TAMPA ELECTRIC
A TECO ENERGY COMPANY

RECEIVED

SEP 27 1990

DER - BAQM

September 26, 1990

VIA FEDERAL EXPRESS
Airbill #7284300951

Mr. Claire Fancy
Florida Department of
Environmental Regulation
Twin Towers Office Bldg.
2600 Blair Stone Road
Tallahassee, FL 32399-2449

Re: Hardee Power Station
Response to Request for Additional Information

Dear Mr. Fancy:

During our meeting of August 10, 1990, you made two requests. Your first request was to estimate the cost effectiveness of utilizing the SCR on oil with a removal efficiency of 65%, with a fuel split of 80% natural gas and 20% oil, and at a capacity factor of 60%. The results of our estimate show a cost effectiveness of $5,078 per ton of NO_x removed. It must be noted that this is an estimate only, since there is no experience base of SCRs successfully running on oil. Included was an estimate for heat rate degradation due to fouling in the HRSG, capacity degradation for same, costs for periodic wash down of the HRSG, and costs for HRSG tube maintenance associated with corrosion. Costs for reduced availability and for research and development of this process have not been included. No cost has been assigned to increased particulate emissions.

Your second request was for a copy of our models. Enclosed is a disc containing three files: DER6YR, DER65OIL, and DER42PPM. DER6YR contains the information used for the three-year catalyst replacement with O&M costs varied by fired hours up to a maximum of six years. In this case the SCR runs on gas only. DER65OIL is essentially the same case, only the SCR also runs with oil (20% of operation) at a 65% removal efficiency. DER42PPM contains the case demonstrating the cost to obtain 42 ppm when firing with oil.

Attached is a printout of each file. Attachment 1 is the printout of DER6YR. Attachment 2 is the printout of DER65OIL. Attachment 3 is the printout of DER42PPM. At the end of each printout is a printout of the formulas utilized with an explanation of these formulas. These latter worksheets are also contained within each of their respective files. Each file is a LOTUS 123 (Version 2.01) WK1 file.

I hope that this fulfills your requests.

Sincerely,

Jerry L. Williams

Jerry L. Williams
Director TPS
Environmental

JLW/sn/LL428.DOC

Enclosures

cc: TECO Power Services Corp.
Seminole Electric Cooperative, Inc.

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)

Capacity factor	25	30	40	50	60	70	80	90	100
% Natural Gas firing	80	80	80	80	80	80	80	80	80
% No. 2 Fuel Oil firing	20	20	20	20	20	20	20	20	20
Annual Costs, $X1000									
Direct Annual Cost									
Differential O&M Cost (2)	1,547	1,547	1,547	1,547	1,935	2,324	2,713	3,101	3,490
Ammonia (3)	120	144	192	240	288	336	384	432	480
Energy (4)									
Heat Rate Penalty	448	538	717	896	1,076	1,255	1,434	1,614	1,793
SCR Power Consumption	209	251	335	419	503	586	670	754	838
Lost Generation Capacity (5)	370	370	370	370	370	370	370	370	370
Total Direct Annual Cost	2,694	2,850	3,161	3,472	4,172	4,871	5,571	6,271	6,971
Indirect Annual Cost									
Capital Recovery (1)	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268
Admin, Property Taxes, and Insurance	598	598	598	598	598	598	598	598	598
Total Indirect Annual Cost	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866
Total Annual Cost	7,560	7,716	8,027	8,338	9,038	9,737	10,437	11,137	11,837
NOx Emissions									
42ppm natural gas, tpy	841	1,009	1,346	1,682	2,018	2,355	2,691	3,028	3,364
9ppm natural gas, tpy	168	202	269	336	404	471	538	606	673
Removed, tpy	673	807	1,076	1,346	1,615	1,884	2,153	2,422	2,691
Cost Effectiveness, $/ton	11,237	9,557	7,457	6,196	5,597	5,169	4,848	4,598	4,398

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)

Capacity factor	25	30	40	50	60	70	80	90	100
% Natural Gas firing	100	100	100	100	100	100	100	100	100
% No. 2 Fuel Oil firing	0	0	0	0	0	0	0	0	0
Annual Costs, $X1000									
Direct Annual Cost									
Differential O&M Cost (2)	1,547	1,547	1,547	1,547	1,935	2,324	2,713	3,101	3,490
Ammonia (3)(7)	150	180	240	300	360	420	480	540	600
Energy (4)									
Heat Rate Penalty	428	513	685	856	1,027	1,198	1,369	1,540	1,711
SCR Power Consumption	262	314	419	524	628	733	838	942	1,047
Lost Generation Capacity (5)	370	370	370	370	370	370	370	370	370
Total Direct Annual Cost	2,756	2,924	3,260	3,596	4,320	5,045	5,769	6,494	7,219
Indirect Annual Cost									
Capital Recovery (1)	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268
Admin, Property Taxes, and Insurance	598	598	598	598	598	598	598	598	598
Total Indirect Annual Cost	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866
Total Annual Cost	7,622	7,790	8,126	8,462	9,186	9,911	10,636	11,360	12,085
NOx Emissions									
42ppm natural gas, tpy	1,051	1,262	1,682	2,103	2,523	2,944	3,364	3,785	4,205
9ppm natural gas, tpy (6)	210	252	336	421	505	589	673	757	841
Removed, tpy	841	1,009	1,346	1,682	2,018	2,355	2,691	3,028	3,364
Cost Effectiveness, $/ton	9,063	7,719	6,039	5,031	4,551	4,209	3,952	3,752	3,592

TECO Power Services - Hardee Power Station
SCR CAPITAL COSTS ($X1000)

SCR Reactor	12,750
SCR Auxilliaries and Ammonia Storage	1,500
SCR Erection	2,625
Foundations, Ammonia System Erection & BOP Equipment	450
Contingency (10%)	1,733
Subtotal	19,058
Sales Tax (6%)	1,143
Indirect costs (14.5%)	2,763
Subtotal	22,964
Escalation (4.7%)	1,620
Total Escalated Cost	24,584
Interest During Construction	3,095
Total Capital Investment	27,679

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)

NOTE:

1. Based on a Total Capital Investment of $27,680,000 with a project specific capital recovery factor of 15.42%. Administrative costs, property taxes, and insurance utilize a factor of 2.16% of Total Capital Investment. The sum of these two factors represent the project specific fixed charge rate of 17.58%.
2. Differential O&M includes maintenance & labor and catalyst replacement. Complete replacement after 3 years of fired hours with a maximum interval of 6 years.
3. Ammonia cost is based on $250/ton and a stoichmetric ratio of 1.2.
4. Energy includes auxilliary power for the SCR as well as a 0.42% CT heat rate penalty for the SCR. The additional fuel cost associated with heat rate penalty utilizes Tampa Electric Company's (TEC) current levelized fuel cost forecast of $11.68/MBtu for natural gas and $14.49 for oil.
   Increased BOP power consumption is charged at $99.98/MWh. This latter factor also utilized the TEC fuel cost forecast.
5. The SCR lost generation capacity is based on an 0.42% penalty. An incremental levelized demand charge of $81.64/kW/yr was utilized based on project specific parameters.
6. SCR removal efficiency is assumed to be 80%.
7. Ammonia feed is assumed to be off when unit is being fired with oil.

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)

Capacity factor	60		6	60
			7	
% Natural Gas firing	100		8	100
% No. 2 Fuel Oil firing	0		9	0
			10	
Annual Costs, $X1000			11	
===================			12	
Direct Annual Cost			13	
Differential O&M Cost (2)	1,935	A	14	3490*(1.11375*U6-11.375)/100
Ammonia (3)	360	B	15	600*(U6/100)*U8/100
Energy (4)			16	
Heat Rate Penalty	1,027	C	17	1.1*(1380*(11.68/10.36)*(U8/100)*(U6/100)+1700*(14.49/12.79)*(U9/100)*(U6/100))
SCR Power Consumption	628	D	18	930*(99.98/88.8)*(U8/100)*(U6/100)
Lost Generation Capacity (5)	370	E	19	220*(81.64/48.54)
	-----		20	-----
Total Direct Annual Cost	4,320		21	@SUM(U19..U14)
			22	
Indirect Annual Cost			23	
Capital Recovery (1)	4,268	F	24	27680*0.1542
Admin, Property Taxes, and Insurance	598	F	25	27680*0.0216
			26	
	-----		27	-----
Total Indirect Annual Cost	4,866		28	@SUM(U26..U24)
			29	
Total Annual Cost	9,186		30	+U28+U21
			31	
NOx Emissions			32	
=============			33	
42ppm natural gas, tpy	2,523	G	34	4205*(U8/100)*(U6/100)
9ppm natural gas, tpy	505		35	0.2*U34
	-----		36	-----
Removed, tpy	2,018		37	+U34-U35
			38	
			39	
Cost Effectiveness, $/ton	4,551		40	(U30*1000)/U37

FORMULA NOTES

A. Differential O&M Cost: The $3,490,000 (from B&V/GE input and TPS project specific factors) is for the 3 year catalyst replacement at 100% capacity factor. The equation which follows was developed to distribute the appropriate figure depending on the capacity factor (and firing hours) of the station.
B. Ammonia: The $600,000 (from B&V/GE) is based on ammonia at $250/ton. This figure varies with capacity factor and gas usage.
C. Heat Rate Penalty: The $1,380,000 and the $1,700,000 (from B&V/GE) are based on a 0.42% heat rate degradation accross the CT and $10.36/MBtu and $12.79/MBtu for levelized fuel forecasts for natural gas and oil, respectively. These values were corrected for the higher heating value for which fuel is purchased and for the current TEC forecast for fuel ($11.68/MBtu and $14.49/MBtu for natural gas and oil respectively). The heat rate penalty varies with capacity factor and respective fuel usage.
D. SCR Power Consumption: The $930,000 (from B&V/GE) is the estimate for power consumption by the dilution air fans, additional pump power, and the ammonia vaporizer at a charge of $88.80/MWHr. This was corrected to the recent TEC forecasts of $99.98/MWHr. This penalty varies with capacity factor and gas usage.
E. Lost Generation Capacity: The $220,000 (from B&V/GE) is based on a 0.45% decrease in capacity utilizing a $48.54/kw/yr demand charge. This was corrected to a project specific demand charge of $81.64/kw/yr.
F. Capital Recovery: See note 1.
G. Emissions: The 4205 tons per year (from B&V/GE) varies with capacity factor and gas usage.

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)
SCR ON OIL WITH 65% REMOVAL

Capacity factor	25	30	40	50	60	70	80	90	100
% Natural Gas firing	80	80	80	80	80	80	80	80	80
% No. 2 Fuel Oil firing	20	20	20	20	20	20	20	20	20
Annual Costs, $X1000									
Direct Annual Cost									
Differential O&M Cost (2)	1,571	1,572	1,575	1,563	1,954	2,346	2,738	3,130	3,522
Ammonia (3)	150	180	240	300	360	420	480	540	600
Energy (4)									
Heat Rate Penalty	1,041	1,250	1,666	2,083	2,499	2,916	3,332	3,749	4,166
SCR Power Consumption	274	329	439	549	658	768	878	988	1,097
Lost Generation Capacity (5)	485	485	485	485	485	485	485	485	485
Total Direct Annual Cost (7)	3,521	3,816	4,405	4,979	5,957	6,935	7,913	8,892	9,870
Indirect Annual Cost									
Capital Recovery (1)	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268	4,268
Admin, Property Taxes, and Insurance	598	598	598	598	598	598	598	598	598
Total Indirect Annual Cost	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866	4,866
Total Annual Cost	8,387	8,682	9,271	9,845	10,823	11,801	12,780	13,758	14,736
NOx Emissions									
42ppm natural gas, tpy	841	1,009	1,346	1,682	2,018	2,355	2,691	3,028	3,364
9ppm natural gas, tpy	168	202	269	336	404	471	538	606	673
Removed on gas, tpy	673	807	1,076	1,346	1,615	1,884	2,153	2,422	2,691
65ppm oil, tpy	331	397	530	662	795	927	1,060	1,192	1,325
Emissions with 65% removal	116	139	185	232	278	325	371	417	464
Removed on oil, tpy	215	258	344	430	517	603	689	775	861
Total removed, tpy (6)	888	1,066	1,421	1,776	2,131	2,487	2,842	3,197	3,552
Cost Effectiveness, $/ton	9,444	8,147	6,525	5,543	5,078	4,746	4,497	4,303	4,148

TECO Power Services - Hardee Power Station
SCR CAPITAL COSTS ($X1000)

SCR Reactor	12,750
SCR Auxilliaries and Ammonia Storage	1,500
SCR Erection	2,625
Foundations, Ammonia System Erection & BOP Equipment	450
Contingency (10%)	1,733
Subtotal	19,058
Sales Tax (6%)	1,143
Indirect costs (14.5%)	2,763
Subtotal	22,964
Escalation (4.7%)	1,620
Total Escalated Cost	24,584
Interest During Construction	3,095
Total Capital Investment	27,679

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)
SCR ON OIL WITH 65% REMOVAL

NOTE:

1. Based on a Total Capital Investment of $27,680,000 with a project specific capital recovery factor of 15.42%. Administrative costs, property taxes, and insurance utilize a factor of 2.16% of Total Capital Investment. The sum of these two factors represent the project specific fixed charge rate of 17.58%. No capital additions were made for the case of running SCR with oil. Operation experience is necessary to determine appropriate modifications.
2. Differential O&M includes maintenance & labor and catalyst replacement. Complete replacement after 3 years of fired hours with a maximum interval of 6 years. For the case of SCR on oil, O&M also includes some annual tube replacements and washing of the HRSG.
3. Ammonia cost is based on $250/ton and a stoichmetric ratio of 1.2.
4. Energy includes auxilliary power for the SCR as well as a 0.42% CT heat rate penalty for the SCR. An additional 5% heat rate penalty was assessed against the steam turbine generator due to fouling of the HRSG when firing on oil.
   The additional fuel cost associated with heat rate penalty utilizes Tampa Electric Company's (TEC) current levelized fuel cost forecast of $11.68/MBtu for natural gas and $14.49 for oil.
   Increased BOP power consumption is charged at $99.98/MWh. This latter factor also utilized the TEC fuel cost forecast.
5. The SCR lost generation capacity is based on an 0.42% penalty, as well as a 5% steam turbine penalty when firing on oil and operating the SCR.
   An incremental levelized demand charge of $81.64/kW/yr was utilized based on project specific parameters.
6. SCR removal efficiency is assumed to be 80% on natural gas firing and 65% on oil firing.
7. Costs associated with reduced availability and with the research and development expected during operation of the SCR when firing on oil have not been included. Included costs are a rough estimate since there is no experience base for successfully firing on oil.

TECO Power Services - Hardee Power Station
SCR - THREE YEAR CATALYST REPLACEMENT
O&M varied based on firing hours
(Maximum interval of 6 years)
SCR ON OIL WITH 65% REMOVAL

			COLUMN R ROW	
Capacity factor	60		7	60
			8	
% Natural Gas firing	80		9	80
% No. 2 Fuel Oil firing	20		10	20
			11	
Annual Costs, $X1000			12	
===================			13	
Direct Annual Cost			14	
Differential O&M Cost (2)	1,954	A	15	(3490*(1.11375*R7-11.375)/100)+160*(R7/100)*R10/100
Ammonia (3)	360	B	16	600*(R7/100)
Energy (4)			17	
Heat Rate Penalty	2,499	C	18	1.1*(1380*(11.68/10.36)*(R9/100)*(R7/100)+1700*(6.6)*(14.49/12.79)*(R10/100)*(R7/100))
SCR Power Consumption	658	D	19	930*((99.98/88.8)*(R9/100)+(124.03/88.8)*(R10/100))*(R7/100)
Lost Generation Capacity (5)	485	E	20	220*(81.64/48.54)*1.31
	-----		21	-----
Total Direct Annual Cost	5,957		22	@SUM(R20..R15)
			23	
Indirect Annual Cost			24	
Capital Recovery (1)	4,268	F	25	27680*0.1542
Admin, Property Taxes, and Insurance	598	F	26	27680*0.0216
			27	
	-----		28	-----
Total Indirect Annual Cost	4,866		29	@SUM(R27..R25)
			30	
Total Annual Cost	10,823		31	+R29+R22
			32	
NOx Emissions		G	33	
============			34	
42ppm natural gas, tpy	2,018		35	4205*(R9/100)*(R7/100)
9ppm natural gas, tpy	404		36	0.2*R35
	-----		37	-----
Removed on gas, tpy	1,615		38	+R35-R36
			39	
65ppm oil, tpy	795		40	6623*(R10/100)*(R7/100)
Emissions with 65% removal	278		41	+R40*0.35
	-----		42	-----
Removed on oil, tpy	517		43	+R40-R41
			44	
Total removed, tpy	2,131		45	+R43+R38
			46	
Cost Effectiveness, $/ton	5,078		47	(R31*1000)/R45

FORMULA NOTES

A. Differential O&M Cost: The $3,490,000 (from B&V/GE input and TPS project specific factors) is for the 3 year catalyst replacement at 100% capacity factor. The equation which follows was developed to distribute the appropriate figure depending on the capacity factor (and firing hours) of the station. The $160,000 is the estimated cost for tube replacements and HRSG wash downs. This figure varies with capacity factor and oil usage.
B. Ammonia: The $600,000 (from B&V/GE) is based on ammonia at $250/ton. This figure varies with capacity factor.
C. Heat Rate Penalty: The $1,380,000 and the $1,700,000 (from B&V/GE) are based on a 0.42% heat rate degradation accross the CT and $10.36/MBtu and $12.79/MBtu for levelized fuel forecasts for natural gas and oil, respectively. These values were corrected for the higher heating value for which fuel is purchased and for the current TEC forecast for fuel ($11.68/MBtu and $14.49/MBtu for natural gas and oil respectively). The factor of 6.6 on oil was the developed estimate for utilizing the SCR on oil. It was based on a 5% heat rate degradation accross the steam turbine due to fouling of the HRSG. The heat rate penalty varies with capacity factor and respective fuel usage.
D. SCR Power Consumption: The $930,000 (from B&V/GE) is the estimate for power consumption by the dilution air fans, additional pump power, and the ammonia vaporizer at a charge of $88.80/MWHr. This was corrected to the recent TEC forecasts of $99.98/MWHr and $124.03/MWHr for gas and oil respectively. This penalty varies with capacity factor and gas and oil usage respectively.
E. Lost Generation Capacity: The $220,000 (from B&V/GE) is based on a 0.45% decrease in capacity utilizing a $48.54/kw/yr demand charge. This was corrected to a project specific demand charge of $81.64/kw/yr. The factor of 1.31 on oil was the developed estimate of the lost generation for utilizing the SCR on oil. It was based on a 5% capacity degradation.
F. Capital Recovery: See note 1.
G. Emissions: The 4205 tons per year and the 6623 tons per year (from B&V/GE) vary with oil usage and capacity factor.

TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil

Capacity factor	25	30	40	50	60	70	80	90	100
% Natural Gas firing	80	80	80	80	80	80	80	80	80
% No. 2 Fuel Oil firing	20	20	20	20	20	20	20	20	20
Annual Costs, $X1000									
Direct Annual Cost									
Differential O&M Cost (2)	464	465	468	470	473	475	478	480	483
Energy (3)									
Heat Rate Penalty	473	568	757	947	1,136	1,325	1,515	1,704	1,893
Pump Power Consumption	10	13	17	21	25	29	34	38	42
Lost Generation Capacity (4)	(229)	(229)	(229)	(229)	(229)	(229)	(229)	(229)	(229)
Total Direct Cost	719	817	1,013	1,209	1,405	1,601	1,797	1,993	2,189
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	1340	1438	1634	1830	2026	2222	2418	2614	2810
NOx Emissions									
65ppm oil, tpy	331	397	530	662	795	927	1,060	1,192	1,325
42ppm oil, tpy	214	257	342	428	514	599	685	770	856
Removed, tpy	117	141	187	234	281	328	375	422	469
Cost Effectiveness, $/ton	11,437	10,228	8,717	7,810	7,206	6,774	6,450	6,199	5,997

TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil
Capital costs ($X1000)

Differential Combustion Turbine Costs	0
HRSG Modification	763
Water Treatment, Storage, and Injection Equipment	1,163
Foundations & BOP Equipment	288
Contingency (10%)	221
Subtotal	2,435
Sales Tax (6%)	146
Indirect costs (14.5%)	353
Subtotal	2,935
Escalation (4.7%)	205
Total Escalated Cost	3,140
Interest During Construction	395
Total Capital Investment	3,535

TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil

NOTE:

1. Based on a Total Capital Investment of $3,533,000 with a project specific capital recovery factor of 15.42% Administrative costs, property taxes, and insurance utilize a factor of 2.16% of Total Capital Investment. The sum of these two factors represent the project specific fixed charge rate of 17.58%.
2. Differential O&M includes BOP maintenance and water treatment chemical costs. Inspection intervals decrease from 6500 operating hours to 1500 operating hours. This increases maintenance $2,288,000 per year of 100% oil firing.
3. Energy includes increased BOP power consumption as well as a 1.2% CC heat rate penalty for the additional injection. The additional fuel cost associated with heat rate penalty utilizes Tampa Electric Company's current levelized fuel cost of $14.49/MBtu for oil. Increased BOP power consumption is charged at $124.03/MWh for oil.
4. Additional generation capacity is based on a 1.8% increase. An incremental levelized demand charge of $81.64/kw/yr was utilized based on project specific parameters.

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. Barry
2.
3.
4.

Remarks:

This is original for file. I had copy of disc made for Steaver.

From: Clair

Date 10/3

Phone

TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil

		COLUMN Q ROW	
Capacity factor	60	4	60
		5	
% Natural Gas firing	80	6	80
% No. 2 Fuel Oil firing	20	7	20
		8	
Annual Costs, $X1000		9	
===================		10	
Direct Annual Cost		11	
Differential O&M Cost (2)	473 A	12	(127*(Q4/100)+2288)*(Q7/100)
Energy (3)		13	
Heat Rate Penalty	1,136 B	14	1.1*(0.012/0.01)*(6330*(14.49/12.79)*(Q7/100)*(Q4/100))
Pump Power Consumption	25 C	15	150*((Q7/100)*(124.03/88.8))*Q4/100
Lost Generation Capacity	(229)D	16	-370*(81.64/48.54)*(Q7/100)*(0.0184/0.01)
	-----	17	-----
Total Direct Cost	1,405	18	@SUM(Q16..Q12)
Indirect Annual Cost		19	
Capital Recovery (1)	545 E	20	(3533)*0.1542
Admin, Property Taxes, Insur	76 E	21	(3533)*0.0216
	-----	22	-----
Total Indirect Annual Cost	621	23	+Q21+Q20
		24	
Total Annual Cost	2026	25	+Q23+Q18
		26	
NOx Emissions		27	
=============		28	
65ppm oil, tpy	795 F	29	6623*(Q7/100)*(Q4/100)
42ppm oil, tpy	514 F	30	4280*(Q7/100)*(Q4/100)
	-----	31	-----
Removed, tpy	281	32	+Q29-Q30
		33	
		34	
Cost Effectiveness, $/ton	7,206	35	(Q25*1000)/Q32
========================			

A. Differential O&M Cost: The $127,000 (from B&V/GE) is for additional water treatment and BOP O&M. It varies with capacity factor and oil usage. The $2,288,000 (from GE) is for decreased inspection intervals and varies linearly with oil usage.
B. Heat Rate Penalty: The $6,330,000 (from B&V) is based on a 1% heat rate penalty utilizing a fuel cost of $12.79/Mbtu for oil at the lower heating value. This was corrected for the 1.2% heat rate penalty (from GE) and for the higher heating value for which fuel is purchased and for the current TEC forecast for fuel ($14.49/mbtu). This penalty varies with oil usage and capacity factor.
C. Pump Power Consumption: The $150,000 (from B&V/GE) is based on a power cost of $88.80/Mwh. This was corrected to the recent TEC forecast of $124.03. This penalty varies with oil usage and capacity factor.
D. Lost Generation Capacity: The $370,000 (from GE/B&V) is based on a 1% increase in capacity utilizing a $48.54/kw/yr demand charge. This was corrected to a 1.84% increase in capacity (from GE) using a project specific demand charge of $81.64/kw/yr. This varies with oil usage.
E. Capital Recovery: See note 1.
F. Emissions: The 6623 tons per year and the 4280 tons per year (from B&V/GE) vary with oil usage and capacity factor.

FEDERAL EXPRESS

[redacted]

QUESTIONS? CALL 800-238-5355 TOLL FREE.

AIRBILL
PACKAGE TRACKING NUMBER

7284300951

7284300951

RECIPIENT'S COPY

[redacted]

Date 9/26/90

1 From (Your Name) Please Print: Jerry L. Williams

Your Phone Number (Very Important): 813-228-4111

Company: TAMPA ELECTRIC

Department/Floor No.

Street Address: 702 NO. FRANKLIN ST.

City: TAMPA State: FL ZIP Required: 33602

2 To (Recipient's Name) Please Print: Mr. Claire Fancy

Recipient's Phone Number (Very Important): (904) 488-1344

Company: Fla. Dept. of Environmental Regulation

Department/Floor No.

Exact Street Address (We Cannot Deliver to P.O. Boxes or P.O. Zip Codes): Twin Towers Building, 2600 Blair Stone Road

City: Tallahassee, State: FL ZIP Required: 32399-2449

YOUR INTERNAL BILLING REFERENCE INFORMATION (First 24 characters will appear on invoice.)

445-146-23-18-281

H IF HOLD FOR PICK-UP, Print FEDEX Address Here
Street Address
City State ZIP Required

3 PAYMENT 1 ☐ Bill Sender 2 ☐ Bill Recipient's FedEx Acct. No. 3 ☒ Bill 3rd Party FedEx Acct. No. 4 ☐ Bill Credit Card
5 ☐ Cash

[redacted]

4 SERVICES (Check only one box)

Priority Overnight Service (Delivery by next business morning†)		Standard Overnight Service (Delivery by next business afternoon†)	
11 ☐	YOUR PACKAGING	51 ☐	
16 ☐	FEDEX LETTER *	56 ☐	FEDEX LETTER *
12 ☐	FEDEX PAK *	52 ☐	FEDEX PAK *
13 ☐	FEDEX BOX	53 ☐	FEDEX BOX
14 ☐	FEDEX TUBE	54 ☐	FEDEX TUBE
Economy Service (formerly Standard Air) (Delivery by second business day†)		Heavyweight Service (for Extra Large or any package over 150 lbs.)	
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30 ☒	ECONOMY SERVICE	80 ☐	DEFERRED HEAVYWEIGHT **

† Delivery commitment may be later in some areas
* Declared Value Limit $100
** Call for delivery schedule

DELIVERY AND SPECIAL HANDLING

1 ☐ HOLD FOR PICK-UP (Fill in Box H)
2 ☒ DELIVER WEEKDAY
3 ☐ DELIVER SATURDAY (Extra charge) (Not available to all locations)
4 ☐ DANGEROUS GOODS (Extra charge) (CSS not available for Dangerous Goods Shipments)
5 ☐ CONSTANT SURVEILLANCE SVC (CSS) (Extra charge) (Release Signature Not Applicable)
6 ☐ DRY ICE ______ Lbs.
7 ☐ OTHER SPECIAL SERVICE ______
8 ☐
9 ☐ SATURDAY PICK UP
10 ☐
11 ☐
12 ☐ HOLIDAY DELIVERY (If offered) (Extra charge)

PACKAGES	WEIGHT In Pounds Only	YOUR DECLARED VALUE	OVER SIZE
Total	Total	Total	

DIM SHIPMENT (Heavyweight Services Only)
lbs.
☐ Regular Stop ☐ Drop Box
☐ On-Call Stop ☐ Station
FedEx Emp. No.

Emp. No. Date
☐ Cash Received
☐ Return Shipment
☐ Third Party ☐ Chg. To Del. ☐ Chg. To Hold
Street Address
City State Zip
Received By:
X
Date/Time Received FedEx Employee Number

5 Release Signature:
Date/Time

Federal Express Use
Base Charges
Declared Value Charge
Other 1
Other 2
Total Charges

REVISION DATE 11/89
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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

AUG 17 1990

4APT-AEB

RECEIVED

AUG 20 1990

DER - BAQM

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: TECO Power Services Corp. Hardee Power Station (PSD-FL-140)

Dear Mr. Fancy:

This is to acknowledge receipt of the preliminary determination for the above referenced facility by letter dated August 2, 1990. We have reviewed the package as submitted and have the following comments.

MODELING/MONITORING

As noted in our comments on the permit application dated August 11, 1989, we indicated that preconstruction monitoring based on regional monitors was acceptable if such monitors could be found to be representative. For SO_2, the monitors located north of the site fall into the representative category and we will accept one of those monitors as fullfilling the PSD requirement for SO_2.

For ozone, we believe the Tampa monitoring site is the most representative site based on the prevailing winds and distance to the Hardee County site. Also, since maximum ozone concentrations will occur downwind from an urban area in the range of 30 or more kilometers, it is possible that the background levels at the site are higher than at sites that are not downwind of the Tampa area. The purpose of PSD monitoring is to quantify the background levels in the impact area.

BACT ANALYSIS

The BACT determination requires the use of wet injection and limits the hours of operation of the combined cycle units to 2190 hours per year. This is equivalent to 25% of capacity which is typical of a "peaking" unit. The simple cycle turbine of Phase IA, however, is not limited on hours of operation. In addition, the combined cycle units have the capacity to use by-pass vents and thus function as simple cycle units. It would appear, then, that the combined cycle units could operate continuously provided the hours of operation in the combined phase did not exceed 2190.

If the units are "peaking" units as the applicant claims, then the combined capacity of all the units (both combined cycle and simple cycle) should be limited to 25% of facility capacity. This is in keeping with the precedent set with Key West and facilities in North and South Carolina. Otherwise, the BACT analysis would indicate the need for add-on NO_x controls.

In addition, the burner design should be evaluated for BACT. The applicant proposes to use General Electric turbines. GE manufactures a "quiet combustor" which achieves NO_x levels of 25 ppm using wet injection when firing natural gas. Other burner designs are available which are capable of achieving equal or better emission levels. For example, the South Bay Power Plant in Chula Vista, CA, has recently proposed a 140 MW combined cycle turbine with emission limits of 9 ppm NO_x and 8 ppm CO firing natural gas, using steam injection. The technology proposed is currently in practice at the Delmarva Power and Light, Hay Road Station, Delaware. NO_x emissions at this facility have been tested at lower than 25 ppm.

In any case, it does not seem appropriate to allow a simple cycle "peaking" unit to operate 8760 hours per year without a lower emission rate. Also, clarification should be given as to whether the combined cycle units will be allowed to operate in simple cycle mode.

As with the Key West permit, the permit should contain provisions to require that the facility must reevaluate BACT, with SCR as a minimum, in the event that the 25% capacity factor is exceeded or the source wishes to operate as other than a peaking unit.

Thank you for the opportunity to review and comment on this package. If you have any questions on these comments, please do not hesitate to contact Mr. Gregg Worley of my staff at (404) 347-2904.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: Mr. Barry Andrews, FDER
TECO Hardee
B. Thomas, SW Dist

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

For Routing To Other Than The Addressee	
To:	Location:
To:	Location:
To:	Location:
From:	Date:

Interoffice Memorandum

TO: Steve Smallwood, Director DARM

FROM: John Shearer, Assistant Secretary

RE: Hardee Power Station BACT Revision
Case No. PA-89-25

DATE: August 10, 1990

On August 8, 1990, I met with representatives of Tampa Electric Company (TECo), TECo Power Services (TPS), and Seminole Electric Cooperative (SECT) to discuss revision of the Department's recommended BACT determination for NO_x as issued June 14, 1990, for the TECO/SECI Hardee Power Station project, Case No. PA-89-25. Updated information presented to me by the applicant appears to substantiate that, at the cumulative capacity factors projected for the Hardee Power Station, a requirement for the installation of selective catalytic reduction (SCR) as BACT is not justified because of the excessive cost (between $4500 and $5600 per ton as compared to EPA's guidelines of $3000 to $4000 per ton) of NO_x reduction with SCR at a cumulative capacity factor of 60%.

The applicant has committed to construct the duct module to accommodate later installation of SCR equipment if the Hardee Power Station operates at a cumulative capacity factor in excess of 60%. Should BACT be re-evaluated, selective catalytic reduction for NO_x control will be required at a minimum for BACT.

Attached are amended conditions of certification which are necessary to implement the revised BACT determination for NO_x to be made the subject of a formal stipulation at the Hardee Power Station certification hearing, August 13-17, 1990. Should the assumptions on costs, fuel usage, or other considerations that were used to arrive at this decision materially change, then the Department shall re-evaluate this determination.

Please direct that a revised BACT narrative incorporating the agreed conditions of certification be prepared for submission to the EPA.

JS/ht

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P.M.: 7/25/89
Tampa, FL

File copy

TAMPA ELECTRIC
A TECO ENERGY COMPANY

July 25, 1989

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Federal Express
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Mr. Claire Fancy
Florida Department of
Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2440

Re: Hardee Power Station
BACT Cost Analysis

Dear Mr. Fancy:

Enclosed, please find a copy of a BACT cost analysis for reducing NO_x emissions from 65 ppm to 42 ppm while burning oil at the Hardee Power Station (HPS).

For the unlikely case of the HPS burning 100% fuel oil at a capacity factor of 100%, the cost per ton of NO_x removed is $4,937. When analyzing the $/ton of NO_x removed for HPS' likely fuel scenario of 80% natural gas and 20% fuel oil, the values are significantly higher. In any case, these values far exceed any $/ton of NO_x removal justified as BACT to date. We therefore believe that the analysis clearly shows that an emissions limit of 42 ppm while burning oil should not be considered BACT for the HPS.

Should you have any questions, please call.

Sincerely,

Jerry L. Williams

Jerry L. Williams
Director
Environmental

PSD-FL-140
cc: EPA, NPS

JLW/dsr/LL412.DOC

Enclosures

cc: Mr. Steve Smallwood, DER
Mr. Hamilton Oven, DER
Mr. Barry Andrews, DER
BA/CHF 7-26-89

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QUESTIONS? CALL 800-238-5355 TOLL FREE.

AIRBILL
PACKAGE TRACKING NUMBER
7284301721

7284301721

RECIPIENT'S COPY

Date 7/25/90

1 From (Your Name) Please Print: Greg M. Nelson
Your Phone Number (Very Important): 813-228-4111
Department/Floor No
Company: TAMPA ELECTRIC
Street Address: 702 NO FRANKLIN ST
City: TAMPA
State: FL
ZIP Required: 33602

2 To (Recipient's Name) Please Print: Claire Fancy
Recipient's Phone Number (Very Important): (904) 488-1344
Department/Floor No
Company: Florida Dept. of Environmental Regulation
Exact Street Address (We Cannot Deliver to P.O. Boxes or P.O. Zip® Codes): 2600 Blair Stone Road, Twin Towers Office Bldg.
City: Tallahassee
State: FL
ZIP Required: 32399-2440

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16 [X] FEDEX LETTER*
12 [ ] FEDEX PAK*
13 [ ] FEDEX BOX
14 [ ] FEDEX TUBE

Standard Overnight Service (Delivery by next business afternoon†)
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56 [ ] FEDEX LETTER*
52 [ ] FEDEX PAK*
53 [ ] FEDEX BOX
54 [ ] FEDEX TUBE

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*Declared Value Limit $100
**Call for delivery schedule

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7 [ ] OTHER SPECIAL SERVICE
8 [ ]
9 [ ] SATURDAY PICK-UP
10 [ ]
11 [ ]
12 [ ] HOLIDAY DELIVERY (If offered) (Extra charge)

PACKAGES	WEIGHT In Pounds Only	YOUR DECLARED VALUE
Total	Total	Total

DIM SHIPMENT

Emp No
Date
[ ] Cash Received
[ ] Return Shipment
[ ] Third Party [ ] Chg To Del [ ] Chg To Hold
Street Address
City State Zip
Received By:
X
Date/Time Received
FedEx Employee Number

5 Release Signature

Federal Express Use
Base Charges
Declared Value Charge
Other 1
Other 2
Total Charges

REVISION DATE 11/89
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TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil

Capacity factor	20	30	40	50	60	70	80	90	100
% Natural Gas firing	80	80	80	80	80	80	80	80	80
% No. 2 Fuel Oil firing	20	20	20	20	20	20	20	20	20
Annual Costs, $X1000									
Direct Annual Cost									
Differential O&M Cost (2)	463	465	468	470	473	475	478	480	483
Energy (3)									
Heat Rate Penalty	379	568	757	947	1,136	1,325	1,515	1,704	1,893
Pump Power Consumption	8	13	17	21	25	29	34	38	42
Lost Generation Capacity	(229)	(229)	(229)	(229)	(229)	(229)	(229)	(229)	(229)
Total Direct Cost	621	817	1,013	1,209	1,405	1,601	1,797	1,993	2,189
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	1242	1438	1634	1830	2026	2222	2418	2614	2810
NOx Emissions									
65ppm oil, tpy	265	397	530	662	795	927	1,060	1,192	1,325
42ppm oil, tpy	171	257	342	428	514	599	685	770	856
Removed, tpy	94	141	187	234	281	328	375	422	469
Cost Effectiveness, $/ton	13,250	10,228	8,717	7,810	7,206	6,774	6,450	6,199	5,997

TECO Power Services - Hardee Power Station
'dditional Injection - 42 ppm gas and oil

Capacity factor	20	30	40	50	60	70	80	90	100
% Natural Gas firing	60	60	60	60	60	60	60	60	60
% No. 2 Fuel Oil firing	40	40	40	40	40	40	40	40	40
Annual Costs, $X1000									
Direct Annual Cost									
Differential O&M Cost (2)	925	930	936	941	946	951	956	961	966
Energy (3)									
Heat Rate Penalty	757	1,136	1,515	1,893	2,272	2,651	3,029	3,408	3,786
Pump Power Consumption	17	25	34	42	50	59	67	75	84
Lost Generation Capacity	(458)	(458)	(458)	(458)	(458)	(458)	(458)	(458)	(458)
Total Direct Cost	1,241	1,634	2,026	2,418	2,810	3,202	3,594	3,986	4,378
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	1862	2255	2647	3039	3431	3823	4215	4607	4999
NOx Emissions									
65ppm oil, tpy	530	795	1,060	1,325	1,590	1,854	2,119	2,384	2,649
42ppm oil, tpy	342	514	685	856	1,027	1,198	1,370	1,541	1,712
Removed, tpy	187	281	375	469	562	656	750	843	937
Cost Effectiveness, $/ton	9,937	8,019	7,060	6,485	6,101	5,827	5,622	5,462	5,334

TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil

Capacity factor	20	30	40	50	60	70	80	90	100
% Natural Gas firing	40	40	40	40	40	40	40	40	40
% No. 2 Fuel Oil firing	60	60	60	60	60	60	60	60	60
Annual Costs, $X1000									
Direct Annual Cost									
Differential O&M Cost (2)	1,388	1,396	1,403	1,411	1,419	1,426	1,434	1,441	1,449
Energy (3)									
Heat Rate Penalty	1,136	1,704	2,272	2,840	3,408	3,976	4,544	5,112	5,680
Pump Power Consumption	25	38	50	63	75	88	101	113	126
Lost Generation Capacity	(687)	(687)	(687)	(687)	(687)	(687)	(687)	(687)	(687)
Total Direct Cost	1,862	2,450	3,038	3,627	4,215	4,803	5,391	5,979	6,567
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	2483	3071	3660	4248	4836	5424	6012	6600	7188
NOx Emissions									
65ppm oil, tpy	795	1,192	1,590	1,987	2,384	2,782	3,179	3,576	3,974
42ppm oil, tpy	514	770	1,027	1,284	1,541	1,798	2,054	2,311	2,568
Removed, tpy	281	422	562	703	843	984	1,125	1,265	1,406
Cost Effectiveness, $/ton	8,832	7,283	6,508	6,043	5,733	5,512	5,346	5,217	5,113

TECO Power Services - Hardee Power Station
Additional Injection - 42 ppm gas and oil

Capacity factor	20	30	40	50	60	70	80	90	100
% Natural Gas firing	20	20	20	20	20	20	20	20	20
% No. 2 Fuel Oil firing	80	80	80	80	80	80	80	80	80
Annual Costs, $X1000									
==================									
Direct Annual Cost									
Differential O&M Cost (2)	1,851	1,861	1,871	1,881	1,891	1,902	1,912	1,922	1,932
Energy (3)									
Heat Rate Penalty	1,515	2,272	3,029	3,786	4,544	5,301	6,058	6,816	7,573
Pump Power Consumption	34	50	67	84	101	117	134	151	168
Lost Generation Capacity	(916)	(916)	(916)	(916)	(916)	(916)	(916)	(916)	(916)
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Direct Cost	2,483	3,267	4,051	4,835	5,620	6,404	7,188	7,972	8,757
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	3104	3888	4672	5457	6241	7025	7809	8593	9378
NOx Emissions									
============									
65ppm oil, tpy	1,060	1,590	2,119	2,649	3,179	3,709	4,239	4,769	5,298
42ppm oil, tpy	685	1,027	1,370	1,712	2,054	2,397	2,739	3,082	3,424
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Removed, tpy	375	562	750	937	1,125	1,312	1,500	1,687	1,874
Cost Effectiveness, $/ton	8,280	6,914	6,232	5,822	5,549	5,354	5,208	5,094	5,003

TECO Power Services - Hardee Power Station
dditional Injection - 42 ppm gas and oil

Capacity factor	20	30	40	50	60	70	80	90	100
% Natural Gas firing	0	0	0	0	0	0	0	0	0
% No. 2 Fuel Oil firing	100	100	100	100	100	100	100	100	100
Annual Costs, $X1000									
===================									
Direct Annual Cost									
Differential O&M Cost (2)	2,313	2,326	2,339	2,352	2,364	2,377	2,390	2,402	2,415
Energy (3)									
Heat Rate Penalty	1,893	2,840	3,786	4,733	5,680	6,626	7,573	8,520	9,466
Pump Power Consumption	42	63	84	105	126	147	168	189	210
Lost Generation Capacity	(1,145)	(1,145)	(1,145)	(1,145)	(1,145)	(1,145)	(1,145)	(1,145)	(1,145)
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Direct Cost	3,103	4,084	5,064	6,044	7,025	8,005	8,985	9,965	10,946
Indirect Annual Cost									
Capital Recovery (1)	545	545	545	545	545	545	545	545	545
Admin, Property Taxes, Insur	76	76	76	76	76	76	76	76	76
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Indirect Annual Cost	621	621	621	621	621	621	621	621	621
Total Annual Cost	3725	4705	5685	6665	7646	8626	9606	10586	11567
NOx Emissions									
===========									
65ppm oil, tpy	1,325	1,987	2,649	3,312	3,974	4,636	5,298	5,961	6,623
42ppm oil, tpy	856	1,284	1,712	2,140	2,568	2,996	3,424	3,852	4,280
	-----	-----	-----	-----	-----	-----	-----	-----	-----
Removed, tpy	469	703	937	1,172	1,406	1,640	1,874	2,109	2,343
Cost Effectiveness, $/ton	7,948	6,694	6,066	5,690	5,439	5,259	5,125	5,020	4,937

NOTE:

Based on a Total Capital Investment of $3,533,000 with a project specific capital recovery factor of 15.42% Administrative costs, property taxes, and insurance utilize a factor of 2.16% of Total Capital Investment. The sum of these two factors represent the project specific fixed charge rate of 17.58%.

2. Differential O&M includes BOP maintenance and water treatment chemical costs. Inspection intervals decrease from 6500 operating hours to 1500 operating hours. This increases maintenance $2,288,000 per year of 100% oil firing.
3. Energy includes increased BOP power consumption as well as a 1.2% CC heat rate penalty for the additional injection. The additional fuel cost associated with heat rate penalty utilizes Tampa Electric Company's current levelized fuel cost of $14.49/MBtu for oil. Increased BOP power consumption is charged at $124.03/MWh for oil.
4. Additional generation capacity is based on a 1.8% increase. An incremental levelized demand charge of $81.64/kW/yr was utilized based on project specific parameters.

TECO Power Services - Hardee Power Station

DITIONAL INJECTION (42 PPM ON OIL) CAPITAL COSTS ($X1000)

Differential Combustion Turbine Costs	0
HRSG Modification	763
Water Treatment, Storage, and Injection Equipment	1,163
Foundations & BOP Equipment	288
Contingency (10%)	221
Subtotal	2,434
Sales Tax (6%)	146
Indirect costs (14.5%)	353
Subtotal	2,933
Escalation (4.7%)	205
Total Escalated Cost	3,138
terest During Construction	395
Total Capital Investment	3,533

For Routing To Other Than The Addressee	
To:	Location:
To:	Location:
To:	Location:
From:	Date:

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Steve Smallwood

THRU: Clair Fancy CHF

FROM: Barry Andrews BA

DATE: June 5, 1990

SUBJ: BACT Determination for Hardee Power Station

Based on my initial review and additional information that has been obtained through meetings with representatives of TECO/Seminole Electric, communication with equipment vendors, and discussions with the EPA and other permitting agencies, this memo outlines my conclusions regarding BACT for the Hardee Power Station. The BACT recommendations are outlined on a pollutant-by-pollutant basis as follows.

Particulates, CO, VOC

BACT to be established as the lesser of the emission levels proposed or the levels established as BACT for identical equipment (GE Frame 7 EA) permitted in other states.

Sulfur Dioxide

BACT to be established by limiting the average annual sulfur content of fuel oil to 0.3 percent.

Nitrogen Oxides

BACT to be established by requiring selective catalytic reduction (SCR) for operating at a capacity factor in excess of 25 percent (2,190 hours per year). For operation at or below a 25 percent capacity factor BACT will be established as the lesser of the emission level proposed or the level established as non SCR BACT for identical equipment (GE Frame 7 EA) in other states.

Basis

For the natural gas firing mode, the use of SCR has been proven to be technically feasible in many cases. The BACT/LAER Clearinghouse indicates that there have been several combined cycle (gas turbine/heat recovery steam generators) facilities that have used SCR as either a proposed or required BACT. A review of recent permitting activities indicates that SCR has been established as BACT for two facilities using the identical equipment (GE Frame 7 EA) that is proposed for the Hardee Power Station. In each case, the economics of SCR NOx control was determined to be similar to that proposed at the Hardee facility (approx. $3,600/ton of NOx removed at 100% capacity factor).

The decision to establish SCR as BACT for natural gas firing is consistent with the guidance that EPA has given with regard to recent permitting activities (Tropicana, Cedar Bay Cogen) and the recent New Source Review workshop in Denver. Basically EPA is saying that if BACT has been established for a particular type of equipment (model), then the same BACT determination should be established for similar proposals unless it can be demonstrated that there are unique differences between the two projects. EPA feels that this type of decision making basis has advantages over the cost per ton method, since it is often difficult to quantify what the <u>actual</u> cost of providing control will be.

For the Hardee facility, the applicant has indicated that the capacity factor is not expected to exceed 25 percent during the first 5 years of operation. This operating scenario is different than the two facilities mentioned above in which operation levels are expected to exceed 80 percent of full capacity. As this is the case, a determination which would only require SCR if operation exceeds 25 percent of full capacity is judged to be reasonable. A determination of this type is consistent with what is happening in other states. NESCAUM, for example, is now evaluating what level of operation should not require SCR. Presently they are looking to establish a cut-off at somewhere between 1,500 and 2,500 hours per year operation. This decision is also consistent with what was established as BACT for the Key West Electric facility. In that case BACT was determined to be the use of SCR for full load operation above 1,870 hours per year.

For oil firing the use of SCR also appears to be technologically feasible. Although the formation of ammonium bisulfate has caused concerns for the oil firing mode, recent information suggests that SCR is still feasible if the ammonia injection ratio is adjusted.

For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this is the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NOx injection ratio. For natural gas firing operation, NOx emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NOx can be controlled with efficiencies of approximately 70 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. Based on these findings, a requirement that SCR be used for both gas and oil firing is deemed appropriate for operation above the 25 percent capacity factor.

BA/plm

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State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Randy Armstrong
Howard Rhodes
Mimi Drew

FROM: Steve Smallwood

DATE: February 28, 1990

SUBJECT: TECO/Seminole - Hardee Power
Project power Plant Siting Application
PA 89-25 - 8185

Personnel in your respective divisions have been reviewing the above referenced application since July 1989. The department needs to prepare its final report by the end of March. Please have the appropriate personnel submit their final reviews and recommendations to Buck Oven by March 13, 1990.

HO/SM/rrs

cc: Power Plant Review Committee
Richard Donelon

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

January 29, 1990

RECEIVED
FEB 9 1990
DER - BAQM

Mr. Wayne E. Daltry
Executive Director
Southwest Florida Regional
Planning Council
P.O. Box 3455
North Ft. Myers, Florida 33918-3455

Re: Hardee Power Station
PA 89-25

Dear Mr. Daltry:

Thank you for your November 20, 1989 letter withdrawing the Southwest Florida Regional Planning Council's (SWFRPC) preliminary findings regarding the Hardee Power Station power plant certification pending clarification and review of various matters. We sincerely appreciate your agency's cooperation. With this letter, Seminole Electric Cooperative, Inc. (SECI) would like to address the "comments and concerns" listed as items 1 through 12 in your November 20 letter and present an overview explaining the procedures of Florida's Electrical Power Plant Siting Act. Our specific responses are set forth in numbered paragraphs corresponding to your November 20 letter.

Specific Responses

Comment No. 1:

> In order to avoid any impacts to fish and wildlife, and their habitat, in the Cecil M. Webb Wildlife Management Area the applicant should be required by the Florida Public Service Commission to propose an alternate corridor, completely outside the Webb W.M.A.

Response:

> SECI is actively working with the Florida Game and Fresh Water Fish Commission, the agency responsible for managing the Webb area, and have recently submitted a mitigation proposal that would more than offset the minimal wildlife impacts caused by the proposed transmission line. We will keep you apprised of the status of these discussions. Please note that the proposed corridor would affect only the northern and western edges of the Webb area, passing through areas already affected by a sewage treatment plant and a highway.

P.O. BOX 272000 • TAMPA, FLORIDA 33688-2000 • (813) 963-0994

Comment No. 2:

The proposed corridor passes through, or adjacent to a number of Developments of Regional Impact in Charlotte and Lee Counties. These are Seminole Trail, Fairway Woodlands, Pine Lakes Country Club, Hancock Creek Commerce, Del Prado North, and Indian Oaks Trade Center. Regional staff can provide the applicant (Seminole Electric Cooperative) with names and addresses of representatives to determine the impact of the corridor, if any, on the DRI's.

Response:

SECI has reconfigured the corridor to avoid passing through the Seminole Trail and Fairway Woodlands DRI's. Pine Lakes Country Club is approximately two miles from the proposed corridor in Lee County, thus there will be no effect on this development. Hancock Creek Commerce is located south of the Lee substation in Lee County and will not be impacted by the corridor. Del Prado North is located within the City of Cape Coral, and is adjacent to the northern boundary of the proposed corridor alignment in Section 30. Although the corridor is adjacent to the Del Prado North boundary for a distance of 0.50 miles, the proposed corridor alignment should not directly impact this development. The Indian Oaks Trade Center is located in Lee County approximately 0.25 miles south of the Lee substation and no impacts from the proposed corridor are anticipated.

Comment No. 3:

That portion of the proposed corridor within the City of Cape Coral should avoid those properties which are designated as a future City Park site within the Cape Coral Comprehensive Plan. City staff has informed Regional Staff that the City will monitor the Florida Public Service Commission Public Hearings Process for this project, and that the City is prepared to intervene in the process, should the proposed corridor appear to traverse the park site.

Response:

SECI has worked closely with City of Cape Coral representatives, including the City Manager, City Attorney, and planning and zoning officials. Also, SECI has appeared before the City Council. Agreement regarding the best route through Cape Coral was achieved several months ago. We currently are awaiting finalization of an amendment to the Cape Coral Zoning Ordinance, after which the City and SECI will enter into a stipulation agreeing that the corridor is consistent and in compliance with the land use plan and zoning ordinance.

Comment No. 4:

The applicant should be required to prepare a wetlands inventory for the proposed corridor. The inventory should map all wetlands within and adjacent to the corridor and should include mitigation for impacts to these wetlands. This inventory should be coordinated with the respective local governments, the Florida Department of Environmental Regulation, the United States Army Corps of Engineers and the South Florida Water Management District.

Response:

As inventory is provided in the Site Certification Application at pages 6-54 through 6-60, and Appendix, Figure 6.1.7-2. This information comports with what typically is provided for linear, transmission line facilities. More detailed information will be developed and made available to the agencies in accordance with the conditions of certification after SECI determines the actual transmission line right of way.

Comment No. 5:

The applicant should be required to mitigate any adverse impacts to water quality caused by corridor clearing and filling, and/or construction of the transmission facilities. Mitigation should be determined by appropriate federal, state, regional and local review and permitting agencies.

Response:

SECI anticipates complying with all applicable mitigation guidelines.

Comment No. 6:

All crossings of streams, wetlands, or other bodies of water, by the proposed facilities should be constructed at such points where road or utility crossings already exist, where feasible.

Response:

SECI agrees with this concern, and anticipates that the final certification order will set forth appropriate, corresponding conditions.

Comment No. 7:

The applicant, in cooperation with a state-certified archaeologist, should perform an archaeological/historical site survey within the proposed corridor. All new or existing sites revealed in the survey should be thoroughly investigated, and appropriate actions taken, before corridor construction is allowed to proceed.

Response:

As stated in the application (Vol. II, pages 6-52 through 6-54) the corridor study area was reviewed by the Florida Department of State, Division of Historical Resources (DHR). This review included known archaeological or historic sites affected by the corridor and also "archaeologically sensitive" areas that need to be surveyed prior to construction. In compliance with The DHR recommendations (Vol. III, Appendix 11.3) SECI will employ a certified professional archaeologist and perform a site specific archaeological/historical survey on those areas identified as "archaeologically sensitive". Prior to commencing this survey, the locations and methodology will be submitted to DHR for approval.

Comment No. 8:

Cutting, clearing, filling, and maintenance for the proposed corridor should be strictly limited to the area necessary for construction of the proposed transmission facilities. The remainder of the corridor width should be managed as a conservation easement.

Response:

SECI agrees with the first sentence, except that the words "and operation" should be inserted after the word "construction". The second sentence is problematic, both from a practical and legal perspective. For example, please note that SECI ultimately will obtain easements along the transmission line corridor in accordance with the grant of eminent domain authority provided by the Florida Legislature. Acquiring a conservation easement in accordance with this process would appear to violate Section 704.06(2), Florida Statutes, which provides that conservation easements may not be acquired "by condemnation or by other exercise of the power of eminent domain."

Comment No. 9:

The roadways required within the proposed corridor should be constructed of dirt and/or gravel, and should not utilize any type of paving material, except in such cases where existing public or private roadways are utilized.

Response:

The transmission line access roads will be constructed of dirt, gravel, or limerock.

Comment No. 10:

The transmission line facilities, or their construction, should avoid adverse impacts to navigation on the Peace River, Shell Creek, and surrounding waterways.

Response:

SECI agrees with this comment and anticipates appropriate, corresponding conditions in the certification order.

Comment No. 11:

Within the site certification application/environmental assessment, the applicant has made a number of commitments and/or statements of intent. These should be incorporated as conditions for approval, provided they do not conflict with the above recommendations, or recommendations of other review agencies.

Response:

SECI agrees with this comment and anticipates appropriate, corresponding conditions in the certification order.

Comment No. 12:

As the proposed transmission line appears to have significant impacts in Charlotte and Lee Counties, the Council recommends that public hearings be required in each impacted County.

Response:

Before proposing the referenced transmmission line corridor, SECI conducted, after publication of notice in newspapers in each county, several public workshops to receive input regarding location of the transmission line. Moreover, SECI has worked closely with government officials of Lee County, Charlotte County, and Cape Coral. SECI representatives appeared before the Charlotte County Board of Commissioners and the Cape Coral City Council. The next public hearing in this process is the land use hearing, which will be held in Hardee County on March 6 and 7, 1990. The certification hearing will be in Hardee County in mid-May, 1990.

General Response

SECI's joint application to construct the Hardee Power Station and directly associated transmission lines is governed by the procedures set forth in the Electrical Power Plant Siting Act ("PPSA", Section 4403.501-.517, Fla. Stat.) and the Department of Environmental Regulation's (DER) implementing regulations, as set forth at Chapter 17-17, Florida Administrative Code.

The PPSA provides a unified and exclusive process for permitting new powerplants and directly associated transmission lines. A PPSA certification order signed by the Governor constitutes "the sole license of the state and any agency [including local governments] as to the approval of the site and the construction and operation of the proposed electric power plant. . .[and associated transmission lines]" Two separate steps in the PPSA certification process are the land use hearing and certification hearing. The land use hearing involves consideration of only whether the plant and directly associated transmission lines are consistent and in compliance with the local government land use plans and zoning ordinances; the certification hearing involves assessment of all other relevant environmental and natural resource issues.

Both hearings are convened before a Division of Administrative Hearings (DOAH) hearing officer. After each hearing, the DOAH hearing officer forwards a recommended order to the Governor and Cabinet, sitting as the Siting Board, for "final agency action". Upon the Siting Board's affirmative finding of consistency and compliance with local land use plans and zoning ordinances, the applicant may proceed with the final certification hearing. However, if the Siting Board concludes that the proposed site does not conform with local government land use plans and zoning ordinances, it is the applicant's responsibility to apply to the respective local governments for rezoning. Should such an application for rezoning be denied, the applicant could appeal to the Siting Board for authorization of a nonconforming use or variance.

The PPSA process ultimately entails balancing the need for the proposed facility and the environmental impact resulting from construction and operation of same. In addition to environmental and natural resource protection, the PPSA contemplates consideration of the need "to provide abundant, low-cost electrical energy." Section 403.502(3), Fla. Stat.

The state agency responsible for sheperding the Hardee Power Station application through the PPSA certification process is DER, not the PSC. (The PSC is responsible for an initial determination of "need" for powerplants.) The appropriate contact is Hamilton (Buck) Oven of DER (904/488-1344). If SWFRPC wishes to participate in the PPSA hearings, it must file a "notice" to this effect with the hearing officer and forward copies to all existing parties. A copy of a recent notice is attached for your convenience.

Thank you for considering our responses. We will contact you in the near future to arrange a meeting so that we may answer all of your questions.

Sincerely,

Mike Roddy

Mike Roddy
Senior Environmental Engineer

MR:bmc

cc: Mr. Richard Melson
Mr. James D. Beasley
Ms. Trudie Bell
Mr. Alton Roane
Dr. Richard Garrity
Mr. Phillip Edwards
US Dept. of Agriculture
Mr.John Adams
Mr. Bill Howell
Mr. Howard Knight
Ms. Patricia Adams
Mr. Mike Best
Mr. Steve Minnis
Mr. John Morgan
Mr. Bryan Sodt
Board of Trustees of the Internal Improvement Trust Fund
Ms. Linda Sumarlidason
Ms. Kim Dryden
Mr. Kevin Doyle
Mr. Robert Taylor
Mr. Norman Feder
Mr. Hamilton Oven
Mr. Jerry Williams
Mr. Bruce Miller
Mr. Paul Darst

Southwest Florida Regional Planning Council

4980 Bayline Drive, 4th Floor, N. Ft. Myers, FL 33917-3909 (813) 995-4282

P.O. Box 3455, N. Ft. Myers, FL 33918-3455 SUNCOM 721-7290 / 7291

November 20, 1989

RECEIVED
NOV 22 1989

Mr. Steve Tribble, Director
Division of Records and Reporting
Florida Public Service Commission
Fletcher Building
101 East Gaines Street
Tallahassee, Florida 32399-0850

RE: IC&R PROJECT #89-168
PROJECT NAME: TECO Power Services, et. al., Proposed Hardee Power Station Site Certification Application/Environmental Assessment

Dear Mr. Tribble:

On November 9, 1989, Regional Staff submitted to you a preliminary finding of "regionally significant and inconsistent" for the above-mentioned project. The letter stating staff findings for this project also contained a series of recommendations. At the November 16, 1989, Council meeting, representatives from the Seminole Electric Cooperative, Inc. requested that the Council table their formal findings of consistency to allow an opportunity to address the Council's concerns. Therefore, at Council direction staff wishes to withdraw the preliminary finding of regionally significant and inconsistent. The Council, however, directed staff to forward the following comments and concerns to be addressed during the formal review of this project:

1. In order to avoid any impacts to fish and wildlife, and their habitat, in the Cecil M. Webb Wildlife Management Area the applicant should be required by the Florida Public Service Commission to propose an alternate corridor, completely outside the Webb W.M.A.

2. The proposed corridor passes through, or adjacent to a number of Developments of Regional Impact in Charlotte and Lee Counties. These are Seminole Trail, Fairway Woodlands, Pine Lakes Country Club, Hancock Creek Commerce, Del Prado North, and Indian Oaks Trade Center. Regional staff can provide the applicant (Seminole Electric Cooperative) with names and addresses of representatives to determine the impact of the corridor, if any, on the DRIs.

3. That portion of the proposed corridor within the City of Cape Coral should avoid those properties which are designated as a future City Park site within the Cape Coral Comprehensive Plan. City staff has informed Regional Staff that the City will monitor the Florida Public Service Commission Public Hearings Process for this project, and that the City is prepared to intervene in the process, should the proposed corridor appear to traverse the park site.

4. The applicant should be required to prepare a wetlands inventory for the proposed corridor. The inventory should map all wetlands within and adjacent to the corridor and should include mitigation for impacts to these wetlands. This inventory should be coordinated with the respective local governments, the Florida Department of Environmental Regulation, the United States Army Corps of Engineers and the South Florida Water Management District.

5. The applicant should be required to mitigate any adverse impacts to water quality caused by corridor clearing and filling, and/or construction of the transmission facilities. Mitigation should be determined by appropriate federal, state, regional and local review and permitting agencies.

6. All crossings of streams, wetlands, or other bodies of water, by the proposed facilities should be constructed at such points where road or utility crossings already exist, where feasible.

7. The applicant, in cooperation with a state-certified archaeologist, should perform an archaeological/historical site survey within the proposed corridor. All new or existing sites revealed in the survey should be thoroughly investigated, and appropriate actions taken, before corridor construction is allowed to proceed.

8. Cutting, clearing, filling and maintenance for the proposed corridor should be strictly limited to the area necessary for construction of the proposed transmission facilities. The remainder of the corridor width should be managed as a conservation easement.

9. The roadways required within the proposed corridor should be constructed of dirt and/or gravel, and should not utilize any type of paving material, except in such cases where existing public or private roadways are utilized.

10. The transmission line facilities, or their construction, should avoid adverse impacts to navigation on the Peace River, Shell Creek, and surrounding waterways.

11. Within the site certification application/environmental assessment, the applicant has made a number of commitments and/or statements of intent. These should be incorporated as conditions for approval, provided they do not conflict with the above recommendations, or recommendations of other review agencies.

12. As the proposed transmission line appears to have significant impacts in Charlotte and Lee Counties, the Council recommends that public hearings be required in each impacted County.

TO: Mr. Steve Tribble
DATE: November 20, 1989
PAGE: 3
RE: IC&R PROJECT #89-168

Please be advised that it is the intent of the Southwest Florida Regional Planning Council to become a party to the on-going site certification process for this project under Chapters 403.501 to 403.519, Florida Statutes (The Florida Electrical Power Plant Siting Act). Please notify the Council of any appropriate comment deadlines so that final comments may be submitted in a timely manner.

Sincerely,

SOUTHWEST FLORIDA REGIONAL PLANNING COUNCIL

Wayne E. Daltry
Executive Director

WED/GEH/rr

cc: Mr. W Michael Roddy, Seminole Electric
Mr. Richard Melson, Hopping, Boyd, Green & Sams
Mr. James D. Beasley, Ausley, McMullen, McGehee, et. al.
Ms. Trudie Bell, FDER
Mr. Alton Roane, Lee County Planning
Dr. Richard Garrity, FDER
Mr. Phillip R. Edwards, FDER
US Dept. of Agriculture
Mr. John F. Adams, USACE
Mr. Bill Howell, FDNR
Mr. Howard Knight, Cape Coral Planning
Ms. Patricia G. Adams, FDER
Mr. Mike Best, Charlotte County Planning
Mr. Steve Minnis, SWFWMD
Mr. John Morgan, SFWMD
Mr. Bryan Sodt, Central Florida RPC
Board of Trustees of the Internal Improvement Trust Fund
Ms. Linda Sumarlidason, FDNR
Ms. Kim Dryden, FG&FWFC
Mr. Kevin Doyle, FDOT
Mr. Robert Taylor, Florida Dept. of State
Mr. Norman Feder, FDOT
Mr. Hamilton S. Oven, Jr., FDER
Mr. Jerry L. Williams, Tampa Electric
Mr. Bruce P. MIller, US EPA
Mr. Paul Darst, Florida DCA

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State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Power Plant Siting Review Committee
Bill Thomas
Clabe Polk

FROM: Buck Oven

DATE: August 22, 1989

SUBJECT: TECO Power Services Corp./Seminole Electric Cooperative, Inc. Hardee Power Station/Power Plant Siting Application PA 88-24, Module No. 8185

Attached please find an amendment to the application for the Hardee Power Station Power Plant Siting Application as submitted by TECO and Seminole. If you have any requests for additional data, please let me know. If you feel the need for a meeting with TECO/Seminole and their consultants, please let me know.

cc: Rick Garritty
Phil Edwards

Attachment

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

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DER-BAQM

4APT/APB-aes

Ms. Patricia G. Adams
Planner
Bureau of Air Quality Management
Florida Department of Environmental
  Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: TECO Power Services Corp./Seminole Electric Cooperative Hardee Power Station/Power Plant Siting Application PSD-FL-140

Dear Ms. Adams:

This is to acknowledge receipt of the above referenced faility's application for a prevention of significant deterioration (PSD) construction permit, transmitted by your letter dated July 5, 1989. As discussed between Mr. Barry Andrews of FDER and Gregg Worley of my staff on July 27, 1989, we have the following comments regarding this application.

Modeling/Monitoring

Based on the PSD significant air monitoring impact levels, the source is required to monitor for ozone and sulfur dioxide (SO_2). Florida has granted an exemption for both pollutants based on the rural nature of the site. We do not agree that the source should be exempt from monitoring for ozone and sulfur dioxide.

This is a large source with over 9,000 tons per year of expected SO_2 emissions from the first phase of construction. Potential VOC emissions from this phase are over 250 tons per year. The site is only 9 kilometers from Hillsborough County, an ozone nonattainment area. For both SO_2 and ozone monitoring, unless regional monitoring data can be justified as representative, preconstruction monitoring should be required.

SO_2 BACT Analysis

The applicant proposes the use of low sulfur fuel as the best available control technology (BACT) for SO_2. It is stated that the primary fuel for the project will be natural gas but that the turbines will also be capable of firing #2 fuel oil and synthetic gas (syn-gas) derived from coal gasification. The maximum emissions from the combustion of fuel oil are projected at over 16,000 tons per year of SO_2. These emissions are roughly equivalent to those expected from the combustion of syn-gas.

The permit should be conditioned so that fuel oil could be used in place of natural gas only as an emergency fuel as defined in the NSPS. Should the applicant desire to fire fuel oil on a more frequent basis, the gas streams from the turbines should be analyzed for the feasibility of flue-gas desulfurization (FGD) applications.

<u>NO_x BACT Analysis</u>

In evaluating alternatives for nitrogen oxides (NO_x) controls, the applicant dismissed the use of selective catalytic reduction (SCR) based on "technical considerations as well as significant economic and environmental impacts." The technical considerations addressed by the applicant appear to center on the arguments that SCR is not technically feasible for applications on simple-cycle turbines or on operations firing fuel oil.

Admittedly, SCR currently must be used in conjunction with a heat recovery steam generator (HRSG) in order to achieve the proper reaction temperature window. Thus, the operation of an SCR system, in its current stage of development, would not be technically feasible during a simple-cycle mode of turbine operation. The use of the simple-cycle mode, however, raises many questions. For example: Why is it necessary to use the simple-cycle when the use of the combined cycle mode is more efficient in terms of power production? What is the feasibility of supplemental firing of the HRSG such that the combined cycle is prepared for quick start-ups?

The applicant also claims that SCR would be technically infeasible due to the firing of fuel oil. As noted in the comments on the SO_2 BACT analysis, though, the firing of fuel oil should be limited to use as an emergency fuel. In addition, while the use of SCR when firing fuel oil may shorten the life of the catalyst and result in higher costs, the fact that the system will operate properly when fuel oil is fired is evidence that SCR is technically feasible for oil-fired applications. Recent permits issued in Rhode Island contain requirements that the SCR systems be operated both when the turbines are fired with natural gas and when they are fired with #2 fuel oil.

In the economic analysis, the applicant estimated a total annualized cost of $22,014,000 for the installation of SCR for the entire 660 MW plant. This results in a total cost effectiveness of roughly $2,000 per ton of NO_x removed, a figure that is within the range that other recently permitted turbine sources are paying for NO_x control.

The applicant then argued that "environmental benefits from installing SCR are small since the predicted impacts are much less than the PSD increment and AAQS." Controlling NO_x with SCR would, however, reduce emissions by over 3,700 tons per year when firing natural gas. The small change in ambient impact is not justification for dismissing a control option. This is reinforced by the recent Administrative Order on PSD Appeal No. 88-11 (enclosed), which stated that the argument "that the modelled negligible impact of the proposed facility on overall air quality is an environmental impact that can be factored into the BACT analysis to justify using less than the most effective technology to control NO_x emissions. . is without merit." Likewise, environmental effects from ammonia slippage or the handling of spent catalyst do not specifically constrain this source from using the most effective control. In summary, the applicant has not demonstrated that SCR should not be considered BACT for the control of NO_x emissions from the combustion turbines.

Thank you for the opportunity to review this application. If you have any questions regarding the comments on modeling or monitoring, please contact Mr. Lew Nagler, staff meteorologist, at (404) 347-2864. Any other quetions may be directed to Gregg Worley of my staff at (404) 347-2864.

Sincerely yours,

Bruce P. Miller

Bruce P. Miller, Chief
Air Programs Branch
Air, Pesticides, and Toxics
Management DIvision

cc: TECO

cc: P. Raval
B. Andrews
M. Linn
B. Owen
B. Thomas, SW Dist.
CHF/BT

Hardee Power Station
<u>Site Certification Application and Environmental Assessment</u>

Clarification No. 1

Date: July 18, 1989

Affected Sections: 5.6.1.2 Model Results
11.1.4 Prevention of Significant Deterioration (Section 7.1)

Question: Why were 32°F and 95°F used in the modeling instead of 68°F?

Response: Because the working fluid for combustion turbines (CTs) is air, their performance is affected by the ambient temperature. Therefore, any change in temperature has a concomitant change in emissions and flow rate. The operating range for the CTs of 32°F to 95°F represents the maximum expected range in both emissions and flow rate. At 32°F, the maximum expected emissions will occur with the maximum flow rate. In contrast, at 95°F the minimum expected emissions will occur with the minimum flow rate. At a temperature of 68°F, the emissions and flow rate will be intermediate between the 32°F and 95°F conditions. Since flow rate can be a major factor in determining the impact of sources, both 32°F and 95°F conditions were modeled. By modeling this maximum expected range in operating conditions, it is assured that the maximum impacts will be determined.

Table 5.2.1-1. Summary of Estimated Cooling Reservoir and Intake Water Quality Conditions, and Reservoir Quality for the Hardee Power Station (Page 1 of 2)

Parameter	Reservoir Intake/Influent Water Quality: Surface Runoff	Surficial Aquifer	Floridan Aquifer Makeup	Treated Neutralization Basin Effluent	Cooling Reservoir Quality[1]	FDER Class III Water Quality Criteria
Calcium, mg/L as CaCO3	63	83	113	1130	220	
Magnesium, mg/L as CaCO3	39	30	49	490	100	
Sodium, mg/L as CaCO3	17	30	37	3050	180	
Potassium, mg/L as CaCO3	0	1	8	80	10	
Total Hardness, mg/L as CaCO3	102	113	162	1620	320	
Alkalinity, mg/L as CaCO3	61	83	160	0	230	>20
Sulfate, mg/L as CaCO3	37	30	26	4540	230	
Chloride, mg/L as CaCO3	21	34	21	210	50	
Silca, mg/L	5.4	17	27	270	50	
Fluoride, mg/L	1.0	0.57	2.0	20	3.6	10
Cyanide, mg/L	<0.004	<0.004	<0.005	0.05	0.01	0.005
MBAS, mg/L	0.040	0.040	<0.180	1.8	0.316	0.5
Oil and Grease, mg/L	<5	<5	<5	0	<5	5
Turbidity, NTU	1.7	51	14	10	32	29 above Background
pH, units	7	7.5	7.5	6-9	7.5	6.0-8.5
Total Dissolved Solids, mg/L	190	158	342	6860	798	
Specific Conductivity, umhos/cm	173	225	320	12100	980	1275
Total Kjeldahl Nitrogen, mg/L	0.74	0.14	0.39	3.9	0.8	
Ammonia Nitrogen, mg/L	0.11	0.07	0.20	2.0	0.4	
Unionized Ammonia, mg/L[2]	0.001	0.002	0.007	0.022	0.014	0.02
Organic Nitrogen, mg/L	0.65	0.07	0.19	1.9	0.4	
Nitrate+Nitrite-Nitrogen, mg/L	0.50	0.085	0.031	0.3	0.1	
Total Nitrogen, mg/L	1.24	0.24	0.421	4.2	0.9	
Orthophosphorus, mg/L	0.41	0.47	0.20	2.0	0.7	
Total Phosphorus, mg/L	0.44	2.08	0.20	2.0	1.1	
Arsenic, ug/L	<5	<9	<10	0.1	20	50
Barium, ug/L	<10	<10	75	750	130	
Beryllium, ug/L	<3	10	<0.9	9	4.5	1100
Cadmium, ug/L	<0.4	6	<0.7	7	2.8	1.2
Chromium, ug/L	<10	<10	13	130	26	50
Copper, ug/L	7	65	7	70	30	30
Iron, ug/L	293	1700	420	0	1200	1000

Table 5.2.1-1. Summary of Estimated Cooling Reservoir and Intake Water Quality Conditions, and Reservoir Quality for the Hardee Power Station (Page 2 of 2)

Parameter	Reservoir Intake/Influent Water Quality: Surface Runoff	Surficial Aquifer	Floridan Aquifer Makeup	Treated Neutralization Basin Effluent	Cooling Reservoir Qulaity[1]	FDER Class III Water Quality Criteria
Lead, ug/L	6.1	<6.7	14	140	26	30
Manganese, ug/L	7.9	28	28	0	44	
Mercury, ug/L	0.24	0.24	<0.2	2	0.4	0.2
Nickel, ug/L	16	16	23	230	45	100
Selenium, ug/L	<5	<5	16	160	29	25
Silver, ug/L	<0.08	<0.08	<0.4	4	0.7	0.07
Strontium, ug/L	100	100	300	3000	540	
Zinc, ug/L	7.4	<50	143	1400	250	1000
Alpha, Gross (pC/L)	1.7	30	8.4	84	22.1	15
Radium 226 (pC/L)	0.7	2.0	3.0	30	5.6	5

Notes: 1. Reservior quality estimates are based on mass balances and do not take into account any chemical reaction, precipitation, sedimentation, deposition or biological activity which may occur in the reservoir and act to remove material from the water column and thus reduce reservoir concentrations.

2. Unionized ammonia concentrations are based on a worst case reservoir water temperature of 95°F (35°C).

data collected by the FDER are being used in this application to satisfy preconstruction monitoring requirements and to establish background concentrations.

The maximum predicted 24-hour and annual average PM concentrations are 7.5 and 0.82 ug/m^3, respectively. Because the maximum 24-hour concentration is below the de minimis monitoring level, preconstruction monitoring is not required for the permit application.

The maximum predicted annual NO_2 concentration is 4.6 ug/m^3, which is below the de minimis monitoring level. Similar to the PM concentrations, preconstruction monitoring requirements is not required for the permit application.

The maximum predicted 1- and 8-hour average CO concentrations are 179 and 38.0 ug/m^3, respectively, which are less than the significance levels. The maximum 8-hour concentration is also less than the de minimis monitoring levels and, therefore, preconstruction monitoring is not required. Because the maximum predicted impacts due to the proposed facility are less than the CO significance levels, additional modeling is not required for this pollutant.

The maximum predicted 24-hour average Be and Hg concentrations are 0.0004 and 0.0016 ug/m^3, respectively, which are less than the de minimis monitoring levels. Therefore, preconstruction monitoring is not required for these pollutants.

PSD CLASS II INCREMENT CONSUMPTION

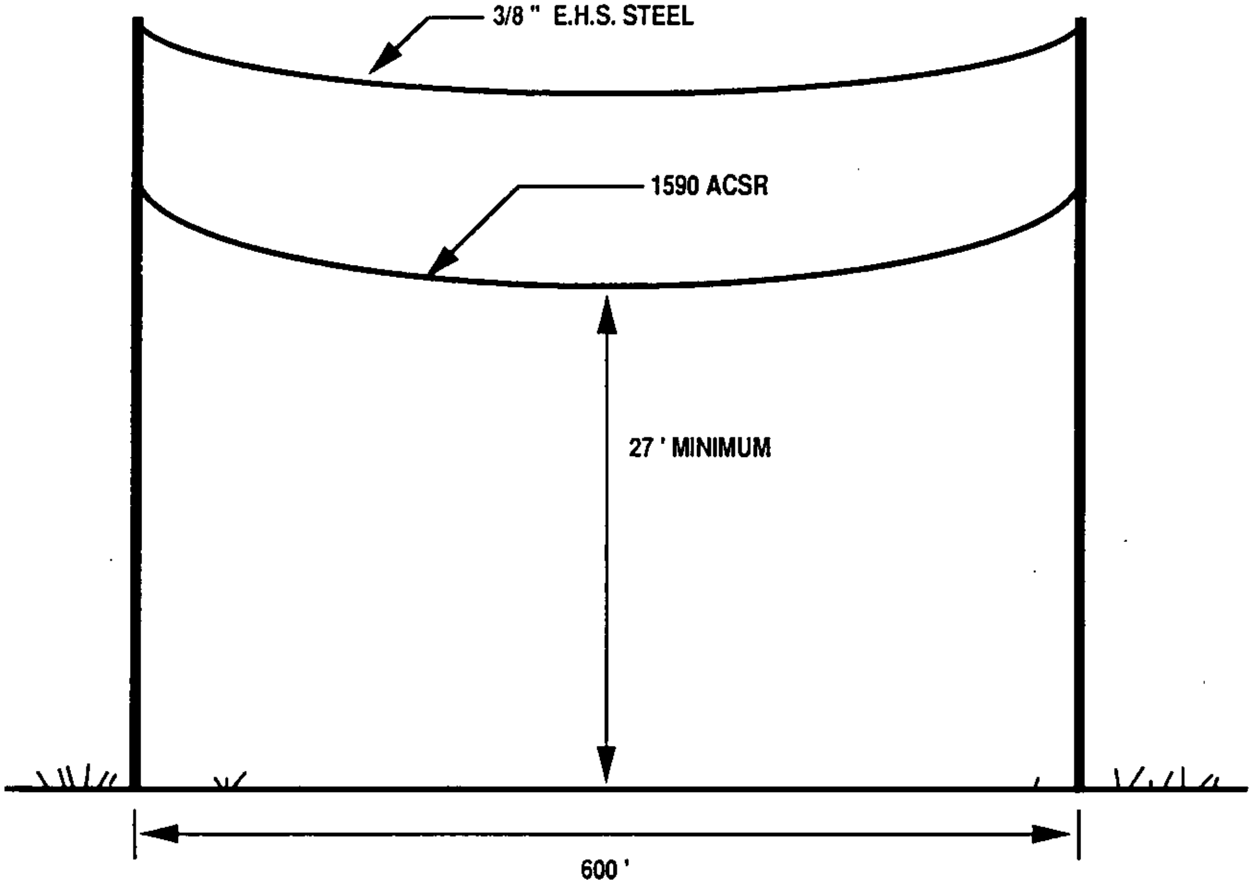
For the refined modeling analysis, summaries of the maximum SO_2, PM, and NO_2 concentrations predicted for comparison to the PSD Class II increments are presented in Table 5.6.1-7. These results show that maximum concentrations due to all PSD sources are less than the maximum allowable PSD Class II increments for all averaging periods and pollutants.

Table 5.6.1-7. Maximum Predicted SO_2, PM, and NO_2 Concentrations for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration (ug/m^3)	PSD Class II Increment (ug/m^3)
<u>SO_2 Concentrations</u>		
3-Hour*	424	512+
24-Hour*	66.0	91+
Annual	8.1	20
<u>PM (TSP) Concentrations</u>		
24-Hour*	8.0	37+
Annual	0.9	19
<u>NO_2 Concentrations</u>		
Annual	4.6	25

* Highest, second-highest concentrations predicted for this averaging period.

+ Not to be exceeded more than once per year.



1590 ACSR (LAPWING)
600 ' RULING SPAN

Figure 6.1.3-2 CONDUCTOR PROFILE FOR H-FRAME CONSTRUCTION

Hardee Power Station

Conductor profiles for H-frame and single pole configurations are presented in Figures 6.1.3-2 and 6.1.3-3, respectively.

Span lengths between structures will average between 183-213 m (600 to 700 ft). Individual span lengths will be determined by the topography of the route and the width of the ROW. The entire line will meet National Electrical Safety Code Standards for clearance to ground and obstructions. Additionally, the minimum clearance from any energized conductor to ground will be 8 m (27 ft).

Existing roadways will be used for access to the transmission line wherever possible. If adequate access roads do not exist, new roads will be constructed which will typically be unpaved and have a maximum width of 6 m (20 ft). It is estimated that approximately 40 miles of new access road will need to be constructed. No new bridges will be required as part of the corridor construction.

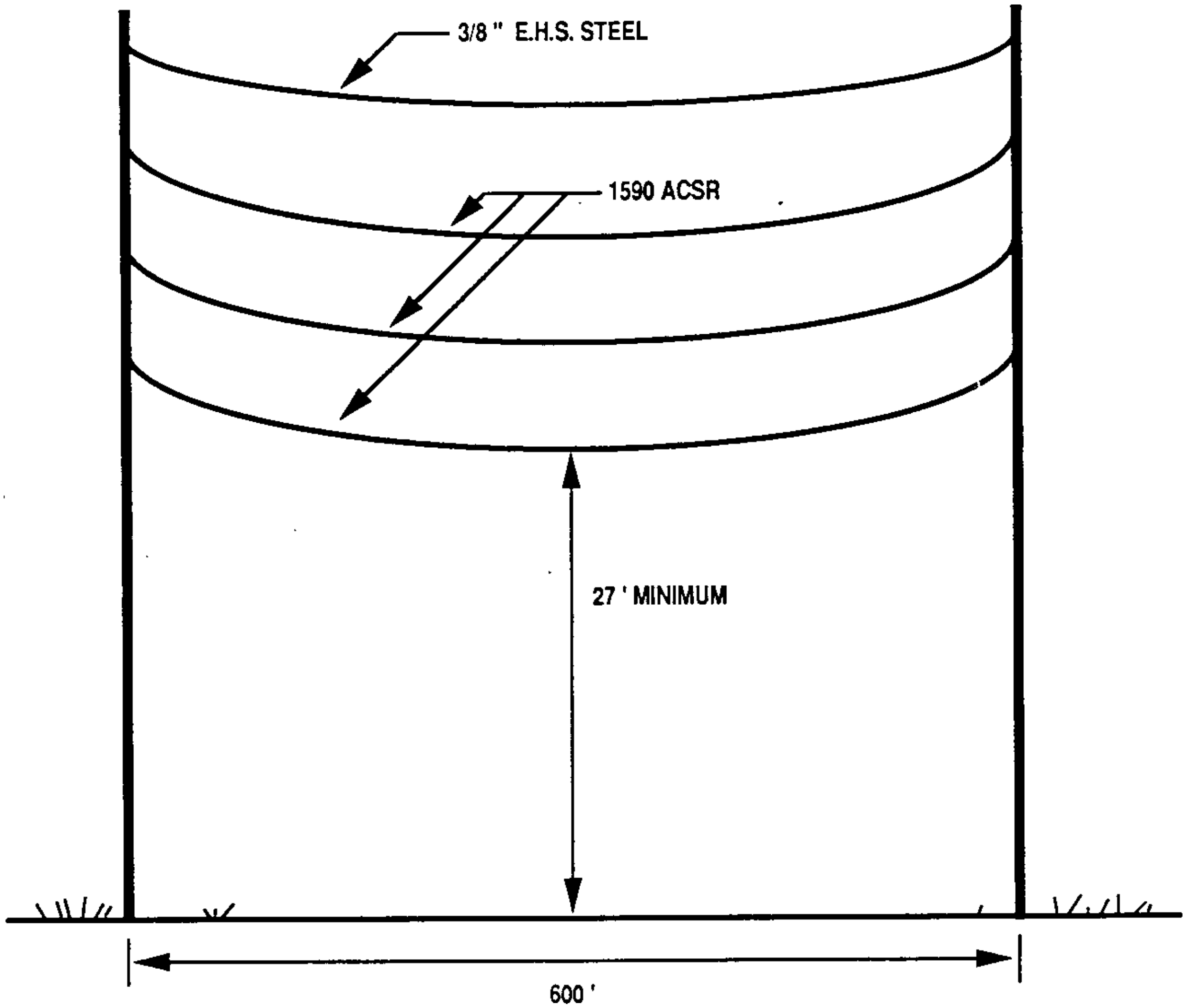
Structure pads will typically be constructed adjacent to the access roads. The pads will be approximately 7 m (24 ft) in width, with the length varying as a function of the distance between the structure and the access road.

6.1.4 Cost Projections

Approximate costs for the transmission lines are presented in Table 6.1.4-1. The actual cost of the transmission lines may vary depending on the final ROW and structure location, cost of ROW acquisition and other site specific conditions.

6.1.5 Corridor Selection

The objective of the transmission line corridor siting study was to select the most favorable corridor in the study area based on a combination of socioeconomic, environmental, engineering and economic considerations. The study area for the corridor selection study (Figure 6.1.5-1) was defined by the geographic distribution of the Hardee Power Station and the three end point substations, i.e., Pebbledale, Vandolah and Lee Substations.



1590 ACSR (LAPWING)
600 ' RULING SPAN

Figure 6.1.3-3 CONDUCTOR PROFILE FOR SINGLE POLE CONSTRUCTION

Hardee Power Station

Table 6.1.4-1. Cost Projections for the Preferred and Alternative Corridors for the Hardee Power Station Project in 1988 Dollars

Corridor	Section	Approximate Length (Miles)	Estimated ROW Cost ($)	Total ROW Preparation Cost ($)	Line Construction Cost ($)	Estimated Cost per mile ($)	Total Cost ($)
Preferred	C1	16	606,000	836,000	2,560,000 to 4,000,000	250,000 to 340,000	4,002,000 to 5,442,000
	C2	8*	580,800	200,000	3,219,200	250,000	4,000,000
	C3	70	2,540,000	875,000	14,084,000	250,000	17,500,000
Alternative	C1	18	1,091,000	528,000	2,880,000 to 4,500,000	250,000 to 340,000	4,499,000 6,119,000

* Two parallel lines of 13 km (8 miles) each.

C1 = Hardee Power Station to Pebbledale Substation
C2 = Hardee Power Station to Vandolah Substation
C3 = Vandolah Substation to Lee Substation

produced during regeneration of the makeup demineralizers. The neutralization basin will be a reinforced concrete basin lined with chemical resistant membrane, brick, and mortar. A chemical waste mixer will be provided to hasten pH adjustment of the chemical wastes. Sulfuric acid and sodium hydroxide, as required for neutralization, will be available from the demineralizer regeneration equipment. The pH adjusted chemical wastewaters will be routed to the cooling reservoir. Table 3.6.7-1 presents the estimated water quality of the neutralization basin effluent.

3.6.8 Miscellaneous Plant Drains

Separate collection systems will be used to collect chemical drain wastewater and miscellaneous plant drain wastewater. Chemical drain wastewaters have been discussed previously in Section 3.6.6. Miscellaneous plant drain wastewater can result from general cleaning and maintenance, such as hosing general plant (i.e., non-chemical) areas. Miscellaneous floor drains will be directed to an oil separator and then routed to the cooling reservoir for reuse as cooling water.

3.7 SOLID AND HAZARDOUS WASTE

3.7.1 Solid Waste

Only small quantities of solid wastes will be generated by the Hardee Power Station facilities since there will be no ash or FGD waste generated or requiring disposal. Solid wastes will be limited to general trash, sanitary waste treatment sludge and infrequent replacement of demineralizer resins. The sanitary waste sludge will be disposed of by a contractor who will remove sludge in the sludge holding compartment once or twice per year. Sanitary waste sludge will be hauled off site for disposal by the contractor. Other solid wastes will be disposed off-site in a sanitary landfill.

3.7.2 Hazardous Waste

The demineralized waste streams can contain up to 10% sulfuric acid or up to 5% sodium hydroxide along with the minerals removed from the ion exchange resins. The wastes will be combined in an elementary neutralization basin

Table 3.6.7-1. Estimated Characteristics of the Neutralization Basin Effluent for the Hardee Power Station (Page 1 of 2)

Parameter	Treated Neutralization Basin Effluent
Calcium, mg/L as $CaCO_3$	1130
Magnesium, mg/L as $CaCO_3$	490
Sodium, mg/L as $CaCO_3$	3050
Potassium, mg/L as $CaCO_3$	80
Total Hardness, mg/L as $CaCO_3$	1620
Alkalinity, mg/L as $CaCO_3$	0
Sulfate, mg/L as $CaCO_3$	4540
Chloride, mg/L as $CaCO_3$	210
Silca, mg/L	270
Fluoride, mg/L	20
Cyanide, mg/L	0.05
MBAS, mg/L	1.8
Oil and Grease, mg/L	0
Turbidity, NTU	10
pH, units	6-9
Total Dissolved Solids, mg/L	6860
Specific Conductivity, umhos/cm	12100
Total Kjeldahl Nitrogen, mg/L	3.9
Ammonia Nitrogen, mg/L	2.0
Organic Nitrogen, mg/L	1.9
Nitrate+Nitrite-Nitrogen, mg/L	0.3
Total Nitrogen, mg/L	4.2
Orthophosphorus, mg/L	2.0
Total Phosphorus, mg/L	2.0
Arsenic, ug/L	0.1
Barium, ug/L	750
Beryllium, ug/L	9
Cadmium, ug/L	7
Chromium, ug/L	130
Copper, ug/L	70
Iron, ug/L	0
Lead, ug/L	140

forest. Generally, however, in the habitat types prevalent in the corridor, creation of desirable edge habitat and maintenance of early successional vegetation could have a positive effect on sensitive species. Gopher tortoises, and several other species of concern in this region prefer relatively open habitats.

Herbicide use will be implemented in such a manner so as to minimize impact to wildlife or aquatic organisms.

Access roads can act as barriers to animals reluctant to cross openings, and can displace (or subject to routine trampling) a certain amount of vegetation. These impacts should be minimal, however, because Tampa Electric intends to use existing roads wherever feasible and minimize the lengths of any essential new roads.

6.1.6.5.4 <u>Effects of Public Access</u>

It is Tampa Electric's policy to install locked gates at all points where the transmission line access road intersects previously fenced property. Therefore, with the exception of Tampa Electric's personnel performing routine maintenance, no increased vehicle access is anticipated. Since no significant increase in human traffic into formerly inaccessible habitats will result, there will be no subsequent increased disturbance to wildlife.

6.1.6.5.5 <u>Other Post Construction Effects</u>

The transmission line will meet EMF limits set forth in Chapter 17-274, F.A.C. Maximum electric and magnetic field strengths at the edge of the ROW for the transmission line were calculated using the Bonneville Power Administration Corona and Fields Effects program. Input data used in the program were based on the generating capacity of the Hardee Power Station and included the following parameters:

1. A maximum current rating of 2,040 amperes;
2. A minimum conductor clearance of 27 ft from the earth;
3. Currents were assumed to be balanced in phase and in magnitude with no zero sequence current;
4. A maximum operating voltage of 242 kV; and
5. Voltages were assumed to be balanced in phase and in magnitude.

Electromagnetic fields strengths will vary depending on the ROW width and structure type. The maximum field strengths at the edge of the transmission ROW will be below the field strength standards listed in Chapter 17-274.450, F.A.C. (i.e., 2.00 kV/m for electric field, and 150 milliGauss for magnetic field). The entire transmission line facility will meet the applicable sections of the National Electrical Safety Code. Due to the design and routing of the proposed transmission line and its location relative to residential areas, EMF and acoustic and electric noise will not be a problem.

6.1.7 Hardee Power Station to Vandolah and Lee Substations Transmission Line

6.1.7.1 Description of Preferred and Alternative Corridors

The preferred corridors from the Hardee Power Station to both the Vandolah and Lee Substations are described below. The corridor description starts at the Hardee Power Station and proceeds south to Vandolah Substation and from Vandolah Substation south to Lee Substation. These transmission lines will be constructed and maintained by SECI.

HARDEE POWER STATION TO VANDOLAH SUBSTATION

This section of the corridor starts at the Hardee Power Station and proceeds south, approximately 13 km (8 miles) to the Vandolah Substation located on Vandolah Road (see Figure 6.1.7-1 in Appendix 11.10). Much of the land between the Hardee Power Station and the Vandolah Substation is owned by various phosphate mining companies and may be mined in the future. Due to the potential for mining activities in this area, the siting study concentrated on routing the corridor adjacent to existing highway and railroad ROWs.

The Hardee Power Station to Vandolah corridor is approximately 13 km (8 miles) and starts at the switchyard of the Hardee Power Station and proceeds south along CR 663. The width of this section of corridor is 0.8 km (0.5 mile) with the exception of a 1.6-km (1-mile) section where it increases to 1.2 km (0.75 mile) near the town of Ft. Green Springs. The expanded corridor width near Ft. Green Springs is designed to allow additional flexibility in siting the ROW in this area to minimize potential impacts to developed areas.

Two parallel 230 kV transmission lines are planned for the Hardee Power Station to Vandolah section of the corridor. Separate ROWs and structures are needed for each of the two transmission lines in this area. Both lines

6.1.7.5.2 Multiple Uses

Various activities including citrus farming, grazing, and agriculture are typically allowed within the ROW as long as these activities do not interfere with full use of the ROW. An easement will be obtained for the construction and operating of the Vandolah and Lee transmission lines, including ingress and egress to the transmission line. Specific uses within the ROW will be addressed individually with affected parties. Multiple use of the ROW may be restricted in certain areas, but in general, compatible multiple uses will be allowed.

6.1.7.5.3 Changes in Species Populations

WILDLIFE AND AQUATIC LIFE

Potential post-construction impacts along the Vandolah and Lee transmission lines fall into four major categories: 1) impacts related to the actual transmission lines and supporting poles; 2) impacts of ROW maintenance procedures; 3) disturbances associated with access roads; and 4) effects of electromagnetic fields.

The primary concern associated with the actual transmission line is the potential increase in bird mortality due to collisions with the wires. The impacts of collisions with power lines on avian mortality are difficult to quantify. It is generally agreed, however, that collisions are a potentially significant cause of mortality among birds. It is also agreed that a large percentage of avian mortality from collisions with power lines can be avoided through careful planning (Anderson, 1978; Lee, 1978; Faanes, 1987). For this reason, the corridor was routed to minimize the potential for collisions by avoiding areas of known bird concentrations and areas used for roosting or nesting by sensitive species.

Special attention has been given to habitats used by wood storks and other wading birds, sandhill cranes, and red-cockaded woodpeckers. Prior to ROW selection, additional field surveys will be undertaken to identify undocumented sites used by sensitive species and smaller areas of significant habitat. The ROW will be routed to minimize impact on these areas.

The ROW must be maintained so that trees cannot grow into the overhead wires. This implies maintenance of a permanent gap in the canopy through any forested areas. In hydric or mesic habitats this may have a slight deleterious effect in drying and heating the microclimate of the adjacent forest. However, creation of desirable edge habitat and maintenance of openings will probably have a positive effect on such sensitive species as gopher tortoises and burrowing owls.

Herbicide use will be implemented in a manner that will minimize impacts to wildlife or aquatic organisms.

Access roads can act as barriers to animals reluctant to cross openings, and can displace (or subject to routine trampling) a certain amount of vegetation. These impacts should be minimal, however, because SECI intends to use existing roads wherever feasible and minimize the lengths of any essential new roads.

6.1.7.5.4 Effects of Public Access

It is SECI's policy to install locked gates at all points where the transmission line access road intersects previously fenced property. Therefore, with the exception of SECI personnel performing routine maintenance, no increased vehicle access is anticipated. Since no significant increase in human traffic into formerly inaccessible habitats will result, there will be no subsequent increased disturbance to wildlife.

6.1.7.5.5 Other Post Construction Effects

The transmission line will meet EMF limits set forth in Chapter 17-274, F.A.C. Maximum electric and magnetic field strengths at the edge of the ROW for the transmission line were calculated using the Bonneville Power Administration Corona and Fields Effects program. Input data used in the program were based on the generating capacity of the Hardee Power Station and included the following parameters:

1. A maximum current rating of 2,040 amperes;
2. A minimum conductor clearance of 27 ft from the earth;
3. Currents were assumed to be balanced in phase and in magnitude with no zero sequence current;
4. A maximum operating voltage of 242 kV; and
5. Voltages were assumed to be balanced in phase and in magnitude.

Electromagnetic fields strengths will vary depending on the ROW width and structure type. The maximum field strengths at the edge of the transmission line ROW will be below the field strength standards listed in Chapter 17-274.450, F.A.C. (i.e., 2.00 kV/m for electric field, and 150 milliGauss for magnetic field). The entire transmission line facility will meet the applicable sections of the National Electrical Safety Code. Due to the design and routing of the proposed transmission line and its location relative to residential areas, EMF and acoustic and electric noise will not be a problem.

6.2 ASSOCIATED NATURAL GAS PIPELINE

6.2.1 Project Description

THe proposed primary fuel for the Hardee Power Station is natural gas. It will be brought to the site by a new gas pipeline, the Hardee Power Station Lateral, connecting with an existing gas pipeline near Polk City, Florida. The Federal energy Regulatory Commission (FERC) issued an environmental assessment on,

January 31, 1989 for a series of proposed Florida Gas Transmission System (FGT) gas pipelines, which inlcuded a portion of the proposed Hardee Power Station Lateral, referred to as the Sarasota Lateral Loop. FERC determined that the construction of the proposed facilities including the Sarasota lateral Loop would not constitute a major federal action significantly affecting the human environment (FERC, 1989).

The Hardee Power Station Lateral incorporates the proposed Sarasota Lateral Loop and continues to the plant site. The Hardee Power Station Lateral begins about 1.6 km (1 mile) north of Polk City where it interconnects with the existing FGT 18-inch St. Petersburg lateral and continues south to the Hardee Power Station (Figure 6.2.1-1).

The gas pipeline will consist of an underground pipeline along a 22 m (75 ft) ROW.. There are no proposed compressor stations along the preferred pipeline corridor.

6.2.2 Corridor Location and Layout

Figures 6.2.1-2 through 6.2.1-5 identify the full length of the proposed 30 m (100 ft) corridor relative to major geographic features. Existing gas pipeline are shown as these figures. Approximately 91% of the proposed gas

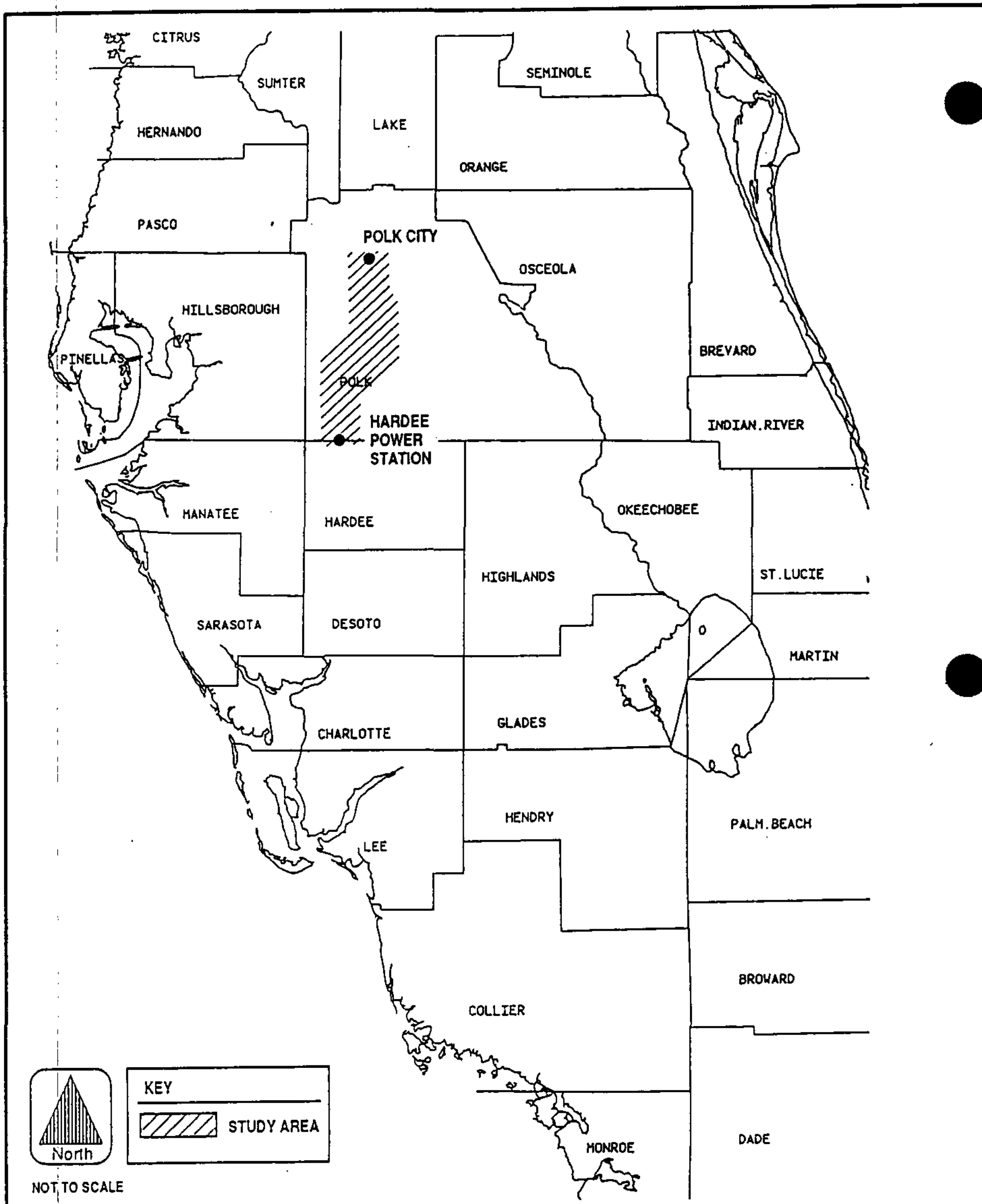


Figure 6.2.1-1 NATURAL GAS PIPELINE STUDY AREA AND INTERCONNECT POINTS

Hardee Power Station

and will use existing highway and railroad ROWs. It will enter the site from CR 663, co-located with the access road.

A 20.3 cm (8-inch) liquid fuel pipeline will be constructed from the plant site west to Port Manatee (see Section 6.3). The proposed pipeline will approach the site from the west (see Section 6.3).

10.2.2 Plant and Associated Facilities Operational Aspects

The operational impacts of the Hardee Power Station are described in Chapter 5 Effects of Plant Operation. The Hardee Power Station project will not have any significant adverse effect on existing or future natural and cultural resources, including reclaimed areas. Table 10.1.2-1 lists applicable FDNR requirements which assure protection of natural resources including: soils and topography, wetlands and water bodies, water quality, vegetation, and wildlife. The following is a summary of the relevant operational aspects of the project to these natural resources and the reclamation requirements.

SOIL AND TOPOGRAPHICAL CONSIDERATIONS

The proposed cooling reservoir is the only major facility planned to be constructed on mined lands. The reclamation requirements [16C-16.0051 (2)] call for slopes of reclaimed lands to be no greater than 4 to 1. The cooling reservoir design is discussed in Section 3.5.1. Its proposed slopes (4 to 1 inside and 20 to 1 outside) and other design aspects are consistent with FDNR requirements. Appropriate vegetative cover will be grown, established and maintained on the outside slopes.

WETLANDS AND WATER BODIES

The plant and associated facilities will be constructed outside of the 100-year floodplain. No impacts to offsite wetlands will result from the Hardee Power Station. One contiguous forested wetland [2.4 ha (5.9 acres)] will be lost during construction of the cooling reservoir (see Sections 2.3.6.1 and 4.2.1.2). The loss of these wetlands are not considered significant adverse effects because of the small size and isolation due to surrounding mining activities. However, these wetland losses will be mitigated as part of Agrico's amended reclamation plan. Water subsidies to the wetlands after construction of the plant and associated facilities will be similar to, if not better than, those prior to mining (see Section 5.8 Changes To Non-Aquatic Population). No adverse water quality impacts, including impacts on aquatic life, will result from the operation of the cooling reservoir (see Sections 5.1 Effects of Operation of the Heat Dissipation System, 5.2 Effects of Chemical and Biocide Discharges, and 5.3 Impacts on Water Supplies).

Although some emergent vegetation may occur along the edges of the cooling reservoir, it is not the function of the cooling reservoir to provide wetland habitat and to be considered as wetland mitigation. The growth of too much emergent vegetation will impede the cooling function of the reservoir. As a result, some of the suggested wetland/water body reclamation and restoration standards (16C-16.0051) are not applicable, e.g., "at least 25% of the highwater surface area" be designed for "emergent and transition zone vegetation." Other suggested reclamation and restoration standards can be achieved, e.g., "berm of earth around each water body which is of sufficient size to retain at least the first inch of runoff."

WATER QUALITY AND QUANTITY

All waters leaving the cooling reservoir and the site will meet applicable water quality standards of the Florida Department of Environmental Regulation at the point of discharge or at the end of a mixing zone and will have no adverse impact to fish and wildlife (see Sections 5.1 Effects of Operation of the Heat Dissipation System, 5.2 Effects of Chemical and Biocide Discharges, and 5.3 Impacts on Water Supplies).

As recommended by FDNR, the HEC-1 model was used to evaluate event specific discharges to Payne Creek and associated dilution for the 10-year, 24-hour storm and the 25-year, 24-hour storm (see Section 5.1.1 Temperature Effect On Receiving Body of Water). The format methodology followed that described

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

The combined cycle facility will be constructed in modules to achieve the desired capacity additions. The final design will depend on the selected combustion turbine with either five or six combustion turbines required to achieve theultimate capacity of 660 MW. Both simple cycle and combined cycle operation are planned; the latter would use by-pass stacks when only combustion turbine operation is needed, or the steam cycle is inoperable. The HRSG would not be supplementally fired.

2.2 FACILITY EMISSIONS AND STACK OPERATING PARAMETERS

The performance information and stack parameters that envelope the combustion turbine manufacturer's designs currently being considered for the project are presented in Table 2-1. This information provides conservative emission estimates of criteria pollutants (Table 2-2), other regulated pollutants (Table 2-3), and non-regulated pollutants (Table 2-4). Specific manufacturer designs would provide emissions no greater than those shown in these tables. The fuel specifications for natural gas and distillate oil are presented in Tables 2-5 and 2-6, respectively.

For a 660-MW (nominal) facility, the maximum emissions are produced with five combustion turbines; the design, stack, and emission characteristics are presented in Tables 2-1 through 2-4. This configuration will also have the highest exhaust flow. Lower exhaust flow rates and emissions will occur for a 660-MW (nominal) facility using six of the smaller combustion turbines. The exhaust flow and corresponding emissions are important in establishing air quality impacts and must be determined separately for each configuration. As a result, the range in stack parameters used in modeling, as well as corresponding sulfur dioxides (SO_2) emissions, are presented in Table 2-7. In either configuration the maximum potential air quality impacts will occur during combined cycle operation when the exhaust temperature is 240°F.

Table 2-7. Stack Parameters and SO_2 Emissions Used in Modeling for the Hardee Power Station

	5 Turbine Option Highest Emission		6 Turbine Option Lowest Flow Rate	
	32°F CASE 1	95°F CASE 2	32°F CASE 3	95°F CASE 4
Stack Gas Flow (ACFM)	947,056	833,126	770,627	654,455
Stack Gas Temperature (°F)	240	240	240	240
Stack Velocity (ft/sec)	78.5	69.1	63.9	54.2
Stack Diameter (ft)	16	16	16	16
Stack Height (ft)*	75	75	75	75
SO_2 Emissions (lb/hr)	734.37	619.56	558.04	456.34

* This stack height was used for the HRSG exhaust along with worst case structure dimensions (see Table 6-13) to conservatively estimate air quality impacts.

Note: Cases 1 and 2 are for five combustion turbines.
Cases 3 and 4 are for six combustion turbines.
Stack parameters and emissions are shown on a per-unit basis.

Table 6-5. Summary of SO2 Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

Facility*	Location from Proposed Facility Distance (km)	Location from Proposed Facility Direction (degrees)	Maximum SO2 Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses: Screen.	Modeled Sources in Analyses: Refined
Gardinier	12.0	61	1,173	241	YES	YES	YES
Imperial Phosphate	12.1	0	275	242	YES	NO	YES
Agrico Chemical Co. (S. Pierce)	14.4	11	4,557	287	YES	YES	YES
Mobil Oil Big Four Mine	15.8	320	569	317	YES	NO	YES
U.S. Agri-Chemicals	16.1	44	2,933	322	YES	YES	YES
Wachula City Power Plant	17.1	127	180	342	NO	--	--
IMC Fort Lonesome	18.6	304	1,714	371	YES	YES	YES
Agrico Chemical Co. (Pierce)	21.6	357	417	433	NO	--	--
Mobil-Electrophosphate Division	22.0	2	1,428	440	YES	NO	YES
Farmland Industries	23.2	12	3,692	464	YES	YES	YES
IMC	23.4	340	10,251	469	YES	YES	YES
IMC/Noralyn Mine Road	24.9	23	505	499	YES	NO	YES
C.F. Industries	25.3	8	8,443	505	YES	YES	YES
Kaplan Industries	25.7	32	385	515	NO	--	--
American Orangr Corp.	27.0	112	198	539	NO	--	--
Conserv. Chemicals	27.5	347	1,597	550	YES	NO	YES
Royster Co.	27.8	4	1,283	555	YES	NO	YES
Mobil Chemical Co./Nichols	28.6	347	1,516	572	YES	NO	YES
IMC/Prairie	29.7	356	137	593	NO	--	--
W.R. Grace & Co.	29.7	10	8,186	594	YES	YES	YES
U.S. Agri-Chemicals	30.1	16	1,575	602	YES	NO	YES
FPL Manatee	37.6	265	85,305	753	YES	YES	YES
Tricil Recovery Services	38.9	27	240	777	NO	--	--
Consolidated Minerals	40.4	344	3,302	809	YES	YES	YES
Teco Big Bend	46.4	292	371,733	927	YES	YES	YES
Citrus World	47.0	50	597	939	NO	--	--
Columbus Company	47.5	295	167	950	NO	--	--
Gardinier	48.4	301	5,181	967	YES	YES	YES
Lakeland City Power	49.0	5	4,014	980	YES	YES	YES
Lakeland City Power	49.0	5	30,176	980	YES	YES	YES
Adams Packing	49.8	20	172	995	NO	--	--

			551,901				

* Refer to Table 6-2 for facility UTM coordinates (East, North) and relative locations (x, y) to proposed site.

Table 6-6. Summary of NO2 Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

Facility*	Location From Proposed Facility Distance (km)	Direction (degrees)	Maximum NO2 Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses: Screen.	Refined
Gardinier	12.0	61	176	241	NO	--	--
Agrico Chemical	14.4	11	139	287	NO	--	--
Mobil Oil Big Four Mine	15.8	320	156	317	NO	--	--
U.S. Agri-Chemicals	16.1	316	131	322	NO	--	--
IMC Fort Lonesome	18.6	304	610	371	YES	NO	YES
Farmland Industries	23.2	12	226	464	NO	--	--
IMC	23.4	340	322	469	NO	--	--
Kaplan Industries	25.7	32	100	515	NO	--	--
Mobil Chemical Co./Nichols	28.6	347	134	572	NO	--	--
W.R. Grace & Co.	29.7	10	528	594	NO	--	--
FPL Manatee	37.6	265	22,734	753	YES	YES	YES
Consolidated Minerals	40.4	344	534	809	NO	--	--
Sherex Polymers	41.9	352	617	838	NO	--	--
Juice Bowl Products	42.7	354	109	855	NO	--	--
Owens-Illinois	44.9	358	391	898	NO	--	--
Teco Big Bend	46.4	292	82,624	927	YES	YES	YES
Citrus World	47.0	50	1,382	939	YES	NO	YES
Gardinier	48.4	301	466	967	NO	--	--
Lakeland City Power	49.0	5	5,028	980	YES	YES	YES
		Total	116,407				

* Refer to Table 6-3 for facility UTM coordinates (East, North) and relative locations (x, y) to proposed site.

Table 6-7. Summary of PM Emission Sources Considered in the Modeling Analysis for the Hardee Power Station

Facility*	Location from Proposed Facility Distance (km)	Location from Proposed Facility Direction (degrees)	Maximum PM Emissions (TPY)	Emission Threshold, Q (TPY)	Included in Modeling	Modeled Sources in Analyses: Screen.	Modeled Sources in Analyses: Refined
Gardinier	12.0	61	132	241	NO	--	--
Imperial Phosphates	12.1	0	162	242	NO	--	--
Agrico Chemical	14.4	11	1,705	287	YES	YES	YES
Mobil Oil Big Four Mine	15.8	320	263	317	NO	--	--
U.S. Agri-Chemicals	16.1	316	871	322	YES	NO	YES
Biochemical Energy, LTD	16.5	125	281	329	NO	--	--
IMC Fort Lonesome	18.6	304	679	371	YES	NO	YES
IMC	19.5	340	168	389	NO	--	--
Agrico Chemical	21.6	357	631	433	YES	NO	YES
C&M Products	21.7	358	162	434	NO	--	--
Mobil-Electrophos Division	22.0	358	555	440	YES	NO	YES
Farmland Industries	23.2	12	977	464	YES	NO	YES
IMC	23.4	340	162	469	NO	--	--
IMC	24.9	337	973	499	YES	NO	YES
C.F. Industries	25.3	352	788	505	YES	NO	YES
IMC/ Uranium Recovery	25.7	8	831	513	YES	NO	YES
American Orange Corp.	27.0	112	180	539	NO	--	--
Conserv Chemical	27.5	13	1,620	550	YES	NO	YES
Royster	27.8	4	210	555	NO	--	--
Mobil Chemical Co./Nichols	28.6	347	433	572	NO	--	--
W.R. Grace & Co.	29.7	10	636	594	YES	NO	YES
Ridge Pallets	30.1	27	180	601	NO	--	--
U.S. Agri-Chemicals	30.1	16	182	602	NO	--	--
Allsun Products	37.4	13	317	749	NO	--	--
FPL Manatee	37.6	265	7,578	753	YES	YES	YES
Consolidated Minerals	40.4	344	740	809	NO	--	--
Pavers, Inc.	41.8	347	114	836	NO	--	--
Rinker Cencon Corp.	42.3	350	159	846	NO	--	--
Quikrete	42.4	349	253	847	NO	--	--
Landia Chemical	44.4	1	2,313	888	YES	NO	YES
Kraft Citrus	44.8	353	108	896	NO	--	--
Owens-Illinois	44.9	358	102	898	NO	--	--
Jahna Concrete, Inc.	45.5	97	139	910	NO	--	--
Teco Big Bend	46.4	292	7,699	927	YES	YES	YES
Agrico Chemical Co.	46.6	66	184	932	NO	--	--
Macasphalt	46.9	99	165	938	NO	--	--
Citrus World	47.0	50	166	939	NO	--	--
FPL Avon Park	47.1	98	212	942	NO	--	--
Gardinier	48.4	301	863	967	NO	--	--
Lakeland City Power	49.0	5	14,705	980	YES	YES	YES
Coca Cola Citrus	49.3	20	334	985	NO	--	--
Adams Packing Association	49.8	20	129	995	NO	--	--
		Total	49,061				

* Refer to Table 6-4 for facility UTM coordinates (East, North) and relative location (x, y) to proposed site.

7.0 AIR QUALITY MODELING RESULTS

7.1 PROPOSED FACILITY ONLY

For the screening analysis, a summary of the maximum SO_2, NO_2, PM, CO, and Be concentrations due to the proposed facility is presented in Table 7-1. Model results were calculated for a range of operating conditions for which maximum impacts could occur (see Section 2.0 for the operating data and rational for modeling these conditions). These operating conditions, which were based on either maximum emissions or minimum flow rate for the units, were as follows (Refer to Table 2-7 for Stack parameters and SO_2 emission):

1. Case 1: Maximum emissions at 32°F;
2. Case 2: Maximum emissions at 95°F;
3. Case 3: Minimum flow rate at 32°F; and
4. Case 4: Minimum flow rate at 95°F.

As indicated in Table 7-1, the maximum concentrations are predicted for the operating conditions with minimum flow rates (Cases 3 and 4). It should be noted that the modeled SO_2 emissions were specific for each case because the maximum predicted SO_2 concentrations were relatively high when compared to PSD Class II increments. For the other pollutants, the emissions from Case 1, which had the highest emissions among the cases, were modeled using the stack parameters for Cases 2,3, and 4; therefore, the maximum impacts predicted for cases 2 through 4 are conservative (lower impacts would be predicted if the emissions associated with each case were modeled). See Section 2.0 for a more detailed discussion about the emission data and associated operating parameters used in the modeling.

The maximum predicted 3-, 24-hour and annual SO_2 concentrations are 424, 62.5 and 6.7 ug/m^3, respectively. The maximum 24-hour concentration is above the <u>de minimis</u> monitoring level and, therefore, preconstruction monitoring data are required to be submitted by the Applicant as part of the permit application. As indicated in Section 5.0, existing monitoring data collected by the FDER are being used in this application to satisfy preconstruction monitoring requirements and to establish background concentrations.

TECO
POWER SERVICES
A TECO ENERGY COMPANY

TO WHOM IT MAY CONCERN:

Please be advised that Jerry L. Williams, Director of Environmental for Tampa Electric Company, is the authorized representative of TECO Power Services Corporation concerning matters with which this permit application deals.

Sincerely,

Richard E. Ludwig
President

REL:ams

TECO POWER SERVICES CORPORATION
P.O. Box 111 Tampa, Florida 33601-0111 (813) 228-4111

6-21-89

BEFORE THE ADMINISTRATOR
U.S. ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

In the Matter of: Columbia Gulf Transmission Company ID No. 105-0640-0021 Applicant	PSD Appeal No. 88-11

ORDER

By petition dated November 14, 1988, and pursuant to 40 CFR §124.19 (1987), the Regional Administrator, U.S. Environmental Protection Agency, Region IV, Atlanta, Georgia, requested review of a determination by the Kentucky Department of Air Quality to issue a prevention of significant deterioration (PSD) permit to Columbia Gulf Transmission Company. The permit would allow Columbia Gulf to construct an 11,864 horsepower (8.9 MW) gas turbine to compress gas at its compressor station in Clementsville, Kentucky. The Department made its permit determination pursuant to a general delegation of PSD-issuing authority from EPA Region IV. Because of the delegation, Kentucky's authority to issue PSD permits is subject to the review provisions of 40 CFR §124.19, and any permit it issues will be an EPA-issued permit for purposes of federal law. 40 CFR §124.41; 45 Fed. Reg. 33413 (May 19, 1980).

The Regional Administrator claims Kentucky's determination of best available control technology (BACT) for the proposed facility is clearly erroneous. The proposed permit calls for no add-on controls to reduce NOx emissions, relying instead on combustor design (so-called "dry controls"), whereas the Region believes water injection controls must be added to satisfy BACT requirements. Kentucky responds by arguing that dry controls are BACT because: (1) the impact of NOx emissions on ambient air quality will be negligible if dry controls are used, thus making the addition of water injection environmentally unnecessary and economically unreasonable; (2) use of water injection will cause additional energy to be consumed and it will cause an increase in CO emissions; and (3) federal new source performance standards (NSPS) do not require water injection for "small" turbines.

Under the rules governing this proceeding, there is no appeal as of right from the permit determination. Ordinarily, a petition for review of a PSD permit determination is not granted unless it is based on a clearly erroneous finding of fact or conclusion of law, or involves an important matter of policy or exercise of discretion that warrants review. The preamble to the regulations states that "this power of review should be only sparingly exercised," and that "most permit conditions should be finally determined at the Regional [state] level * * *." 45 Fed. Reg. 33,412 (May 19, 1980). The burden of demonstrating that the permit conditions should be reviewed is therefore on the petitioner. EPA Region IV has met its burden.

The issues raised by Kentucky's contentions are discussed below.

1. <u>Ambient Air Quality and the BACT Determination</u>

Kentucky argues that the benefits to ambient air quality from adding water injection are negligible, and are clearly outweighed by the additional economic costs associated with this form of NOx control, which it estimates are $2,121.00 for each additional ton of NOx removed. According to modelling results, ambient concentrations of NO_2 from all sources (including the proposed facility) within 50 kilometers of the proposed facility will be 50.67 $\mu g/m^3$ <u>without</u> use of water injection and 50.65 $\mu g/m^3$ <u>with</u> use of water injection. In other words, the total reduction in NO_2 pollution is a mere 0.02 $\mu g/m^3$. This slight numerical improvement in air quality, according to Kentucky and the applicant, is not statistically significant, for it falls within the margin of error employed in the air quality model.

The Region does not dispute Kentucky's evaluation of air quality impacts as presented; however, according to the Region, when the focus is on actual NO_x emissions reductions from the facility itself, the costs of water injection are reasonable. Specifically, by using water injection the facility will emit 114.08 fewer tons of NO_x per year, at a cost of $2,121.00 per ton of NO_x removed, which is below the range of costs ($3,000 -

\$6,500) normally expended for NO_x removal. [1] According to the Region, the definition of BACT mandates use of water injection, the most effective available technology for NO_x removal under consideration in this case, [2] unless the applicant can demonstrate that the economic, environmental, or energy impacts from using this technology make the choice unreasonable. In the Region's opinion, Columbia Gulf did not demonstrate that any of these considerations made the choice of water injection unreasonable.

By looking at the modelled impact of the proposed facility's NO_x emissions, the Department argues that it has identified an environmental impact that it may consider for purposes of its BACT determination. I disagree. BACT is defined in the Clean Air Act as an "emission limitation" set by the permit issuer, based on the "maximum degree of reduction" that can be achieved for each regulated pollutant, on case-by-case basis, after "taking into account energy, environmental, and economic impacts

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[1] The Region also argues that Kentucky has overestimated the incremental costs of NO_x removal using water injection. Kentucky computed the costs per ton assuming 6,000 hours of operation per year. The Region correctly points out that this assumption is unwarranted because the permit does not contain any restrictions limiting hours of operation to 6,000 hours per year. Unrestricted, the facility could operate 8,760 hours per year (24 hrs. x 365 days).

[2] The Region has conceded that although a more effective control technology, selective catalytic reduction, has been successfully employed on gas-fired turbines, that technology would be technically infeasible in this case due to source-specific factors.

and other costs." 42 U.S.C. §7479(3). [3/] The latter clause is in the BACT definition to temper the stringency of the technology requirements whenever one or more of the specified "collateral" impacts -- energy, environmental, or economic -- renders use of the most effective technology inappropriate. As explained by Senator Edmund S. Muskie, the principal architect of the Clean Air Act amendments of 1977:

> One objection which has been raised to requiring the use of the best available pollution control technology is that a technology demonstrated to be applicable in one area of the country is not applicable at a new facility in another area because of difference [sic] in feedstock material, plant configuration or other reasons. For this and other reasons, the committee voted to permit emission limits based on best available technology on a case-by-case judgment at the State level. This flexibility should allow such differences to be accommodated and still maximize the use of improved technology.

Senate Debate on S.252 (June 8, 1977), <u>reprinted in</u> 3 Senate Committee on Environment And Public Works, A Legislative History

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[3/] The complete text of the statutory definition of BACT states:

> The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 [new source standards] or 7412 [hazardous pollutant standards] of this title.

42 U.S.C. §7479(3).

of the Clean Air Act Amendments of 1977 at 729 (Comm. Print August 1978) (Congressional Research Service, Serial No. 95-16). In other words, the collateral impacts clause operates primarily as a safety valve whenever unusual circumstances specific to the facility make it appropriate to use less than the most effective technology. The permit applicant must install the most effective technology if it fails to demonstrate to the satisfaction of the permit issuer that such unusual circumstances exist. [6]

Here, the Department argues that the modelled negligible impact of the proposed facility on overall air quality is an environmental impact that can be factored into the BACT analysis to justify using less than the most effective technology to

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[6] The process of selecting the most effective technology is described in Pennsauken County Resource Recovery Facility, PSD Appeal No. 88-8 (EPA Administrator, Nov. 10, 1988) (Remand Order). Pennsauken cites recent Agency guidance on the subject, which refers to the process as the "top-down" approach to BACT analysis, and quotes from the guidance as follows:

> The first step in this approach is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental or economic objections. Thus, the "top-down" approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best technology available. It also differs from other processes in that it requires the applicant to analyze a control technology only if the applicant opposes that level of control; the other processes required a full analysis of all possible types and levels of control above the baseline case.

Id. at 5.

control NO_x emissions. This argument is without merit. It gives no effect to the primary purpose of the collateral impacts clause, which, as the legislative history indicates, is to focus on local impacts that constrain the source from using the most effective technology. For example, if the most effective technology would impose exceptional demands on local water resources, so that use of the technology would have adverse impacts on the environment, then, under those circumstances, the applicant would have a sound basis for foregoing use of the most effective technology in favor of some less water-intensive technology. This would be a "water resources" equivalent of a "feedstock" or "plant configuration" constraint referred to by Senator Muskie. 5/

In the present case, the Department and the applicant have not demonstrated the existence of any environmental impacts that would constrain or even remotely circumscribe the applicant's ability to use the most effective technology. The negligible air

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5/ Depending on the factors present in a particular case, consideration of collateral impacts can also result in a more stringent BACT determination than would otherwise occur. For example, unusually high costs may represent an adverse economic impact that could, standing alone, justify rejection of the most effective control technology. However, the permitting authority could ultimately conclude that such adverse economic impacts are outweighed by adverse collateral environmental impacts associated with the less effective control option. See North County Resource Recovery Associates, PSD Appeal No. 85-2 (EPA June 3, 1986) (remand order) (environmental impact of pollutants not regulated under the Clean Air Act may necessitate a more stringent emission limit for regulated pollutants undergoing BACT review).

quality impact of the proposed NO_x emissions is clearly not a constraint on implementing the most effective technology. Because it is not a constraint, the modelled impact of the proposed facility's NO_x emissions on air quality should not be considered for purposes of making the BACT determination.

This conclusion is further confirmed by the statutory scheme of the Clean Air Act, which separates issues of overall air quality from issues of technology. Section 165(a)(3) of the Act, 42 USC §7475(a)(3), addresses the direct impact of regulated pollutants on ambient air quality by requiring an applicant for a PSD permit to demonstrate that the proposed facility will not cause or contribute to a violation of national ambient air quality standards or PSD increments, whereas section 165(a)(4) of the Act, 42 USC §7475(a)(4), is concerned exclusively with BACT, which is principally a technology-forcing measure that is intended to foster rapid adoption of improvements in control technology. [6] Both of these provisions of the Clean Air Act

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[6] Section 165 of the Clean Air Act provides, in relevant part, as follows:

> (a) No major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless --
>
> * * *
>
> (3) the owner or operator of such facility demonstrates * * * that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of any (A) [increment], (B) national ambient air quality standard in any air quality control region, or (C)

(continued...)

must be satisfied by an applicant seeking a PSD permit, and compliance with one provision does not relieve or lessen an applicant's burden of complying fully with the other. Thus, even though Columbia Gulf's NO_x emissions will not cause a violation of ambient air quality standards in contravention of section 165(a)(3) of the Act, it must still satisfy the BACT technology requirements imposed by section 165(a)(4).

It does not appear to have done so in this instance, for the record on appeal does not show that any collateral impacts -- in particular, environmental impacts -- operate as a constraint on implementing the most effective technology.

2. Energy Consumption and Increased CO Emissions From Water Injection

Kentucky also claims that water injection is not BACT because it increases fuel consumption by 2.2 percent and carbon monoxide (CO) emissions by 4 tons per year (TPY) -- from 2 TPY to 6 TPY. The Region rejected these arguments, because the projected 2.2 percent increase in energy consumption is, in its opinion, insignificant, since the increase does not place any substantial strain on natural gas demand, and the additional 4 TPY increase

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[6](...continued)
any other applicable emission standard or standard of performance under this chapter; [and]

(4) the proposed facility is subject to the best available control technology [BACT] for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility * * *.

in CO emissions will be offset by a much greater reduction in NO_x emissions -- from 193 TPY to 79 TPY -- which, in the Region's opinion, represents an environmentally beneficial trade-off.

I agree completely with the Region about the trade-off between the CO and NO_x emissions; the increase in CO emissions is simply insignificant in light of the reductions that can be achieved in NO_x emissions. I am less certain about the 2.2 percent increase in energy consumption and what it implies. Nevertheless, it is generally incumbent on the permit issuer and the permit applicant to demonstrate in the record the relevance or significance of any claimed basis for rejecting the most effective technology on energy or other statutory grounds. It is not enough for them to assert, without substantiation, that adoption of the most effective technology will result in an energy penalty. They must provide substantiation and they must show that the penalty is so substantial or unusual as to merit rejection of the most effective technology. They have not done so in this instance, for the record does not disclose any substantial information on the impact of the alleged energy penalty.

3. New Source Performance Standards (NSPS) and BACT

Kentucky believes that because the emission limitation it proposed for Columbia Gulf's NOx emissions (178 ppm) is below the level specified by the NSPS (196 ppm), [7] this fact should serve as further proof that its BACT determination is correct.

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[7] See 40 CFR §60.332(d).

Kentucky notes in this respect that the NSPS contemplate use of dry controls for small gas turbines. Kentucky's reliance on the NSPS is misplaced. Simply meeting or exceeding the NSPS does not attest to the correctness of a BACT determination. As the language of the statute plainly indicates, [8] the applicable NSPS limitation merely serves as a floor for the BACT limitation, i.e., the BACT limitation must never fall below the level of stringency set by the NSPS. Although the NSPS are developed by considering many of the same factors that go into a BACT determination, [9] their utility is limited in any individual case by at least two considerations. The first is that BACT determinations are made on a case-by-case basis whereas the NSPS are set on an industry-wide basis. The second is that BACT determinations are made on the basis of currently available information, whereas the NSPS, although based on current information when promulgated, may not reflect the most current information avail-

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[8] <u>See</u> footnote 3 (last sentence).

[9] The similarity between BACT and NSPS is reflected in the following definition of a "standard of performance" for new sources and by comparing it with the definition of BACT in footnote 3 above:

> [A] standard of performance shall reflect the degree of emission limitation and the percentage reduction achievable through the application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

42 U.S.C. §7411(a)(1).

able at the time of making an individual BACT determination. These two considerations can combine in an individual case to create a substantial gap between the two emission levels. That appears to be the case here, based on the information in the record of this appeal. According to the Region, the applicable NSPS is ten years old and thus does not reflect the most current technological considerations. It therefore appears that Kentucky relied too heavily and, in the final analysis, relied improperly on the NSPS in this case. Moreover, I note that the Region cites three examples of comparable turbines currently using water injection or scheduling it for use -- thus effectively removing concern about the availability of this technology for small turbines. [10/] Kentucky has not shown that water injection is not an available technology for BACT purposes.

Conclusion

The Region has met its burden of showing that Kentucky's permit determination warrants review. As explained above, Kentucky's reliance on negligible ambient air quality impacts to justify using a control technology less effective than water injection represents clear error. Kentucky's rejection of water injection because of associated increases in CO emissions and because of its interpretation of BACT in relationship to the NSPS also represents clear error. Kentucky's concerns over increased

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10/ See Letter from Bruce T. Miller, Chief, Air Programs Branch, EPA Region IV, to Ronald L. McCallum, Chief Judicial Officer, Attachment at 6, dated January 25, 1989.

energy consumption fail to establish that the increases are so substantial or unusual as to warrant rejection of the most effective technology. I therefore conclude that clear error has been shown here also.

According to the procedural rules governing petitions for review, a briefing period is supposed to follow the granting of review. 40 CFR §124.19(c). In a sense, one has already begun, since both Kentucky and the Region, following the filing of the petition, have submitted additional statements of their positions on the issues. Columbia Gulf, however, did not file any extensive submissions during this post-petition period, nor was it required to file any at this stage of the proceedings. Therefore, to restore balance to the record, I propose to set a briefing schedule that takes this background into consideration. Specifically, Columbia Gulf (and, as permitted by the rules, other interested persons) may submit a brief on the issues discussed in this order within thirty (30) days after public notice of the granting of review has been given. See 40 CFR §124.19(c). (Kentucky shall give notice of the briefing schedule and this order, as provided in 40 CFR §124.10.) Kentucky and the Region shall then file their respective responses within twenty (20) days after receipt of each brief filed during the first round of briefing. Columbia Gulf and, if applicable, other interested persons shall then have fifteen (15) days in which to file a reply to the responses.

Also, on or before the date public notice is given, Kentucky shall transmit to the undersigned a complete copy of the administrative record on which it made its permit determination, accompanied by an index of the contents of the administrative record. Copies of the index shall also be sent to the Region and Columbia Gulf and, if requested, to other interested persons. Thereafter, all persons filing briefs in this matter shall support their arguments and factual assertions with appropriate citations to the documents listed in the index.

So ordered.

William K. Reilly

William K. Reilly
Administrator

Dated: JUN 21 1989

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing Order in the matter of Columbia Gulf Transmission Company, PSD Appeal No. 88-11 were sent by First Class Mail to the following persons:

William C. Eddins, Director
Division for Air Quality
Commonwealth of Kentucky
Dep't. for Environmental Protection
18 Reilly Road
Frankfort, KY 40601

Susan Midyett
Columbia Gulf Transmission Company
3805 West Alabama Avenue
Houston, TX

Richard D. Baley
Manager of Design Engineering
Columbia Gulf Transmission Company
3805 West Alabama Avenue
Houston, TX

Daniel Ransbottom
Senior Consultant
Entrix, Inc.
P. O. Box 56288
Houston, TX 77256-6288

James H. Sargent
Regional Counsel
U.S. EPA, Region IV
345 Courtland Street, NE
Atlanta, GA 30365

Bruce P. Miller, Director
Air Programs Branch
U.S. EPA, Region IV
345 Courtland Street, NE
Atlanta, GA 30365

Dated: JUN 21 1989

Brenda H. Selden

Brenda H. Selden, Secretary
to the Chief Judicial Officer