Mitchell, Bruce

From: Forney.Kathleen@epamail.epa.gov
Sent: Friday, April 18, 2008 3:07 PM
To: Mitchell, Bruce
Cc: Forney.Kathleen@epamail.epa.gov
Subject: TECO - Bayside (PSD-FL-399)

Attachments: TECO Bayside Comments.doc; TECO Bayside SCR Cost Analysis.xls

TECO Bayside :omments.doc (35 .. TECO Bayside SCR Cost Analysis...

Hey Bruce,

Attached are my comments on the PSD permit application for the TECO Bayside addition of 8 Pratt & Whitney FT8-3 SwiftPac simple cycle combustion turbines. I am also attaching an excel spreadsheet in which I revised a few of the assumptions used in the applicant's cost analysis for the SCR systems. Additionally, I would remind FDEP that EPA does not have a brightline test or a set threshold for what is too expensive in terms of evaluating a control technology and BACT determinations are case-by-case analyses. Please give me a call if you have any questions or would like to discuss this project further.

Thanks,
Katy

(See attached file: TECO Bayside Comments.doc)(See attached file: TECO Bayside SCR Cost Analysis.xls)

Katy R. Forney
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EPA - Region 4
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EPA Comments - TECO Bayside Power Station in Tampa, Florida.

1. The definition of BACT in the Clean Air Act, in federal PSD regulations, and in Florida's implementing regulations is primarily in terms of an emissions limitation. By far the majority of simple cycle combustion turbines (CT) approved in recent years have been approved with a NO_x BACT emissions limitations between 9 ppmvd and 15 ppmvd (at 15 percent oxygen) when burning natural gas. The PSD permit application did not provide any documentation or analysis supporting the BACT emission limit of 25 ppmvd. A more detailed analysis should be provided before FDEP reaches a final decision on BACT for the simple cycle CTs.

2. According to the PSD application, the annual emissions for this project were calculated using the operating scenario of 59°F and 100% load. Although this seems to be the worst case scenario for NO_x emissions, according to Table B-4 in the appendix, CO and VOC emissions are actually higher at 20 and 50% load at 9.1 lb/hr and 5.1 lb/hr, respectively. The calculation of annual emissions should be done using the worst case scenario for each regulated NSR pollutant and PSD applicability should be evaluated based on the revised annual emissions calculations.

3. Upon review of the BACT economic analysis for SCR control of NO_x emissions from the simple cycle CTs, EPA had the following comments:

    a. The applicant should provide a recent detailed vendor quote specific to the project for the selective catalytic reduction (SCR) system. Without a current vendor quote, it is unclear what is included in the Purchased Equipment Cost (PEC) of $16,104,000 or why it is so high. In a similar project in Florida (Seminole - Payne Creek in 2005) the applicant provided a cost analysis for SCR systems on 10 Pratt & Whitney FT8-3 simple cycle combustion turbines with a total PEC of $11, 227,500. This is about an 80% increase in the cost of each SCR over a 3 year period. Additionally, it is unclear whether the applicant considered installing 4 SCR units (one for each SwiftPac set of turbines) or 8 SCR units (one for each combustion turbine). The BACT cost analysis should reflect the operating scenario that is being considered, especially if it would result in a more cost effective use of the SCR systems.

    b. Given the routine nature of SCR installations on CTs, it is unnecessary to include both a 5% Process Contingency cost and a 15% Project Contingency cost. It is more appropriate in this case to include the standard 3% process contingency figure often used in BACT cost calculations.

    c. It is not clear what is included in the Preproduction Cost value of $577,800. If there are costs included in this figure that, if utilizing a standard cost evaluation method would normally have fallen into another category, then they may be included; otherwise it is not appropriate to include in the cost evaluation.

d. The annual operating cost calculation includes a \$208,800/year value as the Energy Penalty due to turbine backpressure. It is our understanding that this cost was estimated using the lost power generation and cost of electricity at \$0.030/kWh. Although it is appropriate to calculate the cost of the CT backpressure due to SCR, it should be based on the cost of the additional fuel combusted to replace the lost power and not the current price of electricity. Finally, although they cited FDEP as the source, it is still unclear how the \$.030/kWh was derived.

TECO Bayside SCR Cost Analysis

	Proposed by TECO Bayside		Revised by EPA	
	Dollars		**Dollars**	**% of DC**
Direct Capital Cost				
Equipment Cost	$16,104,000		$16,104,000	How many SCR's? No Details or vendor quote
Instrumentation	$0		$0	
Frieght	$0		$0	
Total Purch. Equip. Cost (PEC)	**$16,104,000**		**$16,104,000**	
Installation Cost				
Foundations & Support	$1,288,320	0.08 x PEC	$1,288,320	0.08 x PEC
Handling & Erection	$2,254,560	0.14 x PEC	$2,254,560	0.14 x PEC
Electrical	$644,160	0.04 x PEC	$644,160	0.04 x PEC
Piping	$322,080	0.02 x PEC	$322,080	0.02 x PEC
Insulation for ductwork	$161,040	0.01 x PEC	$161,040	0.01 x PEC
Painting	$161,040	0.01 x PEC	$161,040	0.01 x PEC
Total Installation Cost (TIC)	**$4,831,200**		**$4,831,200**	
Total Direct Capital Cost (DCC)	**$20,935,200**		**$20,935,200**	
Indirect Installation Cost				
General Facilities	$1,046,760	0.05 x DCC	$1,046,760	0.05 x DCC
Engineering & Home Office Fees	$2,093,520	0.10 x DCC	$2,093,520	0.10 x DCC
Process Contingency	$1,046,760	0.05 x DCC	$628,056	0.03 x DCC
Total Indirect Installation Cost	**$4,187,040**		**$3,768,336**	
Project Contingency (PC)	**$3,768,336**	0.15 x (DCC + IIC)	**$0**	not warranted since SCR is common
Total Plant Cost (TPC)	**$28,890,576**	**DCC + IIC + PC**	**$24,703,536**	**DCC + IIC + PC**
Preproduction Costs (PPC)	**$577,812**	0.02 X TPC	**$0**	No reason for this cost to be included
Initial Ammonia Inventory Cost	**$12,436**	14 days supply	**$12,436**	14 days supply
Total Capital Investment (TCI)	**$29,480,824**	**TPC + PPC**	**$24,715,972**	**TPC + PPC**
Direct Annual Costs	**Dollars**	**Notes - BACT Cost Analysis**	**Dollars**	**Notes - BACT Cost Analysis**
Maintenance & Labor	$442,212	0.015 x TCI	$370,740	0.015 x TCI
Catalyst Cost				
replacement (mat. & labor) (RC)	$1,200,000		$1,200,000	
disposal				0.02 x RC
Total Catalyst Replacement Cost (CRC)	**$1,200,000**		**$1,200,000**	
Capital Recovery Factor	0.2953	7% @ 4 years	0.1856	7% @ 7 years
Annualized Catalyst Cost (ACC)	**$354,300**		**$222,664**	CRC x FWF
Energy Cost	$200	OAQPS Algorithm	$200	OAQPS Algorithm
Anhydrous Ammonia (AA)	$ 92,500	$480/ton	$ 92,500	$480/ton
Energy Penalty (EP) - CT backpressure	$208,800	0.2 /inch dP	$20,880	use cost of NG, not $0.030/kwh
Emission Fee Credit (EFC)	-$8,600	$25/ ton Nox	-$8,600	$25/ ton Nox
Total Direct Cost (TDC)	**$1,089,412**		**$698,383**	
Indirect Annual Costs				
Capital Recovery Factor (CRF)	0.1098	7% @ 15 years	0.1098	7% @ 15 years
Capital Recovery	$3,105,100		$2,713,681	
Total Indirect Annual Costs (TIC)	**$3,105,100**		**$2,713,681**	
Total Annual Costs	**$4,194,512**	TCD + TIC	**$3,412,064**	TCD + TIC
Total Cost Effectiveness ($/ton)	$\boxed{\$14,564}$		$\boxed{\$11,847}$	
TPY NOx Removed	288	90% removal efficiency	288	90% removal efficiency

Method 29 Determination of Lead~~, Beryllium,~~ and Mercury from Stationary Sources (I).

Prior to installation and certification of the THC monitor, permittee shall determine and record the THC content for each incoming shipment of raw materials through the Department's Method FL-PRO or through some other method approved by DERM. Such records shall be made available to DERM upon request.

Emission testing shall be performed at the kiln/cooler main stack during a period when the kiln precalciner, cooler, raw mill and preheater are operating simultaneously and under normal operating conditions. EPA-reference methods for sampling pollutants shall be as specified in 40 CFR 60, Appendix A. Prior to any emission testing to demonstrate compliance with any emission limit, the permittee shall determine the clinker production rate for the test according to a factor based on the preheater/precalciner feed rate and notify DERM in advance of the commencement of any test(s). That rate of clinker production shall be used to determine compliance with all clinker-based emission limits in the permit for that test.

These emission units shall comply with all applicable requirements of Rule 62-297.310, F.A.C. General Test Requirements and 40 CFR 60.8. Performance Tests. Revised Table 2-1, Compliance Requirements (attached) also lists the EPA methods.

Testing of emissions shall be conducted with the emission unit operating at capacity and under the different permitted fuels scenarios (petroleum coke, coal, on or off specification used oil, TDF, solid waste, etc.) as specified in Specific Condition No.B.5. Fuel Combustion. The permittee shall provide DERM with a *protocol* that will outline the different fuel scenarios (% of total heat input) that this unit will be burning. Rinker shall obtain the test data necessary to determine whether this kiln is capable of accommodating the burning of coal or petroleum coke and all of the other supplemental fuels specified on Specific Condition B.5. Fuel Combustion. The fuel scenarios tested shall represent the actual combustion percentage (% of total heat input) that is going to be maintained while burning supplemental fuels during normal operation. The frequency of testing shall be determined by DERM.

Permitted capacity is defined as 90-100% of the maximum operating rate allowed by the permit. If it is impracticable to test at permitted capacity, then the unit may be tested at less than 90% of the maximum operating rate allowed by the permit; in this case, subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen consecutive days for the purpose of additional compliance testing to regain the permitted capacity in the permit. **[Rules 62-204.800, 62-297.310, 62-297.400, 62-297.401, F.A.C., and 40 CFR 60 Appendix A and 40 CFR 60.8, Subpart A].**

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. The enclosed Best Available Control Technology determination for VOC is hereby made part of the permit file. The Miami-Dade DERM will revise the present Title V Operation Permit as advised in the Notice of Final (Title V) Permit dated October 31, 2000 and to incorporate additional changes resulting from this permitting action.

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

Executed in Tallahassee, Florida.

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management