benefits of displacing a coal or oil-fired power plant meeting the 1979 NSPS with a new gas-fired combined cycle plant of the same MW output. Also shown is the impact of the incremental premium that must be paid for SCR on the ability of a plant to bid its power under the market clearing price (the highest price the market will pay for power). Figure 2 shows the relative costs for various control technologies, first as a function of the initial capital cost of the power plant and then as a life cycle cost, both as functions of the NOx emission level. DLN at 9 ppm NOx is a clear winner over SCR in this competitive market environment, where the cleanest total solution is one where the economics of reducing the usage of the older plants is a significant consideration.

Regulatory Policy Consistency and Fairness

The EPA promulgated a new NOx NSPS for utility and industrial steam generators in October 1998. The revised Utility and Industrial Boiler NSPS for NOx is:

Applicability	NOx Emission Limit	Fuels
New Utility Units	1.6 LB per MW-Hr of output	Fuel Neutral
Modified/Reconstructed Existing Utility Units	0.15 LB per MMBtu fuel input	Fuel Neutral
New & Existing Industrial Units	0.20 LB per MMBtu fuel input	Fuel Neutral

Note the change from pounds of NOx per unit of heat input to pounds of NOx per unit of electrical output for utility units. There is no percent reduction required and it is fuel neutral.

For a Frame 7FA, 9 ppm NOx is less than 1/8 of the newly revised utility boiler NSPS and for 8,760 hours per year of operation will total less than the 250 tons per year PSD threshold for simple cycle gas turbines.

- Utility Boiler NSPS, NOx limit = 1.6 # NOx/MW-hr
- 7FA STAG, 9 ppm NOx = 0.19 # NOx/MW-hr

A 7FA at 3 ppm NOx emits less than one-twenty fourth of the utility boiler NSPS. For 8,760 hours per year of operation NOx will total less than the 100 TPY PSD threshold for steam electric power plants (EPA has ruled that combined cycle power plants are steam electric power plants).

The new 22-state eastern ozone transport region created by EPA's NOx SIP Call requires that an average NOx limit of 0.15 lb of NOx per million Btu of heat input be achieved. For a gas turbine this is equivalent to about 37 ppm NOx at 15 percent O.

When the boiler NSPS and the SIP call NOx requirements are compared with the extremely stringent gas turbine NOx emission requirements it is obvious that there is neither consistency nor fairness in the NOx emission requirements for gas turbines.

QUESTIONS REGULATORY POLICY MAKERS SHOULD ADDRESS

If a gas turbine can achieve an uncontrolled NOx level of 9 ppm, must the permit require less than that at any cost? The cost effectiveness of reducing NOx from 9 ppm to 3.5 ppm with SCR is approximately $15,000 to $30,000/ton of NOx as previously discussed. Is this reasonable for a BACT or LAER determination? If the cost effectiveness of an add-on control is $100,000/ton should it be required, even as LAER in nonattainment areas? $1,000,000/ton?

While a state agency can impose more stringent requirements than EPA, should a state agency that requires the use of the top-down approach for the determination of BACT, ignore cost effectiveness or impose an arbitrary effectiveness threshold that is much higher for some gas turbines than for other emission sources. Should agencies arbitrarily take a one-number fits all gas turbines approach to BACT, recognizing that BACT, by its very definition, is supposed to be site/project specific?

As previously discussed, some gas turbines can currently achieve an uncontrolled NOx emission level of 9 ppm. Some environmental agencies require the use of add-on controls for those gas turbines to reduce the NOx to 2 or 3 ppm in attainment and nonattainment areas, simply because it can be done, ignoring all other factors. If an uncontrolled NOx Level of 5 ppm is eventually achieved, should add-on controls still be required in attainment or nonattainment areas to reduce NOx to 3 ppm? To 2 ppm? In the extreme case, if an uncontrolled NOx level of 3 ppm is achieved by a gas turbine manufacturer, should such gas turbines be required to use add-on NOx control to reduce NOx to 2.5 ppm if that level were achievable, no matter what the cost? Did the Clean Air Act anticipate this kind of situation?

Many regulators state that economics cannot be considered in determining LAER. Should the negative environmental impacts resulting from emission controls that are required to reduce emissions of a nonattainment pollutant, also be ignored in determining LAER?

Is it a good environmental trade-off to emit ammonia in place of NOx? If the reduction in atmospheric loading (TPY) of NOx is of the same order of magnitude as the ammonia emitted in its place? Is it good environmental policy?

Does it make economic sense to require the use of any technology to control NOx emissions to extremely low levels when it is not clear that control at such low levels can be practically achieved? Is a 2 ppm NOx emission control level achievable even if it can be measured? 3 ppm? While these levels can probably be measured, has anyone considered the ability to control a gas turbine at such low levels under all operating conditions? The one unit operating with SCONOX that appears to be achieving the 2 ppm level operates only at full load with no load following.

10 ppm is the lowest scale certified for a process NOx analyzer. Can the plant to be controlled below 20 percent of scale? Part 75 requires that a majority of readings must be between 20 and 80 percent of measurement range. The reason for that requirement is accuracy!

CONCLUSIONS/ RECOMMENDATIONS

In view of current gas turbine combustion system emission control achievements and the previous discussion, it is recommended that EPA re-examine its nonattainment requirements and amend the regulatory process. First, competing environmental impacts resulting from the use of add-on emission controls should be considered in both attainment and nonattainment areas, when the use of add-on emission controls will result in only a small reduction in nonattainment pollutant emissions. Second, cost effectiveness should be considered in determining LAER when the cost is clearly not "reasonable".

In the case of gas turbine combustion systems, the technology has forged ahead of the regulations for NOx emission control. It makes no economic sense, nor does it provide any real environmental benefit, to require add-on emission controls when combustion systems produce single digit pollutant emissions. Furthermore, gas turbine manufacturers will continue to develop lower NOx combustion systems only as long as economic incentives exist. If it is apparent that add-on controls such as SCR will be required no matter how low the uncontrolled NOx level achieved, the development of lower NOx combustion systems will be discouraged. Contrary to EPA policy, pollution prevention as a concept becomes meaningless for such systems and the inconsistency with that and other government programs and policy, such as the DOE advanced turbine system (ATS) with its 9 ppm NOx goal, becomes all to apparent. While this might not be considered important in combined cycles because SCR could be required, it could be very important for the many simple cycle machines that will be sold in coming years. No SCR currently exists that can be used with simple cycle, high firing temperature, F-technology gas turbines, or the next generation of even higher firing temperature, H-class machines from the ATS program.

VIII. REFERENCES

1. Schorr, M.M.; "NOx Emission Control for Gas Turbines: A 1995 Update on Regulations and Technology," CIBO NOx Control Conference, March 1995.

2. ASME Codes and Standards Committee B133, Subcommittee 2, Environmental Standards for Gas Turbines, Report 9855-3, *Low NOx Measurement: Gas Turbine Plants*, Dec. 4, 1998.

Table 1
Estimated Tons/Year Change in Emissions for STAG 207FA* With SCR & COC (Base Load, 8000 hr/yr, 20 ppm NH Slip, 45 oF Ambient)

	9 ppm NOx w/o SCR	3.5 ppm NOx w/SCR	TPY	3.5 ppm NOx w/SCR & COC	TPY
Natural Gas Only					
NOx	240	92	-148	92	–148
PM	36	41.6	+5.6	69.6	+33.6
NH	0	172	+172	164	+164
SO	40	39	–1	25	–15
Gas+400 hr/yr Oil					
NOx	294	116	–178	116	–178
PM	37.6	45.8	+8.2	86	+48.4
NH	0	172	+172	161	+161
SO	57	56	–1	36	–21

* DLN 2.6 combustor; emissions are per unit
SCR – Selective Catalytic Reduction
COC – CO oxidizing catalyst

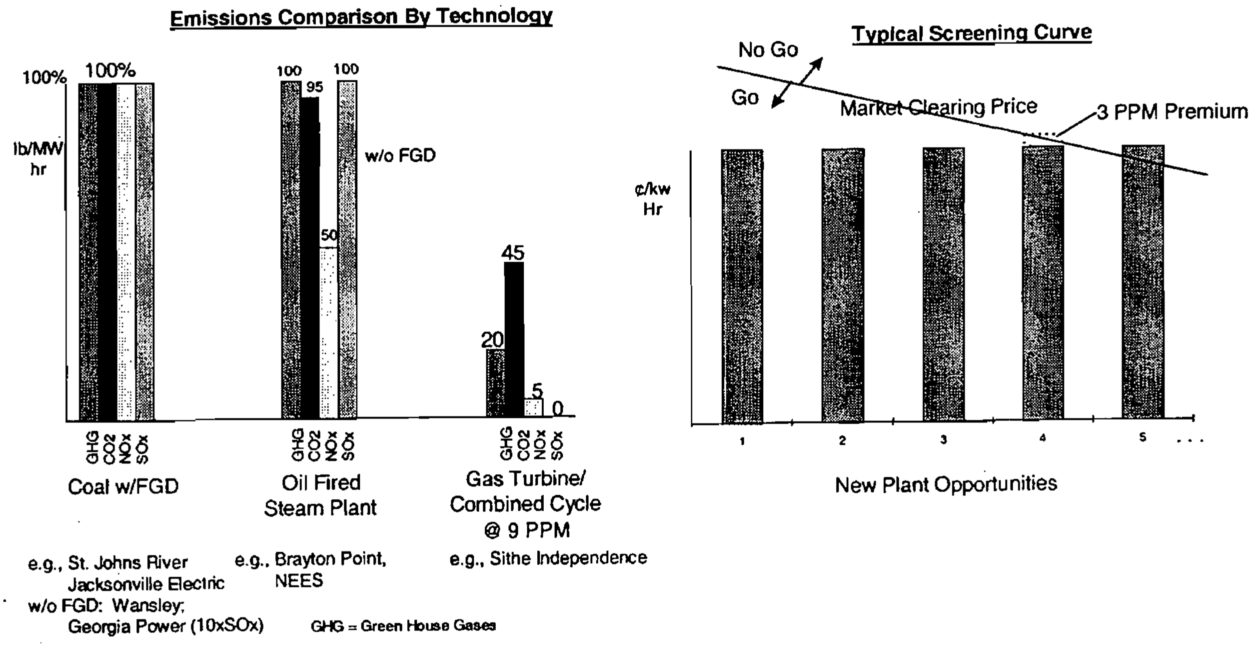
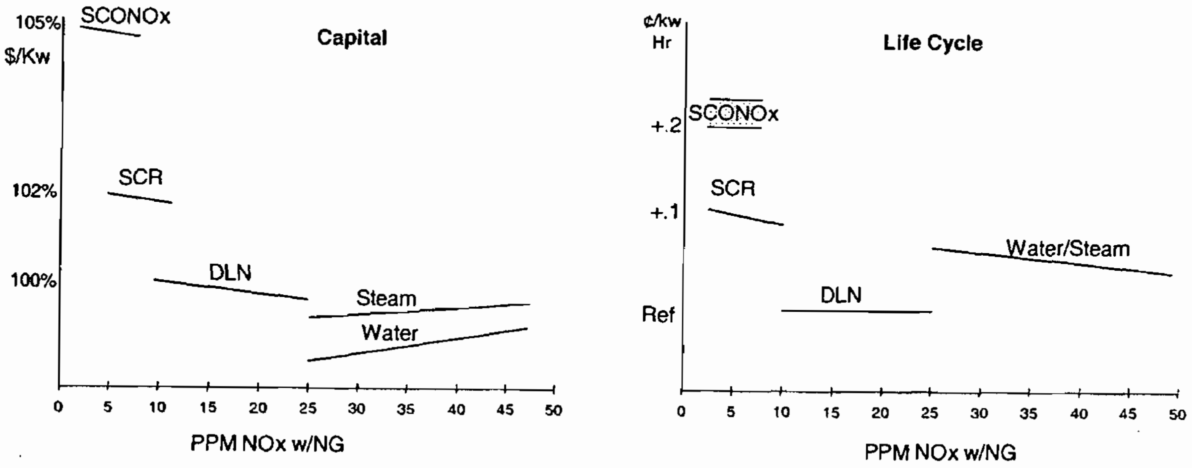


Figure 1. Optimizing Emissions in a Deregulated Electricity Market



- DLN Provides Significant Benefits Added Cost
- Emissions Trading Markets Continue Push Technologies
- Environmental and Safety Hazards Ammonia and Heavy Metal Catalysts Need to be
- Need to Consider Market Impacts

Figure 2. Economic Break Points for Gas Turbine Combined Cycle Plants

For further information, contact your GE Field Representative or write to GE Communication Programs

GE Power Systems

General Electric Company
One River Road
Schenectady, NY 12345

DRAFT

September 18, 2000 FILE NO: 31531.020001

BY HAND

Ms. Ellen Brown
Information Transfer and Program
Integration Division (MD-12)
Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park North Carolina 27711

Re: Comments on Draft Guidance for NOx Control at Combined Cycle Units

Dear Ms. Brown:

These comments are filed on behalf of the Utility Air Regulatory Group (UARG) in response to EPA's request for comments in 65 Fed. Reg. 50202 (August 17, 2000) concerning the Agency's draft best available control technology (BACT) guidance for NOx Control at Combined Cycle Units. UARG is a voluntary, nonprofit, ad hoc group of over 55 electric utilities, the Edison Electric Institute, the National Rural Electric Cooperative Association and the American Public Power Association (Enclosure 1). UARG participates on behalf of its members collectively in federal Clean Air Act rulemakings, guidance, and related litigation concerning issues of general interest to the electric utility industry.

In general, UARG supports EPA's draft guidance. We believe that several related policy issues should be clarified, and provide additional information and support in the attached technical paper by J.E. Cichanowicz and L. A. Angello (Enclosure 2). We believe that state permit writers should have a great deal of flexibility in determining BACT. The Clean Air Act as well as EPA's regulations make it abundantly clear that a BACT determination must be based upon a case-by-case, site-specific balancing of energy, environmental, and economic impacts and other costs, and mandate that this balancing be done by the appropriate State permitting authority.

I. The Clean Air Act

In the 1977 Amendments to the Act, Congress enacted a program for the prevention of significant deterioration of air quality. The Act's general scheme requires EPA to adopt nationally applicable air quality standards and other regulations which the States have "the primary responsibility" to implement. 42 U.S.C. §§7401(a)(3), 7407(a); see also 42 U.S.C. § 7410. In keeping with this scheme, Congress instructed EPA to develop and promulgate nationally applicable PSD regulations defining the requirements that a State must meet if that State chooses to adopt and get EPA approval of a PSD program. 42 U.S.C. §§7410(a)(2)(D), 7471. Congress intended these "measures" to allow States to play a major role in devising the PSD requirements that would work best within their boundaries. *See*, e.g., A Legislative History of the Clean Air Act Amendments of 1977 (hereinafter "1977 Legis. Hist.") at 531-33.

Among the PSD requirements that Congress imposed was that the State require any proposed major emitting facility subject to the PSD program to apply BACT for each pollutant subject to regulation under the Act that the source emits in a significant amount. 42 U.S.C. §7475(a)(4). The Act mandates that BACT limits are to be determined on a case-by-case basis after taking into account energy, environmental, and economic impacts and other costs. 42 U.S.C. §7479(3).[1] As Congress explained, in making this "key decision . . . the State is to take into account energy, environmental, and economic impacts and other costs of the application of best available control technology. The weight assigned to such factors is to be determined by the State." 1977 Legis. Hist. at

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[1] The only constraint Congress placed on the balancing test is that the final decision not yield an emission limit less stringent than any applicable new source performance standard. Id.

1405 (emphasis added).[2] In other words, under the Act, the State can assign whatever weight to these "consideration" factors that the State deems appropriate. Thus, the BACT standard envisaged by Congress is consistent with the general intent of the Act that the States have primary responsibility to determine the content of emission limitations needed to meet "minimal" federal requirements.

Nowhere in the Act is there any suggestion that certain of the BACT criteria – energy, environmental and economic impacts and other costs – should be emphasized over others. Nowhere in the Act is there any indication that BACT limits must be the lowest emission limits that are technically and economically feasible for a similar source or source category.[3] And, nowhere in the Act is there any presumption that some technology is BACT simply because it has been determined to be BACT for a given type of emission source in another location. Congress recognized that the balancing test is mandatory simply because site- specific considerations will warrant emphasis on different considerations.[4]

Federal courts have consistently endorsed the statutory requirement that BACT be determined through a flexible, balancing process. The United States Court of Appeals for the District of Columbia Circuit pointed out, for example, that "BACT is defined, in general, as a level of control technology appropriate to the facts and circumstances of the

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[2] See also 1977 Legis. Hist. at 729 (emphasis added) ("One objection which has been raised to requiring the use of the best available control technology is that a technology demonstrated to be applicable in one area of the country is not applicable at a new facility in another area because of difference[s] in feedstock material, plant configuration or other reasons. For this and other reasons, *the committee voted to permit emission limits based on best available technology on a case-by-case judgment at the State level.*").

[3] Indeed, such an interpretation of the Act would essentially make BACT limits equivalent to "lowest achievable emission rate" limits which Congress has imposed only on sources locating in nonattainment areas. See 42 U.S.C. §7501(3).

[4] 1977 Legis. Hist. at 729.

particular applicant." *Alabama Power v. Costle*, 606 F.2d 1068, 1085 (D.C. Cir. 1979) (emphasis added). The United States Court of Appeals for the Ninth Circuit observed that "the BACT determination is . . . source specific." *Northern Plains Resource Council v. EPA*, 645 F.2d 1349, 1359 (9th Cir. 1981) (emphasis added). Thus, the court concluded while a particular control technology may be BACT for one plant, the permitting authority "might decide that for [another] . . . facility . . . [that technology is] inappropriate for economic *or* energy *or* environmental reasons." Id. (emphasis added).

Court decisions, therefore, confirm what the language of the Act makes plain: a BACT determination must be made on a case-by-case basis by the State after taking into account energy, environmental, and economic impacts and other costs. Uniformity is not mandated by the BACT provisions; flexibility is.

II. EPA's PSD Regulations and Guidance

EPA promulgated a regulatory BACT definition in 1978 that, in all respects relevant here, is identical to the statutory definition. 43 Fed. Reg. 26,388, 26,404 (June 19, 1978).[5] The regulatory definition of BACT, like the statute, establishes that the BACT analysis must include a balancing of the relevant statutory factors. And, like the Act, the regulations limit consideration of technology to control technologies that are deemed "available" to that specific source. Indeed the regulations make it abundantly clear that the statutory criteria, including economic costs and energy, must be answered before a technology used in other types of sources impacts can be transferred to the new source. *See* 43 Fed. Reg. 26,380, 26,397 (1978).

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[5] In response to a legal challenge EPA amended its PSD regulations in 1980. 45 Fed. Reg. 52,676 (1980).{ TA \l "45 Fed. Reg. 52,676 (1980)." \s "45 Fed. Reg. 52,676 (1980)." \c 2 } The current definition of BACT, like the one promulgated in 1978, closely tracks the statutory definition found in 42 U.S.C. §7479(3). See 40 C.F.R. §§52.21(b)(12){ TA \l "). See 40 C.F.R. §§52.21(b)(12)" \s "). See 40 C.F.R. §§52.21(b)(12)" \c 2 }.

Shortly after promulgating its PSD regulations, EPA released Guidelines for Determining Best Available Control Technology which explained that a BACT determination is based upon the standard of flexibility. EPA, OAQPS, Guidelines for Determining Best Available Control Technology (Dec. 1978). Specifically, the permitting authority (in this case, the States) must

> consider a number of local factors (for example the size of the plant, the amount of air quality increment that would be consumed, and desired economic growth in the area) in deciding on a weighting scheme. *State judgment . . . [is one of] the foundations for the BACT determination.*

Id. at 4 (emphasis added). Among the type of "economic impacts" that should be assessed, according to the 1978 Guidelines, are the cost per unit of pollution removed (for example, dollars/ton) and cost versus additional portion of remaining PSD increment preserved for future growth. Id. at 14.

EPA's view of the BACT standard was reinforced in its 1980 PSD Workshop Manual wherein EPA recognized that the reviewer's primary responsibility is to determine the best emissions strategy to balance the environmental benefits gained from applying pollution control technology with the prudent use of energy and justifiable industrial expenditures. EPA, PSD Workshop Manual at II-B-2 (Oct. 1980).

In the mid-1980s, EPA's then-Assistant Administrator for Air and Radiation, J. Craig Potter, became concerned that PSD applicants were not adequately analyzing the full range of alternative control strategies in BACT review." Potter, J. Craig, Memorandum on Improving New Source Review (NSR) Implementation, to all Regional Administrators at 3 (Dec. 1, 1987). To ensure that alternative control strategy analyses were comprehensive, Mr. Potter directed his staff to develop guidance on the use of a "top-down" approach to BACT which required the PSD permit applicant and the permitting agency to evaluate all technologies that were more stringent than the NSPS to determine BACT. The Potter memorandum caused considerable confusion in the regulated community because some permitting agencies (including some EPA Regions) read the memorandum to establish a BACT determination process fundamentally different than the process established by EPA in its PSD rules, in its earlier guidance, and even potentially at odds with the criteria embodied in the statutory BACT definition. To settle a legal challenge to the Potter memorandum, EPA agreed to propose and make available for comment any change to the PSD regulation if it wished to make the top-down approach, in the inflexible manner in which some agencies had interpreted it, mandatory.

In July 1996, EPA issued a proposal to revise the PSD rules. 61 Fed. Reg. 38,250 (1996). In the proposal, EPA explained that the Act establishes two core criteria to be satisfied in making a BACT determination. First, all available control systems for the source, including the most stringent, must be considered. Second, the selection of a particular control system as BACT must be justified in terms of the statutory criteria – energy, environmental and economic impacts and other costs – and be supported by the record, and include an explanation for the rejection of any more stringent control systems. Id. at 38,272. Notably, EPA's proposed revisions to the BACT regulations recognize and endorse the statutory case-by-case approach to making BACT determinations by State permitting authorities.

III. EPA's Proposed BACT Guidance

We endorse EPA's guidance because it assures state permit writers that they have the authority to implement the statutory and regulatory criteria – energy, environmental and economic impacts and other costs – in making BACT determinations. Moreover, state permit writers are free to determine the weights that are to be assigned to these factors. While evident from the Act and EPA's implementing regulations, the guidance should clarify that state permit writers have authority to consider the incremental costs and benefits of requiring selective catalytic reduction technology to further reduce NOx emissions. We agree with EPA that those "energy, environmental and economic impacts and other costs" include the effect of ammonia slip on the formation of fine particles and visibility, the effect of acidifying deposition on soils and water bodies, the possibility of nitrogen deposition causing eutrophication of water bodies, issues related to ammonia safety, and the costs and environmental problems associated with the disposal of spent catalyst materials. We also believe that these criteria allow state permit writers to consider other relevant factors that EPA did not discuss in its draft document. such as efficiency penalties.

Many of these issues are discussed and, to the extent practicable, quantified in the Cichanowicz and Angello report. For example, a state permit writer is authorized to conclude in a case-by-case analysis that BACT for a dry low NO_x combustor would not require SCR where the SCR would provide an incremental reduction of 159 tons of NO_x while releasing 100 tons of ammonia into the atmosphere and producing an addition 500 tons of CO_2. The state permit writer is entitled to weight the statutory factors in a manner that is appropriate for the particular case that is being analyzed.

The draft guidance should clarify that there is nothing "magic" in the Act or EPA's regulations about a 9 ppm emission rate at a dry low NOx combustor. For example, many combined cycle units include supplemental firing (e.g., duct burners) that will have a slightly higher – perhaps 10-12 ppm – emission rate. There is no reason that this analysis would not apply to such units, and the guidance should clarify this point. Moreover, the same analysis would apply to combustors with higher NOx rates. The results of any analysis must be case-by-case, and neither the Clean Air Act nor EPA's rules allow EPA to dictate in the abstract the results of such an analysis.

UARG appreciates the opportunity to comment on EPA's draft guidance. If you have further questions please call Craig S. Harrison (202-778-2240).

Sincerely,

F. William Brownell

Craig S. Harrison

Enclosures

Attachment

DOE Staff Comments on EPA BACT Guidance for Natural Gas Combined Cycle Power Systems

Background

EPA has offered for public comment its August 4, 2000, draft guidance on BACT for NOx control for combined cycle turbines (65FR50202; August 17, 2000). The draft guidance recognizes the multiple benefits of deploying new combined cycle natural gas power systems, and is intended to assist State permitting authorities in setting an appropriate level for ABest Available Control Technology,@ or BACT, when issuing a construction permit to a new powerplant of this type seeking to site in a Aclean area.@ In particular, the guidance discusses the relevant factors in determining whether or not a new class of inherently low NOx natural gas power systems should universally be required to install Selective Catalytic Reduction (SCR) control systems to reduce NOx emissions further. The draft guidance states:

> *In most cases best available control technology (BACT) for controlling NOx emissions from combined cycle natural gas turbines used to generate electricity is a concentration that is achieved by selective catalytic reduction (SCR). This is true at all combined cycle natural gas plants including those that use a variant of the technology called dry low NOx (DLN) turbines that can achieve less than 10 parts per million NOx emissions without add on controls. In some situations, however, the collateral environmental impacts associated with the use of ammonia with SCR may justify not requiring SCR on DLN turbines. ... It is the permit applicant=s obligation to present information on any impacts, specific to the installation of SCR on the unit being permitted, that he wishes to be considered in the BACT determination.*

The draft guidance presents a set of environmental impacts from NOx, or from ammonia emissions associated with SCR systems, including:

Tropospheric Ozone
Fine Particles
Acidifying Deposition
Nitrogen Deposition and Eutrofication

Global Warming and Stratospheric Ozone Depletion
Ammonia Safety
Waste Issues

A subsequent discussion addresses the impact of requiring SCR, in the context of the overall electric power system, as modeled by EPA for its Clean Air Power Initiative (the ACAPI@ program). This discussion concludes that requiring SCR on all combined cycle combustion turbines has the counter-intuitive result of increasing NOx emissions.

Discussion

This paper does not address in detail the generally excellent technical discussion presented in the draft EPA guidance document. However, certain points merit elaboration, as discussed below.

Lower Systems Emissions

The 1999 CAPI modeling assumed that traditional gas turbines either had SCR, or did not. The assumption projects the deployment of traditional turbines, not inherently low NOx turbines. These low NOx turbines reduce NOx emissions by roughly 65% on a heat input basis, and by even more on an electrical output basis due to their higher efficiency, compared to traditional units without SCR. Thus, the CAPI results presented by EPA in the draft guidance document in Exhibit 2 and accompanying text overstate NOx emissions in the case where SCR is not required for gas turbines. Nevertheless, EPA=s analysis strongly supports the point that the cost of producing electricity does matter, and that A... if these turbines must use SCR, more electricity will be produced by dirtier plants and therefore total NOx emissions would increase, not decrease.@

The difference in emissions between a 9 ppmv combined cycle natural gas system and even a very clean coal system (0.15 #NOx/mmBtu) is substantial. Based on information provided us by GE, its newly commercialized AH-frame@ turbine technology emits 85% less NOx than levels budgeted under the EPA NOx SIP call for coal units.

In the same sense, other emissions from these dirtier plants, including particulate matter, mercury and other trace metals, and sulfur dioxide, will also be greater if SCR is universally required on all combined cycle combustion turbines.

Chilling R&D in Technology Advancement

DOE is continuing its proven partnership with the private sector to develop even more improved levels of efficiency and environmental performance in advanced turbines. We have been told by our private sector partners that their limited R&D resources will not be committed to further NOx reduction advancements if the expected result is that even cleaner systems will be required to apply post-combustion cleanup.

Global Implications for Technology Deployment

Besides the obvious benefits cited by EPA regarding pollution prevention versus pollution control, the Agency should consider the global implications of encouraging inherently cleaner energy systems. While many other nations may lack the financial resources to acquire expensive add-on technologies, most would deploy technologies which are both more efficient and are inherently lower emitting. And while these same countries lack resources to develop such technology themselves, they will purchase it from United States companies if it is available. A strong Federal signal to continue development of inherently cleaner power systems will result in lower global emissions of several pollutants.

Other technologies

The draft guidance suggests that other non-ammonia based systems may be available for add-on NOx control for combustion turbines. While such technologies have been under development for some time, they have not been applied to any system comparable in size or operating conditions to today=s new large combined cycle powerplants. In addition, they are projected to cost four times as much as, and have much greater parasitic power requirements than, SCR. Thus, even if deployed, the cost issue for this technology suggests that total system emissions could actually increase as the units drop in the dispatching order or are not deployed.

Recommendations for improvements in the Draft Guideance

The key issue in the draft guidance is not its technical shortcomings, which are relatively minor, but rather its administrative shortcomings. EPA=s approach imposes a significant and unnecessary burden upon permit applicants to prove, case-by-case, the points the Agency has demonstrated generically in the guidance. Rather than face protracted negotiations with a State permitting authority, with the additional uncertainty of EPA=s retained authority to Asecond-guess,@ project proponents are more likely either to include SCR in the plant design, or not propose a new plant at all. If SCR is required, then the tradeoff for a marginally reduced NOx emission rate from the turbine would be a higher cost system which could be lower in the dispatching order, with the associated higher emissions from dirtier generation from other plants. If the turbine is not built at all, an opportunity for cleaner generation is lost, and power would come from dirtier generating units. Either scenario is undesirable.

A two part solution would resolve this dilemma. The first part is for EPA to exercise its clear authority to recognize the bifurcated nature of turbine technology by establishing two categories of combined cycle combustion turbines: first, newer designs which are more efficient and emit below 10 ppmv; and second, the older designs which are relatively less efficient and emit, without add-on controls, about 25 ppmv.

Once these two categories are identified, then the guidance document could identify minimum BACT requirements for each, much as it did at the beginning of the draft document. The difference is that the guidance would not create a rebuttable presumption that SCR is BACT for the inherently cleaner class of combined cycle combustion turbines. For those systems, the guidance would provide that the minimum level of BACT is proper operation and maintenance of the low NOx combustion system.

EPA=s current mechanisms for conveying information on technology improvements to permitting authorities would continue to communicate advances in the performance of inherently low emission combustion turbines. Hence the bifurcated categories (traditional turbines and inherently low NOx turbines) would proceed on separate but parallel paths toward continued reductions in allowable emissions over time.

This two-step approach retains State permitting agency ability to require more stringent controls on the cleaner category of turbines where local conditions warrant, as the Clean Air Act clearly contemplates, while clearly indicating that EPA will accept effective operation of the built-in NOx control system as BACT. In most situations, this approach would relieve the permit applicant from the responsibility of proving the points already demonstrated by EPA, thus expediting permitting of new generation needed to insure electricity reliability. These revisions would also make the guidance flexible enough to accommodate additional technologies in the future.

DEPARTMENT OF ENVIRONMENTAL PROTECTION
FLORIDA

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

December 5, 2000

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: Tampa Electric Company, Polk Power Station
BACT Determination for Syngas Combustion Turbine
PSD-FL-194, Project No. 1050233-007

Dear Mr. Bunyak:

Enclosed for your review and comment is the final report for the above referenced project. Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the review engineer, Mike Halpin, at 850/921-9530.

Sincerely,

Patty Adams
for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: M. Halpin

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

December 5, 2000

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: Tampa Electric Company, Polk Power Station
BACT Determination for Syngas Combustion Turbine
PSD-FL-194, Project No. 1050233-007

Dear Mr. Worley:

Enclosed for your review and comment is the final report for the above referenced project. Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the review engineer, Mike Halpin, at 850/921-9530.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: M. Halpin

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

December 4, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Mark J. Hornick
General Manager – Polk Power Station
Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

Re: NO_x BACT Determination
Polk Power Station

Dear Mr. Hornick:

The Department is in receipt of the seventh NO_x BACT Determination test as well as the NO_X BACT Analysis called for in Specific Conditions 6 and 7 of permit PSD-FL-194 for the combined cycle unit at the above referenced facility. The Department finds that the analysis and submittals are incomplete. In order to continue processing your application, the Department will need the additional information below, specific to the combustion turbine emissions. Should your response to any of these items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Please provide 30 day rolling average NO_X emissions data for calendar months October 1999 through November 2000. This submittal should include actual NO_X emissions (tons) for each calendar month, as well as the following related data:
   a) each calendar month summary should include each daily average NO_X emission value in lb/hr (and ppm corrected to 15% O_2), as well as the total daily heat input by fuel type (e.g. synfuel, natural gas or oil), heating value and daily hours of operation on each fuel; the average daily MW output (from the CT) and average daily SO_2 emission (CEM) rates should also be shown
   b) provide the ultimate analysis of the "as-fired" coal for each calendar month listed above where synfuel was fired in the combustion turbine
   c) if available, provide data on gasifier H_2S and COS removal, as compared to the coal feedstock used
2. Please provide the average nitrogen diluent flow delivered to the CT during each of the seven NO_X BACT tests identified on page 4-1 of the submitted BACT analysis.
3. In a November 8, 1999 letter, EPA Region IV established that BACT for combined cycle turbines is 3.5 ppm NO_x. (Note: EPA wrote the letter after the Florida Department of Environmental Protection proposed a 6 ppm NO_X limit for a GE combined cycle Frame 7 turbine with SCR). Recently (on November 17, 2000) the Department issued a draft permit and BACT Determination for CPV Gulf Coast (PSD-FL-300). In that review, the Department determined that SCR was cost effective for reducing NO_X emissions from 9 ppmvd to 3.5 ppmvd on a General Electric 7FA unit burning natural gas in combined cycle mode. This review additionally concluded that the unit would be capable of

combusting 0.05%S diesel fuel oil for up to 30 days per year while emitting 10ppmvd of NO_X. This determination was made under the assumption that cost of NO_X control by SCR might be as high as $6,000 per ton (with ammonia emissions held to 5 ppmvd), which represents a NO_X control cost significantly higher than that offered in TECO's submittal.

a) Accordingly, this will represent the Department's determination for this project, unless Tampa Electric Company can demonstrate to the Department's satisfaction (absent fuel quality issues) why this installation is significantly different.

b) The Department notes (in reviewing the records for this project), that although the final BACT Determination for NO_X (while firing syngas) was set at 25 ppmvd through the test period, that the initial draft (1993) of the BACT evaluation had concluded that a NO_X emission limit of 12.5 ppmvd was appropriate, even if the application of an SCR was required.

4. Please estimate schedule requirements, which would be necessary to procure and install an SCR for the subject unit. Additionally, please confirm that Engelhard Corporation expects the catalyst life to be 5 to 7 years and will guarantee same for 3 years of operation.

We are awaiting comments from the EPA and the National Park Service. We will forward them to you when received and they will comprise part of this completeness review.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department."*

If you have any questions, please call me or Michael P. Halpin, P.E. at 850/921-9530.

Sincerely,

A.A. Linero, P.E. Administrator
New Source Review Section

AAL/mph

cc: Jerry Kissel, DEP-SWD
Jerry Campbell, HCEPC
Tom Davis, ECT

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General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

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Nar General Manager
Polk Power Station
Stre Tampa Electric Company
P.O. Box 111
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November 16, 2000

Mr. Clair Fancy
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7904 0065 0249

Re: **Tampa Electric Company (TEC) – Polk Power Station Title V Permit BACT Determination for Syngas Combustion Turbine – Test #7**

1050233-007-AC

Dear Mr. Fancy:

As per Specific Condition A.49 of the Polk Power Station Title V Permit, Tampa Electric has completed the seventh and final NO_x BACT Determination Test on the combustion turbine while operating on syngas. Accordingly, the final report is enclosed for your review. In addition, the BACT Analysis called for in Specific Condition A.50 of the Title V Permit is enclosed for your review.

If you have any questions, please feel free to contact Shannon Todd or me at (813) 641-5125.

Sincerely,

Mark J Hornick

Mark J. Hornick
General Manager/Responsible Official
Polk Power Station

EP\gm\SKT210

Enclosures

c/enc: Mr. Al Linero – FDEP
Mr. Syed Arif - FDEP
Mr. Jerry Kissel - FDEP SW

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CERTIFICATION OF RESPONSIBLE OFFICIAL

Based on information and belief formed after reasonable inquiry, I certify that all statements made in these reports are true, accurate and complete.

Mark J Hornick
(Signature of Responsible Official)

11/16/00
(Date)

Name: Mark J. Hornick
(Type or Print)

Title: General Manager, Polk Power Station
(Type or Print)

TAMPA ELECTRIC COMPANY
POLK POWER STATION
BEST AVAILABLE CONTROL
TECHNOLOGY ANALYSIS

Prepared for:

TECO

TAMPA ELECTRIC
Tampa, Florida

Prepared by:

ECT

Environmental Consulting & Technology, Inc.
3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 000656-0100

November 2000

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APPENDICES

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1.0 EXECUTIVE SUMMARY

As required by the Title V Operating Permit (1050233-001-AV) for the Polk Power Station (Polk or PPS) Integrated Gasification Combined Cycle (IGCC) Plant, an updated best available control technology (BACT) analysis is submitted for control of oxides of nitrogen (NO_x) emissions. This analysis was performed as if the combustion turbine (CT) were a new source using the data gathered at this facility, other similar facilities, and the manufacturer's research. Based on this analysis, Tampa Electric Company (TEC) requests that the current NO_x emissions limit of 25 parts per million by dry volume (ppmvd) be continued as the appropriate BACT emissions limit. The 25 ppmvd is based on a statistical analysis of the performance test data collected during the demonstration period for the facility and represents an emissions limit with which the facility can reasonably assure compliance.

Add-on control technologies were also evaluated; however, they were found to be unreasonable based on considerable technical concerns and cost considerations. An evaluation of other similar facilities was conducted, which indicated there was only one other facility regarded as similar based on the criteria used in the analysis. This similar facility has a NO_x emissions limit of 25 ppmvd, which is the same as the current limit for the Polk facility. Manufacturer's research indicated that technological advances have been made that are applicable to new IGCC installations; however, retrofitting these technologies to the Polk facility would require substantial capital investments and equipment downtime. As discussed in this report, an extensive retrofit was not further considered as a control option for this source because the emissions unit must be treated as a new source as specified in the Title V and Prevention of Significant Deterioration (PSD) permit conditions.

This report is divided into the following sections:

- Background.
- Regulatory requirement for BACT analysis.
- Demonstration Period Test Data summary.
- Consideration of appropriate emissions limit.
- Evaluation of available control technologies.
- Manufacturer's research.

2.0 BACKGROUND

TEC operates an IGCC process at the Polk facility. The power generation portion of this process consists of a 192-megawatt (MW) General Electric (GE) model 7FA turbine whose emissions pass through a heat recovery steam generator (HRSG). The resulting steam provides the energy necessary to generate approximately 125 MW from a steam turbine. The construction and operation of this facility was permitted on February 24, 1994, under permit numbers PSD-FL-194 and PA-92-32.

The original permit application included a BACT analysis. At the time of the permit issuance, the BACT for NO_x was determined to be diluent nitrogen injection coupled with a multinozzle quiet combustor (MNQC) for operation using the primary fuel, syngas. The associated NO_x emissions limit is 25 ppmvd at 15-percent oxygen (O_2). The NO_x BACT determination for the back-up fuel, distillate oil, was determined to be water injection with an associated NO_x emissions limit of 42 ppmvd at 15-percent oxygen. These emissions limits were based on the equipment supplier's (GE) guaranteed performance for this equipment installation.

At the same time, GE 7FA turbines configured for natural gas combustion could achieve somewhat lower NO_x emission rates, in the range of 9 to 15 ppmvd, by using air-premix type dry low NO_x (DLN) combustors. In contrast to natural gas, syngas contains over 35-percent hydrogen (H_2), which increases flame speed so much that the air premix type DLN combustor cannot be used for syngas fuel. This distinction is further discussed in Section 6 of this report. The original BACT determination and the issued PSD permit also addressed this difference between NO_x emissions rates for the different fuels.

At the time of the original BACT determination, this turbine was a unique equipment set that fires syngas using a revised MNQC design, which had not yet been in commercial service. Accordingly, the PSD and Title V permits each included a requirement for a testing period of 12 to 18 months, during which the NO_x emissions performance on syngas is tested bi-monthly. At the conclusion of testing period, TEC is to submit a revised

NO_x BACT determination to the Florida Department of Environmental Protection (FDEP). This document is being submitted to fulfill the submittal requirements of the BACT determination and air operation permits.

3.0 REGULATORY REQUIREMENT FOR BACT ANALYSIS

The BACT analysis is addressed in Specific Condition A.50. of the Title V permit, which states:

> "One month after the test period ends (estimated to be by February 2000), the permittee will submit to the Department a NO_X recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_X only and adjust the NO_X emissions limits accordingly."

The provisions of this condition are analyzed in this section, preceding the NO_X BACT analysis.

The permit condition stipulates that the BACT determination should be performed as if the Polk IGCC facility were a new source as opposed to a candidate for replacement of a significant IGCC system or subsystem or major retrofit. This provision is an important element of the determination, as there have been options developed in IGCC technology in the past 10 years that may make some of today's CTs capable of achieving lower NO_X emission rates than the Polk facility. However, these options involve major deviations from Polk's IGCC hardware configuration such as using a different (less efficient) gasification system operating at much higher pressure, employing an entirely different approach to connecting/integrating the major plant subsystems (air separation, gasification, acid gas removal, and power generation), and using completely new turbine combustion hardware and controls.

In other words, even though these new plants are still IGCC facilities, using the same basic CT as Polk (GE's 7FA), they are so different that little, if any, of the IGCC plant's hardware is the same. Thus, in accordance with this permit condition, this analysis treats the Polk facility as a new source and does not analyze the options of replacing a major IGCC system or subsystem or attempting to retrofit Polk with this different technology configuration. For completeness, these differences in configuration are discussed in Section 9.0 of this report, *Manufacturer's Research*. Instead of major modifications to the

IGCC plant, the NO_x BACT analysis addresses two main areas, the establishment of a lower emissions limit for syngas firing within Polk's existing hardware constraints and the use of add-on controls.

When evaluating the performance of other similar facilities, it is important to limit the scope of the analysis. First, as contrasted with the more numerous electrical generating facilities fueled by natural gas, there are considerably fewer facilities fueled by syngas. Natural gas-fired facilities cannot be considered similar to Polk because of the significant differences in the fuel combustion characteristics. Second, the syngas production system is important in evaluating whether the facilities are similar. For example, less efficient gasification systems inherently have more CO_2 and N_2 available for use as diluents for NO_x abatement. Consequently, IGCC plants using either significantly more or less efficient gasification process than Polk's cannot be considered similar. Next, the manufacturer and vintage of the CT is an important element to consider when performing a survey of emissions data for what is considered a similar facility. Finally, the method of operation must be considered when evaluating other similar facilities. For example, other IGCC applications are co-fired with blends of syngas and natural gas or syngas and oil. The NO_x emissions performance data for the few facilities that may be considered similar to the Polk facility are discussed in Section 8 of this report, *Other Plant Experience*.

The manufacturer's research is explored to identify the advances that have been made in GE CT technology that allow the present line of CTs to have considerably better NO_x emissions performance than those from 10 years ago. Additionally, the emissions data and operating experience during the initial test period have been discussed with GE to explore potential operational improvements. These discussions are summarized in this report.

4.0 NO_X EMISSIONS TESTING PERIOD DATA SUMMARY

The NO_x emissions testing period lasted for 12 months and involved seven emissions tests. Appropriate emissions reports for each test have been submitted to FDEP in accordance with the permit requirements. Table 1 summarizes these test results. Each entry in the table represents the average of at least three individual test runs. Appendix B contains the results of the individual 1-hour test runs.

Table 1. TEC Polk Power Station NO_x Emissions Test Data Summary

Test Date	Average NO_x Emissions Result (ppmvd, 15% oxygen, ISO conditions)	Load (MW)
October 14, 1999	16.7	191
December 7, 1999	14.6	190
February 7, 2000	19.0	192
April 17, 2000	17.0	191
June 14, 2000	18.1	190
August 15, 2000	16.6	192
October 17, 2000	22.5	192

Source: ECT, 2000.

The first six tests used a syngas derived from the facility's base coal supply (i.e., Kentucky coal). However, due to mine closure, the facility will continue to gasify a variety of fuel supplies. The syngas burned in the seventh test had a greater heating value and adiabatic flame temperature than that produced from the supply used during the first six tests, leading to greater NO_X emissions, even with using an increased proportional diluent flow rate.

A preliminary analysis of these data indicates the CT has met the 25-ppmvd NO_X emissions limit contained in the permit. The next step in the analysis is to determine the statistical distribution of the emissions test data and to use this statistical analysis to ascertain the confidence level associated with meeting specific emissions levels. For this analysis, the raw data (i.e., each individual test run) are used instead of the average of the three tests runs. This difference in approach is to allow for a larger statistical sampling size, as estimating values such as standard deviation and confidence intervals are sample size dependent, especially for samples of less than 20 data points. Table 2 presents the governing statistical measures.

Table 2. Statistical Analysis of Emissions Test Data

Parameter	NO_x Emissions Result (ppmvd, 15% oxygen, ISO conditions)	Load (MW)
Sample size	21	21
Mean (average)	17.8	191.14
Low	14.0	190
Median	17	191
High	22.5	192
Range	8.5	2
Standard deviation (σ)	2.38	0.9
Mean plus 2 (σ) 90-percent confidence interval	22.55	N/A
Mean plus 3 (σ) 99.7-percent confidence interval	24.93	N/A

Note: N/A = not an appropriate statistical measure for load, maximum load is established as 192 MW.

Source: ECT, 2000.

The emissions test data are approximately normally distributed, with an overall average of 17.8 parts per million (ppm) and median of 17 ppm. The highest observed value is 22.5 ppm, and the lowest is 14.0 ppm. The standard deviation (σ or sigma) is 2.38 ppm.

Assuming a normal distribution of emissions data, a commonly used measure for statistical process control is the use of mean plus a certain number of standard deviations. For example, approximately 90 percent of the data will lie within plus/minus two standard deviations from the mean value, and 99.7 percent of the data will lie within three standard deviations from the mean. The three-sigma approach is commonly used in industrial statistical process control applications, and is also supplemented by a six-sigma approach for additional control.

Based on this analysis, the mean-plus-three-sigma value is 24.93 ppm. Based on the statistical analysis, only a small fraction (0.3 percent) of readings would be outside the mean-plus/minus three-sigma range, either higher or lower. Because the current emissions limit (expressed in pounds per hour) is based on a 30-day rolling average or the average of three test runs for an emissions test, it is not anticipated that this small percentage of values outside the mean-plus-three-sigma value would cause a compliance concern. However, because a considerable fraction (10 percent) of readings are outside the mean-plus/minus-two-sigma range, it could be that a limit based on this value would be difficult to meet. This analysis is used as a basis in the following section that addresses an alternate emissions limit.

5.0 CONSIDERATION OF APPROPRIATE EMISSIONS LIMIT

Originally, the facility was permitted with a NO_x emissions limit of 25 ppmvd based on the manufacturer's emissions guarantee. The statistical analysis of the demonstration test data was used to determine the emissions levels that are represented by the mean-plus-two-sigma (22.55 ppmvd) and the mean-plus-three-sigma (24.93 ppmvd) values. Based on the previous discussion (performed in Section 4.0) of the statistical distribution of the data, it is thought that the mean-plus-two-sigma limit is too stringent. However, the three-sigma limit is an appropriate limit as it provides for reasonably expected emissions variations that are associated with fluctuations in meteorological conditions, fuel supply, and other process parameters. Additionally, the data collected during this analysis are for a relatively new and clean CT. As the CT ages, it is reasonable to expect a degradation in both the combustion efficiency and emissions performance. Hence, this three-sigma limit will provide for reasonable variations and anticipated degradation with equipment aging.

As was discussed in Section 4, the performance test conducted on October 17, 2000, indicated a greater NO_x emissions rate than the previous tests. This difference is attributed to a change in coal supply and a resulting greater heat content and adiabatic flame temperature of the syngas. This variation in NO_x emissions with changes in fuel supply is an important factor to consider when establishing the appropriate BACT emissions limit for this facility. The proposed 25-ppm NO_x emissions limit is expected to allow TEC to burn a variety of syngas compositions that are derived from the entire fuel portfolio for the facility. Any NO_x emissions limit less than 25 ppm would unduly restrict the facility's ability to gasify the existing range of feed stock.

Thus, for the remainder of this analysis, it is assumed the current CT emission level of 25 ppmvd of NO_x for firing of coal-based syngas will be retained. This determination of a proposed emissions rate is important for the evaluation of cost effectiveness of add-on control technology.

6.0 EVALUATION OF AVAILABLE CONTROL TECHNOLOGIES

The initial BACT analysis evaluated several available control technologies. The use of a nitrogen diluent with an advanced combustor design was selected, and the appropriate control technology is installed and in use for this system. Despite this prior selection of controls, there have been recent advances in control technology that warrant a revisit of the control technologies, including cost estimates.

The original BACT analysis (1992) addressed the following six combustion process modifications as available control technologies. This evaluation will update the analysis presented in the original BACT analysis for these six combustion process modifications, and also addresses the additional option of catalytic combustion controls (e.g., XONON):

- Flue gas recirculation (FGR).
- Low excess air (LEA).
- Low-NO_x burners.
- Water/steam/diluent injection with standard combustor design.
- Water/steam/diluent injection with advanced combustor design (multinozzle quiet combustor).
- Dry low-NO_x combustor design.

The BACT analysis also addressed the following three postcombustion exhaust gas treatment systems:

- Selective noncatalytic reduction (SNCR).
- Nonselective catalytic reduction (NSCR).
- Selective catalytic reduction (SCR).

This BACT analysis will update the analysis for these three postcombustion exhaust gas treatment systems and also addresses the additional option of $SCONO_x$™, a catalytic adsorption and desorption/reaction control system.

6.1 COMBUSTION PROCESS MODIFICATIONS

The original analysis asserted that the first three combustion process modifications are applicable to boilers and, therefore, are not applicable to CTs. Thus, FGR, LEA, and low-NO_x burners (i.e., boiler-specific low-NO_x configuration) were not considered in the original analysis. There have been no changes in technology for these options that would make them applicable to the CTs today, thus these options are not considered further in this analysis.

Of the next two options, water/steam/diluent injection with standard combustor design and water/steam/diluent injection with advanced combustor design, the second option was chosen as BACT and is installed on the equipment. Since this selected option provides better NO_x emissions control than the first option, further discussion of these options is not warranted in this analysis. Recent advances in the selected option (water/steam/diluent injection with advanced combustor design) for NO_x control are discussed in Section 9.0 of this report, Manufacturer's Research.

The dry low-NO_x combustor design (i.e., premix combustion) technology was discussed in the original BACT analysis. This analysis stated that although this technology has shown considerable NO_x emissions reductions for natural gas combustion, it has not been developed for synthetic coal gas as a fuel. There are considerable differences between the two fuels, including British thermal unit (BTU) content and fuel burning characteristics, which preclude the direct application of the advances in dry low-NO_x design for natural gas to syngas combustion. As a result of these differences, no turbine manufacturer currently offers dry low-NO_x technology as a control option for syngas fuel.

One of the overriding technical concerns with the application of dry low-NO_x technology to syngas fuels is the presence of hydrogen in the syngas fuel. The hydrogen flame speed is considerably greater than that for natural gas. This higher flame speed can contribute to flash back, which can cause substantial damage to the dry low-NO_x combustor. Thus, the option of dry low-NO_x combustor design is not considered further in this analysis.

An emerging combustion technology potentially capable of reducing gas turbine NO_x emissions to 2 to 5 ppmvd is catalytic combustion. Catalytica, Inc., was the first to commercially develop catalytic combustion controls for certain (mostly smaller) turbines and markets this system under the name XONON™. Catalytic combustion technology is not yet commercially available for 190-MW, F-Class turbines. Additionally, no gas turbine manufacturer is currently developing this technology for syngas applications. Therefore, catalytic combustion does not represent an available control option for the Polk facility and is not further considered in this analysis.

6.2 POSTCOMBUSTION EXHAUST GAS TREATMENT

The four following postcombustion exhaust gas treatment systems are evaluated in this section:

- SNCR.
- NSCR.
- SCR.
- Catalytic adsorption and desorption/reaction control system ($SCONO_x$™).

6.2.1 SELECTIVE NONCATALYTIC REDUCTION

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000 degrees Fahrenheit (°F).

The maximum temperature of the CT exhaust gas stream is approximately 1,060°F; thus, this technology is not technically feasible. Therefore, SNCR does not represent an available control option for the Polk facility and is not further considered in this analysis.

6.2.2 NONSELECTIVE CATALYTIC REDUCTION

The NSCR process uses a platinum/rhodium catalyst to reduce NO_x to nitrogen and water vapor under fuel-rich (less than 3-percent oxygen) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines. Due to the high excess air rates used to fire the turbine, the oxygen content of CT exhaust gases is typically over 11 percent. Therefore, NSCR does not represent an available control option for the Polk facility and is not further considered in this analysis.

6.2.3 SELECTIVE CATALYTIC REDUCTION

SCR reduces NO_x emissions by reacting ammonia with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. Ammonia is injected upstream of the catalyst bed where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \qquad (1)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (2)$$

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the cross-sectional area of the catalyst bed), ammonia/NO_x molar ratio, and catalyst bed temperature. Residence time is a function of catalyst bed depth. Increasing the residence time (increasing catalyst bed depth) will improve NO_x removal efficiency but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with ammonia theoretically requires a 1:1 molar ratio. Ammonia/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted ammonia (ammonia slip) emissions.

Reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (1) and (2) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place, resulting in an increase in NO_x emissions.

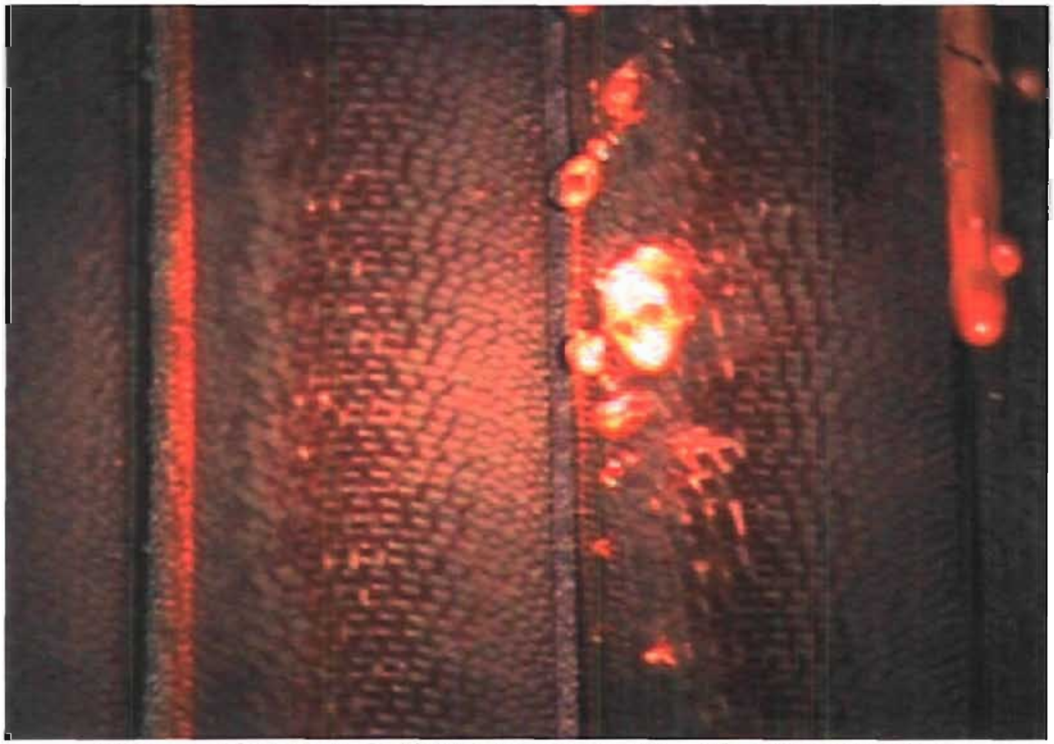
Specially formulated high temperature zeolite catalysts have been recently developed that function at exhaust stream temperatures up to a maximum of approximately 1,025°F. NO_x removal efficiencies for SCR systems typically range from 50 to 90 percent.

SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, mercury, potassium, sodium, and calcium. Due to the potential for chemical poisoning with fuels other than natural gas, application of SCR to CTs has been primarily limited to natural gas-fired units.

Of particular concern in this project is the use of the SCR catalyst on a sulfur-containing fuel. Yellow deposits composed of sulfur, and sulfur compounds have been noted from the high-pressure evaporator tubes to the low-pressure economizer. The temperature range associated with these deposits includes the normal operating temperature range of typical SCR catalysts. Several photographs were taken during a recent equipment shutdown that indicated the presence of sulfur compound deposition in the equipment, which is an overriding technical concern for fouling of the SCR control system. A sampling of these photographs is included in Figure 1 to support the assertion that the sulfur compounds in the exhaust stream present a technical obstacle to the use of an SCR emissions control system. Thus, there are significant amounts of sulfur and sulfur compounds in the exhaust stream that will adversely affect the performance of an SCR.

SCR catalyst will promote the oxidation of flue gas SO_2 to sulfur trioxide (SO_3), which will then combine with water vapor to form sulfuric acid (H_2SO_4). Accordingly, corrosion of downstream piping and heat transfer equipment (which would operate at temperatures below the H_2SO_4 dew-point) would be of concern when using SCR with sulfur-bearing fuels. Also, SO_3 will combine with unreacted ammonia to form ammonium bisulfate and ammonium sulfate. Ammonia bisulfate is a hygroscopic solid at approximately

Deposits in the HRSG, low-pressure section of economizer



Close-up of deposits in HRSG, low-pressure section of economizer.

FIGURE 1. (Page 1 of 2)

SITE PHOTOGRAPHS

Source: ECT, 2000.

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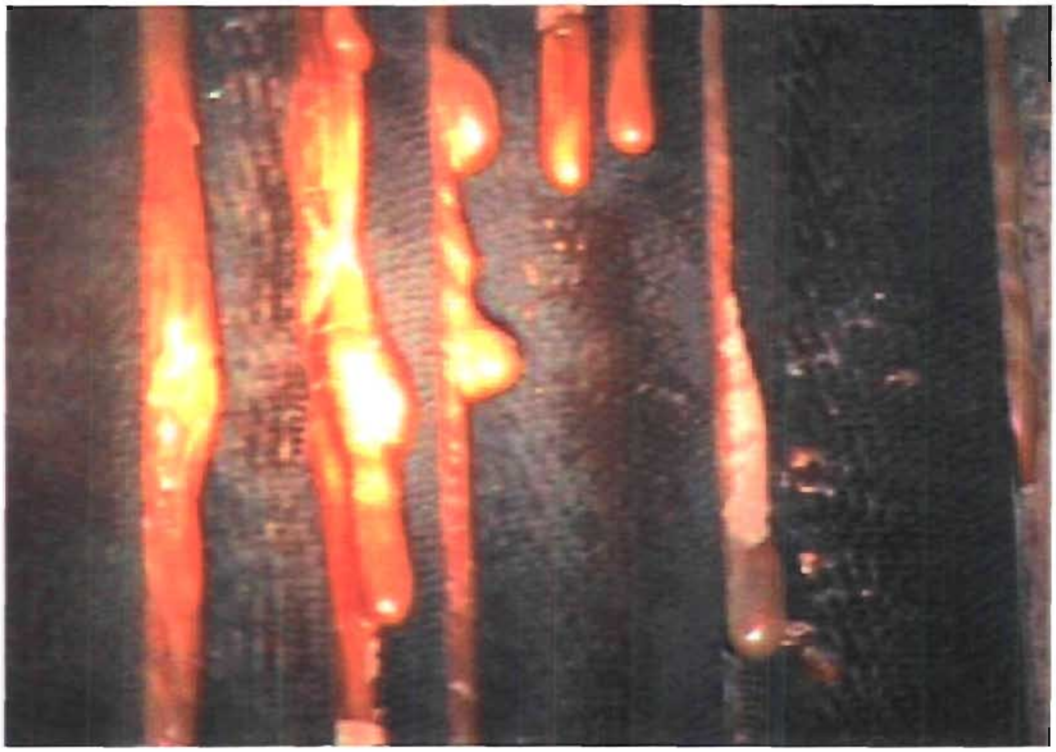
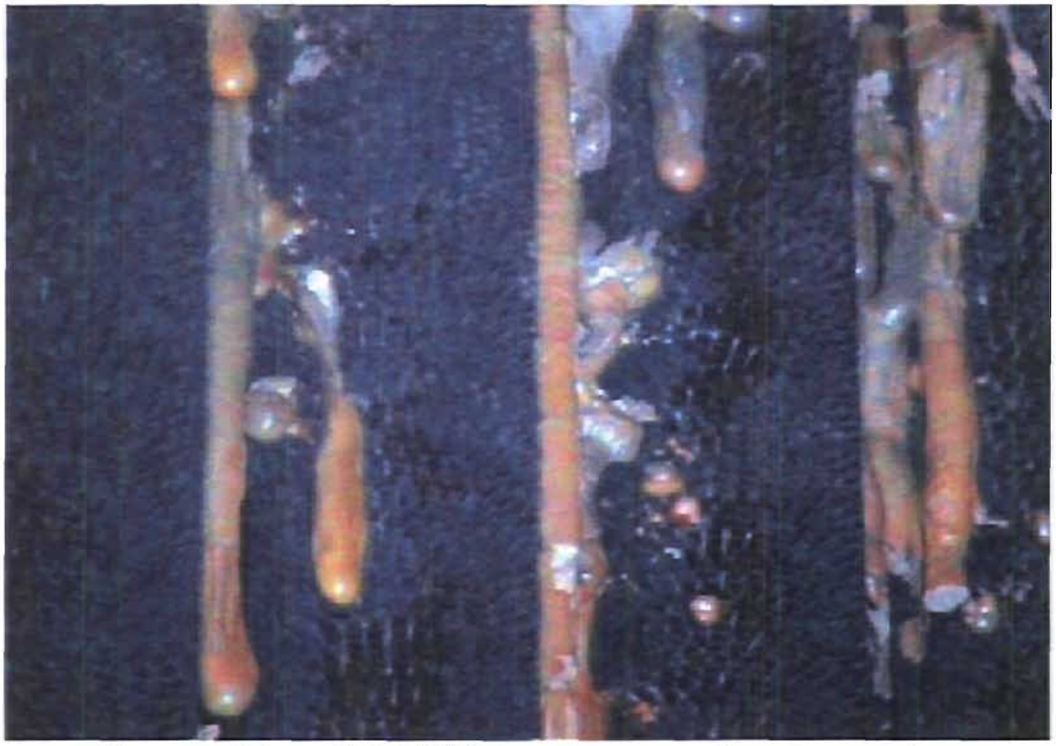


Close-up of deposits in HRSG, low-pressure section of economizer.



Close-up of deposits in HRSG, low-pressure section of economizer.

FIGURE 1. (Page 2 of 2)

SITE PHOTOGRAPHS

Source: ECT, 2000.

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380°F and will deposit on equipment surfaces below this temperature as a white solid. Both ammonium bisulfate and ammonium sulfate would be expected to deposit on HRSG heat transfer equipment where temperatures below 380°F will occur. Since ammonium bisulfate is hygroscopic, the material will absorb water, forming a sticky substance that can cause fouling of heat transfer equipment. Ammonium bisulfate cannot be easily removed due to its sticky nature; a unit shutdown would be required to clean fouled equipment. Formation of ammonium salts will also result in a significant increase in particulate matter (PM) emissions. Additionally, these deposits would be expected to increase the pressure drop across the equipment, adversely affecting overall CT efficiency.

The technical difficulties associated with SCR and sulfur-bearing fuels have been documented for fuels having relatively low sulfur contents. For example, the United Airlines cogeneration facility fires very low-sulfur (0.04 percent, 0.02 pound per million British thermal unit [lb/MMBtu]) Jet-A fuel as a back-up fuel[1]. Although this level is approximately half the sulfur level of the syngas fired at the Polk facility, the SCR catalyst was replaced three times during the first year of operation due to sulfur poisoning, and the back sections of the HRSG required washing to remove ammonium sulfate salt build-up.

Two examples of SCR applied to CTs firing sulfur-bearing fuels outside the United States were reported in the Lowest Achievable Emission Rate (LAER) analysis submitted for the Star Enterprise Delaware City Refinery permitted in 1998[2]. This analysis included two examples, one by the Japanese National Railway (JNR) and another in Linkoping, Sweden. The JNR facility had 50,000 hours of operating experience on a very low-sulfur fuel (0.007 weight percent, 0.004 lb/MMBtu); however, due to ammonium sulfate deposition, the unit is operated at approximately one-half of its design efficiency (40 percent actual versus 80 percent design NO_x reduction). By operating significantly below the

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[1] General Electric Company, Industrial and Power Systems, Position Paper, The Use of SCR When Firing Gas Turbines with Distillate Oil, May 31, 1994.

[2] Air Quality Permit Application for the Star Enterprise Delaware City Refinery, Submitted to the State of Delaware Department of Natural Resources and Environmental Control, Division of Air and Waste Management, Permit Number APC-97/0503.

design ammonia/NO_x injection ratio, ammonia slip (and the associated formation of ammonium sulfate) is virtually eliminated.

The Linkoping installation had 16,000 hours of operation. The unit is designed to achieve greater than 90 percent NO_x removal with low ammonia slip. It is equipped with an HRSG, and it has steam-fired sootblowers operated at 725 pounds per square inch (psi). During the summer of 1995, while firing fuel oil with sulfur levels between 0.05 and 0.1 percent, some deposits were found in the economizer section of the HRSG. The catalyst had to be removed during cleaning to avoid wetting it; the cleaning process took 1 week. In the fall of 1996, the fuel oil sulfur content rose to approximately 0.13 percent (0.07 lb/MMBtu). This increased level resulted in further, increased deposits and a significant increase in the HRSG pressure drop, which forced a turbine shutdown due to excessive backpressure.

These reported experiences indicate the following overriding concerns with application of SCR to sulfur-containing fuel combustion processes:

- HRSG deposits will form even at low fuel sulfur levels.
- The large HRSG pressure drop increases that have been predicted in this service (large enough to shut down the turbine) are now confirmed in an actual oil-fired CT HRSG.
- Sootblowers do not seem to be effective in preventing deposition.

Although the fuels used at the Polk facility have relatively low sulfur contents (i.e., syngas and low sulfur distillate oil), the sulfur levels are more than sufficient to cause problems with operation of a SCR control system. The Title V Air Operating Permit for SO_2 emissions limits the sulfur content of the syngas to 0.1 lb/MMBtu (as elemental sulfur). Normal operating experience indicates typical syngas sulfur content of 0.07 lb/MMBtu. This sulfur content is substantially greater (up to 10 times greater) than demonstrated to cause the technical difficulties described in this section.

Recent advances in catalyst design allow for SCR catalysts that minimize the conversion of SO_2 to SO_3. However, these catalysts are specifically formulated for use in specific applications in the chemical process industry. Discussions with the catalyst manufacturer (Englehard 2000)[3] indicate that this special catalyst is not formulated for use in combustion turbine applications. Additionally, Englehard indicated that they do not have a catalyst available for combustion turbine applications that would lessen the rate of this side reaction that can cause subsequent deposition problems.

In contrast, natural gas has a sulfur content of approximately 0.02 to 0.27 grains of sulfur per 100 standard cubic feet (gr S/100 scf), or 2.72×10^{-5} to 3.67×10^{-4} lb/MMBtu. This sulfur level is considerably less than that which has been shown to cause the equipment fouling described in this report.

Problems associated with ammonium salt deposition can be ameliorated to some extent by reducing the ammonia/NO_x molar ratio when firing sulfur-containing fuels. However, all known successful applications of SCR for CTs are on natural gas-fired units. There are no applications of SCR to CTs fired with synthetic coal gas, including the LAER determination for the Star Enterprises Maryland facility. It should also be noted that the original equipment manufacturer[4] does not promote the application of a SCR to a syngas-fired unit.

For the purposes of providing a complete analysis of the SCR as an option for control, even with the overwhelming technical concerns, a cost-effective analysis of SCR control technology is presented in Section 6.3 and is summarized in Table 3. As demonstrated in this analysis, the expected cost effectiveness for SCR was determined to be $4,660 per ton of NO_x removed This economic analysis includes increased costs that would accrue due to downtime required for cleaning of fouled heat transfer equipment. Since Polk Unit 1 does not have a by-pass stack, the unit must be shut down completely during any

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[3] Englehard, 2000. Telephone conversation, November 8, 2000, between Mr. Fred Booth, Englehard Corporation and Mr. John Shrock, ECT.

[4] General Electric Company, Industrial and Power Systems, Position Paper, The Use of SCR When Firing Gas Turbines with Distillate Oil, May 31, 1994.

outage caused by the SCR system. This cost control is greater than those previously considered to be reasonable for BACT NO_x determinations.

6.2.4 CATALYTIC ADSORPTION AND DESORPTION/REACTION CONTROL SYSTEM ($SCONO_x$™)

$SCONO_x$™ is a NO_x and CO catalytic absorption control system developed by Goal Line Environmental Technologies (GLET) and exclusively offered by Alstom Power. The $SCONO_x$™ system operates at a temperature range of 300 to 700°F. The $SCONO_x$™ process is further described in the information sheet included in Appendix C provided by the supplier of this technology.

The $SCONO_x$™ process addresses the sulfur poisoning issue by installing a $SCOSO_x$™ guard bed upstream of the $SCONO_x$™ catalyst bed. Even with the $SCOSO_x$™ guard bed, experience with natural gas-fired turbine exhausts indicates the first stage of the $SCONO_x$™ experiences sulfur poisoning. This first stage needs to be washed with an acid wash solution more frequently than the rest of the bed and also needs replacement on a more frequent basis. Thus, the $SCOSO_x$™ guard bed is not entirely effective at removing sulfur and sulfur compounds from the exhaust stream. Any effects noticed using the extremely low-sulfur natural gas fuel are expected to be amplified when using the higher sulfur content syngas or distillate oil fuel.

For the purposes of providing a complete analysis of the $SCONO_x$™ process as an option for control, even with the overwhelming technical concerns, a cost-effective analysis of $SCONO_x$™ control technology is presented in Section 6.3, and is summarized in Table 3. As demonstrated in this analysis, the expected cost effectiveness for $SCONO_x$™ was determined to be $10,820 per ton of NO_x removed. This economic analysis includes the increased costs that would accrue due to downtime required for cleaning of fouled heat transfer equipment. This cost control is greater than those previously considered to be reasonable for BACT NO_x determinations.

6.3 COST-EFFECTIVENESS ANALYSIS

Economic analyses of the SCR and SCONO$_x$™ control technology alternatives were performed to compare the capital and annual costs in terms of the cost-effectiveness. The cost-effectiveness of a control technology is defined as the cost per ton of pollutant removed. As shown in Table 3, SCR is more cost-effective than SCONO$_x$™ (i.e., the cost per ton to control NO$_x$ is approximately two times higher for SCONO$_x$™). However, neither SCONO$_x$™ nor SCR are considered to be a cost effective alternative for controlling NO$_x$ at this installation. A discussion of the methodology used to perform the cost analysis follows in this section. Details of the costs associated with the SCR and SCONO$_x$™ systems are contained in Sections 6.3.1 and 6.3.2.

Table 3. BACT Analysis Summary of Cost-Effectiveness

	SCR Syngas Firing	SCR Oil Firing	SCONOx™ Syngas Firing	SCONOx™ Oil Firing
Baseline NO$_x$ (ppmvd)	25.0	42.0	25.0	42.0
Baseline NO$_x$ (lb/hr)	222.5	311.0	222.5	311.0
Baseline NO$_x$ (tpy)	877.1	136.2	877.1	136.2
Controlled NO$_x$ (ppmvd)*	3.5	5.9	2.0	3.4
Controlled NO$_x$ (lb/hr)	31.2	43.5	17.8	24.9
Controlled NO$_x$ (tpy)†	122.8	19.1	70.2	10.9
Emissions decrease (tpy)†	754.3	117.1	806.9	125.3
Unit 1 Total	701.68			
Emissions decrease (tpy)		871.4 818.78		932.2
Annualized cost ($)		$4,061,000		$10,086,500
Cost effectiveness ($/ton)		$4,660		$10,820

*SCR assumes an 86-percent control efficiency based on syngas firing inlet concentration of 25 ppm and outlet concentration of 3.5 ppm. This efficiency is assumed to apply to oil firing. The SCONOx™ assumes a 92-percent control efficiency based on syngas firing inlet concentration of 25 ppm and outlet concentration of 2 ppm. This efficiency is assumed to apply to oil firing.

†Annual emission estimates are based on maximum permitted heat input using oil firing for 876 hours per year (the permit limit) and 7884 hours per year on syngas.

Source: ECT, 2000.

Capital Costs

Capital costs include the initial cost of the components intrinsic to the complete control system, (e.g., SCR includes the catalyst bed, support frame, ammonia storage tanks, piping, rotating equipment, instrumentation, and monitoring equipment), and installation costs.

One additional initial capital cost associated with the SCR control option arises from the physical changes that are needed to accommodate the HRSG washing to remove anticipated ammonia sulfate deposits. These changes are required to allow for containment of the water used in washing which is estimated at approximately 20,000 gallons per occurrence. The changes involve installation of appropriate containment (i.e., both a sump and appropriate drainage system for the HRSG), pumps, and piping. Because the washing operation will be performed using scaffolding, appropriate brackets for the scaffolding will also need to be installed. The total capital cost for the HRSG modifications to allow for washing is estimated at $300,000, and is included in the capital costs for the SCR system.

Similar to the SCR control technology, the capital cost site upgrades to accommodate handling of wash water is also anticipated for the SCONO$_x$™ control technology due to the requirements for washing of the catalyst. Because the SCONO$_x$™ system is an ammonia free system, the difficulties with ammonia sulfate deposits and associated fouling are not anticipated. However, the SCONO$_x$™ control system is sensitive to the sulfur levels in the exhaust. Even with the low sulfur content of a natural gas fired combustion turbine exhaust stream, a SCONO$_x$™ guard bed is used to protect the SCONO$_x$™ main catalyst. Based on the higher sulfur content of the syngas CT exhaust, it is anticipated that similar semi-annual cleaning of the catalyst will be required.

Annual operating costs consist of the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, labor, raw materials, and utilities. Table 4 summarizes specific factors used in estimating the capital and annual operating costs. Additional cost assumptions, such as the costs for electricity and steam, are contained in Table 5.

Table 4. Capital and Annual Operating Cost Factors

Cost Item	Factor
Direct Capital Costs	
Sales tax	0.06 × control system cost
Freight	0.05 × control system cost
Instrumentation	0.10 × control system cost
Foundations and supports	0.08 × purchased equipment cost
Handling and erection	0.14 × purchased equipment cost
Electrical	0.04 × purchased equipment cost
Piping	0.02 × purchased equipment cost
Insulation	0.01 × purchased equipment cost
Painting	0.01 × purchased equipment cost
Indirect Capital Costs	
Engineering	0.10 × purchased equipment cost
Construction and field expenses	0.05 × purchased equipment cost
Contractor fees	0.10 × purchased equipment cost
Start-up	0.02 × purchased equipment cost
Performance testing	0.01 × purchased equipment cost
Contingencies	0.03 × purchased equipment cost
Direct Annual Operating Costs	
Supervisor labor	0.15 × total operator labor cost
Maintenance materials	1.00 × total maintenance labor cost
Indirect Annual Operating Costs	
Overhead	0.60 × total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 × total capital investment
Property taxes	0.01 × total capital investment
Insurance	0.01 × total capital investment

Sources: EPA, 1996.
ECT, 2000.

Table 5. Economic Cost Factors

Factor	Units	Value
Interest rate	%	7.0
Control system life	Years	10
SCR catalyst life	Years	5*
SCONOx^{TM} catalyst life	Cost assumes leasing arrangement	
Aqueous ammonia cost	$/ton	113
Natural gas cost†	$/ft^3	0.00388
Steam cost**	$/lb	0.006
Electricity cost	$/kWh	0.04
Labor costs (base rates)	$/hour	
Operator		22.00
Maintenance		22.00

*The vendor's control system performance guarantee is for 3 years of operation or 3.5 years after catalyst delivery, whichever occurs first.

†Natural gas is used in the SCONO$_x^{TM}$ system for regenerating the catalyst, and not for firing the combustion turbine. Cost estimate from DOE, 1999.[5]

**Cost estimate from DOE, 1999.[5]

Sources: TECO, 2000.
ECT, 2000.

The capital cost estimating technique used in this analysis is based on the factored method of determining direct and indirect installation costs. This technique is a modified version of the "Lang Method," whereby installation costs are expressed as a function of known equipment costs. This method is consistent with the latest U.S. EPA guidance manual (OAQPS Control Cost Manual) on estimating control technology costs (EPA, 1996)[6]. The estimation factors used to calculate total capital costs are shown in Table 4.

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for efficient operation of the device. These may include such items as reagent storage, supply piping, and distributed controls. Aux-

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[5] DOE, 1999. Cost Analysis of NO$_x$ Control Alternatives for Stationary Gas Turbines. U.S. Department of Energy. Environmental Programs, Chicago Operations Office, 9800 South Cass Avenue, Chicago, IL 60439. November 5, 1999.

[6] EPA, 1996. U.S. Environmental Protection Agency (EPA). 1996. OAQPS Control Cost Manual, 5th Edition. EPA-453/B-96-001. Research Triangle Park, NC.

iliary equipment costs are taken as a straight percentage of the basic equipment cost, the percentage being based on the average requirements of typical systems and their auxiliary equipment (EPA, 1996). In this analysis, the basic equipment costs were based on recent quotes (i.e., 11/16/00 for SCONO$_x$^{TM} and 11/25/00 for SCR) by qualified vendors for similar equipment (Appendix D). The costs were then scaled based on the differences in exhaust flowrate between the actual equipment and that for which the quote was prepared. In this case the cost estimates were based on the Siemens Westinghouse Model V84.3a2 with an exhaust flow rate of 3,515,508 lb/hr. The project unit, a General Electric 7FA, has an exhaust flow rate of 3,940,000 lb/hr. The resulting scaling factor of 1.12 was used to adjust the costs of the equipment and catalyst to the larger GE unit. Instrumentation, usually not included in the basic equipment cost, is estimated at 10 percent of the basic equipment cost.

Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection, piping, electrical, painting, and facilities.

Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Direct installation costs are expressed as a function of the purchased equipment cost based on the average installation requirements of typical systems.

Indirect installation costs are designated as a percentage of the total direct cost (purchased equipment cost plus the direct installation cost) of the system. Other indirect costs include equipment startup and performance testing, working capital, and interest during construction.

Annualized Costs

Annualized costs are comprised of direct and indirect operating costs. Direct costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Annualized cost factors used to estimate total annualized cost are listed in Table 4. Annualized cost factors were obtained from the current EPA manual on estimating control technology costs (EPA, 1996).

Direct operating labor costs vary according to the system operating mode and operating time. Labor supervision is estimated as 15 percent of operating labor. Maintenance costs are calculated as 3 percent of total direct cost (TDC). Replacement part costs, such as the cost to replace aged catalyst, have been included where appropriate. Because the SCONO$_x$™ catalyst is leased, an annual lease cost is used instead of a replacement cost. Raw material and utility costs are based upon estimated annual consumption. The presence of a catalyst bed would increase turbine back-pressure resulting in efficiency losses to the system. This is reflected in the economic analysis as the value of lost power output based on turbine vendor estimates. With low inlet emission rates (i.e., 25 ppmvd), the catalyst is assumed to require replacement every five years due to aging, which is at a longer interval than the vendor's catalyst lifetime guarantee of three years. This extension of the lifetime of the catalyst serves to reduce the annual costs associated with catalyst replacement, which is based on the cost of replacement catalyst as provided by the catalyst vendor.

With the exception of overhead, indirect operating costs are calculated as a percentage of the total capital cost. The indirect capital costs are based on the capital recovery factor (CRF), defined by the following equation:

$$CRF = i(1+i)^n / [(1+i)^n - 1]$$

Where "i" is the annual interest rate and "n" is the equipment economic life in years. A control systems economic life is typically 10 to 20 years (EPA, 1996). In this analysis, a 10-year equipment economic life was assumed. The average interest rate is assumed to be 7.0 percent (EPA, 1996), although TEC currently incurs greater interest costs for this type of capital equipment. The CRF is therefore conservatively calculated to be 0.14238; however, this value would likely be higher for this facility because of the higher interest rates that would be expected for TEC.

Cost Effectiveness

The cost-effectiveness of an available control technology is based on the annualized cost of the available control technology and its annual pollutant emission reduction. Cost-effectiveness is calculated by dividing the annualized cost of the available control technology by the theoretical mass (tons) of pollutant removed by that control technology each year. The basis for determining the percent reduction of a given technology was based on information contained in U. S. EPA literature and from vendors of the control equipment.

6.3.1 SELECTIVE CATALYTIC REDUCTION

An assessment of economic impacts was performed by comparing control costs between the existing baseline case of advanced combustor technology and baseline technology with the addition of SCR controls. In the base case, the uncontrolled, annual NO_x emission rate is 1,013.3 tons per year (tpy) based on CT baseload operation for 8,760 hr/yr at 59°F and assuming oil firing for 10-percent of the year. No provisions (i.e., emission reductions) are included for the 432 hours of anticipated outages, since no operational constraints are being requested. This approach is conservative, as it will tends to overestimate emissions reductions resulting in lesser cost effectiveness values. The SCR controlled annual NO_x emission rate, based on 3.5 ppmvd effluent concentration on syngas (i.e., 86-percent control efficiency), is 122.8 tpy. Baseline technology is expected to achieve a NO_x exhaust concentration of 25 ppmvd at 15-percent O_2. SCR technology was premised to achieve NO_x concentrations of 3.5 ppmvd at 15-percent O_2. Base case and controlled NO_x emission rates are summarized in Table 3.

Average cost effectiveness for the application of SCR technology was determined to be $4,660 per ton of NO_x removed. Based on recent Florida DEP BACT determinations, the control cost for SCR is not considered to be economically reasonable for this installation. Tables 6 and 7 summarize the results of the capital and annual operating costs associated with the SCR system.

Table 6. Capital Costs for SCR Catalyst System

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment*	2,047,900	A
Sales tax	122,900	0.06 × A
Instrumentation	204,800	0.10 × A
Freight	102,400	0.05 × A
HRSG Modification	300,000	
Subtotal Purchased Equipment	**2,778,000**	**B**
Installation		
Foundations and supports	222,200	0.08 × B
Handling and erection	388,900	0.14 × B
Electrical	111,100	0.04 × B
Piping	55,600	0.02 × B
Insulation for ductwork	27,800	0.01 × B
Painting	27,800	0.01 × B
Subtotal Installation Cost	**833,400**	
Subtotal Direct Costs	**3,611,400**	
Indirect Costs		
Engineering	277,800	0.10 × B
Construction and field expenses	138,900	0.05 × B
Contractor fees	277,800	0.10 × B
Startup	55,600	0.02 × B
Performance test	27,800	0.01 × B
Contingency	83,300	0.03 × B
Subtotal Indirect Costs	**861,200**	
TOTAL CAPITAL INVESTMENT	**4,472,600**	(TCI)

*Includes estimated $100,000 for ammonia storage tank.

Source: ECT, 2000.

Table 7. Annual Operating Costs for SCR Catalyst System

Item	Dollars	OAQPS Factor
Direct Costs		
Operator/supervisor Labor	13,800	
Maintenance Labor and Material	24,000	
Subtotal Labor and Maintenance Costs	**37,800**	C
Catalyst costs		
Replacement (materials, labor, disposal)	1,713,300	
Annualized Catalyst Costs	**417,900**	5 yr replacement
Aqueous ammonia costs	226,900	$113/ton
Electricity costs	62,800	NH_3 pump/vaporization
Scheduled Outages	60,000	labor and materials
Unscheduled Outages	1,934,400	labor, materials, and 6 days electrical loss
Energy Penalties		
Turbine backpressure-control system	363,000	0.54% penalty
Turbine backpressure-catalyst plugging	363,300	0.54% penalty
Subtotal Direct Costs	**3,466,400**	(TDC)
Indirect Costs		
Overhead	22,700	0.60 x C
Administrative charges	89,500	0.02 x TCI
Property taxes	44,700	0.01 x TCI
Insurance	44,700	0.01 x TCI
Capital recovery	414,800	10 yrs @ 7%
Subtotal Indirect Costs	**616,400**	
Emission fee credit	(21,800)	$25/ton
TOTAL ANNUAL COST	**4,061,000**	

Source: ECT, 2000.

The installation of SCR technology will cause an increase in back pressure on the CT due to the pressure drop across the catalyst bed. Additional energy would be needed for the pumping of aqueous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. A SCR control system for the CT is projected to have a pressure drop across the catalyst bed of approximately 2.7 inches of water. This pressure drop will result in a 0.54 percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 9,082,368 kilowatt hours (kwh) (30,990 MMBtu) per year at baseload (192 MW) operation for 8,760 hours per year. The lost power generation energy penalty, based on a power cost of $0.04/kwh, is $363,300 per year. This cost was included in the BACT analysis.

The fouling of the control equipment or the downstream equipment will also cause an increase in turbine backpressure. Thus, there are two energy penalties associated with each control technology. The first energy penalty is from the pressure drop across a clean configuration of the control system. The second energy penalty is from the pressure drop caused by fouling of the catalyst or the downstream exhaust equipment. It is assumed that the catalyst will be cleaned when the increased pressure drop from fouling is equal to twice the pressure drop associated with a clean system (i.e., when the total pressure drop is three times that of a clean system). For the SCR system, the nominal pressure drop is 2.7 inches of water. Thus, the catalyst will cleaned when the total pressure drop is at 8.1 inches of water. Because the catalyst condition will vary between clean and plugged, the increased pressure drop from fouling will approximately be equal to the nominal pressure drop. Hence, the annual costs associated with the pressure drop from plugging are estimated as the same costs as from the nominal pressure drop across the system.

The annual operating costs include costs for three outages per year. For the SCR system, these outages are for cleaning deposits in the HRSG and other portions of the exhaust system. The outages result from the high sulfur content of the exhaust gas. In preparing the cost estimates for this analysis, it is assumed that one of the two outages can coincide with a planned outage. However, the other outages would be unscheduled. This arrangement is appropriate as the combustion turbine has a designed availability of 95 percent.

There are two main costs that are associated with an outage. The first cost is the labor and materials costs that are associated with the cleaning activities. This cost is estimated by plant engineering staff as $60,000 per occurrence. This cost would apply to both scheduled and unscheduled outages.

The cost associated with unscheduled outages was also included in the analysis. It was estimated that two unscheduled outages per year, each lasting 6 days, would occur. This would result in lost energy production from the combined CT/HRSG system. At $20 per megawatt hour (the incremental cost of power generation), this outage would result in $151,200 per day for a total of $1,814,400 per year.

The incremental cost of power generation represents the differential cost to TEC of acquiring the power that would otherwise be generated by the Polk syngas fired turbine had a forced outage due to SCR failure not occurred. This differential cost is the cost of the replacement power less the cost of generating the power at the Polk facility. There are a variety of factors that contribute to the determination of the incremental cost, including the availability of other units in the TEC system, and the associated costs of generating additional electricity or the purchase of power from other sources comprising the power grid. Based on an internal review of historical and projected TEC generating capability and associated costs, including purchase from the power grid, if necessary, this incremental cost is estimated at $20 per megawatt hour.

If these costs were estimates as a lost factor, the total cost would be substantially higher, especially if an outage were to occur during peak demand periods. However, the costs are conservatively estimated as internal costs. These costs were assumed to be the same for both the SCR and SCONO$_x$™ systems.

6.3.2 SCONO$_X$™

The economic impact analysis for the SCONO$_x$™ system was conducted in the same manner as that described above for the SCR system. Assuming the same baseline conditions (i.e., 1,013.3 tpy emissions) the controlled annual NO$_x$ emission rate, based on 92-percent control efficiency for the SCONO$_x$™, is 81.1 tpy (70.2 tpy on syngas). Baseline technology is expected to achieve a NO$_x$ exhaust concentration of 25 ppmvd at 15-percent O$_2$. SCONO$_x$™ technology, which is generally higher performance than SCR, was premised to achieve NO$_x$ concentrations of 2.0 ppmvd at 15-percent O$_2$. The base case and controlled NO$_x$ emission rates are summarized in Table 3.

The specific capital and annual operating costs for the SCONO$_x$™ control system are contained in Tables 8 and 9. Average cost effectiveness for the application of SCONO$_x$™ technology to the CT was determined to be \$10,820 per ton of NO$_x$ removed. The control cost for SCONO$_x$™ is substantially higher than previously considered reasonable by the FDEP. One notable difference in the analysis for SCONO$_x$™ is that a catalyst maintenance agreement is assumed. Therefore, maintenance labor and catalyst replacement costs were replaced by a single \$2,800,000 annual cost. Because of the high purchase cost of the SCONO$_x$™ catalyst, this annual maintenance agreement is considered to be the more economical option. The same internal cost that was assumed in the SCR analysis for unscheduled outages to correct catalyst fouling was used for the SCONO$_x$™ analysis.

In addition to the annual maintenance costs, several other items are unique to the SCONO$_x$™ system. For instance, natural gas is used for hydrogen reforming in the process to regenerate the catalyst. A significant amount of steam is required as the carrier for the gas. The cost estimates for the natural gas, steam, and electricity to run the process was based on information contained in a recent Department of Energy (DOE) cost analysis study of NO$_x$ control alternatives (DOE,1999).

Table 8. Capital Costs for SCONO$_x$™ System

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	7,845,200	A
Sales tax	470,700	0.06 x A
Instrumentation	784,500	0.01 x A
Freight	392,300	0.05 x A
HRSG Modifications	300,000	
Subtotal Purchased Equipment	**9,792,700**	**B**
Installation		
Foundations and supports	783,400	0.08 x B
Handling and erection	1,371,000	0.14 x B
Electrical	391,700	0.04 x B
Piping	195,900	0.02 x B
Insulation for ductwork	97,900	0.01 x B
Painting	97,900	0.01 x B
Subtotal Installation Cost	**2,937,800**	
Subtotal Direct Costs	**12,730,500**	
Indirect Costs		
Engineering	979,300	0.10 x B
Construction and field expenses	489,600	0.05 x B
Contractor fees	479,300	0.10 x B
Startup	195,900	0.02 x B
Performance test	97,900	0.01 x B
Contingency	293,800	0.03 x B
Subtotal Indirect Costs	**3,035,800**	
TOTAL CAPITAL INVESTMENT	**15,766,300**	(TCI)

Source: ECT, 2000.

Table 9. Annual Operating Costs for SCONO$_x$™ System

Item	Dollars	OAQPS Factor
Direct Costs		
Operator/supervisor Labor	13,800	
Maintenance Labor and Material	0	Maintenance agreement
Subtotal Labor and Maintenance Costs	**13,800**	C
System Maintenance and Catalyst Replacement (materials, labor, and disposal)	2,801,900	Maintenance agreement
Natural gas costs (H_2 reforming)*	91,400	14 ft^3/hr per MW capacity
Electricity costs*	40,400	0.6 kW per MW capacity
Steam costs (H_2 carrier)*	938,500	93 lb/hr per MW capacity
Scheduled Outages	60,000	labor and materials
Unscheduled Outages	1,934,400	labor, materials, and 6 days electrical loss
Energy Penalties		
Turbine backpressure-control system	672,800	1.0 % penalty
Turbine backpressure-catalyst plugging	672,800	0.2 % penalty
Subtotal Direct Costs	**7,226,000**	(TDC)
Indirect Costs		
Overhead	8,300	0.60 x C
Administrative charges	315,300	0.02 x TCI
Property taxes	157,700	0.01 x TCI
Insurance	157,700	0.01 x TCI
Capital recovery	2,244,800	10 yrs @ 7%
Subtotal Indirect Costs	**2,883,800**	
Emission fee credit	(23,300)	$25/ton
TOTAL ANNUAL COST	**10,086,500**	

*DOE, 1999

Source: ECT, 2000.

The annual operating costs include costs for three outages per year. For the SCONO$_x$™ system, these outages are for the cleaning of the catalyst. The outages result from the high sulfur content of the exhaust gas. In preparing the cost estimates for this analysis, it is assumed that one of the two outages can coincide with a planned outage. However, the other outages would be unscheduled. This arrangement is appropriate as the combustion turbine has a designed availability of 95 percent.

There are two main costs that are associated with an outage. The first cost is the labor and materials costs that are associated with the cleaning activities. This cost is estimated by plant engineering staff as $60,000 per occurrence. This cost would apply to both scheduled and unscheduled outages.

The cost associated with unscheduled outages was also included in the analysis. It was estimated that two unscheduled outages per year, each lasting 6 days, would occur. This would result in lost energy production from the combined CT/HRSG system. At $20 per megawatt hour (the incremental cost of power generation), this outage would result in $151,200 per day for a total of $1,814,400 per year.

The incremental cost of power generation represents the differential cost to TEC of acquiring the power that would otherwise be generated by the Polk syngas fired turbine had a forced outage due to SCONO$_x$^{TM} failure not occurred. This differential cost is the cost of the replacement power less the cost of generating the power at the Polk facility. There are a variety of factors that contribute to the determination of the incremental cost, including the availability of other units in the TEC system, and the associated costs of generating additional electricity or the purchase of power from other sources comprising the power grid. Based on an internal review of historical and projected TEC generating capability and associated costs, including purchase from the power grid, if necessary, this incremental cost is estimated at $20 per megawatt hour.

If these costs were estimates as a lost revenue factor, the total cost would be substantially higher, especially if an outage were to occur during peak demand periods. However, the costs are conservatively estimated as internal costs. These costs were assumed to be the same for both the SCR and SCONO$_x$™ systems.

As with SCR, the installation of SCONO$_x$™ technology will also cause an increase in back pressure on the CT due to the pressure drop across the catalyst bed. A SCONO$_x$™ control system for the CT is projected to have a pressure drop across the catalyst bed of approximately 5.0 inches of water. This pressure drop will result in a 1.0 percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 16,819,200 kwh (57,389 MMBtu) per year at baseload (192 MW) operation for 8,760 hr/yr. The lost power generation energy penalty, based on a power cost of $0.04/kwh, is $672,768 per year.

The fouling of the control equipment or the downstream equipment will also cause an increase in turbine backpressure. Thus, there are two energy penalties associated with each control technology. The first energy penalty is from the pressure drop across a clean configuration of the control system. The second energy penalty is from the pressure drop caused by fouling of the catalyst or the downstream exhaust equipment. It is assumed that the catalyst will be cleaned when the increased pressure drop from fouling is equal to twice the pressure drop associated with a clean system (i.e., when the total pressure drop is three times that of a clean system). For the SCONOx™ system, the nominal pressure drop is 5 inches of water. Thus, the catalyst will cleaned when the total pressure drop is at 15 inches of water. Because the catalyst condition will vary between clean and plugged, the increased pressure drop from fouling will approximately be equal to the nominal pressure drop. Hence, the annual costs associated with the pressure drop from plugging are estimated as the same costs as from the nominal pressure drop across the system.

7.0 GOOD COMBUSTION PRACTICES

Since facility start-up, including during the NO_x emissions testing period, the facility has been operating the CT in a manner that allows for reliable, stable, and reasonably economic performance of the entire IGCC facility. The facility's engineering staff have worked to identify several opportunities for reducing NO_x emissions and, as appropriate, have implemented these procedures. However, as reinforced by the nearly consistent NO_x emissions test results during the testing period[7], additional opportunities do not exist for combustion practice improvements that do not involve major capital expenditures. These expenditures/improvements represent a retrofit to the existing equipment and, as discussed previously, are not considered further in this analysis.

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[7] Test of October 17, 2000, indicated increase NO_x emissions, which is attributed to higher heating value and adiabatic flame temperature of the fuel. This increase in NO_x emissions occurred even though diluent flow was increased during this testing

8.0 OTHER PLANT EXPERIENCE

One aspect of the required BACT analysis is to survey other similar facilities and their experience and abilities in achieving low-NO_x emissions rates. The term similar facilities is taken to mean large General Electric CTs of a comparable vintage and technology to what is installed at the Polk facility which are fueled by syngas produced in a gasification plant that is similar in efficiency and configuration to Polk. Based on our analysis, there is only one similar facility, the Cinergy/Global Energy Wabash River facility located in Indiana. The facility operates a 265-MW General Electric 7FA CT that combusts syngas created using Global Energy's E-Gas process, a two-stage entrained flow gasification system and is permitted with a NO_x emissions limit of 25 ppmvd. Fuel saturation and steam injection are used to suppress NO_x formation which is a departure from the configuration at Polk which uses nitrogen diluent. The Wabash River facility indicates that typical operations involve NO_x emissions rates ranging from 22 to 24 ppmvd at 15-percent oxygen. The NO_x emissions are maintained at less than the permitted emission rate by adjusting the steam injection rate[8].

There are several other IGCC plants containing syngas-fueled CTs, most of which were recently constructed. These facilities are different enough from Polk either in fuel plant configuration, in turbine manufacturer or vintage that they do not meet the definition of "similar facilities" as discussed in Section 3. Nevertheless, these IGCC facilities are included in this discussion because most have some relevant features. There are eight main facilities comprising this category that are discussed in this section.

The first facility that was somewhat similar to the Polk facility was the commercial-scale demonstration of a 120-MW power plant conducted adjacent to Southern California Edison's Cool Water Generating Station. This facility-fired syngas produced from low and high sulfur coals (approximately 0.35 and 3.1 weight percent sulfur) in a 65-MW CT. It operated between 1984 and 1989. Note that the CT is considerably smaller in capacity (a

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[8] Conversation between Mr. John McDaniel, Tampa Electric Company, and Wabash River facility turbine operator, November 7, 2000.

GE 7E) than the one located at the Polk facility (a GE 7F). Water saturation of the fuel was used to reduce NO_X emissions, which typically averaged 22 ppmvd at 15-percent oxygen for various coals tested during the demonstration period. Based on the considerable difference in the specific turbine used at the Cool Water facility and the Polk facility, this operation is not considered a similar facility. However, it is appropriate to note that the proposed emissions limit for the Polk facility is based on an average NO_X emissions rate observed during the demonstration phase that was less than the average NO_X emissions rates observed for the Cool Water demonstration project.

The next facility is the Star Enterprises Delaware facility that was permitted in March 1998. The facility was permitted under a LAER limit of 15 ppmvd at 15-percent oxygen for a GE model PG6101FA turbine (90-MW nominal) without operation of the associated duct burner and 16 ppmvd with the operation of the associated duct burner. The basis for the LAER determination was not under the federal NSR provisions, but instead under a Delaware program as Delaware uses the "dual source" definition of stationary source as opposed to the federal plant-wide definition. In the permit application, the applicant identified that the LAER limit of 15 ppm represented an advance in permitted level for NO_X emissions, as prior to this facility the most stringent emissions limit was the 25-ppm limit that is in place for the Polk facility.

In the permit application document, Star Enterprises identifies the reason that an emissions level less than 25 ppmvd may be achievable:

> "However, because of more recent advances in diluent and fuel rate control and combustor design, lower levels (below 20 ppmvd) may be possible."

This turbine incorporates an incremental advance in emissions control technology in the combustor design, and is considered one generation of development ahead of the turbine installed at the Polk facility. An essential element of this design improvement is a relatively larger air separation plant than at Polk to provide additional diluent to the combustion turbine. The combustor modification would be of no value for NO_X reduction without the availability of additional diluent. This facility gasifies petroleum coke in Texaco quench gasifiers to produce the syngas fuel, and the syngas composition is expected to be similar to Polk's.

To locate other coal gasification CTs, the analysis expands to facilities located abroad. Note that these facilities are subject to a different set of environmental regulations than the Polk facility. However, they are used for reference when analyzing performance of somewhat similar facilities. There are two facilities in this category. The Demkolec plant located at Buggenum in the Netherlands, and the Elcogas facility funded by the EEC at Puertollano in Spain. Buggenum employs the Shell coal gasification technology and has operated primarily on various coal feedstocks but is currently blending in some waste materials. Puertollano has a very similar gasification technology, the Prenflo process, gasifying a 50/50 blend of local coal and petroleum coke. Buggenum uses a Siemens V94.2 combustion turbine (250 MW) while Puertollano uses the more advanced Siemens V94.3 (300 MW). Both use a combination of syngas saturation and nitrogen injection for NO_x control. Puertollano's permitted NO_x emissions are 150 milligrams per normal cubic meter (mg/Nm^3) at 6 percent O_2 (approximately 29 ppmvd at 15 percent O_2). The facility has reported that they are able to operate within their permit limits. Buggenum has reported that they typically operate at less than 10 ppmvd NO_x but graphical data presented at the 1998 Gasification Technology Conference shows many points up to 20 ppmvd.

There are also four recently constructed IGCC plants which produce syngas from heavy oil gasification. These four facilities, all are located in Europe, are discussed following:

- API (Falconara, Italy).
- Sarlux/Enron (Italy).
- ISAB (Priolo, Italy).
- Shell (Pernis Refinery, Netherlands).

API uses an ABB type 13E2 CT, with nitrogen diluent for syngas-fired NO_x emissions control and water injection for diesel oil-fired NO_x emissions control. API is also equipped with an SCR. The SCR may approach technical feasibility at this facility since API utilizes a more expensive deeper sulfur removal system, resulting in a fuel gas containing approximately 80 percent less sulfur than Polk's syngas fuel. The permitted NO_x emissions limits are 17 ppmvd for syngas and 42 ppmvd for oil firing. The current operational experience indicates NO_x emissions of 20 to 30 ppmvd for diesel firing and 15 to 20 ppmvd for syngas firing; however, the data collected for syngas firing are only at 66 percent of full load. Thus, it may be inferred that the facility is having some difficulty in achieving the 17-ppmvd emissions limit for syngas firing. One possible explanation for this difficulty is that, according to our information, the SCR system has not been operated, at least in part due to Greenpeace objections to the NH_3 emissions associated with SCR.

The total nominal power output rating of the Sarlux/Enron facility is 550 MW. Three GE Model 109E CTs are operated in combined-cycle mode. Each turbine is rated at 123 MW on natural gas firing and 138 MW on syngas. The facility started full operation on syngas in August 2000. The NO_x emissions limit for the facility is 60 milligrams per normal cubic meter (mg/Nm^3) at 15-percent oxygen. This limit is comparable to 30 ppmvd at 15-percent oxygen. The facility uses a high moisture fuel feed (approximately 42 percent) as the primary NO_x control mechanism. Preliminary performance information from the facility indicates this emissions limit is being met.

The ISAB facility uses two Siemens/Ansaldo V94.2K combustion turbines in combined cycle mode for a total output of 512 MW. Like Sarlux, they use syngas saturation for NO_x control, and like API, ISAB is also equipped with SCR. The permitted NO_x emissions limit is 18 ppmv and the reported operation is in the 10 to 15 ppmvd range.

Shell Pernis produces syngas that is used to supplement natural gas fuel to 2 GE MS6451B combustion turbines. This plant also is equipped with duct firing. It is reported to control NOx emissions to less than 30 ppmvd (15 percent O_2) using steam injection. This configuration is so different from Polk's that the associated NO_x experience is the least relevant of all facilities discussed in this section.

As discussed earlier in this section, these additional facilities were examined in the spirit of providing the agency with a comprehensive review of other IGCC plant operating experience. However, due to differences in turbine make, model, and vintage, fuels gasified, NOx control, and methods of operation, none of these additional facilities can be considered similar for the purposes of this review.

9.0 MANUFACTURER'S RESEARCH

GE is considering several advances in syngas fired CT design to potentially allow new model 7FA CTs to attempt to achieve 9- to 15-ppmvd NO_x emissions rates in a new and clean configuration. This range is the lower anticipated limit of NO_x performance, which incorporates both recent modifications to IGCC plant designs (i.e., greater quantity of diluent supply) along with larger combustors as described following this section. This anticipated performance is comparable to the performance that can be achieved using natural gas as a fuel. However, the advances in technology proposed to achieve this reduced emission operation are not readily adapted to the current Polk IGCC configuration without major capital expenditures (i.e., on the order of several million dollars) and successful development and application of an unproven design concept.

These changes in NO_x emissions rates will be achieved through years of development work and essentially two major generations of equipment changes. In general, it is not a simple matter to implement these changes to the equipment at Polk.

These planned advances in CT emissions performance arise from two main areas, combustor redesign to accommodate additional diluent flow and fuel plant modifications to provide the additional diluent. The Polk facility CT has a 14-inch diameter and 22-inch-long combustor, and the latest turbine design has a larger diameter and longer combustor. This increase in combustor size allows for reduced NO_x emissions by providing adequate residence time and mixing for the additional diluent. This possible combustion modification is not currently commercially available for a GE 7FA turbine. If this type of modification were to be implemented, this change would involve considerable modifications to the associated piping and physical configuration, which would involve considerable turbine downtime and substantial capital expenditures. Another concern is that this possible modification would require additional diluent to achieve any of the emissions reductions, as described in the following.

The second main area involved in the reduced emissions is the supply of additional diluent. The Polk facility uses nitrogen as a diluent. The facility is designed such that the diluent is supplied by the cryogenic air separation plant at the facility. As air is cooled, nitrogen condenses before oxygen does. The nitrogen is used as the diluent, and the oxygen is used as part of the gasification process. As part of the design of the Polk facility, the supply and demand for nitrogen diluent and oxygen supply for the gasification process were balanced. Thus, it is not a simple matter to add more diluent to the CT without affecting the relationship between the related processes. The facility is currently using the maximum amount of nitrogen diluent that is available in a stable, reliable supply, while maintaining consistent power output. Short of making major modifications to the facility or the processing parameters for essentially the entire facility, there is not an opportunity to create additional diluent for the CT.

Additionally, the Polk IGCC facility test results were reviewed with several combustion and environmental experts of GE's Power Systems Division. This review was held at the conclusion of the demonstration period and involved meetings and discussions between TEC and GE staff. Based on this review, GE has reiterated their support for a 25-ppm NO_x emissions limit for the PPS facility. This support is included in Appendix A of this submittal.

APPENDIX A

LETTER FROM GE REGARDING ANTICIPATED PERFORMANCE FOR THE PPS FACILITY TURBINE

GE Power Systems

Douglas M. Todd
Manager – Process Power Plants

General Electric Company
1 River Road, Bldg. 2 - Room 720
Schenectady, NY 12345
518 385-3791 Fax 518 385-2590

November 7, 2000

Mr. Shannon K. Todd
Tampa Electric Co.
PO Box 111
Tampa, Florida 33601-0111

Dear Mr. Todd:

GE is pleased to support Tampa Electric in the effort to complete the BACT determination for the 107FA IGCC at Polk Power Station. We have reviewed in detail your submittal to the Florida Department of Environmental Protection and concur with the conclusions.

In 1995, GE developed special technology for IGCC combustors which was based on standard size 7FA diffusion combustors modified for specific quantities of diluent waste Nitrogen available from the Texaco gasification process. The goal was to lower NOx emissions from coal fired power plants below 25 ppmvd at 15 % oxygen without using extensive amounts of diluent water. As demonstrated by some of the test results, this effort was successful. However, due to fluctuations in ambient conditions, process parameters, and fuel characteristics, NOx emissions can vary greatly as seen in the wide range of measured results.

Since 1995, GE has continued with extensive combustion development in cooperation with gasification suppliers to lower NOx emissions further as shown in your report. The current state of the art requires additional diluent injection and larger size combustors to accommodate the added diluent.

Because we understand that there is no additional diluent available from the gasification process at Polk and SCR is not suitable for the sulfur levels of the syngas, we concur that 25 ppmvd NOx at 15% oxygen is a limit with which Tampa Electric Company can reasonably assure compliance at all times.

Douglas M Todd

Douglas M. Todd

E-mail douglas.todd@ps.ge.com

APPENDIX B

EMISSIONS TEST DATA, DETAILED SUMMARY AND STATISTICAL MEASURES

TECO Polk Power Station
NOx Emissions Test Data Summary

Test Date	**NO_x Emission Factor (ppmdv) - average**	**Load (MW)**	test 1	test 2	test 3
October 14, 1999	16.7	191	16.7	16.7	16.7
December 7, 1999	14.6	190	14.6	15.1	14.0
February 7, 2000	19.0	192	19.0	19.2	18.8
April 17, 2000	17.0	191	17.4	17.0	16.6
June 14, 2000	18.1	190	18.2	18.2	18.1
August 15, 2000	16.6	192	16.7	16.7	16.5
October 17, 2000	22.5	192	22.5	22.5	22.5
Average	17.80	191.14			
Median	17.00	191			
Range	8.50	2			
Median plus 1/2 range	21.25	192			
Std. Dev.	2.38	0.90			
Average + 2 sigma	22.55	N/A			
Average + 3 sigma	24.93	N/A			
Average + 6 sigma	32.06	N/A			
number of one hour tests	21				

Note: N/A = not an appropriate statistical measure for load, maximum load is established as 192 MW.

APPENDIX C

VENDOR INFORMATION FOR SCONO$_X$ SYSTEM

INTRODUCTION

ABB Alstom Power Environmental Systems (AAP) has licensed the SCONOx™ technology from Goal Line Environmental Technologies for NOx abatement on combined cycle gas turbines. Goal Line is involved in catalytic research and development, and has developed processes for the control of CO, VOC, NOx, and SOx emissions from combustion processes such as turbines, boilers and engines.

The SCONOx™ system is a breakthrough in control technology that greatly reduces NOx, CO and non-methane VOC emissions from exhaust streams without the use of ammonia. The system does not produce by-products that can coat boiler tubes, causing performance loss and corrosion. SCONOx™ also has the capacity to reduce emissions to lower levels as regulations change by simply adding more catalyst.

This ultra-clean technology is ideal for retrofit projects because of its wide operating temperature range (300°F to 700°F). This wide range offers maximum flexibility in unit location and allows for installation downstream of the HRSG. Retrofit installations do not require boiler splitting and installation can be accomplished in much less time as a result.

Because the inputs that are needed to run SCONOx™ (natural gas, water, steam, electricity, and ambient air) are already present at most power plants, the logistics of plant operation do not change when the system is installed.

Section 1

Process Details and Control

The SCONOx™ system is a breakthrough in pollution control technology that utilizes a single catalyst for the reduction of CO and NOx. The system uses no ammonia, and can operate effectively at temperatures ranging from 300°F to 700°F; making it well suited to both new and retrofit applications. Because the inputs that are needed to run SCONOx™ (natural gas, water, steam, and electricity) are already present at most power plants, the logistics of plant operation do not change when the system is installed.

Oxidation/Absorption Cycle

The SCONOx™ catalyst works by simultaneously oxidizing CO to CO_2, NO to NO_2, and then absorbing NO_2 onto its surface through the use of a potassium carbonate absorber coating. These reactions are shown below, and are referred to as the "Oxidation/Absorption Cycle".

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2$$
$$NO + \tfrac{1}{2}O_2 \rightarrow NO_2$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3$$

The CO_2 in the above reactions exhausts up the stack. Note that during this cycle, the potassium carbonate coating reacts to form potassium nitrites and nitrates, which are then present on the surface of the catalyst. This reaction can be compared to a sponge absorbing water--just as a sponge absorbs water and must be wrung out periodically, the SCONOx™ catalyst must be regenerated to maintain maximum NOx absorption. The carbonate absorber coating on the surface of the catalyst absorbs nitrogen compounds, and the catalyst must enter the regeneration cycle.

Regeneration Cycle

The regeneration of the SCONOx™ catalyst, one of the features that makes the system so unique, is accomplished by passing a controlled mixture of regeneration gases across the surface of the catalyst in the absence of oxygen. The regeneration gases react with nitrites and nitrates to form water and elemental nitrogen. Carbon dioxide in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation/absorption cycle began. This cycle is referred to as the "Regeneration Cycle", and the relevant reaction is shown below.

$$KNO_2 + KNO_3 + 4H_2 + CO_2 \rightarrow K_2CO_3 + 4H_2O + N_2$$

Water (as steam) and elemental nitrogen are exhausted up the stack instead of NOx, and potassium carbonate is once again present on the surface of the catalyst, allowing the oxidation/absorption cycle to begin again. There is no net gain or net loss of potassium carbonate after both the oxidation/absorption cycle and the regeneration cycle have been completed; the process operates as a true catalyst.

Because the regeneration cycle must take place in an oxygen free environment, a section of catalyst undergoing regeneration must be isolated from exhaust gases. This is accomplished using a set of louvers, one upstream of the section being regenerated and one downstream. During the regeneration cycle, these louvers close and a valve opens, allowing regeneration gas into the section. Tadpole seals on the isolation louvers provide a durable and effective barrier against leaks during operation. At any given time four of five of these sections are in the oxidation/absorption cycle and one of five are in the regeneration cycle. Because the same number of rows is always in the regeneration cycle, the production of regeneration gas always proceeds at a constant rate. A regeneration cycle typically is set to last for three to seven minutes, so each section is in the oxidation/absorption cycle for twelve to twenty eight minutes.

Regeneration Gas Production

The technology for producing a regeneration gas containing a dilute concentration of hydrogen from natural gas is well developed, and there are numerous reactions by which this can be accomplished. For installations below 450°F the SCONOx™ system uses an inert gas generator for the production of hydrogen and carbon dioxide. The regeneration gas will be diluted to under 4% hydrogen using steam as a carrier gas; the typical system is designed for 2% hydrogen. The appropriate reaction for producing regeneration gas is listed below.

$$CH_4 + \tfrac{1}{2}O_2 + H_2O \rightarrow CO_2 + 3H_2$$

For installations with operating temperatures greater than 450°F, the catalyst can be regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the SCONOx™ catalyst. The reforming catalyst intiates the conversion of methane to hydrogen, and the conversion is completed over the SCONOx catalyst.

The Reformer Catalyst works to partially reform the methane regeneration gas to hydrogen (2% by volume) to be used in the regeneration of the SCONOx™ and SCOSOx™ catalysts. The reformer converts methane to hydrogen by the steam reforming reaction shown in the equation below.

$$CH_4 + 2H_2O \rightarrow 4H_2 + CO_2$$

The Reformer Catalyst is placed upstream of the SCONOx™ catalyst in a Steam Reformer Reactor. The catalyst is designed for a minimum 50% conversion of methane to hydrogen.

A gradual decrease in temperature is indicative of sulfur masking. To impede the rate of catalyst masking a Sulfur Filter is recommended. The Sulfur Filter is placed in the inlet natural gas feed prior to the regeneration production skid. The Sulfur Filter consists of impregnated granular activated carbon that is housed in a stainless steel vessel. Spent media is discarded as a non-hazardous waste.

SCOSOx™ Sulfur Removal Catalyst

The SCOSOx™ Sulfur Removal Catalyst works in conjunction with the SCONOx™ system and removes sulfur compounds from the exhaust stream. The SCOSOx™ Sulfur Removal Catalyst utilizes the same oxidation/absorption cycle and a regeneration cycle as the SCONOx™ system. However, SCOSOx™ selectively removes the sulfur from the exhaust stream. Chemical reactions for the SCOSOx™ system oxidation/absorption cycle are shown below.

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2$$
$$SO_2 + \tfrac{1}{2}O_2 \rightarrow SO_3$$

$$SO_3 + \text{SORBER} \rightarrow [SO_3 + \text{SORBER}]$$

For the SCOSOx™ process below 500°F, the reaction for the regeneration cycle is also similar to that of the SCONOx™ catalyst:

$$[SO_3 + \text{SORBER}] + 4H_2 \rightarrow H_2S + 3H_2O + [\text{SORBER}]$$

For the SCOSOx™ process above 500°F, the reaction for the regeneration cycle follows another similar path:

$$[SO_3 + \text{SORBER}] + H_2 \rightarrow SO_2 + H_2O + [\text{SORBER}]$$

Note that the regeneration gas used for the both types of catalyst (SCONOx™ and SCOSOx™ is the same (hydrogen), allowing them to be regenerated simultaneously. The SCOSOx™ catalyst is placed upstream of the SCONOx™ catalyst, and enhances the efficiency of NOx absorption as well as removing sulfur compounds.

SCONOx™ Control System

A Programmable Logic Controller (PLC) controls the SCONOx™ system. This controller is programmed to control all essential SCONOx™ functions, including the opening and closing of louver doors and regeneration gas inlet and outlet valves, and the maintaining of regeneration gas flow to achieve positive pressure in each section during the regeneration cycle.

A control program run on a PC, supervises the system. The control program monitors, records, and reports system performance. It sends notifications and warnings when appropriate, and it allows the user to control the system by changing set points, such as pressures, regeneration cycle times, and flows. The PLC can, however, operate independently of the control program--a PC crash or loss of power will not interrupt the operation of the system.

Section 2

Project Scope

The AAP Environmental Systems Scope of Supply for execution of the Project will include services and equipment as described below. In general, the Scope of Supply can be defined by the following categories:

Process Design, Engineering and Design of the System
Project Management and Project Services
SCONOx™ and SCOSOx™ Catalyst
Catalyst Rack and Reactor Housing
Inlet and Outlet Transitions including Expansion Joints
Catalyst Module Inlet and Outlet Dampers
Regeneration Gas Production and Distribution
Regeneration Gas Condensing and Scrubbing System (Optional)
Catalyst Removal System
Control System (PLC)

Equipment and Services Provided by Others

All required permits (air, site, construction, etc.)
Supply of 480 volt power to the SCONOx system
Supply of natural gas for the SCONOx system
Supply of cooling water for the SCONOx system
Supply of 600 degree steam for the SCONOx system
Supply of compressed air for the SCONOx system
Supply of Continuous Emission Monitoring System
Mechanical Installation of the System
Electrical Installation of the System

Section 3

Equipment List

SCONOx™ Reactor Assembly

The installation will have a SCONOx™ reactor assembly that will be constructed of sub-assembled modules to form the complete assembly.

Each section will have a set of dampers, front and back, to be closed when the section is in regeneration mode. Dampers will have tadpole seals to help isolate the section during regeneration. Each section will have one inlet regeneration gas valve and two outlet regeneration gas valves, which will open sequentially when the section is in regeneration mode. Two sections will be in the regeneration cycle at any given time.

Regeneration Gas Mixing Assembly

The Regeneration Gas Mixing Assembly will contain all pressure reducing valves, flow meters, and other equipment necessary to ensure the correct ratios of inert gas and steam that are introduced into the SCONOx™ catalyst.

Regeneration Gas Distribution Piping and Valves

The regeneration gas is piped to the reformer catalyst and then to the reactor via a main header and distributed to each of the ten sections of catalyst. Each catalyst section has one inlet regeneration gas valve and two outlet regeneration gas valves at the gas entrance side of the catalyst section.

SCONOx™ Catalyst

The SCONOx™ catalyst is a proprietary catalyst manufactured by Goal Line, which simultaneously oxidizes and absorbs CO and NOx through the use of a potassium carbonate absorber coating.

SCOSOx™ Catalyst

The SCOSOx™ catalyst is very similar to the SCONOx™ catalyst, and is also manufactured only by Goal Line. The SCOSOx™ catalyst favors the absorption of sulfur compounds instead of NOx, and works to enhance the efficiency of the SCONOx™ process in the removal of NOx. SCOSOx™ catalyst blocks have the same cross-sectional dimensions as SCONOx™ blocks, but will not be as deep.

Catalyst Removal System

The catalyst is removed and replaced using a service platform, which is raised and lowered to any one of the catalyst shelves. A mechanical winch is used to pull the catalyst in and out of the selected shelf.

Control System

A programmable logic controller (PLC) runs the control system with inputs made from a PC. The PLC controls all aspects of operation for the SCONOx system. The control system is shipped pre-wired and factory tested to the extent possible. All interconnecting wiring between the control panel and the field instruments is by others.

APPENDIX D

VENDOR QUOTES FOR COMPARABLE CONTROL EQUIPMENT

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

DATE:	**October 25, 2000**	**NO. PAGES**	**3**
TO:	**ECT** **ATTN: John Shrock** **ENGELHARD** **ATTN: Nancy Ellison**	**via e-mail**	
FROM:	**Fred Booth**	**Ph 410-569-0297 // FAX 410-569-1841**	

RE: **ECT 000610-0200**
Camet® CO and NOxCAT™ VNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00990

We provide Engelhard Budgetary Proposal EPB00990 for Engelhard **Camet®** CO and **NOxCAT™ VNX™** vanadia-titania SCR Catalyst systems per your e-mail request of October 23, 2000.

Our Proposal is based on:

- CO Catalyst for 80% CO reduction;
- SCR Catalyst for NOx reduction from given inlet levels to 3.5 ppmvd @ 15% O_2 with ammonia slip of 5 ppmvd @ 15% O_2 ; We note your request for design with ammonia slip of 9 ppmvd @ 15% O_2. There will be only minor changes to data herein.
- Assumed HRSG inside liner dimensions of 67 ft. H x 26 ft. W;
- Assumed 19% aqueous ammonia to ammonia skid;
- Scope as noted: Typical to HRSG supplier

We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A Booth

Frederick A. Booth
Senior Sales Engineer

4

ENGELHARD CORPORATION
CAMET® CO CATALYST SYSTEM
NOxCAT™ VNX™ SCR NOx ABATEMENT CATALYST SYSTEM

Engelhard Corporation ("Engelhard") offers to supply to Buyer the **Camet®** metal substrate CO System and **NOxCAT™ VNX™** ceramic substrate SCR systems summarized per the technical data and site conditions provided.

Scope of Supply: The equipment supplied is installed by others in accordance with Engelhard design and installation instructions.

Engelhard **Camet®** CO and **NOxCAT™ VNX™** SCR catalyst in modules;
Internal support frames for catalyst modules - installed inside internally insulated casing (casing by others);
Ammonia Delivery System Components: Aqueous (19% Sol.) Ammonia to skid

- Ammonia Injection Grid (AIG);
- AIG manifold with flow control valves ;
- NH_3/Air dilution skid: Pre-piped & wired (including all valves and fittings)
    - Two (2) dilution air fans, one for back-up purposes
    - Panel mounted system controls for:
        - Blowers (on/off/flow indicators)
        - Air/ammonia flow indicator and controller
        - System pressure indicators
        - Main power disconnect switch

BUDGET PRICES: **Per Turbine** **See Performance data**

Excluded from Scope of Supply:

Ammonia storage and pumping
Any transitions to and from reactor
Electrical grounding equipment
Foundations
All other items not specifically listed in Scope of Supply
Internally insulated reactor Housing (HRSG Casing)
Any interconnecting field piping or wiring
Utilities
All Monitors

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	Three (3) Years of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life.
Expected Life	5 - 7 years

CO / SCR SYSTEM DESIGN BASIS:

Gas Flow from:	Combustion Turbine + Duct Burner
Gas Flow:	Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data - Designed for Gas Velocities within ±15% at the reactor inlet
Temperature (At catalyst face):	Designed for Gas Temperature with maximum range ±20°F at the reactor inlet
CO Inlet (At catalyst face):	See Performance Data
CO Reduction	80% Reduction
NOx Inlet (At catalyst face):	See Performance Data
NOx Reduction :	To 3.5 ppmvd @ 15% O_2 (NG)
NH_3 Slip:	5 ppmvd @ 15%O_2
HRSG Cross Section	67 ft. H x 26 ft. W

Performance Data and Budget Pricing

GIVEN / CALCULATED DATA	100% - FIRED	100% - UNFIRED	75% - UNFIRED	65% - UNFIRED
TURBINE EXHAUST FLOW, lb/hr	3,515,500	3,484,300	2,886,000	2,628,300
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	74.43	74.52	74.64	74.72
O2	12.46	12.75	13.15	13.36
CO2	3.82	3.69	3.51	3.41
H2O	8.42	8.17	7.82	7.63
Ar	0.87	0.87	0.88	0.88
GIVEN: TURBINE CO, ppmvd @ 15% O2	10	10	10	10
CALC.: TURBINE CO, lb/hr	39.3	37.5	29.5	26.1
GIVEN: TURBINE NOx, ppmvd @ 15% O2	35	35	35	35
CALC.: TURBINE NOx, lb/hr	225.7	215.7	169.4	149.9
BURNER INPUT, MMBtuh	95	0	0	0
BURNER CO ADDED, lb/MMBtuh	0.09	0.09	0.09	0.09
BURNER CO ADDED, lb/hr	8.2	0.0	0.0	0.0
BURNER NOx ADDED, lb/MMBtuh	0.08	0.08	0.08	0.08
BURNER NOx ADDED, lb/hr	7.6	0.0	0.0	0.0
TOTAL GAS FLOW AFTER BURNER, lb/hr	3,520,052	3,484,300	2,886,000	2,628,300
GAS ANALYSIS AFTER BURNER, % VOL. N2	74.26	74.52	74.64	74.72
O2	11.98	12.75	13.15	13.36
CO2	4.04	3.69	3.51	3.41
H2O	8.85	8.17	7.82	7.63
Ar	0.87	0.87	0.88	0.88
CALC. GAS MOL. WT. AFTER BURNER	28.36	28.40	28.43	28.44
TOTAL CO AFTER BURNER, lb/hr	47.5	37.5	29.5	26.1
TOTAL CO AFTER BURNER, ppmvd @ 15% O2	11.4	10.0	10.0	10.0
TOTAL NOx AFTER BURNER, lb/hr	233.3	215.7	169.4	149.9
TOTAL NOx AFTER BURNER, ppmvd @ 15% O2	34.1	35.0	35.0	35.0
FLUE GAS TEMP. @ CO and SCR CATALYST, F (+/-20)	650	650	650	650
DESIGN REQUIREMENTS				
CO CATALYST CO OUT, ppmvd @ 15% O2	3.0	3.0	3.0	3.0
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	3.5	3.5	3.5
NH3 SLIP, ppmvd @ 15% O2	5	5	5	5
GUARANTEED PERFORMANCE DATA				
CO CATALYST CO CONVERSION, % - Min.	80.0%	80.0%	80.0%	80.0%
CO OUT, lb/hr - Max.	9.5	7.5	5.9	5.2
CO OUT, ppmvd @ 15% O2 - Max.	2.3	2.0	2.0	2.0
CO PRESSURE DROP, "WG - Max.	0.6	0.6	0.5	0.4
SCR CATALYST NOx CONVERSION, % - Min.	89.7%	90.0%	90.0%	90.0%
NOx OUT, lb/hr - Max.	24.0	21.6	16.9	15.0
NOx OUT, ppmvd @ 15% O2 - Max.	3.5	3.5	3.5	3.5
EXPECTED AQUEOUS NH3 (19% SOL.) FLOW, lb/hr	458.4	437.4	343.7	304.1
NH3 SLIP, ppmvd @ 15% O2 - Max.	5	5	5	5
SCR PRESSURE DROP, "WG - Max.	2.7	2.7	2.1	1.9

CO SYSTEM	**$585,000**
REPLACEMENT CO CATALYST MODULES	**$483,000**
SCR SYSTEM	**$1,738,000**
REPLACEMENT SCR CATALYST MODULES	**$1,250,000**

Dear Mr. Shrock,

Please note the following in response to your inquiry of last week, requesting budget pricing for two SCONOx systems on S-W V84.3a2 CCGTs. Pricing provided is on a per unit basis.

The specified temperature range was 300 to 700 degrees F. We have assumed an operating temperature of 600 degrees F, consistent with typical SCR operating temperatures. Should the temperature be significantly lower than 600 F, additional catalyst may be required.

The NOx emission reduction from 35 to 2 ppm is more than the typical application with 25 ppm or less NOx emissions. This reduction efficiency requirement of 95% results in additional catalyst, and this is reflected in the cost.

The SCONOx system will reduce CO emissions by 90%, so the system will exceed the specified CO reduction requirement, at no additional cost.

Leasing of the catalyst utilized in the SCONOx system is our preferred commercial framework, as this reduces the initial cost and provides our customers with a long-term commitment by ALSTOM Power for the performance of the SCONOx system. In this arrangement, the physical and mechanical equipment only is sold, and the required catalyst is leased on a long term basis, complete with catalyst and equipment maintenance.

Budgetary numbers for the leasing program include $7 million dollars for the initial equipment, with a annual lease cost of $2.5 million dollars. These numbers are budgetary only and are subject to change pending resolution of technical, scope, and commercial terms.

The budgetary price for the supply of the complete system, in accordance with the information provided, including catalyst, based on the prevailing price of platinum, is $20 million dollars.

I trust this meets with your immediate needs, but please call me if you have any questions.

Sincerely,

Rick Oegema
Product Manager

(Embedded image moved to file: pic22424.pcx)	jshrock@ectinc.com 10/16/2000 09:45 AM

Please respond to jshrock@ectinc.com

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Laura Crouch
Manager, Air Programs -
Environmental Affairs
Tampa Electric Company
P. O. Box 111
Tampa, FL 33601

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 3048

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* J. Spa

B. Date of Delivery

C. Signature
X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

DOWNTOWN STA TAMPA FL
DEC 31 2001

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

Ms. Laura Crouch AL USE

7000 2870 0000 7028 3048

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	**$**

Postmark Here
12/21/01

Sent To
Tampa Electric Co.
Street, Apt. No.; or PO Box No.
P.O. Box 111
City, State, ZIP+4
Tampa, FL 33601

PS Form 3800, May 2000 **See Reverse for Instructions**

SENDER: ***COMPLETE THIS SECTION***

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Laura R. Crouch
Manager, Air Programs - Environmental Affairs
Tampa Electric Company
PO Box 111
Tampa, FL 33601

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 3000

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* J. Soo

B. Date of Delivery

C. Signature
X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☒ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

DOWNTOWN STATION TAMPA FL 33601 USPS
DEC 19 2001

DOWNTOWN STATION TAMPA FL 3360
DEC 19 2001

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

7000 2870 0000 7028 3000

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Sent To Laura R. Crouch

Street, Apt. No.; or PO Box No. PO Box 111

City, State, ZIP+ 4 Tampa, FL 33601

PS Form 3800, May 2000 **See Reverse for Instructions**

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Mark J. Hornick
General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

MAY 17 2001

B. Date of Delivery

C. Signature

X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1453 1934

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7099 3400 0000 1453 1934

Article Sent To:

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark
Here

Mr. Mark J. Hornick
General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

See Reverse for Instructions

Is your **RETURN ADDRESS** completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3\. Article Addressed to:

Mr. Mark J. Hornick
General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

4a. Article Number
7099 3400 0000 1453 3310

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7\. Date of Delivery
12/8/00

5\. Received By: *(Print Name)*

6\. Signature: *(Addressee or Agent)*
X

8\. Addressee's Address *(Only if requested and fee is paid)*

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7099 3400 0000 1453 3310

Article Sent To:

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark Here

To

Mr. Mark J. Hornick
General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

Name

Street

City

PS Form 3800, July 1999 See Reverse for Instructions

TAMPA ELECTRIC COMPANY
POLK POWER STATION
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

Prepared for:

TECO
TAMPA ELECTRIC
Tampa, Florida

Prepared by:

ECT

Environmental Consulting & Technology, Inc.
3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 000656-0100

November 2000

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1.0 EXECUTIVE SUMMARY

As required by the Title V Operating Permit (1050233-001-AV) for the Polk Power Station (Polk or PPS) Integrated Gasification Combined Cycle (IGCC) Plant, an updated best available control technology (BACT) analysis is submitted for control of oxides of nitrogen (NO_x) emissions. This analysis was performed as if the combustion turbine (CT) were a new source using the data gathered at this facility, other similar facilities, and the manufacturer's research. Based on this analysis, Tampa Electric Company (TEC) requests that the current NO_x emissions limit of 25 parts per million by dry volume (ppmvd) be continued as the appropriate BACT emissions limit. The 25 ppmvd is based on a statistical analysis of the performance test data collected during the demonstration period for the facility and represents an emissions limit with which the facility can reasonably assure compliance.

Add-on control technologies were also evaluated; however, they were found to be unreasonable based on considerable technical concerns and cost considerations. An evaluation of other similar facilities was conducted, which indicated there was only one other facility regarded as similar based on the criteria used in the analysis. This similar facility has a NO_x emissions limit of 25 ppmvd, which is the same as the current limit for the Polk facility. Manufacturer's research indicated that technological advances have been made that are applicable to new IGCC installations; however, retrofitting these technologies to the Polk facility would require substantial capital investments and equipment downtime. As discussed in this report, an extensive retrofit was not further considered as a control option for this source because the emissions unit must be treated as a new source as specified in the Title V and Prevention of Significant Deterioration (PSD) permit conditions.

This report is divided into the following sections:

- Background.
- Regulatory requirement for BACT analysis.
- Demonstration Period Test Data summary.
- Consideration of appropriate emissions limit.
- Evaluation of available control technologies.
- Manufacturer's research.

2.0 BACKGROUND

TEC operates an IGCC process at the Polk facility. The power generation portion of this process consists of a 192-megawatt (MW) General Electric (GE) model 7FA turbine whose emissions pass through a heat recovery steam generator (HRSG). The resulting steam provides the energy necessary to generate approximately 125 MW from a steam turbine. The construction and operation of this facility was permitted on February 24, 1994, under permit numbers PSD-FL-194 and PA-92-32.

The original permit application included a BACT analysis. At the time of the permit issuance, the BACT for NO_x was determined to be diluent nitrogen injection coupled with a multinozzle quiet combustor (MNQC) for operation using the primary fuel, syngas. The associated NO_x emissions limit is 25 ppmvd at 15-percent oxygen (O_2). The NO_x BACT determination for the back-up fuel, distillate oil, was determined to be water injection with an associated NO_x emissions limit of 42 ppmvd at 15-percent oxygen. These emissions limits were based on the equipment supplier's (GE) guaranteed performance for this equipment installation.

At the same time, GE 7FA turbines configured for natural gas combustion could achieve somewhat lower NO_x emission rates, in the range of 9 to 15 ppmvd, by using air-premix type dry low NO_x (DLN) combustors. In contrast to natural gas, syngas contains over 35-percent hydrogen (H_2), which increases flame speed so much that the air premix type DLN combustor cannot be used for syngas fuel. This distinction is further discussed in Section 6 of this report. The original BACT determination and the issued PSD permit also addressed this difference between NO_x emissions rates for the different fuels.

At the time of the original BACT determination, this turbine was a unique equipment set that fires syngas using a revised MNQC design, which had not yet been in commercial service. Accordingly, the PSD and Title V permits each included a requirement for a testing period of 12 to 18 months, during which the NO_x emissions performance on syngas is tested bi-monthly. At the conclusion of testing period, TEC is to submit a revised

NO_x BACT determination to the Florida Department of Environmental Protection (FDEP). This document is being submitted to fulfill the submittal requirements of the BACT determination and air operation permits.

3.0 REGULATORY REQUIREMENT FOR BACT ANALYSIS

The BACT analysis is addressed in Specific Condition A.50. of the Title V permit, which states:

> "One month after the test period ends (estimated to be by February 2000), the permittee will submit to the Department a NO_x recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_x only and adjust the NO_x emissions limits accordingly."

The provisions of this condition are analyzed in this section, preceding the NO_x BACT analysis.

The permit condition stipulates that the BACT determination should be performed as if the Polk IGCC facility were a new source as opposed to a candidate for replacement of a significant IGCC system or subsystem or major retrofit. This provision is an important element of the determination, as there have been options developed in IGCC technology in the past 10 years that may make some of today's CTs capable of achieving lower NO_x emission rates than the Polk facility. However, these options involve major deviations from Polk's IGCC hardware configuration such as using a different (less efficient) gasification system operating at much higher pressure, employing an entirely different approach to connecting/integrating the major plant subsystems (air separation, gasification, acid gas removal, and power generation), and using completely new turbine combustion hardware and controls.

In other words, even though these new plants are still IGCC facilities, using the same basic CT as Polk (GE's 7FA), they are so different that little, if any, of the IGCC plant's hardware is the same. Thus, in accordance with this permit condition, this analysis treats the Polk facility as a new source and does not analyze the options of replacing a major IGCC system or subsystem or attempting to retrofit Polk with this different technology configuration. For completeness, these differences in configuration are discussed in Section 9.0 of this report, *Manufacturer's Research*. Instead of major modifications to the

IGCC plant, the NO_x BACT analysis addresses two main areas, the establishment of a lower emissions limit for syngas firing within Polk's existing hardware constraints and the use of add-on controls.

When evaluating the performance of other similar facilities, it is important to limit the scope of the analysis. First, as contrasted with the more numerous electrical generating facilities fueled by natural gas, there are considerably fewer facilities fueled by syngas. Natural gas-fired facilities cannot be considered similar to Polk because of the significant differences in the fuel combustion characteristics. Second, the syngas production system is important in evaluating whether the facilities are similar. For example, less efficient gasification systems inherently have more CO_2 and N_2 available for use as diluents for NO_x abatement. Consequently, IGCC plants using either significantly more or less efficient gasification process than Polk's cannot be considered similar. Next, the manufacturer and vintage of the CT is an important element to consider when performing a survey of emissions data for what is considered a similar facility. Finally, the method of operation must be considered when evaluating other similar facilities. For example, other IGCC applications are co-fired with blends of syngas and natural gas or syngas and oil. The NO_x emissions performance data for the few facilities that may be considered similar to the Polk facility are discussed in Section 8 of this report, *Other Plant Experience.*

The manufacturer's research is explored to identify the advances that have been made in GE CT technology that allow the present line of CTs to have considerably better NO_x emissions performance than those from 10 years ago. Additionally, the emissions data and operating experience during the initial test period have been discussed with GE to explore potential operational improvements. These discussions are summarized in this report.

4.0 NO$_X$ EMISSIONS TESTING PERIOD DATA SUMMARY

The NO$_X$ emissions testing period lasted for 12 months and involved seven emissions tests. Appropriate emissions reports for each test have been submitted to FDEP in accordance with the permit requirements. Table 1 summarizes these test results. Each entry in the table represents the average of at least three individual test runs. Appendix B contains the results of the individual 1-hour test runs.

Table 1. TEC Polk Power Station NO$_x$ Emissions Test Data Summary

Test Date	Average NO$_x$ Emissions Result (ppmvd, 15% oxygen, ISO conditions)	Load (MW)
October 14, 1999	16.7	191
December 7, 1999	14.6	190
February 7, 2000	19.0	192
April 17, 2000	17.0	191
June 14, 2000	18.1	190
August 15, 2000	16.6	192
October 17, 2000	22.5	192

Source: ECT, 2000.

The first six tests used a syngas derived from the facility's base coal supply (i.e., Kentucky coal). However, due to mine closure, the facility will continue to gasify a variety of fuel supplies. The syngas burned in the seventh test had a greater heating value and adiabatic flame temperature than that produced from the supply used during the first six tests, leading to greater NO$_X$ emissions, even with using an increased proportional diluent flow rate.

A preliminary analysis of these data indicates the CT has met the 25-ppmvd NO$_X$ emissions limit contained in the permit. The next step in the analysis is to determine the statistical distribution of the emissions test data and to use this statistical analysis to ascertain the confidence level associated with meeting specific emissions levels. For this analysis, the raw data (i.e., each individual test run) are used instead of the average of the three tests runs. This difference in approach is to allow for a larger statistical sampling size, as estimating values such as standard deviation and confidence intervals are sample size dependent, especially for samples of less than 20 data points. Table 2 presents the governing statistical measures.

Table 2. Statistical Analysis of Emissions Test Data

Parameter	NO_x Emissions Result (ppmvd, 15% oxygen, ISO conditions)	Load (MW)
Sample size	21	21
Mean (average)	17.8	191.14
Low	14.0	190
Median	17	191
High	22.5	192
Range	8.5	2
Standard deviation (σ)	2.38	0.9
Mean plus 2 (σ) 90-percent confidence interval	22.55	N/A
Mean plus 3 (σ) 99.7-percent confidence interval	24.93	N/A

Note: N/A = not an appropriate statistical measure for load, maximum load is established as 192 MW.

Source: ECT, 2000.

The emissions test data are approximately normally distributed, with an overall average of 17.8 parts per million (ppm) and median of 17 ppm. The highest observed value is 22.5 ppm, and the lowest is 14.0 ppm. The standard deviation (σ or sigma) is 2.38 ppm.

Assuming a normal distribution of emissions data, a commonly used measure for statistical process control is the use of mean plus a certain number of standard deviations. For example, approximately 90 percent of the data will lie within plus/minus two standard deviations from the mean value, and 99.7 percent of the data will lie within three standard deviations from the mean. The three-sigma approach is commonly used in industrial statistical process control applications, and is also supplemented by a six-sigma approach for additional control.

Based on this analysis, the mean-plus-three-sigma value is 24.93 ppm. Based on the statistical analysis, only a small fraction (0.3 percent) of readings would be outside the mean-plus/minus three-sigma range, either higher or lower. Because the current emissions limit (expressed in pounds per hour) is based on a 30-day rolling average or the average of three test runs for an emissions test, it is not anticipated that this small percentage of values outside the mean-plus-three-sigma value would cause a compliance concern. However, because a considerable fraction (10 percent) of readings are outside the mean-plus/minus-two-sigma range, it could be that a limit based on this value would be difficult to meet. This analysis is used as a basis in the following section that addresses an alternate emissions limit.

5.0 CONSIDERATION OF APPROPRIATE EMISSIONS LIMIT

Originally, the facility was permitted with a NO_x emissions limit of 25 ppmvd based on the manufacturer's emissions guarantee. The statistical analysis of the demonstration test data was used to determine the emissions levels that are represented by the mean-plus-two-sigma (22.55 ppmvd) and the mean-plus-three-sigma (24.93 ppmvd) values. Based on the previous discussion (performed in Section 4.0) of the statistical distribution of the data, it is thought that the mean-plus-two-sigma limit is too stringent. However, the three-sigma limit is an appropriate limit as it provides for reasonably expected emissions variations that are associated with fluctuations in meteorological conditions, fuel supply, and other process parameters. Additionally, the data collected during this analysis are for a relatively new and clean CT. As the CT ages, it is reasonable to expect a degradation in both the combustion efficiency and emissions performance. Hence, this three-sigma limit will provide for reasonable variations and anticipated degradation with equipment aging.

As was discussed in Section 4, the performance test conducted on October 17, 2000, indicated a greater NO_x emissions rate than the previous tests. This difference is attributed to a change in coal supply and a resulting greater heat content and adiabatic flame temperature of the syngas. This variation in NO_x emissions with changes in fuel supply is an important factor to consider when establishing the appropriate BACT emissions limit for this facility. The proposed 25-ppm NO_x emissions limit is expected to allow TEC to burn a variety of syngas compositions that are derived from the entire fuel portfolio for the facility. Any NO_x emissions limit less than 25 ppm would unduly restrict the facility's ability to gasify the existing range of feed stock.

Thus, for the remainder of this analysis, it is assumed the current CT emission level of 25 ppmvd of NO_x for firing of coal-based syngas will be retained. This determination of a proposed emissions rate is important for the evaluation of cost effectiveness of add-on control technology.

6.0 EVALUATION OF AVAILABLE CONTROL TECHNOLOGIES

The initial BACT analysis evaluated several available control technologies. The use of a nitrogen diluent with an advanced combustor design was selected, and the appropriate control technology is installed and in use for this system. Despite this prior selection of controls, there have been recent advances in control technology that warrant a revisit of the control technologies, including cost estimates.

The original BACT analysis (1992) addressed the following six combustion process modifications as available control technologies. This evaluation will update the analysis presented in the original BACT analysis for these six combustion process modifications, and also addresses the additional option of catalytic combustion controls (e.g., XONON):

- Flue gas recirculation (FGR).
- Low excess air (LEA).
- Low-NO_x burners.
- Water/steam/diluent injection with standard combustor design.
- Water/steam/diluent injection with advanced combustor design (multinozzle quiet combustor).
- Dry low-NO_x combustor design.

The BACT analysis also addressed the following three postcombustion exhaust gas treatment systems:

- Selective noncatalytic reduction (SNCR).
- Nonselective catalytic reduction (NSCR).
- Selective catalytic reduction (SCR).

This BACT analysis will update the analysis for these three postcombustion exhaust gas treatment systems and also addresses the additional option of $SCONO_x$™, a catalytic adsorption and desorption/reaction control system.

6.1 COMBUSTION PROCESS MODIFICATIONS

The original analysis asserted that the first three combustion process modifications are applicable to boilers and, therefore, are not applicable to CTs. Thus, FGR, LEA, and low-NO_x burners (i.e., boiler-specific low-NO_x configuration) were not considered in the original analysis. There have been no changes in technology for these options that would make them applicable to the CTs today, thus these options are not considered further in this analysis.

Of the next two options, water/steam/diluent injection with standard combustor design and water/steam/diluent injection with advanced combustor design, the second option was chosen as BACT and is installed on the equipment. Since this selected option provides better NO_x emissions control than the first option, further discussion of these options is not warranted in this analysis. Recent advances in the selected option (water/steam/diluent injection with advanced combustor design) for NO_x control are discussed in Section 9.0 of this report, Manufacturer's Research.

The dry low-NO_x combustor design (i.e., premix combustion) technology was discussed in the original BACT analysis. This analysis stated that although this technology has shown considerable NO_x emissions reductions for natural gas combustion, it has not been developed for synthetic coal gas as a fuel. There are considerable differences between the two fuels, including British thermal unit (BTU) content and fuel burning characteristics, which preclude the direct application of the advances in dry low-NO_x design for natural gas to syngas combustion. As a result of these differences, no turbine manufacturer currently offers dry low-NO_x technology as a control option for syngas fuel.

One of the overriding technical concerns with the application of dry low-NO_x technology to syngas fuels is the presence of hydrogen in the syngas fuel. The hydrogen flame speed is considerably greater than that for natural gas. This higher flame speed can contribute to flash back, which can cause substantial damage to the dry low-NO_x combustor. Thus, the option of dry low-NO_x combustor design is not considered further in this analysis.

An emerging combustion technology potentially capable of reducing gas turbine NO_x emissions to 2 to 5 ppmvd is catalytic combustion. Catalytica, Inc., was the first to commercially develop catalytic combustion controls for certain (mostly smaller) turbines and markets this system under the name XONON™. Catalytic combustion technology is not yet commercially available for 190-MW, F-Class turbines. Additionally, no gas turbine manufacturer is currently developing this technology for syngas applications. Therefore, catalytic combustion does not represent an available control option for the Polk facility and is not further considered in this analysis.

6.2 POSTCOMBUSTION EXHAUST GAS TREATMENT

The four following postcombustion exhaust gas treatment systems are evaluated in this section:

- SNCR.
- NSCR.
- SCR.
- Catalytic adsorption and desorption/reaction control system (SCONO$_x$™).

6.2.1 SELECTIVE NONCATALYTIC REDUCTION

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000 degrees Fahrenheit (°F).

The maximum temperature of the CT exhaust gas stream is approximately 1,060°F; thus, this technology is not technically feasible. Therefore, SNCR does not represent an available control option for the Polk facility and is not further considered in this analysis.

6.2.2 NONSELECTIVE CATALYTIC REDUCTION

The NSCR process uses a platinum/rhodium catalyst to reduce NO_x to nitrogen and water vapor under fuel-rich (less than 3-percent oxygen) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines. Due to the high excess air rates used to fire the turbine, the oxygen content of CT exhaust gases is typically over 11 percent. Therefore, NSCR does not represent an available control option for the Polk facility and is not further considered in this analysis.

6.2.3 SELECTIVE CATALYTIC REDUCTION

SCR reduces NO_x emissions by reacting ammonia with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. Ammonia is injected upstream of the catalyst bed where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \qquad (1)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (2)$$

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the cross-sectional area of the catalyst bed), ammonia/NO_x molar ratio, and catalyst bed temperature. Residence time is a function of catalyst bed depth. Increasing the residence time (increasing catalyst bed depth) will improve NO_x removal efficiency but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with ammonia theoretically requires a 1:1 molar ratio. Ammonia/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted ammonia (ammonia slip) emissions.

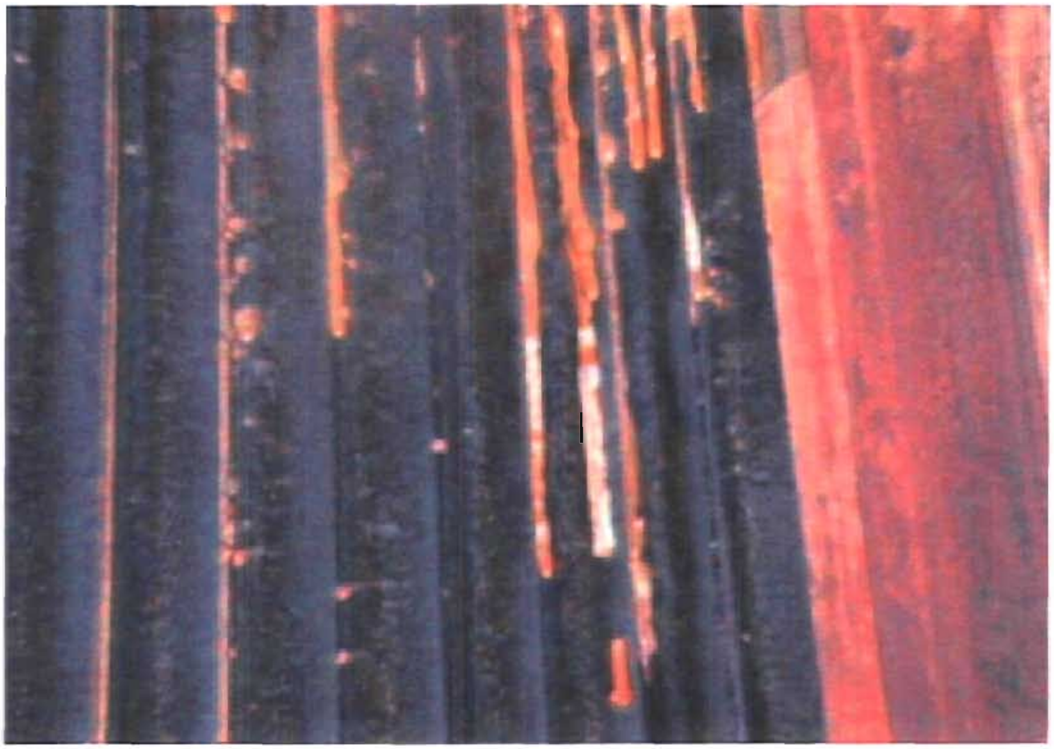
Reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (1) and (2) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place, resulting in an increase in NO_x emissions.

Specially formulated high temperature zeolite catalysts have been recently developed that function at exhaust stream temperatures up to a maximum of approximately 1,025°F. NO_x removal efficiencies for SCR systems typically range from 50 to 90 percent.

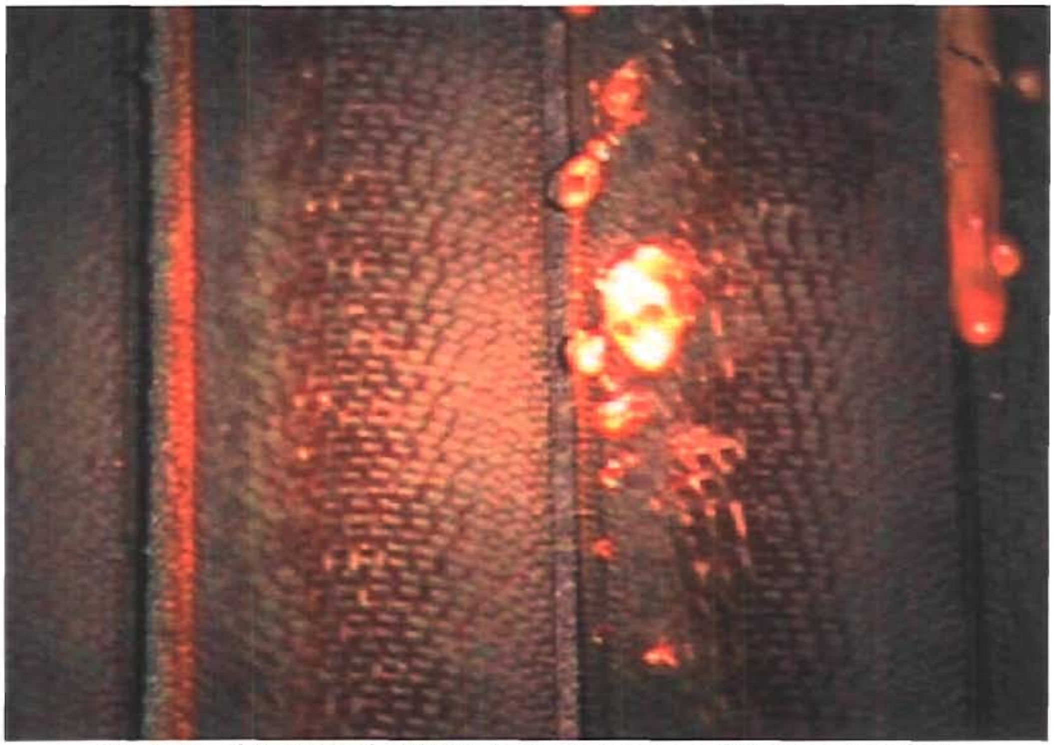
SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, mercury, potassium, sodium, and calcium. Due to the potential for chemical poisoning with fuels other than natural gas, application of SCR to CTs has been primarily limited to natural gas-fired units.

Of particular concern in this project is the use of the SCR catalyst on a sulfur-containing fuel. Yellow deposits composed of sulfur, and sulfur compounds have been noted from the high-pressure evaporator tubes to the low-pressure economizer. The temperature range associated with these deposits includes the normal operating temperature range of typical SCR catalysts. Several photographs were taken during a recent equipment shutdown that indicated the presence of sulfur compound deposition in the equipment, which is an overriding technical concern for fouling of the SCR control system. A sampling of these photographs is included in Figure 1 to support the assertion that the sulfur compounds in the exhaust stream present a technical obstacle to the use of an SCR emissions control system. Thus, there are significant amounts of sulfur and sulfur compounds in the exhaust stream that will adversely affect the performance of an SCR.

SCR catalyst will promote the oxidation of flue gas SO_2 to sulfur trioxide (SO_3), which will then combine with water vapor to form sulfuric acid (H_2SO_4). Accordingly, corrosion of downstream piping and heat transfer equipment (which would operate at temperatures below the H_2SO_4 dew-point) would be of concern when using SCR with sulfur-bearing fuels. Also, SO_3 will combine with unreacted ammonia to form ammonium bisulfate and ammonium sulfate. Ammonia bisulfate is a hygroscopic solid at approximately



Deposits in the HRSG, low-pressure section of economizer



Close-up of deposits in HRSG, low-pressure section of economizer.

FIGURE 1. (Page 1 of 2)

SITE PHOTOGRAPHS

Source: ECT, 2000.

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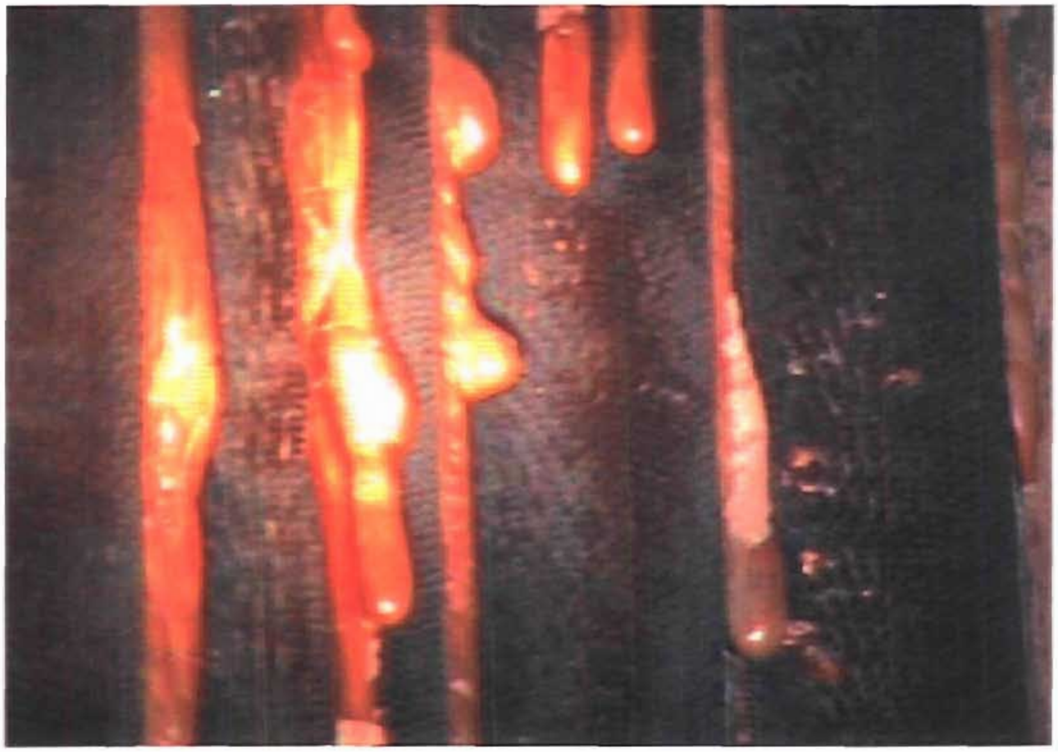
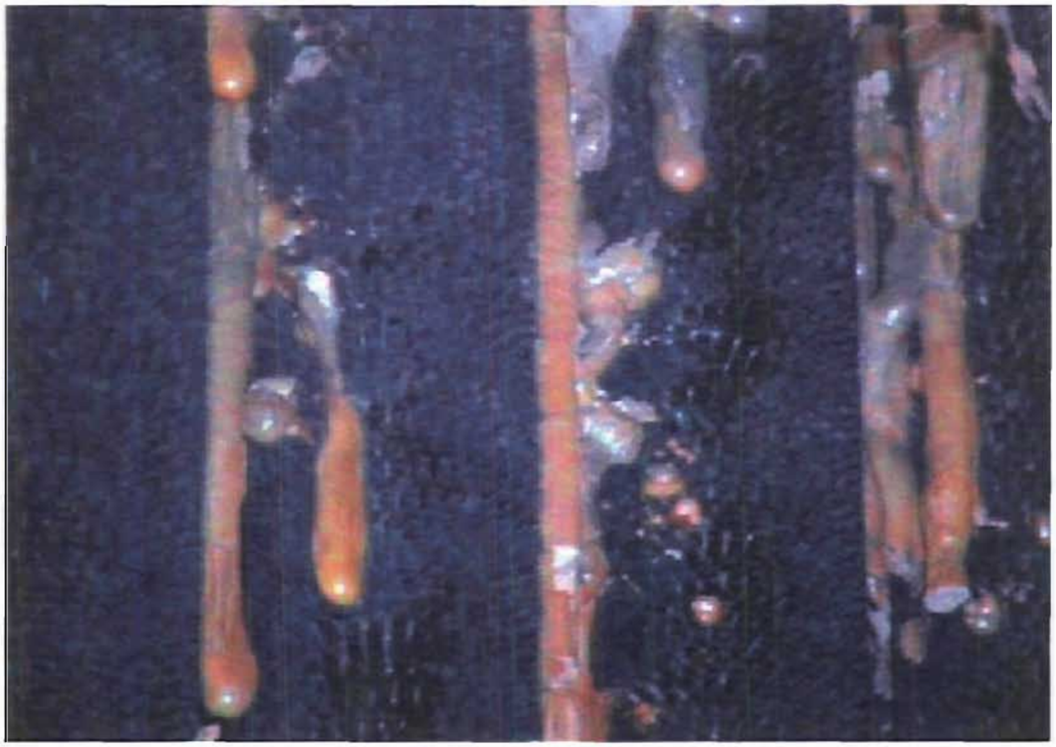


Close-up of deposits in HRSG, low-pressure section of economizer.



Close-up of deposits in HRSG, low-pressure section of economizer.

FIGURE 1. (Page 2 of 2)

SITE PHOTOGRAPHS

Source: ECT, 2000.

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380°F and will deposit on equipment surfaces below this temperature as a white solid. Both ammonium bisulfate and ammonium sulfate would be expected to deposit on HRSG heat transfer equipment where temperatures below 380°F will occur. Since ammonium bisulfate is hygroscopic, the material will absorb water, forming a sticky substance that can cause fouling of heat transfer equipment. Ammonium bisulfate cannot be easily removed due to its sticky nature; a unit shutdown would be required to clean fouled equipment. Formation of ammonium salts will also result in a significant increase in particulate matter (PM) emissions. Additionally, these deposits would be expected to increase the pressure drop across the equipment, adversely affecting overall CT efficiency.

The technical difficulties associated with SCR and sulfur-bearing fuels have been documented for fuels having relatively low sulfur contents. For example, the United Airlines cogeneration facility fires very low-sulfur (0.04 percent, 0.02 pound per million British thermal unit [lb/MMBtu]) Jet-A fuel as a back-up fuel[1]. Although this level is approximately half the sulfur level of the syngas fired at the Polk facility, the SCR catalyst was replaced three times during the first year of operation due to sulfur poisoning, and the back sections of the HRSG required washing to remove ammonium sulfate salt build-up.

Two examples of SCR applied to CTs firing sulfur-bearing fuels outside the United States were reported in the Lowest Achievable Emission Rate (LAER) analysis submitted for the Star Enterprise Delaware City Refinery permitted in 1998[2]. This analysis included two examples, one by the Japanese National Railway (JNR) and another in Linkoping, Sweden. The JNR facility had 50,000 hours of operating experience on a very low-sulfur fuel (0.007 weight percent, 0.004 lb/MMBtu); however, due to ammonium sulfate deposition, the unit is operated at approximately one-half of its design efficiency (40 percent actual versus 80 percent design NO_x reduction). By operating significantly below the

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[1] General Electric Company, Industrial and Power Systems, Position Paper, The Use of SCR When Firing Gas Turbines with Distillate Oil, May 31, 1994.

[2] Air Quality Permit Application for the Star Enterprise Delaware City Refinery, Submitted to the State of Delaware Department of Natural Resources and Environmental Control, Division of Air and Waste Management, Permit Number APC-97/0503.

design ammonia/NO_x injection ratio, ammonia slip (and the associated formation of ammonium sulfate) is virtually eliminated.

The Linkoping installation had 16,000 hours of operation. The unit is designed to achieve greater than 90 percent NO_x removal with low ammonia slip. It is equipped with an HRSG, and it has steam-fired sootblowers operated at 725 pounds per square inch (psi). During the summer of 1995, while firing fuel oil with sulfur levels between 0.05 and 0.1 percent, some deposits were found in the economizer section of the HRSG. The catalyst had to be removed during cleaning to avoid wetting it; the cleaning process took 1 week. In the fall of 1996, the fuel oil sulfur content rose to approximately 0.13 percent (0.07 lb/MMBtu). This increased level resulted in further, increased deposits and a significant increase in the HRSG pressure drop, which forced a turbine shutdown due to excessive backpressure.

These reported experiences indicate the following overriding concerns with application of SCR to sulfur-containing fuel combustion processes:

- HRSG deposits will form even at low fuel sulfur levels.
- The large HRSG pressure drop increases that have been predicted in this service (large enough to shut down the turbine) are now confirmed in an actual oil-fired CT HRSG.
- Sootblowers do not seem to be effective in preventing deposition.

Although the fuels used at the Polk facility have relatively low sulfur contents (i.e., syngas and low sulfur distillate oil), the sulfur levels are more than sufficient to cause problems with operation of a SCR control system. The Title V Air Operating Permit for SO_2 emissions limits the sulfur content of the syngas to 0.1 lb/MMBtu (as elemental sulfur). Normal operating experience indicates typical syngas sulfur content of 0.07 lb/MMBtu. This sulfur content is substantially greater (up to 10 times greater) than demonstrated to cause the technical difficulties described in this section.

Recent advances in catalyst design allow for SCR catalysts that minimize the conversion of SO_2 to SO_3. However, these catalysts are specifically formulated for use in specific applications in the chemical process industry. Discussions with the catalyst manufacturer (Englehard 2000)[3] indicate that this special catalyst is not formulated for use in combustion turbine applications. Additionally, Englehard indicated that they do not have a catalyst available for combustion turbine applications that would lessen the rate of this side reaction that can cause subsequent deposition problems.

In contrast, natural gas has a sulfur content of approximately 0.02 to 0.27 grains of sulfur per 100 standard cubic feet (gr S/100 scf), or 2.72×10^{-5} to 3.67×10^{-4} lb/MMBtu. This sulfur level is considerably less than that which has been shown to cause the equipment fouling described in this report.

Problems associated with ammonium salt deposition can be ameliorated to some extent by reducing the ammonia/NO_x molar ratio when firing sulfur-containing fuels. However, all known successful applications of SCR for CTs are on natural gas-fired units. There are no applications of SCR to CTs fired with synthetic coal gas, including the LAER determination for the Star Enterprises Maryland facility. It should also be noted that the original equipment manufacturer[4] does not promote the application of a SCR to a syngas-fired unit.

For the purposes of providing a complete analysis of the SCR as an option for control, even with the overwhelming technical concerns, a cost-effective analysis of SCR control technology is presented in Section 6.3 and is summarized in Table 3. As demonstrated in this analysis, the expected cost effectiveness for SCR was determined to be $4,660 per ton of NO_x removed This economic analysis includes increased costs that would accrue due to downtime required for cleaning of fouled heat transfer equipment. Since Polk Unit 1 does not have a by-pass stack, the unit must be shut down completely during any

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[3] Englehard, 2000. Telephone conversation, November 8, 2000, between Mr. Fred Booth, Englehard Corporation and Mr. John Shrock, ECT.

[4] General Electric Company, Industrial and Power Systems, Position Paper, The Use of SCR When Firing Gas Turbines with Distillate Oil, May 31, 1994.

outage caused by the SCR system. This cost control is greater than those previously considered to be reasonable for BACT NO_x determinations.

6.2.4 CATALYTIC ADSORPTION AND DESORPTION/REACTION CONTROL SYSTEM (SCONO$_X$™)

SCONO$_x$™ is a NO_x and CO catalytic absorption control system developed by Goal Line Environmental Technologies (GLET) and exclusively offered by Alstom Power. The SCONO$_x$™ system operates at a temperature range of 300 to 700°F. The SCONO$_x$™ process is further described in the information sheet included in Appendix C provided by the supplier of this technology.

The SCONO$_x$™ process addresses the sulfur poisoning issue by installing a SCOSO$_x$™ guard bed upstream of the SCONO$_x$™ catalyst bed. Even with the SCOSO$_x$™ guard bed, experience with natural gas-fired turbine exhausts indicates the first stage of the SCONO$_x$™ experiences sulfur poisoning. This first stage needs to be washed with an acid wash solution more frequently than the rest of the bed and also needs replacement on a more frequent basis. Thus, the SCOSO$_x$™ guard bed is not entirely effective at removing sulfur and sulfur compounds from the exhaust stream. Any effects noticed using the extremely low-sulfur natural gas fuel are expected to be amplified when using the higher sulfur content syngas or distillate oil fuel.

For the purposes of providing a complete analysis of the SCONO$_x$™ process as an option for control, even with the overwhelming technical concerns, a cost-effective analysis of SCONO$_x$™ control technology is presented in Section 6.3, and is summarized in Table 3. As demonstrated in this analysis, the expected cost effectiveness for SCONO$_x$™ was determined to be \$10,820 per ton of NO_x removed. This economic analysis includes the increased costs that would accrue due to downtime required for cleaning of fouled heat transfer equipment. This cost control is greater than those previously considered to be reasonable for BACT NO_x determinations.

6.3 COST-EFFECTIVENESS ANALYSIS

Economic analyses of the SCR and SCONO$_x$™ control technology alternatives were performed to compare the capital and annual costs in terms of the cost-effectiveness. The cost-effectiveness of a control technology is defined as the cost per ton of pollutant removed. As shown in Table 3, SCR is more cost-effective than SCONO$_x$™ (i.e., the cost per ton to control NO$_x$ is approximately two times higher for SCONO$_x$™). However, neither SCONO$_x$™ nor SCR are considered to be a cost effective alternative for controlling NO$_x$ at this installation. A discussion of the methodology used to perform the cost analysis follows in this section. Details of the costs associated with the SCR and SCONO$_x$™ systems are contained in Sections 6.3.1 and 6.3.2.

Table 3. BACT Analysis Summary of Cost-Effectiveness

	SCR Syngas Firing	SCR Oil Firing	SCONOx™ Syngas Firing	SCONOx™ Oil Firing
Baseline NO$_x$ (ppmvd)	25.0	42.0	25.0	42.0
Baseline NO$_x$ (lb/hr)	222.5	311.0	222.5	311.0
Baseline NO$_x$ (tpy)	877.1	136.2	877.1	136.2
Controlled NO$_x$ (ppmvd)*	3.5	5.9	2.0	3.4
Controlled NO$_x$ (lb/hr)	31.2	43.5	17.8	24.9
Controlled NO$_x$ (tpy)†	122.8	19.1	70.2	10.9
Emissions decrease (tpy)†	754.3	117.1	806.9	125.3
Unit 1 Total				
Emissions decrease (tpy)		871.4		932.2
Annualized cost ($)		$4,061,000		$10,086,500
Cost effectiveness ($/ton)		$4,660		$10,820

*SCR assumes an 86-percent control efficiency based on syngas firing inlet concentration of 25 ppm and outlet concentration of 3.5 ppm. This efficiency is assumed to apply to oil firing. The SCONOx™ assumes a 92-percent control efficiency based on syngas firing inlet concentration of 25 ppm and outlet concentration of 2 ppm. This efficiency is assumed to apply to oil firing.

†Annual emission estimates are based on maximum permitted heat input using oil firing for 876 hours per year (the permit limit) and 7884 hours per year on syngas.

Source: ECT, 2000.

Capital Costs

Capital costs include the initial cost of the components intrinsic to the complete control system, (e.g., SCR includes the catalyst bed, support frame, ammonia storage tanks, piping, rotating equipment, instrumentation, and monitoring equipment), and installation costs.

One additional initial capital cost associated with the SCR control option arises from the physical changes that are needed to accommodate the HRSG washing to remove anticipated ammonia sulfate deposits. These changes are required to allow for containment of the water used in washing which is estimated at approximately 20,000 gallons per occurrence. The changes involve installation of appropriate containment (i.e., both a sump and appropriate drainage system for the HRSG), pumps, and piping. Because the washing operation will be performed using scaffolding, appropriate brackets for the scaffolding will also need to be installed. The total capital cost for the HRSG modifications to allow for washing is estimated at $300,000, and is included in the capital costs for the SCR system.

Similar to the SCR control technology, the capital cost site upgrades to accommodate handling of wash water is also anticipated for the SCONO$_x$™ control technology due to the requirements for washing of the catalyst. Because the SCONO$_x$™ system is an ammonia free system, the difficulties with ammonia sulfate deposits and associated fouling are not anticipated. However, the SCONO$_x$™ control system is sensitive to the sulfur levels in the exhaust. Even with the low sulfur content of a natural gas fired combustion turbine exhaust stream, a SCONO$_x$™ guard bed is used to protect the SCONO$_x$™ main catalyst. Based on the higher sulfur content of the syngas CT exhaust, it is anticipated that similar semi-annual cleaning of the catalyst will be required.

Annual operating costs consist of the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, labor, raw materials, and utilities. Table 4 summarizes specific factors used in estimating the capital and annual operating costs. Additional cost assumptions, such as the costs for electricity and steam, are contained in Table 5.

Table 4. Capital and Annual Operating Cost Factors

Cost Item	Factor
<u>Direct Capital Costs</u>	
Sales tax	0.06 × control system cost
Freight	0.05 × control system cost
Instrumentation	0.10 × control system cost
Foundations and supports	0.08 × purchased equipment cost
Handling and erection	0.14 × purchased equipment cost
Electrical	0.04 × purchased equipment cost
Piping	0.02 × purchased equipment cost
Insulation	0.01 × purchased equipment cost
Painting	0.01 × purchased equipment cost
<u>Indirect Capital Costs</u>	
Engineering	0.10 × purchased equipment cost
Construction and field expenses	0.05 × purchased equipment cost
Contractor fees	0.10 × purchased equipment cost
Start-up	0.02 × purchased equipment cost
Performance testing	0.01 × purchased equipment cost
Contingencies	0.03 × purchased equipment cost
<u>Direct Annual Operating Costs</u>	
Supervisor labor	0.15 × total operator labor cost
Maintenance materials	1.00 × total maintenance labor cost
<u>Indirect Annual Operating Costs</u>	
Overhead	0.60 × total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 × total capital investment
Property taxes	0.01 × total capital investment
Insurance	0.01 × total capital investment

Sources: EPA, 1996.
ECT, 2000.

Table 5. Economic Cost Factors

Factor	Units	Value
Interest rate	%	7.0
Control system life	Years	10
SCR catalyst life	Years	5*
SCONOx™ catalyst life	Cost assumes leasing arrangement	
Aqueous ammonia cost	$/ton	113
Natural gas cost†	$/ft^3	0.00388
Steam cost**	$/lb	0.006
Electricity cost	$/kWh	0.04
Labor costs (base rates)	$/hour	
Operator		22.00
Maintenance		22.00

*The vendor's control system performance guarantee is for 3 years of operation or 3.5 years after catalyst delivery, whichever occurs first.

†Natural gas is used in the SCONO$_x$™ system for regenerating the catalyst, and not for firing the combustion turbine. Cost estimate from DOE, 1999.[5]

**Cost estimate from DOE, 1999.[5]

Sources: TECO, 2000.
ECT, 2000.

The capital cost estimating technique used in this analysis is based on the factored method of determining direct and indirect installation costs. This technique is a modified version of the "Lang Method," whereby installation costs are expressed as a function of known equipment costs. This method is consistent with the latest U.S. EPA guidance manual (OAQPS Control Cost Manual) on estimating control technology costs (EPA, 1996)[6]. The estimation factors used to calculate total capital costs are shown in Table 4.

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for efficient operation of the device. These may include such items as reagent storage, supply piping, and distributed controls. Aux-

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[5] DOE, 1999. Cost Analysis of NO$_x$ Control Alternatives for Stationary Gas Turbines. U.S. Department of Energy. Environmental Programs, Chicago Operations Office, 9800 South Cass Avenue, Chicago, IL 60439. November 5, 1999.

[6] EPA, 1996. U.S. Environmental Protection Agency (EPA). 1996. OAQPS Control Cost Manual, 5th Edition. EPA-453/B-96-001. Research Triangle Park, NC.

iliary equipment costs are taken as a straight percentage of the basic equipment cost, the percentage being based on the average requirements of typical systems and their auxiliary equipment (EPA, 1996). In this analysis, the basic equipment costs were based on recent quotes (i.e., 11/16/00 for SCONO$_x$^{TM} and 11/25/00 for SCR) by qualified vendors for similar equipment (Appendix D). The costs were then scaled based on the differences in exhaust flowrate between the actual equipment and that for which the quote was prepared. In this case the cost estimates were based on the Siemens Westinghouse Model V84.3a2 with an exhaust flow rate of 3,515,508 lb/hr. The project unit, a General Electric 7FA, has an exhaust flow rate of 3,940,000 lb/hr. The resulting scaling factor of 1.12 was used to adjust the costs of the equipment and catalyst to the larger GE unit. Instrumentation, usually not included in the basic equipment cost, is estimated at 10 percent of the basic equipment cost.

Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection, piping, electrical, painting, and facilities.

Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Direct installation costs are expressed as a function of the purchased equipment cost based on the average installation requirements of typical systems.

Indirect installation costs are designated as a percentage of the total direct cost (purchased equipment cost plus the direct installation cost) of the system. Other indirect costs include equipment startup and performance testing, working capital, and interest during construction.

Annualized Costs

Annualized costs are comprised of direct and indirect operating costs. Direct costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Annualized cost factors used to estimate total annualized cost are listed in Table 4. Annualized cost factors were obtained from the current EPA manual on estimating control technology costs (EPA, 1996).

Direct operating labor costs vary according to the system operating mode and operating time. Labor supervision is estimated as 15 percent of operating labor. Maintenance costs are calculated as 3 percent of total direct cost (TDC). Replacement part costs, such as the cost to replace aged catalyst, have been included where appropriate. Because the SCONO$_x$™ catalyst is leased, an annual lease cost is used instead of a replacement cost. Raw material and utility costs are based upon estimated annual consumption. The presence of a catalyst bed would increase turbine back-pressure resulting in efficiency losses to the system. This is reflected in the economic analysis as the value of lost power output based on turbine vendor estimates. With low inlet emission rates (i.e., 25 ppmvd), the catalyst is assumed to require replacement every five years due to aging, which is at a longer interval than the vendor's catalyst lifetime guarantee of three years. This extension of the lifetime of the catalyst serves to reduce the annual costs associated with catalyst replacement, which is based on the cost of replacement catalyst as provided by the catalyst vendor.

With the exception of overhead, indirect operating costs are calculated as a percentage of the total capital cost. The indirect capital costs are based on the capital recovery factor (CRF), defined by the following equation:

$$CRF = i(1+i)^n / [(1+i)^n - 1]$$

Where "i" is the annual interest rate and "n" is the equipment economic life in years. A control systems economic life is typically 10 to 20 years (EPA, 1996). In this analysis, a 10-year equipment economic life was assumed. The average interest rate is assumed to be 7.0 percent (EPA, 1996), although TEC currently incurs greater interest costs for this type of capital equipment. The CRF is therefore conservatively calculated to be 0.14238; however, this value would likely be higher for this facility because of the higher interest rates that would be expected for TEC.

Cost Effectiveness

The cost-effectiveness of an available control technology is based on the annualized cost of the available control technology and its annual pollutant emission reduction. Cost-effectiveness is calculated by dividing the annualized cost of the available control technology by the theoretical mass (tons) of pollutant removed by that control technology each year. The basis for determining the percent reduction of a given technology was based on information contained in U. S. EPA literature and from vendors of the control equipment.

6.3.1 SELECTIVE CATALYTIC REDUCTION

An assessment of economic impacts was performed by comparing control costs between the existing baseline case of advanced combustor technology and baseline technology with the addition of SCR controls. In the base case, the uncontrolled, annual NO_x emission rate is 1,013.3 tons per year (tpy) based on CT baseload operation for 8,760 hr/yr at 59°F and assuming oil firing for 10-percent of the year. No provisions (i.e., emission reductions) are included for the 432 hours of anticipated outages, since no operational constraints are being requested. This approach is conservative, as it will tends to overestimate emissions reductions resulting in lesser cost effectiveness values. The SCR controlled annual NO_x emission rate, based on 3.5 ppmvd effluent concentration on syngas (i.e., 86-percent control efficiency), is 122.8 tpy. Baseline technology is expected to achieve a NO_x exhaust concentration of 25 ppmvd at 15-percent O_2. SCR technology was premised to achieve NO_x concentrations of 3.5 ppmvd at 15-percent O_2. Base case and controlled NO_x emission rates are summarized in Table 3.

Average cost effectiveness for the application of SCR technology was determined to be $4,660 per ton of NO_x removed. Based on recent Florida DEP BACT determinations, the control cost for SCR is not considered to be economically reasonable for this installation. Tables 6 and 7 summarize the results of the capital and annual operating costs associated with the SCR system.

Table 6. Capital Costs for SCR Catalyst System

Item	Dollars	OAQPS Factor
<u>Direct Costs</u>		
Purchased equipment*	2,047,900	A
Sales tax	122,900	0.06 × A
Instrumentation	204,800	0.10 × A
Freight	102,400	0.05 × A
HRSG Modification	300,000	
Subtotal Purchased Equipment	**2,778,000**	**B**
Installation		
Foundations and supports	222,200	0.08 × B
Handling and erection	388,900	0.14 × B
Electrical	111,100	0.04 × B
Piping	55,600	0.02 × B
Insulation for ductwork	27,800	0.01 × B
Painting	27,800	0.01 × B
Subtotal Installation Cost	**833,400**	
Subtotal Direct Costs	**3,611,400**	
<u>Indirect Costs</u>		
Engineering	277,800	0.10 × B
Construction and field expenses	138,900	0.05 × B
Contractor fees	277,800	0.10 × B
Startup	55,600	0.02 × B
Performance test	27,800	0.01 × B
Contingency	83,300	0.03 × B
Subtotal Indirect Costs	**861,200**	
TOTAL CAPITAL INVESTMENT	**4,472,600**	(TCI)

*Includes estimated $100,000 for ammonia storage tank.

Source: ECT, 2000.

Table 7. Annual Operating Costs for SCR Catalyst System

Item	Dollars	OAQPS Factor
Direct Costs		
Operator/supervisor Labor	13,800	
Maintenance Labor and Material	24,000	
Subtotal Labor and Maintenance Costs	**37,800**	C
Catalyst costs		
Replacement (materials, labor, disposal)	1,713,300	
Annualized Catalyst Costs	**417,900**	5 yr replacement
Aqueous ammonia costs	226,900	$113/ton
Electricity costs	62,800	NH_3 pump/vaporization
Scheduled Outages	60,000	labor and materials
Unscheduled Outages	1,934,400	labor, materials, and 6 days electrical loss
Energy Penalties		
Turbine backpressure-control system	363,000	0.54% penalty
Turbine backpressure-catalyst plugging	363,300	0.54% penalty
Subtotal Direct Costs	**3,466,400**	(TDC)
Indirect Costs		
Overhead	22,700	0.60 x C
Administrative charges	89,500	0.02 x TCI
Property taxes	44,700	0.01 x TCI
Insurance	44,700	0.01 x TCI
Capital recovery	414,800	10 yrs @ 7%
Subtotal Indirect Costs	**616,400**	
Emission fee credit	(21,800)	$25/ton
TOTAL ANNUAL COST	**4,061,000**	

Source: ECT, 2000.

The installation of SCR technology will cause an increase in back pressure on the CT due to the pressure drop across the catalyst bed. Additional energy would be needed for the pumping of aqueous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. A SCR control system for the CT is projected to have a pressure drop across the catalyst bed of approximately 2.7 inches of water. This pressure drop will result in a 0.54 percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 9,082,368 kilowatt hours (kwh) (30,990 MMBtu) per year at baseload (192 MW) operation for 8,760 hours per year. The lost power generation energy penalty, based on a power cost of $0.04/kwh, is $363,300 per year. This cost was included in the BACT analysis.

The fouling of the control equipment or the downstream equipment will also cause an increase in turbine backpressure. Thus, there are two energy penalties associated with each control technology. The first energy penalty is from the pressure drop across a clean configuration of the control system. The second energy penalty is from the pressure drop caused by fouling of the catalyst or the downstream exhaust equipment. It is assumed that the catalyst will be cleaned when the increased pressure drop from fouling is equal to twice the pressure drop associated with a clean system (i.e., when the total pressure drop is three times that of a clean system). For the SCR system, the nominal pressure drop is 2.7 inches of water. Thus, the catalyst will cleaned when the total pressure drop is at 8.1 inches of water. Because the catalyst condition will vary between clean and plugged, the increased pressure drop from fouling will approximately be equal to the nominal pressure drop. Hence, the annual costs associated with the pressure drop from plugging are estimated as the same costs as from the nominal pressure drop across the system.

The annual operating costs include costs for three outages per year. For the SCR system, these outages are for cleaning deposits in the HRSG and other portions of the exhaust system. The outages result from the high sulfur content of the exhaust gas. In preparing the cost estimates for this analysis, it is assumed that one of the two outages can coincide with a planned outage. However, the other outages would be unscheduled. This arrangement is appropriate as the combustion turbine has a designed availability of 95 percent.

There are two main costs that are associated with an outage. The first cost is the labor and materials costs that are associated with the cleaning activities. This cost is estimated by plant engineering staff as $60,000 per occurrence. This cost would apply to both scheduled and unscheduled outages.

The cost associated with unscheduled outages was also included in the analysis. It was estimated that two unscheduled outages per year, each lasting 6 days, would occur. This would result in lost energy production from the combined CT/HRSG system. At $20 per megawatt hour (the incremental cost of power generation), this outage would result in $151,200 per day for a total of $1,814,400 per year.

The incremental cost of power generation represents the differential cost to TEC of acquiring the power that would otherwise be generated by the Polk syngas fired turbine had a forced outage due to SCR failure not occurred. This differential cost is the cost of the replacement power less the cost of generating the power at the Polk facility. There are a variety of factors that contribute to the determination of the incremental cost, including the availability of other units in the TEC system, and the associated costs of generating additional electricity or the purchase of power from other sources comprising the power grid. Based on an internal review of historical and projected TEC generating capability and associated costs, including purchase from the power grid, if necessary, this incremental cost is estimated at $20 per megawatt hour.

If these costs were estimates as a lost factor, the total cost would be substantially higher, especially if an outage were to occur during peak demand periods. However, the costs are conservatively estimated as internal costs. These costs were assumed to be the same for both the SCR and SCONO$_x$™ systems.

6.3.2 SCONO$_X$™

The economic impact analysis for the SCONO$_x$™ system was conducted in the same manner as that described above for the SCR system. Assuming the same baseline conditions (i.e., 1,013.3 tpy emissions) the controlled annual NO$_x$ emission rate, based on 92-percent control efficiency for the SCONO$_x$™, is 81.1 tpy (70.2 tpy on syngas). Baseline technology is expected to achieve a NO$_x$ exhaust concentration of 25 ppmvd at 15-percent O_2. SCONO$_x$™ technology, which is generally higher performance than SCR, was premised to achieve NO$_x$ concentrations of 2.0 ppmvd at 15-percent O_2. The base case and controlled NO$_x$ emission rates are summarized in Table 3.

The specific capital and annual operating costs for the SCONO$_x$™ control system are contained in Tables 8 and 9. Average cost effectiveness for the application of SCONO$_x$™ technology to the CT was determined to be $10,820 per ton of NO$_x$ removed. The control cost for SCONO$_x$™ is substantially higher than previously considered reasonable by the FDEP. One notable difference in the analysis for SCONO$_x$™ is that a catalyst maintenance agreement is assumed. Therefore, maintenance labor and catalyst replacement costs were replaced by a single $2,800,000 annual cost. Because of the high purchase cost of the SCONO$_x$™ catalyst, this annual maintenance agreement is considered to be the more economical option. The same internal cost that was assumed in the SCR analysis for unscheduled outages to correct catalyst fouling was used for the SCONO$_x$™ analysis.

In addition to the annual maintenance costs, several other items are unique to the SCONO$_x$™ system. For instance, natural gas is used for hydrogen reforming in the process to regenerate the catalyst. A significant amount of steam is required as the carrier for the gas. The cost estimates for the natural gas, steam, and electricity to run the process was based on information contained in a recent Department of Energy (DOE) cost analysis study of NO$_x$ control alternatives (DOE,1999).

Table 8. Capital Costs for SCONO$_x$™ System

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	7,845,200	A
Sales tax	470,700	0.06 x A
Instrumentation	784,500	0.01 x A
Freight	392,300	0.05 x A
HRSG Modifications	300,000	
Subtotal Purchased Equipment	**9,792,700**	**B**
Installation		
Foundations and supports	783,400	0.08 x B
Handling and erection	1,371,000	0.14 x B
Electrical	391,700	0.04 x B
Piping	195,900	0.02 x B
Insulation for ductwork	97,900	0.01 x B
Painting	97,900	0.01 x B
Subtotal Installation Cost	**2,937,800**	
Subtotal Direct Costs	**12,730,500**	
Indirect Costs		
Engineering	979,300	0.10 x B
Construction and field expenses	489,600	0.05 x B
Contractor fees	479,300	0.10 x B
Startup	195,900	0.02 x B
Performance test	97,900	0.01 x B
Contingency	293,800	0.03 x B
Subtotal Indirect Costs	**3,035,800**	
TOTAL CAPITAL INVESTMENT	**15,766,300**	(TCI)

Source: ECT, 2000.

Table 9. Annual Operating Costs for SCONO$_x$™ System

Item	Dollars	OAQPS Factor
Direct Costs		
Operator/supervisor Labor	13,800	
Maintenance Labor and Material	0	Maintenance agreement
Subtotal Labor and Maintenance Costs	**13,800**	C
System Maintenance and Catalyst Replacement (materials, labor, and disposal)	2,801,900	Maintenance agreement
Natural gas costs (H_2 reforming)*	91,400	14 ft^3/hr per MW capacity
Electricity costs*	40,400	0.6 kW per MW capacity
Steam costs (H_2 carrier)*	938,500	93 lb/hr per MW capacity
Scheduled Outages	60,000	labor and materials
Unscheduled Outages	1,934,400	labor, materials, and 6 days electrical loss
Energy Penalties		
Turbine backpressure-control system	672,800	1.0 % penalty
Turbine backpressure-catalyst plugging	672,800	0.2 % penalty
Subtotal Direct Costs	**7,226,000**	(TDC)
Indirect Costs		
Overhead	8,300	0.60 x C
Administrative charges	315,300	0.02 x TCI
Property taxes	157,700	0.01 x TCI
Insurance	157,700	0.01 x TCI
Capital recovery	2,244,800	10 yrs @ 7%
Subtotal Indirect Costs	**2,883,800**	
Emission fee credit	(23,300)	$25/ton
TOTAL ANNUAL COST	**10,086,500**	

*DOE, 1999

Source: ECT, 2000.

The annual operating costs include costs for three outages per year. For the SCONO$_x$™ system, these outages are for the cleaning of the catalyst. The outages result from the high sulfur content of the exhaust gas. In preparing the cost estimates for this analysis, it is assumed that one of the two outages can coincide with a planned outage. However, the other outages would be unscheduled. This arrangement is appropriate as the combustion turbine has a designed availability of 95 percent.

There are two main costs that are associated with an outage. The first cost is the labor and materials costs that are associated with the cleaning activities. This cost is estimated by plant engineering staff as $60,000 per occurrence. This cost would apply to both scheduled and unscheduled outages.

The cost associated with unscheduled outages was also included in the analysis. It was estimated that two unscheduled outages per year, each lasting 6 days, would occur. This would result in lost energy production from the combined CT/HRSG system. At $20 per megawatt hour (the incremental cost of power generation), this outage would result in $151,200 per day for a total of $1,814,400 per year.

The incremental cost of power generation represents the differential cost to TEC of acquiring the power that would otherwise be generated by the Polk syngas fired turbine had a forced outage due to SCONO$_x$^{TM} failure not occurred. This differential cost is the cost of the replacement power less the cost of generating the power at the Polk facility. There are a variety of factors that contribute to the determination of the incremental cost, including the availability of other units in the TEC system, and the associated costs of generating additional electricity or the purchase of power from other sources comprising the power grid. Based on an internal review of historical and projected TEC generating capability and associated costs, including purchase from the power grid, if necessary, this incremental cost is estimated at $20 per megawatt hour.

If these costs were estimates as a lost revenue factor, the total cost would be substantially higher, especially if an outage were to occur during peak demand periods. However, the costs are conservatively estimated as internal costs. These costs were assumed to be the same for both the SCR and $SCONO_x$™ systems.

As with SCR, the installation of $SCONO_x$™ technology will also cause an increase in back pressure on the CT due to the pressure drop across the catalyst bed. A $SCONO_x$™ control system for the CT is projected to have a pressure drop across the catalyst bed of approximately 5.0 inches of water. This pressure drop will result in a 1.0 percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 16,819,200 kwh (57,389 MMBtu) per year at baseload (192 MW) operation for 8,760 hr/yr. The lost power generation energy penalty, based on a power cost of $0.04/kwh, is $672,768 per year.

The fouling of the control equipment or the downstream equipment will also cause an increase in turbine backpressure. Thus, there are two energy penalties associated with each control technology. The first energy penalty is from the pressure drop across a clean configuration of the control system. The second energy penalty is from the pressure drop caused by fouling of the catalyst or the downstream exhaust equipment. It is assumed that the catalyst will be cleaned when the increased pressure drop from fouling is equal to twice the pressure drop associated with a clean system (i.e., when the total pressure drop is three times that of a clean system). For the SCONOx™ system, the nominal pressure drop is 5 inches of water. Thus, the catalyst will cleaned when the total pressure drop is at 15 inches of water. Because the catalyst condition will vary between clean and plugged, the increased pressure drop from fouling will approximately be equal to the nominal pressure drop. Hence, the annual costs associated with the pressure drop from plugging are estimated as the same costs as from the nominal pressure drop across the system.

7.0 GOOD COMBUSTION PRACTICES

Since facility start-up, including during the NO_x emissions testing period, the facility has been operating the CT in a manner that allows for reliable, stable, and reasonably economic performance of the entire IGCC facility. The facility's engineering staff have worked to identify several opportunities for reducing NO_x emissions and, as appropriate, have implemented these procedures. However, as reinforced by the nearly consistent NO_x emissions test results during the testing period[7], additional opportunities do not exist for combustion practice improvements that do not involve major capital expenditures. These expenditures/improvements represent a retrofit to the existing equipment and, as discussed previously, are not considered further in this analysis.

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[7] Test of October 17, 2000, indicated increase NO_x emissions, which is attributed to higher heating value and adiabatic flame temperature of the fuel. This increase in NO_x emissions occurred even though diluent flow was increased during this testing

8.0 OTHER PLANT EXPERIENCE

One aspect of the required BACT analysis is to survey other similar facilities and their experience and abilities in achieving low-NO_X emissions rates. The term similar facilities is taken to mean large General Electric CTs of a comparable vintage and technology to what is installed at the Polk facility which are fueled by syngas produced in a gasification plant that is similar in efficiency and configuration to Polk. Based on our analysis, there is only one similar facility, the Cinergy/Global Energy Wabash River facility located in Indiana. The facility operates a 265-MW General Electric 7FA CT that combusts syngas created using Global Energy's E-Gas process, a two-stage entrained flow gasification system and is permitted with a NO_X emissions limit of 25 ppmvd. Fuel saturation and steam injection are used to suppress NO_X formation which is a departure from the configuration at Polk which uses nitrogen diluent. The Wabash River facility indicates that typical operations involve NO_X emissions rates ranging from 22 to 24 ppmvd at 15-percent oxygen. The NO_X emissions are maintained at less than the permitted emission rate by adjusting the steam injection rate[8].

There are several other IGCC plants containing syngas-fueled CTs, most of which were recently constructed. These facilities are different enough from Polk either in fuel plant configuration, in turbine manufacturer or vintage that they do not meet the definition of "similar facilities" as discussed in Section 3. Nevertheless, these IGCC facilities are included in this discussion because most have some relevant features. There are eight main facilities comprising this category that are discussed in this section.

The first facility that was somewhat similar to the Polk facility was the commercial-scale demonstration of a 120-MW power plant conducted adjacent to Southern California Edison's Cool Water Generating Station. This facility-fired syngas produced from low and high sulfur coals (approximately 0.35 and 3.1 weight percent sulfur) in a 65-MW CT. It operated between 1984 and 1989. Note that the CT is considerably smaller in capacity (a

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[8] Conversation between Mr. John McDaniel, Tampa Electric Company, and Wabash River facility turbine operator, November 7, 2000.

GE 7E) than the one located at the Polk facility (a GE 7F). Water saturation of the fuel was used to reduce NO_x emissions, which typically averaged 22 ppmvd at 15-percent oxygen for various coals tested during the demonstration period. Based on the considerable difference in the specific turbine used at the Cool Water facility and the Polk facility, this operation is not considered a similar facility. However, it is appropriate to note that the proposed emissions limit for the Polk facility is based on an average NO_x emissions rate observed during the demonstration phase that was less than the average NO_x emissions rates observed for the Cool Water demonstration project.

The next facility is the Star Enterprises Delaware facility that was permitted in March 1998. The facility was permitted under a LAER limit of 15 ppmvd at 15-percent oxygen for a GE model PG6101FA turbine (90-MW nominal) without operation of the associated duct burner and 16 ppmvd with the operation of the associated duct burner. The basis for the LAER determination was not under the federal NSR provisions, but instead under a Delaware program as Delaware uses the "dual source" definition of stationary source as opposed to the federal plant-wide definition. In the permit application, the applicant identified that the LAER limit of 15 ppm represented an advance in permitted level for NO_x emissions, as prior to this facility the most stringent emissions limit was the 25-ppm limit that is in place for the Polk facility.

In the permit application document, Star Enterprises identifies the reason that an emissions level less than 25 ppmvd may be achievable:

> "However, because of more recent advances in diluent and fuel rate control and combustor design, lower levels (below 20 ppmvd) may be possible."

This turbine incorporates an incremental advance in emissions control technology in the combustor design, and is considered one generation of development ahead of the turbine installed at the Polk facility. An essential element of this design improvement is a relatively larger air separation plant than at Polk to provide additional diluent to the combustion turbine. The combustor modification would be of no value for NO_x reduction without the availability of additional diluent. This facility gasifies petroleum coke in Texaco quench gasifiers to produce the syngas fuel, and the syngas composition is expected to be similar to Polk's.

To locate other coal gasification CTs, the analysis expands to facilities located abroad. Note that these facilities are subject to a different set of environmental regulations than the Polk facility. However, they are used for reference when analyzing performance of somewhat similar facilities. There are two facilities in this category. The Demkolec plant located at Buggenum in the Netherlands, and the Elcogas facility funded by the EEC at Puertollano in Spain. Buggenum employs the Shell coal gasification technology and has operated primarily on various coal feedstocks but is currently blending in some waste materials. Puertollano has a very similar gasification technology, the Prenflo process, gasifying a 50/50 blend of local coal and petroleum coke. Buggenum uses a Siemens V94.2 combustion turbine (250 MW) while Puertollano uses the more advanced Siemens V94.3 (300 MW). Both use a combination of syngas saturation and nitrogen injection for NO_x control. Puertollano's permitted NO_x emissions are 150 milligrams per normal cubic meter (mg/Nm^3) at 6 percent O_2 (approximately 29 ppmvd at 15 percent O_2). The facility has reported that they are able to operate within their permit limits. Buggenum has reported that they typically operate at less than 10 ppmvd NO_x but graphical data presented at the 1998 Gasification Technology Conference shows many points up to 20 ppmvd.

There are also four recently constructed IGCC plants which produce syngas from heavy oil gasification. These four facilities, all are located in Europe, are discussed following:

- API (Falconara, Italy).
- Sarlux/Enron (Italy).
- ISAB (Priolo, Italy).
- Shell (Pernis Refinery, Netherlands).

API uses an ABB type 13E2 CT, with nitrogen diluent for syngas-fired NO_x emissions control and water injection for diesel oil-fired NO_x emissions control. API is also equipped with an SCR. The SCR may approach technical feasibility at this facility since API utilizes a more expensive deeper sulfur removal system, resulting in a fuel gas containing approximately 80 percent less sulfur than Polk's syngas fuel. The permitted NO_x emissions limits are 17 ppmvd for syngas and 42 ppmvd for oil firing. The current operational experience indicates NO_x emissions of 20 to 30 ppmvd for diesel firing and 15 to 20 ppmvd for syngas firing; however, the data collected for syngas firing are only at 66 percent of full load. Thus, it may be inferred that the facility is having some difficulty in achieving the 17-ppmvd emissions limit for syngas firing. One possible explanation for this difficulty is that, according to our information, the SCR system has not been operated, at least in part due to Greenpeace objections to the NH_3 emissions associated with SCR.

The total nominal power output rating of the Sarlux/Enron facility is 550 MW. Three GE Model 109E CTs are operated in combined-cycle mode. Each turbine is rated at 123 MW on natural gas firing and 138 MW on syngas. The facility started full operation on syngas in August 2000. The NO_x emissions limit for the facility is 60 milligrams per normal cubic meter (mg/Nm^3) at 15-percent oxygen. This limit is comparable to 30 ppmvd at 15-percent oxygen. The facility uses a high moisture fuel feed (approximately 42 percent) as the primary NO_x control mechanism. Preliminary performance information from the facility indicates this emissions limit is being met.

The ISAB facility uses two Siemens/Ansaldo V94.2K combustion turbines in combined cycle mode for a total output of 512 MW. Like Sarlux, they use syngas saturation for NO_x control, and like API, ISAB is also equipped with SCR. The permitted NO_x emissions limit is 18 ppmv and the reported operation is in the 10 to 15 ppmvd range.

Shell Pernis produces syngas that is used to supplement natural gas fuel to 2 GE MS6451B combustion turbines. This plant also is equipped with duct firing. It is reported to control NOx emissions to less than 30 ppmvd (15 percent O_2) using steam injection. This configuration is so different from Polk's that the associated NO_x experience is the least relevant of all facilities discussed in this section.

As discussed earlier in this section, these additional facilities were examined in the spirit of providing the agency with a comprehensive review of other IGCC plant operating experience. However, due to differences in turbine make, model, and vintage, fuels gasified, NOx control, and methods of operation, none of these additional facilities can be considered similar for the purposes of this review.

9.0 MANUFACTURER'S RESEARCH

GE is considering several advances in syngas fired CT design to potentially allow new model 7FA CTs to attempt to achieve 9- to 15-ppmvd NO_x emissions rates in a new and clean configuration. This range is the lower anticipated limit of NO_x performance, which incorporates both recent modifications to IGCC plant designs (i.e., greater quantity of diluent supply) along with larger combustors as described following this section. This anticipated performance is comparable to the performance that can be achieved using natural gas as a fuel. However, the advances in technology proposed to achieve this reduced emission operation are not readily adapted to the current Polk IGCC configuration without major capital expenditures (i.e., on the order of several million dollars) and successful development and application of an unproven design concept.

These changes in NO_x emissions rates will be achieved through years of development work and essentially two major generations of equipment changes. In general, it is not a simple matter to implement these changes to the equipment at Polk.

These planned advances in CT emissions performance arise from two main areas, combustor redesign to accommodate additional diluent flow and fuel plant modifications to provide the additional diluent. The Polk facility CT has a 14-inch diameter and 22-inch-long combustor, and the latest turbine design has a larger diameter and longer combustor. This increase in combustor size allows for reduced NO_x emissions by providing adequate residence time and mixing for the additional diluent. This possible combustion modification is not currently commercially available for a GE 7FA turbine. If this type of modification were to be implemented, this change would involve considerable modifications to the associated piping and physical configuration, which would involve considerable turbine downtime and substantial capital expenditures. Another concern is that this possible modification would require additional diluent to achieve any of the emissions reductions, as described in the following.

The second main area involved in the reduced emissions is the supply of additional diluent. The Polk facility uses nitrogen as a diluent. The facility is designed such that the diluent is supplied by the cryogenic air separation plant at the facility. As air is cooled, nitrogen condenses before oxygen does. The nitrogen is used as the diluent, and the oxygen is used as part of the gasification process. As part of the design of the Polk facility, the supply and demand for nitrogen diluent and oxygen supply for the gasification process were balanced. Thus, it is not a simple matter to add more diluent to the CT without affecting the relationship between the related processes. The facility is currently using the maximum amount of nitrogen diluent that is available in a stable, reliable supply, while maintaining consistent power output. Short of making major modifications to the facility or the processing parameters for essentially the entire facility, there is not an opportunity to create additional diluent for the CT.

Additionally, the Polk IGCC facility test results were reviewed with several combustion and environmental experts of GE's Power Systems Division. This review was held at the conclusion of the demonstration period and involved meetings and discussions between TEC and GE staff. Based on this review, GE has reiterated their support for a 25-ppm NO_x emissions limit for the PPS facility. This support is included in Appendix A of this submittal.

APPENDIX A

LETTER FROM GE REGARDING ANTICIPATED PERFORMANCE FOR THE PPS FACILITY TURBINE

GE Power Systems

Douglas M. Todd
Manager – Process Power Plants

General Electric Company
1 River Road, Bldg. 2 - Room 720
Schenectady, NY 12345
518 385-3791 Fax 518 385-2590

November 7, 2000

Mr. Shannon K. Todd
Tampa Electric Co.
PO Box 111
Tampa, Florida 33601-0111

Dear Mr. Todd:

GE is pleased to support Tampa Electric in the effort to complete the BACT determination for the 107FA IGCC at Polk Power Station. We have reviewed in detail your submittal to the Florida Department of Environmental Protection and concur with the conclusions.

In 1995, GE developed special technology for IGCC combustors which was based on standard size 7FA diffusion combustors modified for specific quantities of diluent waste Nitrogen available from the Texaco gasification process. The goal was to lower NOx emissions from coal fired power plants below 25 ppmvd at 15 % oxygen without using extensive amounts of diluent water. As demonstrated by some of the test results, this effort was successful. However, due to fluctuations in ambient conditions, process parameters, and fuel characteristics, NOx emissions can vary greatly as seen in the wide range of measured results.

Since 1995, GE has continued with extensive combustion development in cooperation with gasification suppliers to lower NOx emissions further as shown in your report. The current state of the art requires additional diluent injection and larger size combustors to accommodate the added diluent.

Because we understand that there is no additional diluent available from the gasification process at Polk and SCR is not suitable for the sulfur levels of the syngas, we concur that 25 ppmvd NOx at 15% oxygen is a limit with which Tampa Electric Company can reasonably assure compliance at all times.

Douglas M Todd

Douglas M. Todd

E-mail douglas.todd@ps.ge.com

APPENDIX B

EMISSIONS TEST DATA, DETAILED SUMMARY AND STATISTICAL MEASURES

TECO Polk Power Station
NOx Emissions Test Data Summary

Test Date	NO$_x$ Emission Factor (ppmdv) - average	Load (MW)	test 1	test 2	test 3
October 14, 1999	16.7	191	16.7	16.7	16.7
December 7, 1999	14.6	190	14.6	15.1	14.0
February 7, 2000	19.0	192	19.0	19.2	18.8
April 17, 2000	17.0	191	17.4	17.0	16.6
June 14, 2000	18.1	190	18.2	18.2	18.1
August 15, 2000	16.6	192	16.7	16.7	16.5
October 17, 2000	22.5	192	22.5	22.5	22.5
Average	17.80	191.14			
Median	17.00	191			
Range	8.50	2			
Median plus 1/2 range	21.25	192			
Std. Dev.	2.38	0.90			
Average + 2 sigma	22.55	N/A			
Average + 3 sigma	24.93	N/A			
Average + 6 sigma	32.06	N/A			
number of one hour tests	21				

Note: N/A = not an appropriate statistical measure for load, maximum load is established as 192 MW.

APPENDIX C

VENDOR INFORMATION FOR SCONO$_X$ SYSTEM

INTRODUCTION

ABB Alstom Power Environmental Systems (AAP) has licensed the SCONOx™ technology from Goal Line Environmental Technologies for NOx abatement on combined cycle gas turbines. Goal Line is involved in catalytic research and development, and has developed processes for the control of CO, VOC, NOx, and SOx emissions from combustion processes such as turbines, boilers and engines.

The SCONOx™ system is a breakthrough in control technology that greatly reduces NOx, CO and non-methane VOC emissions from exhaust streams without the use of ammonia. The system does not produce by-products that can coat boiler tubes, causing performance loss and corrosion. SCONOx™ also has the capacity to reduce emissions to lower levels as regulations change by simply adding more catalyst.

This ultra-clean technology is ideal for retrofit projects because of its wide operating temperature range (300°F to 700°F). This wide range offers maximum flexibility in unit location and allows for installation downstream of the HRSG. Retrofit installations do not require boiler splitting and installation can be accomplished in much less time as a result.

Because the inputs that are needed to run SCONOx™ (natural gas, water, steam, electricity, and ambient air) are already present at most power plants, the logistics of plant operation do not change when the system is installed.

Section 1

Process Details and Control

The SCONOx™ system is a breakthrough in pollution control technology that utilizes a single catalyst for the reduction of CO and NOx. The system uses no ammonia, and can operate effectively at temperatures ranging from 300°F to 700°F; making it well suited to both new and retrofit applications. Because the inputs that are needed to run SCONOx™ (natural gas, water, steam, and electricity) are already present at most power plants, the logistics of plant operation do not change when the system is installed.

Oxidation/Absorption Cycle

The SCONOx™ catalyst works by simultaneously oxidizing CO to CO_2, NO to NO_2, and then absorbing NO_2 onto its surface through the use of a potassium carbonate absorber coating. These reactions are shown below, and are referred to as the "Oxidation/Absorption Cycle".

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2$$
$$NO + \tfrac{1}{2}O_2 \rightarrow NO_2$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3$$

The CO_2 in the above reactions exhausts up the stack. Note that during this cycle, the potassium carbonate coating reacts to form potassium nitrites and nitrates, which are then present on the surface of the catalyst. This reaction can be compared to a sponge absorbing water--just as a sponge absorbs water and must be wrung out periodically, the SCONOx™ catalyst must be regenerated to maintain maximum NOx absorption. The carbonate absorber coating on the surface of the catalyst absorbs nitrogen compounds, and the catalyst must enter the regeneration cycle.

Regeneration Cycle

The regeneration of the SCONOx™ catalyst, one of the features that makes the system so unique, is accomplished by passing a controlled mixture of regeneration gases across the surface of the catalyst in the absence of oxygen. The regeneration gases react with nitrites and nitrates to form water and elemental nitrogen. Carbon dioxide in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation/absorption cycle began. This cycle is referred to as the "Regeneration Cycle", and the relevant reaction is shown below.

$$KNO_2 + KNO_3 + 4H_2 + CO_2 \rightarrow K_2CO_3 + 4H_2O + N_2$$

Water (as steam) and elemental nitrogen are exhausted up the stack instead of NOx, and potassium carbonate is once again present on the surface of the catalyst, allowing the oxidation/absorption cycle to begin again. There is no net gain or net loss of potassium carbonate after both the oxidation/absorption cycle and the regeneration cycle have been completed; the process operates as a true catalyst.

Because the regeneration cycle must take place in an oxygen free environment, a section of catalyst undergoing regeneration must be isolated from exhaust gases. This is accomplished using a set of louvers, one upstream of the section being regenerated and one downstream. During the regeneration cycle, these louvers close and a valve opens, allowing regeneration gas into the section. Tadpole seals on the isolation louvers provide a durable and effective barrier against leaks during operation. At any given time four of five of these sections are in the oxidation/absorption cycle and one of five are in the regeneration cycle. Because the same number of rows is always in the regeneration cycle, the production of regeneration gas always proceeds at a constant rate. A regeneration cycle typically is set to last for three to seven minutes, so each section is in the oxidation/absorption cycle for twelve to twenty eight minutes.

Regeneration Gas Production

The technology for producing a regeneration gas containing a dilute concentration of hydrogen from natural gas is well developed, and there are numerous reactions by which this can be accomplished. For installations below 450°F the SCONOx™ system uses an inert gas generator for the production of hydrogen and carbon dioxide. The regeneration gas will be diluted to under 4% hydrogen using steam as a carrier gas; the typical system is designed for 2% hydrogen. The appropriate reaction for producing regeneration gas is listed below.

$$CH_4 + \frac{1}{2}O_2 + H_2O \rightarrow CO_2 + 3H_2$$

For installations with operating temperatures greater than 450°F, the catalyst can be regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the SCONOx™ catalyst. The reforming catalyst intiates the conversion of methane to hydrogen, and the conversion is completed over the SCONOx catalyst.

The Reformer Catalyst works to partially reform the methane regeneration gas to hydrogen (2% by volume) to be used in the regeneration of the SCONOx™ and SCOSOx™ catalysts. The reformer converts methane to hydrogen by the steam reforming reaction shown in the equation below.

$$CH_4 + 2H_2O \rightarrow 4H_2 + CO_2$$

The Reformer Catalyst is placed upstream of the SCONOx™ catalyst in a Steam Reformer Reactor. The catalyst is designed for a minimum 50% conversion of methane to hydrogen.

A gradual decrease in temperature is indicative of sulfur masking. To impede the rate of catalyst masking a Sulfur Filter is recommended. The Sulfur Filter is placed in the inlet natural gas feed prior to the regeneration production skid. The Sulfur Filter consists of impregnated granular activated carbon that is housed in a stainless steel vessel. Spent media is discarded as a non-hazardous waste.

SCOSOx™ Sulfur Removal Catalyst

The SCOSOx™ Sulfur Removal Catalyst works in conjunction with the SCONOx™ system and removes sulfur compounds from the exhaust stream. The SCOSOx™ Sulfur Removal Catalyst utilizes the same oxidation/absorption cycle and a regeneration cycle as the SCONOx™ system. However, SCOSOx™ selectively removes the sulfur from the exhaust stream. Chemical reactions for the SCOSOx™ system oxidation/absorption cycle are shown below.

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2$$
$$SO_2 + \tfrac{1}{2}O_2 \rightarrow SO_3$$

$$SO_3 + \text{SORBER} \rightarrow [SO_3 + \text{SORBER}]$$

For the SCOSOx™ process below 500°F, the reaction for the regeneration cycle is also similar to that of the SCONOx™ catalyst:

$$[SO_3 + \text{SORBER}] + 4H_2 \rightarrow H_2S + 3H_2O + [\text{SORBER}]$$

For the SCOSOx™ process above 500°F, the reaction for the regeneration cycle follows another similar path:

$$[SO_3 + \text{SORBER}] + H_2 \rightarrow SO_2 + H_2O + [\text{SORBER}]$$

Note that the regeneration gas used for the both types of catalyst (SCONOx™ and SCOSOx™ is the same (hydrogen), allowing them to be regenerated simultaneously. The SCOSOx™ catalyst is placed upstream of the SCONOx™ catalyst, and enhances the efficiency of NOx absorption as well as removing sulfur compounds.

SCONOx™ Control System

A Programmable Logic Controller (PLC) controls the SCONOx™ system. This controller is programmed to control all essential SCONOx™ functions, including the opening and closing of louver doors and regeneration gas inlet and outlet valves, and the maintaining of regeneration gas flow to achieve positive pressure in each section during the regeneration cycle.

A control program run on a PC, supervises the system. The control program monitors, records, and reports system performance. It sends notifications and warnings when appropriate, and it allows the user to control the system by changing set points, such as pressures, regeneration cycle times, and flows. The PLC can, however, operate independently of the control program--a PC crash or loss of power will not interrupt the operation of the system.

Section 2

Project Scope

The AAP Environmental Systems Scope of Supply for execution of the Project will include services and equipment as described below. In general, the Scope of Supply can be defined by the following categories:

Process Design, Engineering and Design of the System
Project Management and Project Services
SCONOx™ and SCOSOx™ Catalyst
Catalyst Rack and Reactor Housing
Inlet and Outlet Transitions including Expansion Joints
Catalyst Module Inlet and Outlet Dampers
Regeneration Gas Production and Distribution
Regeneration Gas Condensing and Scrubbing System (Optional)
Catalyst Removal System
Control System (PLC)

Equipment and Services Provided by Others

All required permits (air, site, construction, etc.)
Supply of 480 volt power to the SCONOx system
Supply of natural gas for the SCONOx system
Supply of cooling water for the SCONOx system
Supply of 600 degree steam for the SCONOx system
Supply of compressed air for the SCONOx system
Supply of Continuous Emission Monitoring System
Mechanical Installation of the System
Electrical Installation of the System

Section 3

Equipment List

SCONOx™ Reactor Assembly

The installation will have a SCONOx™ reactor assembly that will be constructed of sub-assembled modules to form the complete assembly.

Each section will have a set of dampers, front and back, to be closed when the section is in regeneration mode. Dampers will have tadpole seals to help isolate the section during regeneration. Each section will have one inlet regeneration gas valve and two outlet regeneration gas valves, which will open sequentially when the section is in regeneration mode. Two sections will be in the regeneration cycle at any given time.

Regeneration Gas Mixing Assembly

The Regeneration Gas Mixing Assembly will contain all pressure reducing valves, flow meters, and other equipment necessary to ensure the correct ratios of inert gas and steam that are introduced into the SCONOx™ catalyst.

Regeneration Gas Distribution Piping and Valves

The regeneration gas is piped to the reformer catalyst and then to the reactor via a main header and distributed to each of the ten sections of catalyst. Each catalyst section has one inlet regeneration gas valve and two outlet regeneration gas valves at the gas entrance side of the catalyst section.

SCONOx™ Catalyst

The SCONOx™ catalyst is a proprietary catalyst manufactured by Goal Line, which simultaneously oxidizes and absorbs CO and NOx through the use of a potassium carbonate absorber coating.

SCOSOx™ Catalyst

The SCOSOx™ catalyst is very similar to the SCONOx™ catalyst, and is also manufactured only by Goal Line. The SCOSOx™ catalyst favors the absorption of sulfur compounds instead of NOx, and works to enhance the efficiency of the SCONOx™ process in the removal of NOx. SCOSOx™ catalyst blocks have the same cross-sectional dimensions as SCONOx™ blocks, but will not be as deep.

Catalyst Removal System

The catalyst is removed and replaced using a service platform, which is raised and lowered to any one of the catalyst shelves. A mechanical winch is used to pull the catalyst in and out of the selected shelf.

Control System

A programmable logic controller (PLC) runs the control system with inputs made from a PC. The PLC controls all aspects of operation for the SCONOx system. The control system is shipped pre-wired and factory tested to the extent possible. All interconnecting wiring between the control panel and the field instruments is by others.

APPENDIX D

VENDOR QUOTES FOR COMPARABLE CONTROL EQUIPMENT

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

DATE:	**October 25, 2000**	**NO. PAGES**	**3**
TO:	**ECT** **ATTN: John Shrock** **ENGELHARD** **ATTN: Nancy Ellison**	**via e-mail**	
FROM:	**Fred Booth**	**Ph 410-569-0297 // FAX 410-569-1841**	

RE: **ECT 000610-0200**
Camet® CO and NOxCAT™ VNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00990

We provide Engelhard Budgetary Proposal EPB00990 for Engelhard **Camet®** CO and **NOxCAT™ VNX™** vanadia-titania SCR Catalyst systems per your e-mail request of October 23, 2000.

Our Proposal is based on:

- CO Catalyst for 80% CO reduction;
- SCR Catalyst for NOx reduction from given inlet levels to 3.5 ppmvd @ 15% O_2 with ammonia slip of 5 ppmvd @ 15% O_2; We note your request for design with ammonia slip of 9 ppmvd @ 15% O_2. There will be only minor changes to data herein.
- Assumed HRSG inside liner dimensions of 67 ft. H x 26 ft. W;
- Assumed 19% aqueous ammonia to ammonia skid;
- Scope as noted: Typical to HRSG supplier

We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A Booth

Frederick A. Booth
Senior Sales Engineer

ENGELHARD CORPORATION
CAMET® CO CATALYST SYSTEM
NOxCAT™ VNX™ SCR NOx ABATEMENT CATALYST SYSTEM

Engelhard Corporation ("Engelhard") offers to supply to Buyer the **Camet®** metal substrate CO System and **NOxCAT™ VNX™** ceramic substrate SCR systems summarized per the technical data and site conditions provided.

Scope of Supply: The equipment supplied is installed by others in accordance with Engelhard design and installation instructions.
Engelhard **Camet®** CO and **NOxCAT™ VNX™** SCR catalyst in modules;
Internal support frames for catalyst modules - installed inside internally insulated casing (casing by others);
Ammonia Delivery System Components: Aqueous (19% Sol.) Ammonia to skid
- Ammonia Injection Grid (AIG);
- AIG manifold with flow control valves ;
- NH_3/Air dilution skid: Pre-piped & wired (including all valves and fittings)
  - Two (2) dilution air fans, one for back-up purposes
  - Panel mounted system controls for:

Blowers (on/off/flow indicators)	System pressure indicators
Air/ammonia flow indicator and controller	Main power disconnect switch

BUDGET PRICES: Per Turbine See Performance data

Excluded from Scope of Supply:

Ammonia storage and pumping
Any transitions to and from reactor
Electrical grounding equipment
Foundations
All other items not specifically listed in Scope of Supply
Internally insulated reactor Housing (HRSG Casing)
Any interconnecting field piping or wiring
Utilities
All Monitors

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	Three (3) Years of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life.
Expected Life	5 - 7 years

CO / SCR SYSTEM DESIGN BASIS:

Gas Flow from:	Combustion Turbine + Duct Burner
Gas Flow:	Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data - Designed for Gas Velocities within ±15% at the reactor inlet
Temperature (At catalyst face):	Designed for Gas Temperature with maximum range ±20°F at the reactor inlet
CO Inlet (At catalyst face):	See Performance Data
CO Reduction	80% Reduction
NOx Inlet (At catalyst face):	See Performance Data
NOx Reduction :	To 3.5 ppmvd @ 15% O_2 (NG)
NH_3 Slip:	5 ppmvd @ 15%O_2
HRSG Cross Section	67 ft. H x 26 ft. W

ENGELHARD

ECT 000610-0200
CO and SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00990
October 25, 2000

Performance Data and Budget Pricing

GIVEN / CALCULATED DATA	100% - FIRED	100% - UNFIRED	75% - UNFIRED	65% - UNFIRED
TURBINE EXHAUST FLOW, lb/hr	3,515,500	3,484,300	2,886,000	2,628,300
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	74.43	74.52	74.64	74.72
O2	12.46	12.75	13.15	13.36
CO2	3.82	3.69	3.51	3.41
H2O	8.42	8.17	7.82	7.63
Ar	0.87	0.87	0.88	0.88
GIVEN: TURBINE CO, ppmvd @ 15% O2	10	10	10	10
CALC.: TURBINE CO, lb/hr	39.3	37.5	29.5	26.1
GIVEN: TURBINE NOx, ppmvd @ 15% O2	35	35	35	35
CALC.: TURBINE NOx, lb/hr	225.7	215.7	169.4	149.9
BURNER INPUT, MMBtuh	95	0	0	0
BURNER CO ADDED, lb/MMBtuh	0.09	0.09	0.09	0.09
BURNER CO ADDED, lb/hr	8.2	0.0	0.0	0.0
BURNER NOx ADDED, lb/MMBtuh	0.08	0.08	0.08	0.08
BURNER NOx ADDED, lb/hr	7.6	0.0	0.0	0.0
TOTAL GAS FLOW AFTER BURNER, lb/hr	3,520,052	3,484,300	2,886,000	2,628,300
GAS ANALYSIS AFTER BURNER, % VOL. N2	74.26	74.52	74.64	74.72
O2	11.98	12.75	13.15	13.36
CO2	4.04	3.69	3.51	3.41
H2O	8.85	8.17	7.82	7.63
Ar	0.87	0.87	0.88	0.88
CALC. GAS MOL. WT. AFTER BURNER	28.36	28.40	28.43	28.44
TOTAL CO AFTER BURNER, lb/hr	47.5	37.5	29.5	26.1
TOTAL CO AFTER BURNER, ppmvd @ 15% O2	11.4	10.0	10.0	10.0
TOTAL NOx AFTER BURNER, lb/hr	233.3	215.7	169.4	149.9
TOTAL NOx AFTER BURNER, ppmvd @ 15% O2	34.1	35.0	35.0	35.0
FLUE GAS TEMP. @ CO and SCR CATALYST, F (+/-20)	650	650	650	650
DESIGN REQUIREMENTS				
CO CATALYST CO OUT, ppmvd @ 15% O2	3.0	3.0	3.0	3.0
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	3.5	3.5	3.5
NH3 SLIP, ppmvd @ 15% O2	5	5	5	5
GUARANTEED PERFORMANCE DATA				
CO CATALYST CO CONVERSION, % - Min.	80.0%	80.0%	80.0%	80.0%
CO OUT, lb/hr - Max.	9.5	7.5	5.9	5.2
CO OUT, ppmvd @ 15% O2 - Max.	2.3	2.0	2.0	2.0
CO PRESSURE DROP, "WG - Max.	0.6	0.6	0.5	0.4
SCR CATALYST NOx CONVERSION, % - Min.	89.7%	90.0%	90.0%	90.0%
NOx OUT, lb/hr - Max.	24.0	21.6	16.9	15.0
NOx OUT, ppmvd @ 15% O2 - Max.	3.5	3.5	3.5	3.5
EXPECTED AQUEOUS NH3 (19% SOL.) FLOW, lb/hr	458.4	437.4	343.7	304.1
NH3 SLIP, ppmvd @ 15% O2 - Max.	5	5	5	5
SCR PRESSURE DROP, "WG - Max.	2.7	2.7	2.1	1.9

CO SYSTEM	**$585,000**
REPLACEMENT CO CATALYST MODULES	**$483,000**
SCR SYSTEM	**$1,738,000**
REPLACEMENT SCR CATALYST MODULES	**$1,250,000**

Dear Mr. Shrock,

Please note the following in response to your inquiry of last week, requesting budget pricing for two SCONOx systems on S-W V84.3a2 CCGTs. Pricing provided is on a per unit basis.

The specified temperature range was 300 to 700 degrees F. We have assumed an operating temperature of 600 degrees F, consistent with typical SCR operating temperatures. Should the temperature be significantly lower than 600 F, additional catalyst may be required.

The NOx emission reduction from 35 to 2 ppm is more than the typical application with 25 ppm or less NOx emissions. This reduction efficiency requirement of 95% results in additional catalyst, and this is reflected in the cost.

The SCONOx system will reduce CO emissions by 90%, so the system will exceed the specified CO reduction requirement, at no additional cost.

Leasing of the catalyst utilized in the SCONOx system is our preferred commercial framework, as this reduces the initial cost and provides our customers with a long-term commitment by ALSTOM Power for the performance of the SCONOx system. In this arrangement, the physical and mechanical equipment only is sold, and the required catalyst is leased on a long term basis, complete with catalyst and equipment maintenance.

Budgetary numbers for the leasing program include $7 million dollars for the initial equipment, with a annual lease cost of $2.5 million dollars. These numbers are budgetary only and are subject to change pending resolution of technical, scope, and commercial terms.

The budgetary price for the supply of the complete system, in accordance with the information provided, including catalyst, based on the prevailing price of platinum, is $20 million dollars.

I trust this meets with your immediate needs, but please call me if you have any questions.

Sincerely,

Rick Oegema
Product Manager

(Embedded image moved to file: pic22424.pcx)   jshrock@ectinc.com
10/16/2000 09:45 AM

Please respond to jshrock@ectinc.com