# Department of Environmental Protection

Jeb Bush
Governor

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

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. 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

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

| | | |
|---|---|---|
| Postage | $ | |
| Certified Fee | | Postmark Here |
| Return Receipt Fee (Endorsement Required) | | 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

**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

***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

DEC 19 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 3000

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**

Check Message

Dec 14 '01 13:18

| | | |
|---|---|---|
| D.0.7 | Check condition of remote Fax. | 68136415081 |

# 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
Laura Crouch, TEC
Shannon Todd, TEC
Howard Rhodes, FDEP
Clair Fancy, FDEP
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**

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 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 SCO-NOX 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 ofNOx 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 1 3 2001

4 APT-ARB

RECEIVED
JUN 1 8 2001
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
G. 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 0 5 2001



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. Hennick, TEC
B. Oven, DEP, PPSO
B. Thomas, SWD
J. Spence, Polk Co. ESD
J. Davis, P.E., ECT
J. Bunyak, NPS

TECO

TAMPA ELECTRIC

RECEIVED

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 <u>assuming that the SCR system does not impact the availability of Polk Unit 1</u>. These are significant issues, and TEC requests that the Department include it in its analysis of this project.

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

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

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

**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

**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 ______

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

Susie Lee Slaton

cc: M. Halpin
B. Thomas, SWD
G. Spence, Polk Co ESD
B. Oven, DEP
G. Worley, EPA
G. 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 clean-up 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 fact. If there are none, the petidicated 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.

?651 5/23/01