EXHIBIT NO. 2

DOCKET NO: 031033-EI

WITNESS: VARIOUS

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT OF STIPULATED NON-CONFIDENTIAL DOCUMENTS:

1. Tampa Electric Company's April 2001, FPSC Form 423-2 (2/87);
2. Tampa Electric Company's December 2001, Schedule A3
3. Tampa Electric Company's December 2002, Schedule A3
4. Tampa Electric Company's December 2003, Schedule A3
5. Tampa Electric Company's December 2001, Schedule A5
6. Tampa Electric Company's December 2002, Schedule A5
7. Tampa Electric Company's December 2003, Schedule A5
8. 2002 and 2003 TECO Energy, Inc. Annual Reports to Shareholders
9. 2002 and 2003 Tampa Electric Company's Securities and Exchange Commission (SEC) 10K Reports
10. Schedule 5: "History and Forecast of Fuel Requirements"; page II-9, Tampa Electric Company's 2003 Ten Year Site Plan

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 2
COMPANY/ FPSC
WITNESS: Non-Confidential Stip 1
DATE: 05/27-28/09

DOCKET NO. 031033-EI

10. Tampa Electric Company's response to staff's 1st set of interrogatories (Nos. 1-4). Tampa Electric Company's response to staff's 2nd set of interrogatories (Nos. 19-24 and 29).
11. Tampa Electric Company's response to staff's 4th set of interrogatories (Nos. 53, 61, 62, 64-67, 72 and 73)
12. Tampa Electric Company's response to staff's 6th set of interrogatories (No. 85)
13. Tampa Electric Company's response to staff's 1st set of admissions (Nos. 1-2)
14. Tampa Electric's responses to Office of Public Counsel's 1st set of interrogatories (No. 10).
15. Tampa Electric's responses to Office of Public Counsel's 2nd set of interrogatories (Nos. 18, 23, 24, and 33).
16. Tampa Electric's responses to Florida Industrial Power Users Group 1st set of interrogatories (No. 24).
17. Tampa Electric's responses to CSX Transportation 2nd set of interrogatories (Nos. 5-7)
18. Tampa Electric's responses to CSX Transportation 3rd set of interrogatories (Nos. 8-11)
19. CSX Transportation's responses to Tampa Electric Company's 1st set of interrogatories (Nos. 4-5, 22, and 24).

DOCKET NO. 020001-EI

20. Tampa Electric Company's response to staff's 3rd request for production of documents (No. 12)

PROFERRED BY: STAFF

** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
ORIGIN, TONNAGE, DELIVERED PRICE AND AS RECEIVED QUALITY

1. Reporting Month: April Year: 2001

2. Reporting Company: Tampa Electric Company

3. Plant Name: Electro-Coal Transfer Facility - Gannon Station (1)

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Director Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: Jeffrey Chronister, Director Financial Reporting

6. Date Completed: June 15, 2001

Line No. (a)	Supplier Name (b)	Mine Location (c)	Purchase Type (d)	Trans-port Mode (e)	Tons (f)	Effective Purchase Price ($/Ton) (g)	Total Transport Charges ($/Ton) (h)	Delivered Price Transfer Facility ($/Ton) (i)	As Received Coal Quality: Sulfur Content % (j)	BTU Content (BTU/lb) (k)	Ash Content % (l)	Moisture Content % (m)
1.	Sugar Camp	10,IL,059,165	LTC	RB	47,069.60	$27.494	$7.600	$35.094	2.70	12,572	9.10	7.08
2.	Sugar Camp	10,IL,059,165	S	RB	68,751.42	$25.844	$7.950	$33.794	3.52	11,869	11.98	7.11
3.	Jader Fuel Co	10,IL,165	LTC	RB	21,202.70	$26.000	$7.600	$33.600	2.85	12,768	10.06	5.22
4.	Jader Fuel Co	9,KY,233	S	RB	44,133.00	$25.400	$7.600	$33.000	1.69	12,375	9.61	7.45
5.	Jader Fuel Co	10,IL,165	LTC	RB	1,583.10	$24.550	$7.600	$32.150	3.31	12,657	11.06	4.47
6.	American Coal	10,IL,165	S	RB	46,714.00	$25.600	$5.790	$31.390	1.34	12,023	6.45	11.95
7.	Sugar Camp	10,IL,059,165	S	RB	1,658.70	$25.844	$7.600	$33.444	3.52	11,869	11.98	7.11
8.	American Coal	10,IL,165	LTC	RB	44,355.00	$28.270	$5.790	$34.060	1.19	12,037	6.36	12.04
9.	Triton	19,WY,005	S	RB	76,683.00	$4.810	$17.780	$22.590	0.23	8,718	4.66	28.11
10.	Lodestar	9,KY,225	S	RB	15,307.00	$28.000	$7.600	$35.600	1.49	11,847	12.09	8.09

(1) As Electro-Coal Transfer Facility is a central storage site for coal prior to its delivery to the power plant, the coal from suppliers noted on this schedule is usually delivered to Gannon Station but could ultimately be delivered to Big Bend Station or Polk Station.

FPSC FORM 423-2 (2/87)

CONFIDENTIAL

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2001

REVISED WITH
FEB. 2002 FILING

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	80,855	130,781	(49,926)	-38.2%	4,028,693	3,215,056	813,637	25.3%
2	LIGHT OIL	342,914	267,953	74,961	28.0%	14,635,750	13,395,968	1,239,782	9.3%
3	COAL	26,886,650	27,639,335	(752,685)	-2.7%	333,923,632	334,372,119	(448,487)	-0.1%
4	NATURAL GAS	196,031	101,952	94,079	92.3%	16,308,870	2,629,257	13,679,613	520.3%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	27,506,450	28,140,021	(633,571)	-2.3%	368,896,945	353,612,400	15,284,545	4.3%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	1,516	2,819	(1,303)	-46.2%	89,679	65,708	23,971	36.5%
9	LIGHT OIL	6,089	5,372	717	13.3%	210,575	205,050	5,525	2.7%
10	COAL	1,247,436	1,432,600	(185,162)	-12.9%	15,533,571	17,126,324	(1,592,753)	-9.3%
11	NATURAL GAS	6,287	1,701	4,586	269.6%	311,518	37,754	273,784	725.1%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,261,330	1,442,492	(181,162)	-12.6%	16,145,342	17,434,836	(1,289,494)	-7.4%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	2,800	4,261	(1,461)	-34.3%	143,160	98,981	44,179	44.6%
16	LIGHT OIL (BBL)	11,408	7,910	3,498	44.2%	414,884	391,145	23,739	6.1%
17	COAL (TON)	585,813	644,815	(59,002)	-9.2%	7,288,712	7,745,240	(456,528)	-5.9%
18	NATURAL GAS (MCF)	69,442	17,500	51,942	296.8%	3,387,801	399,300	2,988,501	748.4%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	17,565	26,936	(9,371)	-34.8%	898,474	625,680	272,794	43.6%
22	LIGHT OIL	62,007	45,717	16,290	35.6%	2,374,840	2,250,184	124,656	5.5%
23	COAL	13,755,421	14,940,367	(1,184,946)	-7.9%	167,785,452	179,128,789	(11,343,337)	-6.3%
24	NATURAL GAS	69,703	17,986	51,717	287.5%	3,373,038	410,596	2,962,442	721.5%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	13,904,696	15,031,006	(1,126,310)	-7.5%	174,431,803	182,415,249	(7,983,446)	-4.4%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.12%	0.20%	(0.00)	-	0.56%	0.38%	0.00	-
29	LIGHT OIL	0.48%	0.37%	0.00	-	1.30%	1.18%	0.00	-
30	COAL	98.90%	99.31%	(0.00)	-	96.21%	98.23%	(0.02)	-
31	NATURAL GAS	0.50%	0.12%	0.00	-	1.93%	0.22%	0.02	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	28.88	30.69	(1.82)	-5.9%	28.14	32.48	(4.34)	-13.4%
36	LIGHT OIL ($/BBL)	30.06	33.88	(3.82)	-11.3%	35.28	34.25	1.03	3.0%
37	COAL ($/TON)	45.90	42.86	3.03	7.1%	45.81	43.17	2.64	6.1%
38	NATURAL GAS ($/MCF)	2.82	5.83	(3.00)	-51.5%	4.81	6.58	(1.77)	-26.9%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	4.60	4.86	(0.25)	-5.2%	4.48	5.14	(0.65)	-12.7%
42	LIGHT OIL	5.53	5.86	(0.33)	-5.6%	6.16	5.95	0.21	3.5%
43	COAL	1.95	1.85	0.10	5.7%	1.99	1.87	0.12	6.6%
44	NATURAL GAS	2.81	5.67	(2.86)	-50.4%	4.84	6.40	(1.57)	-24.5%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	1.98	1.87	0.11	5.7%	2.11	1.94	0.18	9.1%

REVISED 02/02

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2001

REVISED WITH
FEB. 2002 FILING

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	11,588	9,555	2,033	21.3%	10,019	9,522	497	5.2%
49	LIGHT OIL	10,184	8,510	1,674	19.7%	11,278	10,974	304	2.8%
50	COAL	11,027	10,429	598	5.7%	10,801	10,459	342	3.3%
51	NATURAL GAS	11,087	10,574	513	4.9%	10,828	10,876	(48)	-0.4%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	11,024	10,420	604	5.8%	10,804	10,463	341	3.3%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.33	4.64	0.69	14.9%	4.49	4.89	(0.40)	-8.2%
56	LIGHT OIL	5.63	4.99	0.64	12.8%	6.95	6.53	0.42	6.4%
57	COAL	2.16	1.93	0.23	11.9%	2.15	1.95	0.20	10.3%
58	NATURAL GAS	3.12	5.99	(2.87)	-47.9%	5.24	6.96	(1.72)	-24.7%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.18	1.95	0.23	11.8%	2.28	2.03	0.25	12.3%

REVISED 02/02

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	235,302	427,635	(192,333)	-45.0%	4,372,207	5,268,790	(896,583)	-17.0%
2	LIGHT OIL	520,279	840,485	(320,206)	-38.1%	9,851,474	16,148,494	(6,297,020)	-39.0%
3	COAL	24,267,038	25,108,360	(841,322)	-3.4%	310,692,261	329,791,838	(19,099,577)	-5.8%
4	NATURAL GAS	1,417,141	2,379,610	(962,469)	-40.4%	31,676,384	41,479,333	(9,802,949)	-23.6%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	26,439,760	28,756,090	(2,316,330)	-8.1%	356,592,326	392,688,455	(36,096,129)	-9.2%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	4,473	11,199	(6,726)	-60.1%	86,648	131,838	(45,190)	-34.3%
9	LIGHT OIL	9,476	14,882	(5,406)	-36.3%	191,196	241,140	(49,944)	-20.7%
10	COAL	1,157,370	1,257,922	(100,552)	-8.0%	14,875,280	15,848,013	(972,733)	-6.1%
11	NATURAL GAS	6,072	41,388	(35,316)	-85.3%	473,450	758,310	(284,860)	-37.6%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,177,391	1,325,391	(148,000)	-11.2%	15,626,574	16,979,301	(1,352,727)	-8.0%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	7,087	16,635	(9,548)	-57.4%	137,183	196,270	(59,087)	-30.1%
16	LIGHT OIL (BBL)	15,139	28,385	(13,246)	-46.7%	322,371	507,477	(185,106)	-36.5%
17	COAL (TON)	550,494	553,670	(3,176)	-0.6%	7,100,139	7,050,889	49,250	0.7%
18	NATURAL GAS (MCF)	69,009	424,524	(355,515)	-83.7%	5,151,423	7,727,438	(2,576,015)	-33.3%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	44,462	104,454	(59,992)	-57.4%	860,634	1,232,378	(371,744)	-30.2%
22	LIGHT OIL	86,120	159,231	(73,111)	-45.9%	1,855,534	2,882,291	(1,026,757)	-35.6%
23	COAL	12,588,244	13,085,564	(497,320)	-3.8%	165,425,948	165,442,088	(16,141)	0.0%
24	NATURAL GAS	72,666	436,388	(363,722)	-83.3%	5,420,729	7,944,073	(2,523,344)	-31.8%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	12,791,493	13,785,637	(994,144)	-7.2%	173,562,845	177,500,830	(3,937,985)	-2.2%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.38%	0.84%	(0.00)	-	0.55%	0.78%	(0.00)	-
29	LIGHT OIL	0.80%	1.12%	(0.00)	-	1.22%	1.42%	(0.00)	-
30	COAL	98.30%	94.91%	0.03	-	95.19%	93.34%	0.02	-
31	NATURAL GAS	0.52%	3.12%	(0.03)	-	3.03%	4.47%	(0.01)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	33.20	25.71	7.49	29.2%	31.87	26.84	5.03	18.7%
36	LIGHT OIL ($/BBL)	34.37	29.61	4.76	16.1%	30.56	31.82	(1.26)	-4.0%
37	COAL ($/TON)	44.08	45.35	(1.27)	-2.8%	43.76	46.77	(3.01)	-6.4%
38	NATURAL GAS ($/MCF)	20.54	5.61	14.93	266.4%	6.15	5.37	0.78	14.6%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.29	4.09	1.20	29.3%	5.08	4.28	0.80	18.8%
42	LIGHT OIL	6.04	5.28	0.76	14.5%	5.31	5.60	(0.29)	-5.2%
43	COAL	1.93	1.92	0.01	0.5%	1.88	1.99	(0.12)	-5.8%
44	NATURAL GAS	19.50	5.45	14.05	257.6%	5.84	5.22	0.62	11.9%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.07	2.09	(0.02)	-0.9%	2.05	2.21	(0.16)	-7.1%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,940	9,327	613	6.6%	9,933	9,348	585	6.3%
49	LIGHT OIL	9,088	10,700	(1,612)	-15.1%	9,705	11,953	(2,248)	-18.8%
50	COAL	10,877	10,403	474	4.6%	11,121	10,439	682	6.5%
51	NATURAL GAS	11,967	10,544	1,423	13.5%	11,449	10,476	973	9.3%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,864	10,401	463	4.5%	11,107	10,454	653	6.2%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.26	3.82	1.44	37.7%	5.05	4.00	1.05	26.3%
56	LIGHT OIL	5.49	5.65	(0.16)	-2.8%	5.15	6.70	(1.55)	-23.1%
57	COAL	2.10	2.00	0.10	5.0%	2.09	2.08	0.01	0.5%
58	NATURAL GAS	23.34	5.75	17.59	305.9%	6.69	5.47	1.22	22.3%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.25	2.17	0.08	3.7%	2.28	2.31	(0.03)	-1.3%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	308,050	477,113	(169,063)	-35.4%	5,680,792	4,614,332	1,066,460	23.1%
2	LIGHT OIL	286,365	746,423	(460,058)	-61.6%	7,068,479	11,587,378	(4,518,899)	-39.0%
3	COAL	14,252,294	19,737,978	(5,485,684)	-27.8%	269,619,940	292,613,438	(22,993,498)	-7.9%
4	NATURAL GAS	18,464,477	27,710,418	(9,245,941)	-33.4%	183,341,150	178,041,749	5,299,401	3.0%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	33,311,186	48,671,932	(15,360,746)	-31.6%	465,710,361	486,856,897	(21,146,536)	-4.3%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	5,708	10,240	(4,532)	-44.3%	103,238	93,240	9,998	10.7%
9	LIGHT OIL	3,938	11,283	(7,345)	-65.1%	103,103	166,158	(63,055)	-37.9%
10	COAL	669,630	900,809	(231,179)	-25.7%	12,321,871	13,316,755	(994,884)	-7.5%
11	NATURAL GAS	439,113	521,259	(82,146)	-15.6%	3,561,167	3,341,905	219,262	6.6%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,118,389	1,443,591	(325,202)	-22.5%	16,089,379	16,918,058	(828,679)	-4.9%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	8,868	15,363	(6,495)	-42.3%	159,945	140,242	19,703	14.0%
16	LIGHT OIL (BBL)	7,622	19,820	(12,198)	-61.5%	184,718	301,080	(116,362)	-38.6%
17	COAL (TON)	296,662	400,470	(103,808)	-25.9%	5,736,824	6,044,776	(307,952)	-5.1%
18	NATURAL GAS (MCF)	3,186,879	3,785,711	(598,832)	-15.8%	27,084,260	25,034,707	2,049,553	8.2%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	55,635	97,486	(41,851)	-42.9%	1,003,422	891,834	111,588	12.5%
22	LIGHT OIL	43,133	114,698	(71,565)	-62.4%	1,036,758	1,744,490	(707,732)	-40.6%
23	COAL	7,077,081	9,551,576	(2,474,495)	-25.9%	137,018,691	145,268,621	(8,249,931)	-5.7%
24	NATURAL GAS	3,317,541	3,891,740	(574,199)	-14.8%	28,464,068	25,735,529	2,728,539	10.6%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	10,493,390	13,655,500	(3,162,110)	-23.2%	167,522,939	173,640,474	(6,117,535)	-3.5%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.51%	0.71%	(0.00)	-	0.64%	0.55%	0.00	-
29	LIGHT OIL	0.35%	0.78%	(0.00)	-	0.64%	0.98%	(0.00)	-
30	COAL	59.87%	62.40%	(0.03)	-	76.58%	78.71%	(0.02)	-
31	NATURAL GAS	39.26%	36.11%	0.03	-	22.13%	19.75%	0.02	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	34.74	31.06	3.68	11.9%	35.52	32.90	2.61	7.9%
36	LIGHT OIL ($/BBL)	37.57	37.66	(0.09)	-0.2%	38.27	38.49	(0.22)	-0.6%
37	COAL ($/TON)	48.04	49.29	(1.24)	-2.5%	47.00	48.41	(1.41)	-2.9%
38	NATURAL GAS ($/MCF)	5.79	7.32	(1.53)	-20.8%	6.77	7.11	(0.34)	-4.8%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.54	4.89	0.64	13.1%	5.66	5.17	0.49	9.4%
42	LIGHT OIL	6.64	6.51	0.13	2.0%	6.82	6.64	0.18	2.6%
43	COAL	2.01	2.07	(0.05)	-2.5%	1.97	2.01	(0.05)	-2.3%
44	NATURAL GAS	5.57	7.12	(1.55)	-21.8%	6.44	6.92	(0.48)	-6.9%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	3.17	3.56	(0.39)	-10.9%	2.78	2.80	(0.02)	-0.9%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,747	9,520	227	2.4%	9,719	9,565	154	1.6%
49	LIGHT OIL	10,953	10,166	787	7.7%	10,056	10,499	(443)	-4.2%
50	COAL	10,569	10,603	(34)	-0.3%	11,120	10,909	211	1.9%
51	NATURAL GAS	7,555	7,466	89	1.2%	7,993	7,701	292	3.8%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,383	9,459	(76)	-0.8%	10,412	10,264	148	1.4%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.40	4.66	0.74	15.9%	5.50	4.95	0.55	11.1%
56	LIGHT OIL	7.27	6.62	0.65	9.8%	6.86	6.97	(0.11)	-1.6%
57	COAL	2.13	2.19	(0.06)	-2.7%	2.19	2.20	(0.01)	-0.5%
58	NATURAL GAS	4.20	5.32	(1.12)	-21.1%	5.15	5.33	(0.18)	-3.4%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.98	3.37	(0.39)	-11.6%	2.89	2.88	0.01	0.3%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2001

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	8,500	4,261	4,239	99.5%	146,825	98,981	47,844	48.3%
3 UNIT COST ($/BBL)	23.67	27.49	(3.82)	-13.9%	26.48	31.15	(4.67)	-15.0%
4 AMOUNT ($)	201,161	117,131	84,030	71.7%	3,887,529	3,082,874	804,655	26.1%
5 BURNED:								
6 UNITS (BBL)	2,800	4,261	(1,461)	-34.3%	143,160	98,981	44,179	44.6%
7 UNIT COST ($/BBL)	28.88	30.69	(1.82)	-5.9%	28.14	32.48	(4.34)	-13.4%
8 AMOUNT ($)	80,855	130,781	(49,926)	-38.2%	4,028,693	3,215,056	813,637	25.3%
9 ENDING INVENTORY:								
10 UNITS (BBL)	65,265	61,600	3,665	5.9%	65,265	61,600	3,665	5.9%
11 UNIT COST ($/BBL)	26.42	26.42	0.00	0.0%	26.42	26.42	0.00	0.0%
12 AMOUNT ($)	1,724,509	1,627,453	97,056	6.0%	1,724,509	1,627,453	97,056	6.0%
13								
14 DAYS SUPPLY:	1,787	1,665	122	7.3%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	32,300	26,600	5,700	21.4%	612,978	578,318	34,660	6.0%
17 UNIT COST ($/BBL)	23.82	32.80	(8.98)	-27.4%	33.60	33.80	(0.20)	-0.6%
18 AMOUNT ($)	769,299	872,450	(103,151)	-11.8%	20,595,906	19,545,120	1,050,786	5.4%
19 BURNED:								
20 UNITS (BBL)	11,408	7,910	3,498	44.2%	414,884	391,145	23,739	6.1%
21 UNIT COST ($/BBL)	30.06	33.88	(3.82)	-11.3%	35.28	34.25	1.03	3.0%
22 AMOUNT ($)	342,914	267,953	74,961	28.0%	14,635,750	13,395,968	1,239,782	9.3%
23 ENDING INVENTORY:								
24 UNITS (BBL)	108,902	51,532	57,370	111.3%	108,902	51,532	57,370	111.3%
25 UNIT COST ($/BBL)	30.27	33.26	(2.99)	-9.0%	30.27	33.26	(2.99)	-9.0%
26 AMOUNT ($)	3,296,029	1,713,789	1,582,240	92.3%	3,296,029	1,713,789	1,582,240	92.3%
27								
28 DAYS SUPPLY: NORMAL	90	43	47	108.9%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	16	7	9	122.2%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	549,674	702,000	(152,326)	-21.7%	7,299,102	8,058,092	(758,990)	-9.4%
32 UNIT COST ($/TON)	43.91	41.48	2.43	5.9%	45.31	42.10	3.22	7.6%
33 AMOUNT ($)	24,136,661	29,117,474	(4,980,813)	-17.1%	330,752,205	339,230,889	(8,478,684)	-2.5%
34 BURNED:								
35 UNITS (TONS)	585,813	644,815	(59,002)	-9.2%	7,288,712	7,745,240	(456,528)	-5.9%
36 UNIT COST ($/TON)	45.90	42.86	3.03	7.1%	45.81	43.17	2.64	6.1%
37 AMOUNT ($)	26,886,650	27,639,335	(752,685)	-2.7%	333,923,632	334,372,119	(448,487)	-0.1%
38 ENDING INVENTORY:								
39 UNITS (TONS)	625,480	935,942	(310,462)	-33.2%	625,480	935,942	(310,462)	-33.2%
40 UNIT COST ($/TON)	44.71	40.44	4.28	10.6%	44.71	40.44	4.28	10.6%
41 AMOUNT ($)	27,967,859	37,847,208	(9,879,349)	-26.1%	27,967,859	37,847,208	(9,879,349)	-26.1%
42								
43 DAYS SUPPLY:	33	49	(16)	-32.6%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	69,442	17,500	51,942	296.8%	3,387,801	399,300	2,988,501	748.4%
46 UNIT COST ($/MCF)	2.82	5.83	(3.00)	-51.5%	4.81	6.58	(1.77)	-26.9%
47 AMOUNT ($)	196,031	101,952	94,079	92.3%	16,303,062	2,629,257	13,673,805	520.1%
48 BURNED:								
49 UNITS (MCF)	69,442	17,500	51,942	296.8%	3,387,801	399,300	2,988,501	748.4%
50 UNIT COST ($/MCF)	2.82	5.83	(3.00)	-51.5%	4.81	6.58	(1.77)	-26.9%
51 AMOUNT ($)	196,031	101,952	94,079	92.3%	16,308,870	2,629,257	13,679,613	520.3%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2001

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	6,118
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	6,118

(2) RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(11,883)	(361,694)
OTHER USAGE	(513)	(15,621)
TOTAL	(12,396)	(377,315)

(3) RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	47,454
IGNITION #2 OIL	355,576
IGNITION PROPANE	3,805
AERIAL SURVEY ADJ.	0
ADDITIVES	136,079
GREEN FUEL	0
TOTAL	542,914

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	10,985	16,635	(5,650)	-34.0%	130,276	196,270	(65,994)	-33.6%
3 UNIT COST ($/BBL)	30.91	25.25	5.66	22.4%	29.84	26.11	3.73	14.3%
4 AMOUNT ($)	339,534	420,015	(80,481)	-19.2%	3,888,040	5,124,890	(1,236,850)	-24.1%
5 BURNED:								
6 UNITS (BBL)	7,087	16,635	(9,548)	-57.4%	137,183	196,270	(59,087)	-30.1%
7 UNIT COST ($/BBL)	33.20	25.71	7.49	29.2%	31.87	26.84	5.03	18.7%
8 AMOUNT ($)	235,302	427,635	(192,333)	-45.0%	4,372,207	5,268,790	(896,583)	-17.0%
9 ENDING INVENTORY:								
10 UNITS (BBL)	10,742	59,129	(48,387)	-81.8%	10,742	59,129	(48,387)	-81.8%
11 UNIT COST ($/BBL)	35.83	25.70	10.14	39.4%	35.83	25.70	10.14	39.4%
12 AMOUNT ($)	384,932	1,519,455	(1,134,523)	-74.7%	384,932	1,519,455	(1,134,523)	-74.7%
13								
14 DAYS SUPPLY:	36	185	(149)	-80.3%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	23,538	37,907	(14,369)	-37.9%	409,287	620,731	(211,444)	-34.1%
17 UNIT COST ($/BBL)	34.90	29.92	4.98	16.6%	30.99	30.99	(0.00)	0.0%
18 AMOUNT ($)	821,406	1,134,124	(312,718)	-27.6%	12,683,028	19,237,885	(6,554,857)	-34.1%
19 BURNED:								
20 UNITS (BBL)	15,139	28,385	(13,246)	-46.7%	322,371	507,477	(185,106)	-36.5%
21 UNIT COST ($/BBL)	34.37	29.61	4.76	16.1%	30.56	31.82	(1.26)	-4.0%
22 AMOUNT ($)	520,279	840,485	(320,206)	-38.1%	9,851,474	16,148,494	(6,297,020)	-39.0%
23 ENDING INVENTORY:								
24 UNITS (BBL)	89,540	113,465	(23,925)	-21.1%	89,540	113,465	(23,925)	-21.1%
25 UNIT COST ($/BBL)	32.91	29.66	3.25	11.0%	32.91	29.66	3.25	11.0%
26 AMOUNT ($)	2,946,602	3,364,854	(418,252)	-12.4%	2,946,602	3,364,854	(418,252)	-12.4%
27								
28 DAYS SUPPLY: NORMAL	85	103	(18)	-17.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	13	16	(3)	-20.1%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	435,481	556,000	(120,519)	-21.7%	6,913,016	7,328,000	(414,984)	-5.7%
32 UNIT COST ($/TON)	44.82	44.50	0.32	0.7%	44.08	46.33	(2.25)	-4.9%
33 AMOUNT ($)	19,519,186	24,740,420	(5,221,234)	-21.1%	304,696,657	339,502,615	(34,805,958)	-10.3%
34 BURNED:								
35 UNITS (TONS)	550,494	553,670	(3,176)	-0.6%	7,100,139	7,050,889	49,250	0.7%
36 UNIT COST ($/TON)	44.08	45.35	(1.27)	-2.8%	43.76	46.77	(3.01)	-6.4%
37 AMOUNT ($)	24,267,038	25,108,360	(841,322)	-3.4%	310,692,261	329,791,838	(19,099,577)	-5.8%
38 ENDING INVENTORY:								
39 UNITS (TONS)	438,357	1,253,931	(815,574)	-65.0%	438,357	1,253,931	(815,574)	-65.0%
40 UNIT COST ($/TON)	42.96	46.67	(3.72)	-8.0%	42.96	46.67	(3.72)	-8.0%
41 AMOUNT ($)	18,831,125	58,525,510	(39,694,385)	-67.8%	18,831,125	58,525,510	(39,694,385)	-67.8%
42								
43 DAYS SUPPLY:	24	65	(41)	-63.2%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	69,009	424,524	(355,515)	-83.7%	5,151,423	7,727,438	(2,576,015)	-33.3%
46 UNIT COST ($/MCF)	20.54	5.61	14.93	266.4%	6.15	5.37	0.78	14.6%
47 AMOUNT ($)	1,417,141	2,379,610	(962,469)	-40.4%	31,675,411	41,479,330	(9,803,919)	-23.6%
48 BURNED:								
49 UNITS (MCF)	69,009	424,524	(355,515)	-83.7%	5,151,423	7,727,438	(2,576,015)	-33.3%
50 UNIT COST ($/MCF)	20.54	5.61	14.93	266.4%	6.15	5.37	0.78	14.6%
51 AMOUNT ($)	1,417,141	2,379,610	(962,469)	-40.4%	31,676,384	41,479,333	(9,802,949)	-23.6%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	13,013
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	13,013

(2) RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(9,573)	(300,073)
OTHER USAGE	(839)	(27,430)
TOTAL	(10,412)	(327,503)

(3) RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	55,414
IGNITION #2 OIL	287,060
IGNITION PROPANE	7,812
AERIAL SURVEY ADJ.	(944,984)
ADDITIVES	9,591
GREEN FUEL	0
TOTAL	(585,107)

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

SCHEDULE A5
PAGE 1 OF 2

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	2,193	15,363	(13,170)	-85.7%	161,473	140,242	21,231	15.1%
3 UNIT COST ($/BBL)	32.38	30.55	1.83	6.0%	33.95	31.77	2.18	6.8%
4 AMOUNT ($)	71,019	469,340	(398,321)	-84.9%	5,481,908	4,456,060	1,025,848	23.0%
5 BURNED:								
6 UNITS (BBL)	8,866	15,363	(6,495)	-42.3%	159,945	140,242	19,703	14.0%
7 UNIT COST ($/BBL)	34.74	31.06	3.68	11.9%	35.52	32.90	2.61	7.9%
8 AMOUNT ($)	308,050	477,113	(169,063)	-35.4%	5,680,792	4,614,332	1,066,460	23.1%
9 ENDING INVENTORY:								
10 UNITS (BBL)	12,270	9,463	2,807	29.7%	12,270	9,463	2,807	29.7%
11 UNIT COST ($/BBL)	34.67	30.62	4.05	13.2%	34.67	30.62	4.05	13.2%
12 AMOUNT ($)	425,454	289,779	135,675	46.8%	425,454	289,779	135,675	46.8%
13								
14 DAYS SUPPLY:	34	261	(227)	-87.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	7,527	23,770	(16,243)	-68.3%	276,815	365,129	(88,314)	-24.2%
17 UNIT COST ($/BBL)	43.50	37.29	6.21	16.7%	38.40	38.92	(0.51)	-1.3%
18 AMOUNT ($)	327,447	886,345	(558,898)	-63.1%	10,630,753	14,210,231	(3,579,478)	-25.2%
19 BURNED:								
20 UNITS (BBL)	7,622	19,820	(12,198)	-61.5%	184,718	301,080	(116,362)	-38.6%
21 UNIT COST ($/BBL)	37.57	37.66	(0.09)	-0.2%	38.27	38.49	(0.22)	-0.6%
22 AMOUNT ($)	288,365	746,423	(460,058)	-61.6%	7,068,479	11,587,378	(4,518,899)	-39.0%
23 ENDING INVENTORY:								
24 UNITS (BBL)	76,706	82,746	(6,040)	-7.3%	76,706	82,746	(6,040)	-7.3%
25 UNIT COST ($/BBL)	37.06	37.73	(0.68)	-1.8%	37.06	37.73	(0.68)	-1.8%
26 AMOUNT ($)	2,842,484	3,122,367	(279,883)	-9.0%	2,842,484	3,122,367	(279,883)	-9.0%
27								
28 DAYS SUPPLY: NORMAL	100	41	59	143.9%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	11	12	(1)	-7.3%	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	445,241	349,300	95,941	27.5%	5,937,741	6,580,600	(642,859)	-9.8%
32 UNIT COST ($/TON)	49.02	49.37	(0.35)	-0.7%	47.48	48.28	(0.80)	-1.7%
33 AMOUNT ($)	21,827,551	17,245,718	4,581,833	26.6%	281,909,128	317,718,458	(35,807,330)	-11.3%
34 BURNED:								
35 UNITS (TONS)	296,662	400,470	(103,808)	-25.9%	5,736,824	6,044,776	(307,952)	-5.1%
36 UNIT COST ($/TON)	48.04	49.29	(1.24)	-2.5%	47.00	48.41	(1.41)	-2.9%
37 AMOUNT ($)	14,252,294	19,737,978	(5,485,684)	-27.8%	269,619,940	292,613,438	(22,993,498)	-7.9%
38 ENDING INVENTORY:								
39 UNITS (TONS)	639,274	990,979	(351,705)	-35.5%	639,274	990,979	(351,705)	-35.5%
40 UNIT COST ($/TON)	48.10	48.71	(0.61)	-1.3%	48.10	48.71	(0.61)	-1.3%
41 AMOUNT ($)	30,747,121	48,269,813	(17,522,692)	-36.3%	30,747,121	48,269,813	(17,522,692)	-36.3%
42								
43 DAYS SUPPLY:	47	21	26	125.7%	-	-	-	-
NATURAL GAS(4)								
44 PURCHASES:								
45 UNITS (MCF)	3,186,879	3,785,711	(598,832)	-15.8%	27,084,260	25,034,707	2,049,553	8.2%
46 UNIT COST ($/MCF)	5.79	7.32	(1.53)	-20.8%	6.77	7.11	(0.34)	-4.8%
47 AMOUNT ($)	18,464,477	27,710,417	(9,245,940)	-33.4%	183,341,150	178,041,748	5,299,402	3.0%
48 BURNED:								
49 UNITS (MCF)	3,186,879	3,785,711	(598,832)	-15.8%	27,084,260	25,034,707	2,049,553	8.2%
50 UNIT COST ($/MCF)	5.79	7.32	(1.53)	-20.8%	6.77	7.11	(0.34)	-4.8%
51 AMOUNT ($)	18,464,477	27,710,418	(9,245,941)	-33.4%	183,341,150	178,041,749	5,299,401	3.0%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
58								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	17,078
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	17,078

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(7,769)	(280,135)
OTHER USAGE	(624)	(22,924)
TOTAL	(8,393)	(303,059)

(3) RECONCILIATION - COALS

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	27,261
IGNITION #2 OIL	263,057
IGNITION PROPANE	8,091
AERIAL SURVEY ADJ.	0
ADDITIVES	39,986
GREEN FUEL	0
TOTAL	338,395

TECO ENERGY

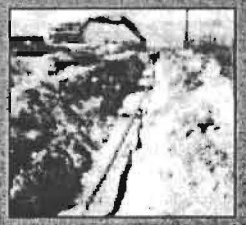
2002 Annual Report

TECO Energy, Inc.

TECO Energy, Inc. (NYSE: TE) is an integrated utility company with a family of unregulated businesses. In addition to the regulated operations of Tampa Electric and Peoples Gas System, TECO Energy is engaged in independent power generation, river and ocean transportation, coal mining, non-conventional fuels production and energy services. The company has major operations in Florida, the Southern U.S. and Central America.

Regulated Utilities

Tampa Electric



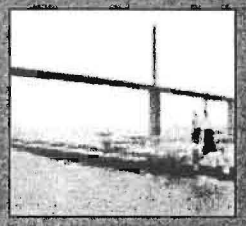
Peoples Gas

Unregulated Businesses

TECO Coal

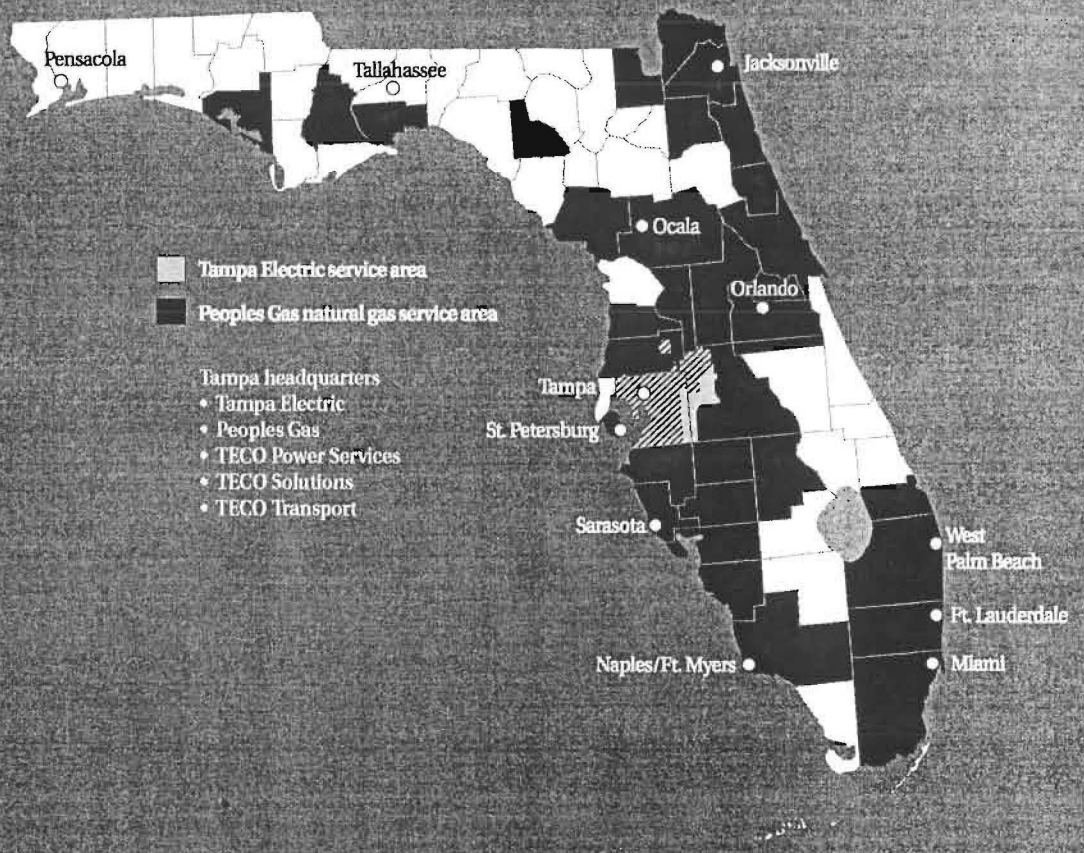
TECO Power Services

TECO Solutions



TECO Transport

Regulated utility locations



2002 Highlights

TECO Energy, Inc.

- Net income growth of 9 percent over 2001
- Return on equity of 14 percent
- $900-million funding plan almost three-fourths complete by year-end

Listed on the 2003 Forbes Platinum 400, "The Best Big Companies in America"

Florida Operations/Regulated Utilities

- Continued strong customer growth at regulated utilities; 2.5 percent at Tampa Electric and more than 4 percent at Peoples Gas
- First phase of Tampa Electric Gannon/Bayside repowering nearly complete

Peoples Gas continues system expansion; receives $12 million addition to base rates

Unregulated Businesses

TECO Coal increases synthetic fuel production

- Sale of TECO Coalbed Methane generates $140 million in cash

Construction on 4,400 megawatts of generation at TECO Power Services nearly complete

- Two smaller TPS generating projects suspended, pending power price improvement

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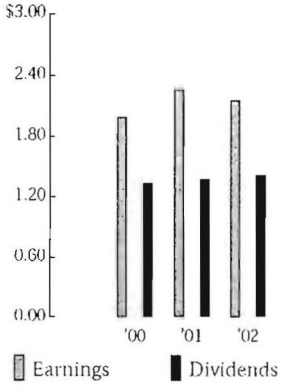
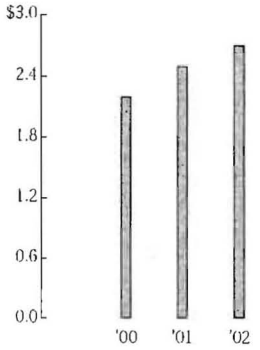
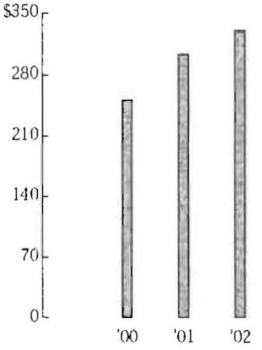
Earnings/Dividends Per Share[1]
(dollars per share)



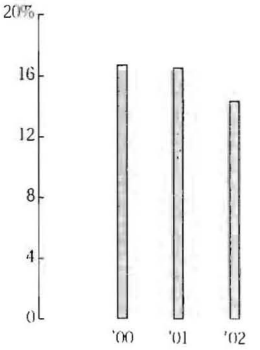
Operating Revenues[2]
(billions of dollars)



Net Income[1]
(millions of dollars)



Return on Average Common Equity[1]
(percent)



(1) Includes discontinued operations.
(2) Consolidated revenues from continuing operations

February 9, 2003

Dear Fellow Shareholders:

Once, when asked what the stock market would do, J.P. Morgan replied, "It will fluctuate." In no year of my career has this simple truth seemed more real than in 2002, especially for the energy industry.

This year, the Dow Jones Utility Index bottomed out at a 12-year low point. Credit rating agencies issued 182 downgrades within the energy sector during the first three quarters of 2002. This has had a dramatic impact on our industry, shaking investor confidence and increasing the cost of capital.

To complicate matters further, pessimism about oversupply and lower earnings prospects in the independent power market has dampened the financial community's interest in companies with merchant power interests.

Even though TECO Energy continues to earn the majority of its net income from regulated utility operations, we have not been immune from downward pressure on our securities. As shareholders ourselves, we are disappointed in our stock's performance over the past year.

Even so, with return on equity of 14 percent and five years of net income growth, TECO Energy is one of 30 energy companies ranked in the 2003 Forbes Platinum 400, "The Best Big Companies in America."

We've made it clear to our investors that 2003 will be a challenging year for TECO Energy, as our construction program begins winding down.

Yet at the same time, we remain focused on — not threatened by — the coming year.

And while we recognize the realities of the market, the economy and our own challenges, we have positioned ourselves to maximize efficiencies within our operating units, with a renewed focus on our regulated utilities.

Tampa Electric Poised for Expansion

Tampa Electric continues to make steady progress on one of the largest construction projects underway in the State of Florida, adding nearly 600 megawatts of incremental capacity to its system.

The Gannon-to-Bayside repowering is on schedule and on budget, with its first phase nearly complete and scheduled to be commercially operational mid-year.

This additional capacity will serve a customer base that continues to grow at a rate of more than 2 percent per year. The company connected its 600,000th customer during the first quarter of 2003.

When the repowering is complete, Tampa Electric's system will be one of the cleanest in the nation, and the company will be aligned with all current and most proposed environmental regulations.

Tampa Electric continues to identify strategies for streamlining its operations and improving its overall efficiency.

Tampa Electric's employees continue to outpace previous customer satisfaction and safety records. Customer favorability for 2002 was 97 percent, and the number of reportable safety incidents continues to be at its lowest in decades.

Peoples Gas Thriving in Fertile Florida Energy Market

Peoples Gas' results improved nearly 5 percent over 2001, through customer growth and resulting higher usage.

In December, Peoples Gas received regulatory authorization to increase its rates, the first such increase in a decade. The company's annual base revenues are expected to increase by more than $12 million as a result.

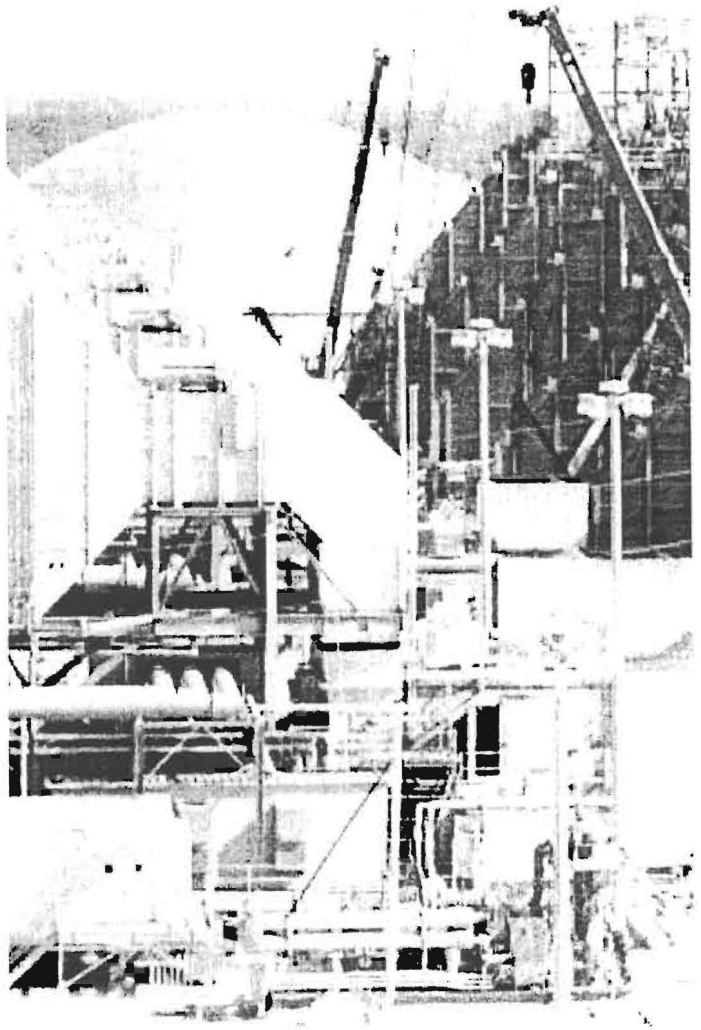
In the 10 years since the last Peoples Gas rate increase, the company has expanded its pipeline distribution system from 5,000 to 9,000 miles and added more than 100,000 homes and businesses to its customer base.

Municipal franchises are a key part of Peoples Gas' system, and a source of growth for the company. Over the past several years, the company has successfully negotiated more than 40 franchise agreements throughout the state, both new contracts and renewals.

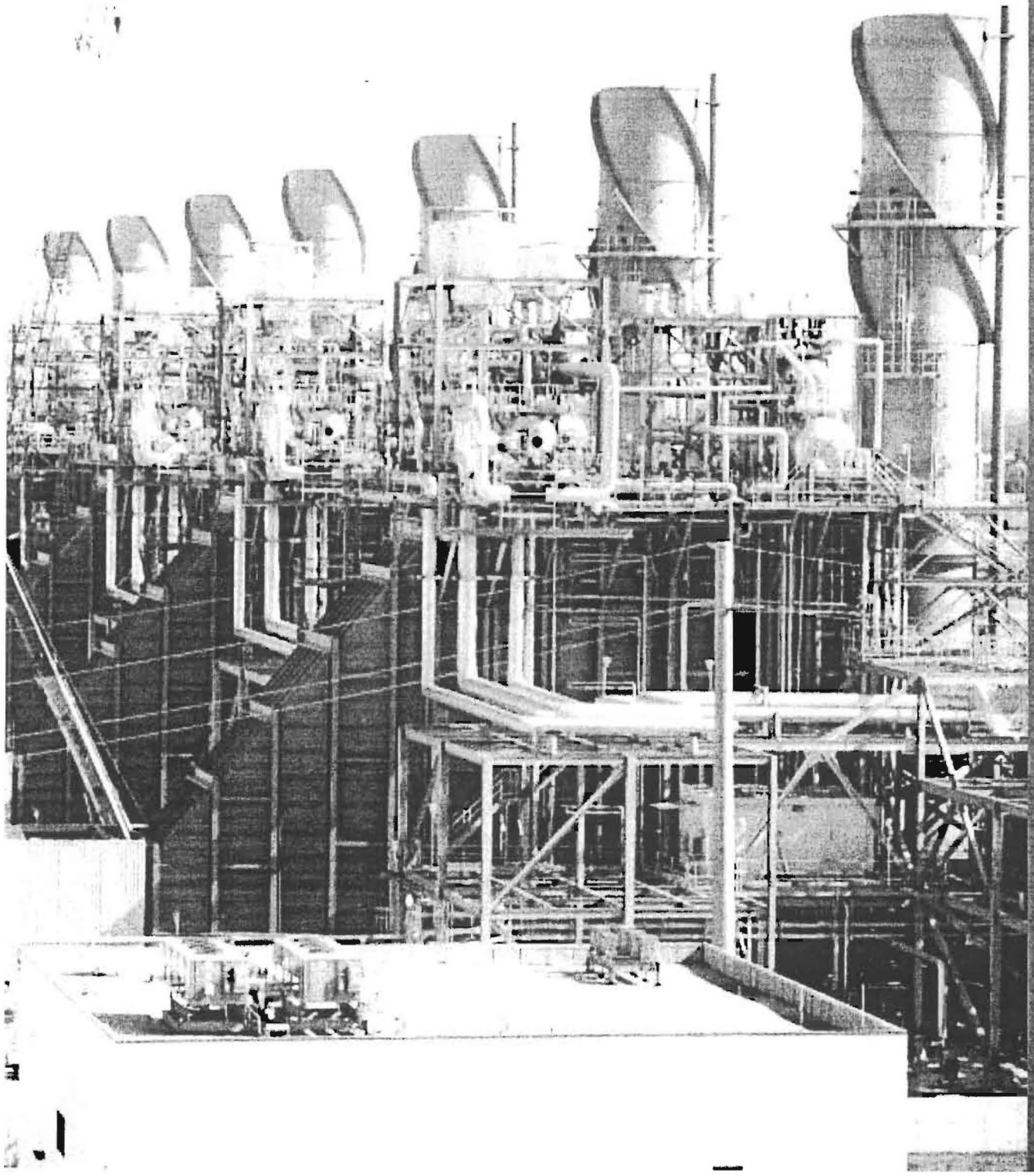
In 2002, the utility also enjoyed record performance for safety and improved its already-strong customer satisfaction levels.

In the energy industry, customer satisfaction, in large part, is driven by reliable service. The new Gulfstream Pipeline, delivering natural gas via the Gulf of Mexico, began service this year.

Peoples Gas now has a contract and interconnections



Robert D. Fagan, Chairman, President and Chief Executive Officer



Tampa Electric's Bayside Power Station readies for operation. When fully operational, the repowered facility will make Tampa Electric's system one of the cleanest in the nation.

with this new supplier, and continues its relationship with the Florida Gas Transmission line to the north.

Additional natural gas supplies in the state allow Peoples Gas to increase its market penetration and enhance the availability and reliability of its service for a growing customer base.

Unregulated Businesses Round Out the Mix

Beyond TECO Energy's base of stable utility operations, we benefit from a balanced mix of unregulated businesses, which have proven their worth over time.

TECO Coal's net income jumped substantially in 2002, through higher production of synthetic fuel and improved pricing for all coal types. These factors helped offset increased production costs.

TECO Transport provided net income lower than in 2001, reflecting the continued economic downturn. Despite temporarily lower cargo volumes and weak pricing, this 40-year marine transportation veteran is a stable, proven contributor to TECO Energy's earnings.

At TECO Power Services, progress continues on the two largest independent power projects in the nation, Union Power Station in Arkansas and Gila River Power Station in Arizona. The plants are expected to be fully operational by June and August 2003, respectively.

Two smaller facilities — Dell and McAdams — have been postponed and all new project development curtailed.

In late 2002, to help maximize synergies among all of our businesses, regulated and unregulated, we tapped John Ramil, president of Tampa Electric Company, to take on additional responsibility at the holding company level.

In addition to his role at Tampa Electric, John is now executive vice president of TECO Energy. We are confident that bringing his leadership to more areas of the company will benefit our shareholders.

More natural gas for Florida. *The new Gulfstream Pipeline adds to Florida's fuel supplies, enhancing Peoples Gas System's reliability.*

Cash Generation Plan for 2003 Nearly Complete by Year-End

In September, TECO Energy unveiled a preliminary plan for 2003, addressing its funding needs for the construction of our major power projects.

In addition to the capital expenditure reductions announced in early 2002, we identified $900 million in savings from further capital expenditure reductions and cash generation from financial transactions and the sale of certain non-core assets.

By year-end, we had achieved nearly three-fourths of the cash needed for 2003. Clearly, we are off to a strong start.

To go the distance, we are poised to continue doing what we've done all along — executing a solid business plan and working toward our commitments to Wall Street and to our shareholders.

Moving Forward in Uncertain Times

Even the most experienced economist can't tell us precisely when the economic downturn will end, or when the energy sector will be back on its feet. But even within that gray area lie some absolutes.

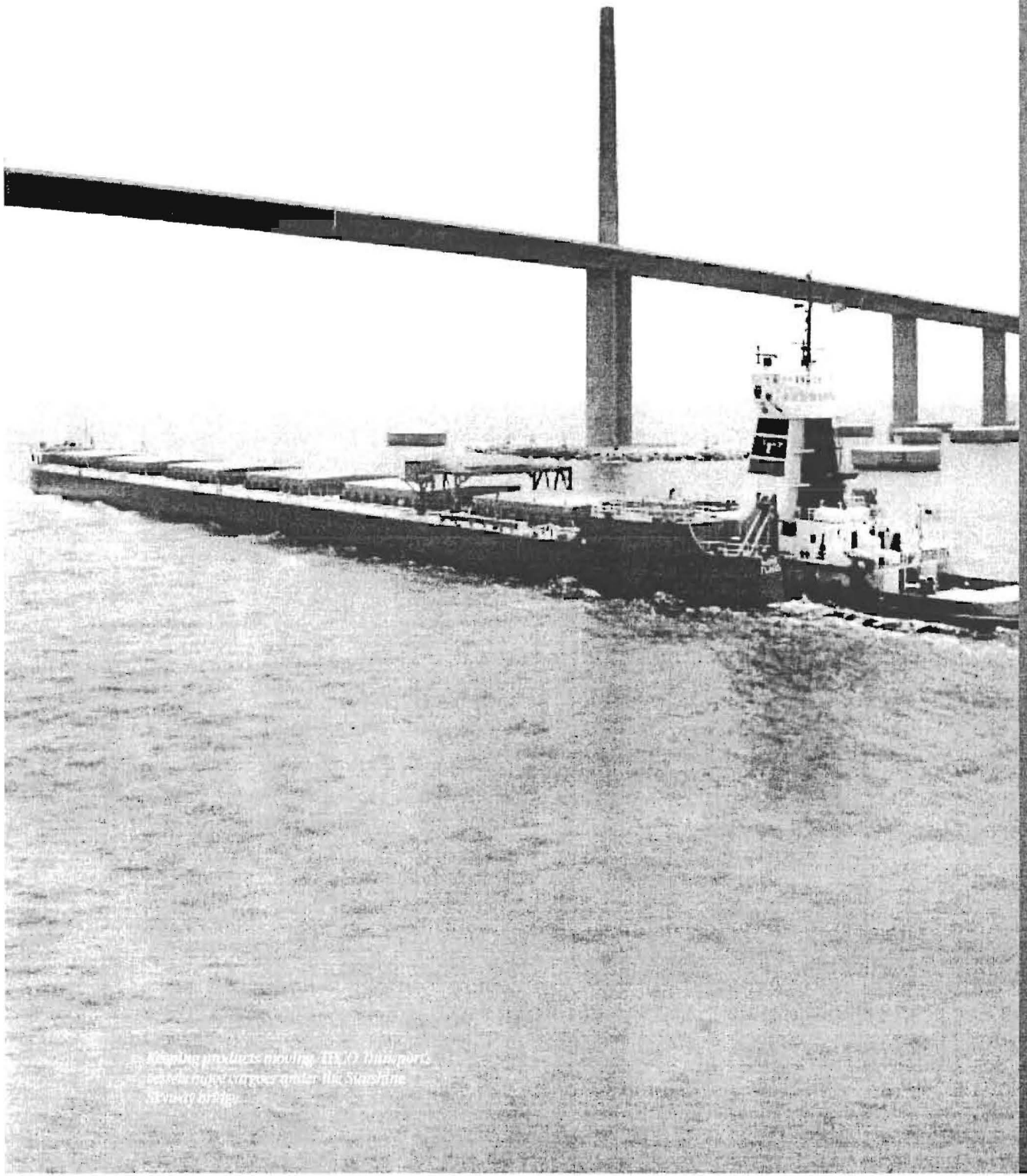
The energy business, which closely tracks the U.S. economy, is cyclic in nature. It will rebound. Long-term, as I've said before, energy demand will only go up. That is our business, and it is essential to homes and businesses alike.

Further, Florida, home to our principal businesses, has the strongest growth in the nation. Our vibrant state's demand for energy grows at a similar pace.

In any situation of uncertainty, flexibility is the key to success. At TECO Energy, we are all sharply focused on strategies that are shaped to realistically face market conditions. These strategies are honed as they should be — with shareholder value at their core.

Sincerely,

Robert D. Fagan
Chairman, President and Chief Executive Officer



Roaring products hauling, TECO Transport's barges make cargo under the Sunshine Skyway bridge.

A Word from the General Counsel

In any business, it's smart to be ahead of the game. Several years ago, well before the recent emphasis on compliance issues, TECO Energy formalized its corporate compliance plan, and the company dedicates extensive resources to the compliance function. As a result, we have been recognized as a leader in that field.

We have long had a rigorous internal audit function, as well as industry-leading Standards of Integrity, which serve as our company's code of ethics. (These can be viewed on the company's Web site.)

In fact, the corporate governance and ethics guidelines recently proposed by the New York Stock Exchange and the Securities and Exchange Commission, as well as legal requirements passed by Congress, are already part of our corporate culture.

For many years, the vast majority of our directors have been independent, and these independent directors have made up our already existing Audit, Governance and Nominating, and Compensation committees.

We also have a history of providing complete and open disclosure of material information to the public, well before the SEC's Regulation FD.

And, our alignment with you, our shareholders, goes far beyond our codes of conduct. For example, TECO Energy's stock ownership requirements for its officers are among the strongest in our industry.

As you can see, TECO Energy has strong standards in place, which we believe will benefit shareholders by contributing to the company's long-term success.

Sincerely,

Sheila M. McDevitt
Senior Vice President – General Counsel

Management's Discussion & Analysis of Financial Condition & Results of Operations

This Management's Discussion and Analysis contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. These forward-looking statements include references to our anticipated capital investments, financing requirements, project completion dates, future transactions and other plans. Certain factors that could cause actual results to differ materially from those projected in these forward-looking statements include the following: energy price changes affecting TECO Power Services' (TPS') merchant plants; TPS' ability to sell the output of the merchant plants operating or under construction at a premium to the forward curve prices and to obtain power contracts to reduce earnings volatility; any unanticipated need for additional debt or equity capital that might result from lower than expected cash flow or higher than projected capital requirements; TECO Energy's ability to successfully complete the sale of its synthetic fuel and gasification facilities to successfully complete its cash generation plan; and TECO Energy's ability to maintain credit ratings sufficient to avoid posting letters of credit relating to TPS' construction loans and to avoid providing additional assurances to counterparties. Other factors include: general economic conditions, particularly those in Tampa Electric's service area affecting energy sales; weather variations affecting energy sales and operating costs; potential competitive changes in the electric and gas industries, particularly in the area of retail competition; regulatory actions affecting Tampa Electric, Peoples Gas System or TPS; commodity price changes affecting the competitive positions of Tampa Electric and Peoples Gas System, as well as the margins at TECO Coal; changes in and compliance with environmental regulations that may impose additional costs or curtail some activities; TPS' ability to successfully construct and operate its projects on schedule and within budget; the ability of TECO Energy's subsidiaries to operate equipment without undue accidents, breakdowns or failures; interest rates, credit ratings and other factors that could impact TECO Energy's ability to obtain access to sufficient capital on satisfactory terms; and TECO Coal's ability to successfully operate its synthetic fuel production facilities in a manner qualifying for Section 29 federal income tax credits, the use of which could be limited by TECO Energy's taxable income or by changes in law, regulation or administration. Some of these factors and others are discussed more fully under "Investment Considerations."

2002 Earnings Summary

		2002	Change	2001	Change	2000
Consolidated revenues *(millions)*		**$ 2,675.8**	7.5%	$2,488.1	11.9%	$2,223.1
Earnings per share - basic	Continuing operations	**$ 1.95**	-4.4%	$ 2.04	12.7%	$ 1.81
	Discontinued operations	**.20**	-9.1%	.22	22.2%	.18
	Earnings per share	**$ 2.15**	-4.9%	$ 2.26	13.6%	$ 1.99
Earnings per share - diluted	Continuing operations	**$ 1.95**	-3.4%	$ 2.02	12.8%	$ 1.79
	Discontinued operations	**.20**	-9.1%	.22	22.2%	.18
	Earnings per share	**$ 2.15**	-4.0%	$ 2.24	13.7%	$ 1.97
Net income from continuing operations *(millions)*		**$ 298.2**	8.9%	$ 273.8	20.3%	$ 227.5
Average common shares outstanding	Basic (millions)	**153.2**[3]	13.9%	134.5[2]	6.8%	125.9[1]
	Diluted (millions)	**153.3**[3]	13.2%	135.4[2]	7.2%	126.3[1]
Return on average common equity[4]		**14.3%**		16.5%		16.7%

(1) Average shares outstanding reflects the repurchase of 1.6 million shares in 2000.
(2) Average shares outstanding for 2001 reflects the issuance of 8.625 million shares in March and 3.5 million shares in October.
(3) Average shares outstanding for 2002 reflects the issuance of 15.525 million shares in June and 19.385 million shares in October.
(4) Includes results from Discontinued operations (TECO Coalbed Methane).

TECO Energy's revenues increased by more than 7 percent in 2002 to $2.7 billion; revenues in 2001 increased 11.9 percent to $2.5 billion. In 2002, net income from continuing operations rose almost 9 percent to $298.2 million, up from $273.8 million in 2001. Net income from continuing operations was $227.5 million in 2000. Earnings per share - basic from continuing operations were $1.95 per share in 2002 compared with $2.04 per share in 2001. The number of average shares outstanding at Dec. 31, 2002 was almost 14 percent higher than at Dec. 31, 2001. Earnings per share – basic from continuing operations were $1.81 in 2000.

Included in the 2002 results from continuing operations are a $34.1-million pretax ($20.9-

million after-tax) charge related to a debt refinancing and a $5.8 million after-tax asset valuation charge related to the proposed sale of TPS' minority interest in power generating facilities in the Czech Republic. Excluding these unusual items, non-Generally Accepted Accounting Principles (GAAP), or pro forma, net income from continuing operations rose 19 percent to $324.9 million or from $2.04 per share in 2001 to $2.12 per share in 2002. Results from discontinued operations reflect results at the coalbed methane business, which was sold in December 2002.

Total net income and earnings per share, including continuing operations and discontinued operations, were $330.1 million and $2.15 per share, respectively. Total non-GAAP net income and earnings per share, excluding the debt refinancing and asset valuation charges and the $7.7 million gain on the sale of TECO Coalbed Methane, were $349.1 million and $2.28 per share, respectively.

The 2002 results reflect continued customer growth and increased energy usage in the Florida utility operations, higher allowance for funds used during construction (AFUDC – non-cash credit to income with a corresponding increase in utility plant which represents the cost of borrowed funds and a reasonable return on the equity funds used for construction) at Tampa Electric, improved results at TPS, and increased synthetic fuel production at TECO Coal. These improvements were partially offset by lower results at TECO Transport.

Net income from continuing operations in 2001 was $273.8 million, up more than 20 percent from $227.5 million in 2000. These results reflected continued customer growth and increased energy usage in the Florida operations, higher AFUDC at Tampa Electric, an 18 percent increase in net income at TPS from the new generation projects acquired or brought on line in 2000 and 2001 and improved results from the Guatemalan operations, and higher conventional coal production and prices and increased synthetic fuel production at TECO Coal. These improvements were partially offset by higher interest expense associated with increased borrowing levels and a $6.1 million after-tax asset valuation charge related to TPS' sale of its interest in Energía Global International, Ltd. (EGI).

Strategy and Outlook

In late 1999, TECO Energy announced a three-pronged business strategy which was to focus on its Florida operations, which include Tampa Electric, Peoples Gas System (PGS) and the Florida energy services businesses, TECO Solutions; to expand its domestic independent power operations at TPS; and to use the returns of its family of other profitable unregulated businesses to support growth. Since that time, the company has undertaken a number of initiatives to advance the announced strategy. These initiatives include continued development of the regulated electric and gas businesses in Florida, including significant additions to Tampa Electric's electric generation facilities, development of independent power generation projects in the Sunbelt of the United States and continued good operations and returns from its family of other unregulated businesses. However, conditions in energy markets and the independent power business have changed since then.

In 2001, future wholesale power prices declined significantly in markets across the country due to a combination of the slowing of wholesale electric competition; uneconomic dispatch; the U.S. economic slowdown; and the large amount of new generating capacity either completed or under construction and expected to come online in 2002 and 2003. The price outlook remained weak throughout 2002 and the prospects for price recovery in 2003 are uncertain. The low power prices have caused weaker earnings expectations from independent power projects and have caused some developers to cancel or delay projects in some markets.

In light of the capital required to complete the committed regulated and unregulated power plant projects, during 2002 TECO Energy took a number of steps to provide the needed cash while, at the same time, strengthening its balance sheet. These steps included accessing the capital markets for funding, initiating other cash generation measures and reducing capital expenditures. During 2002, the company issued new common equity on two occasions totaling $553 million in net proceeds. In January 2002, the company issued $436 million in net proceeds of mandatorily convertible equity units, which will convert to TECO Energy common shares in January 2005. In addition, the company has reduced its capital expenditure forecast for 2002 through 2004 on two separate occasions. The first reduction in January 2002 totaled approximately $700 million, primarily through delaying, for an extended period, generation projects that were not yet under construction for TPS and Tampa Electric. The second reduction was effected in September as part of a comprehensive cash business plan.

In September 2002, the company announced a preliminary 2003 business plan that focused on the generation of cash to support the construction of the Union and Gila River power stations at TPS and the Gannon to Bayside repowering project at Tampa Electric so as to avoid accessing the capital markets for incremental debt in 2003. This was done in the face of downgrades by equity analysts and the credit rating agencies of both TECO Energy and other companies in the energy sector. The industry's situation deteriorated in late 2002 to the state of a severe credit crisis, highlighting the importance of TECO Energy's execution of the announced plan.

The major components of the plan included: 1) a reduction of capital expenditures of $250 million, including the suspension of construction of the Dell and McAdams power stations, changing the timing of the completion of Bayside Unit 2 and general capital spending reductions at all of the companies, which allowed TECO Energy to sustain its previously forecasted capital expenditure levels; 2) $400 million from the sale of the TECO Coalbed Methane gas assets, the proposed sale of the majority of its interest in facilities that produce synthetic fuel which qualify for Section 29 tax credits at TECO Coal, and the proposed sale of the coal gasification unit at Tampa Electric's Polk Power Station; and 3) $250 million of cash from other financial transactions or asset sales including the repatriation of cash and additional cash from non-recourse refinancing on generating facilities in Guatemala. In addition, TECO Energy ceased work on any new development in the independent power area beyond the already announced and initiated activities.

TECO Energy expects an extended period of lower earnings and to be in a weaker financial position during the current cycle of low wholesale power prices. As previously discussed, the company took decisive steps during 2002 to improve its financial position. The company will continue to take steps as necessary to position itself for a return to a stronger financial position and to a return to earnings growth in the future.

During this period of low wholesale power prices, TECO Energy expects to continue to benefit from deriving the majority of net income and cash flow from its regulated businesses, Tampa Electric and PGS, which operate in one of the highest growth utility markets in the nation. In 2003, about 75 percent of net income is expected to come from regulated utility operations in Florida. Growth is expected to continue in Florida because the state's economy, with its small industrial base, was not impacted by the economic slowdown to the same degree as some manufacturing-based areas of the country.

Operating Results

Management's Discussion & Analysis of Financial Condition & Results of Operations utilize TECO Energy's consolidated financial statements, which have been prepared in accordance with GAAP, to analyze the financial condition of the company.

TECO Energy's reported operating results are affected by a number of critical accounting policies that include such items as accounting for regulated activities, accounting for derivatives, asset impairment testing, accounting for unconsolidated affiliates and others. (See the **Critical Accounting Policies and Estimates** section.)

The following table shows the unconsolidated revenues, net income and earnings per share contributions from continuing operations of the significant business segments. (See **Note Q** to the **Consolidated Financial Statements.**)

(millions) Except per share amounts	*2002*	*Change*	*2001*	*Change*	*2000*
Unconsolidated Revenues[1]					
Regulated Companies					
Tampa Electric	$1,583.2	12.1%	$1,412.7	4.4%	$1,353.8
Peoples Gas System	318.1	-9.9%	352.9	12.2%	314.5
Total Regulated	$1,901.3	7.7%	$1,765.6	5.8%	$1,668.3
Unregulated Companies					
TECO Power Services	$ 309.8	7.9%	$ 287.1	44.2%	$ 199.1
TECO Transport	254.6	-7.4%	274.9	1.9%	269.8
TECO Coal	317.1	4.5%	303.4	30.3%	232.8
Other unregulated businesses	122.1	14.2%	106.9	30.5%	81.8
Total Unregulated	$1,003.6	3.2%	$ 972.3	24.1%	$ 783.5
Net Income[2]					
Regulated Companies					
Tampa Electric	$ 171.8	11.6%	$ 154.0	6.6%	$ 144.5
Peoples Gas System	24.2	4.8%	23.1	6.0%	21.8
Total Regulated	196.0	10.7%	177.1	6.5%	166.3
Unregulated Companies					
TECO Power Services	34.1	26.8%	26.9	18.0%	22.8
TECO Transport	21.0	-23.9%	27.6	-5.5%	29.2
TECO Coal	76.5	29.7%	59.0	76.1%	33.5
Other unregulated businesses	6.8	70.0%	4.0	233.3%	1.2
Total Unregulated	138.4	17.8%	117.5	35.5%	86.7
Financing/Other	(36.2)	74.0%	(20.8)	-18.4%	(25.5)
Net income from continuing operations	298.2	8.9%	273.8	20.3%	227.5
Discontinued operations	31.9	6.7%	29.9	27.7%	23.4
Net income total	$ 330.1	8.7%	$ 303.7	21.0%	$ 250.9
Earnings per Share - Basic[2]					
Regulated Companies					
Tampa Electric	$ 1.12	-2.6%	$ 1.15	—	$ 1.15
Peoples Gas System	.16	-5.9%	.17	—	.17
Total Regulated	1.28	-3.0%	1.32	—	1.32
Unregulated Companies					
TECO Power Services	.22	10.0%	.20	11.1%	.18
TECO Transport	.14	-30.0%	.20	-13.0%	.23
TECO Coal	.50	13.6%	.44	63.0%	.27
Other unregulated businesses	.04	33.3%	.03	200%	.01
Total Unregulated	.90	3.4%	.87	26.1%	.69
Financing/Other	(.23)	53.3%	(.15)	-25.0%	(.20)
EPS from continuing operations	1.95	-4.4%	2.04	12.7%	1.81
Discontinued operations	.20	-9.0%	.22	22.2%	.18
EPS Total	$ 2.15	-4.9%	$ 2.26	13.6%	$ 1.99

(1) Revenues for all periods have been adjusted to reflect the presentation of energy marketing related revenues on a net basis, the reclassification of TECO Coalbed Methane results to discontinued operations, and the reclassification of earnings from equity investments from Revenues to Other Income.

(2) Beginning in 2001, segment net income was reported on a basis that included internally allocated financing costs. Prior period net income has been reclassified to reflect estimated internally allocated financing costs that would have been attributable to such prior periods. Internally allocated finance costs for 2002, 2001 and 2000 were at pretax rates of 7%, 7%, and 6.75%, respectively, based on the average investment in each subsidiary.

Tampa Electric - Electric Operations

Tampa Electric Results

Tampa Electric's net income increased almost 12 percent in 2002, reflecting continued good residential and commercial customer growth, increased sales to phosphate customers and more favorable summer weather, partially offset by lower sales to other utilities and higher operations and maintenance expenses. The equity component of AFUDC, primarily from the Gannon to Bayside Units 1 and 2 repowering project, increased to $24.9 million, compared to $6.6 million in 2001.

Tampa Electric's net income increased almost 7 percent in 2001, reflecting good customer growth, slightly higher residential and commercial per-customer energy usage, and a favorable customer mix, partially offset by higher operations, maintenance and depreciation expenses. In addition, AFUDC equity, primarily from the Gannon to Bayside Units 1 and 2 repowering project, increased to $6.6 million, compared with $1.6 million in 2000.

Net income increased in both 2002 and 2001 while operating income decreased due to higher AFUDC and lower interest expense which affect net income but not operating income.

Summary of Operating Results

(millions)	*2002*	*Change*	*2001*	*Change*	*2000*
Revenues	$1,583.2	12.1%	$1,412.7	4.4%	$1,353.8
Other operating expenses	212.3	11.3%	190.7	1.3%	188.3
Maintenance	108.7	9.2%	99.5	3.5%	96.1
Depreciation	189.8	9.5%	173.4	7.3%	161.6
Taxes, other than income	112.3	7.2%	104.8	6.2%	98.7
Non-fuel operating expenses	623.1	9.6%	568.4	4.4%	544.7
Fuel	424.1	22.4%	346.5	7.1%	323.5
Purchased power	253.7	21.0%	209.7	9.2%	192.1
Total fuel expense	677.8	21.9%	556.2	7.9%	515.6
Total operating expenses	$1,300.9	15.7%	$1,124.6	6.1%	$1,060.3
Operating income	$ 282.3	-2.0%	$ 288.1	-1.8%	$ 293.5
Net income	$ 171.8	11.6%	$ 154.0	6.6%	$ 144.5

Tampa Electric Operating Revenues

The economy in Tampa Electric's service area continued to grow in 2002, aided by the region's relatively low labor rates, attractive cost of living and affordable housing. The Tampa metropolitan area's employment grew slightly in 2002, in spite of the continued U.S. economic slowdown. The local Tampa area unemployment rate rose to 4.2 percent in November 2002, up slightly from 4.0 percent in December 2001, compared to 5.0 percent for the State of Florida and 6.0 percent for the nation. The Tampa area, with its diverse service-based economy, did not experience the same drop in economic activities as those areas of the country with manufacturing-based economies. Tampa Electric experienced minimal impact by the slowdown in the tourist industry because the areas served are not as sensitive to changes in the tourist industry as some other areas of Florida.

Retail megawatt hour sales rose 5.6 percent in 2002, primarily from increased residential and commercial sales from higher numbers of customers, higher per-customer usage and warmer-than-normal summer weather. Electricity sales to the lower-margin industrial customers in the phosphate industry increased 18.2 percent in 2002 after a 10.9 percent decline in 2001. The phosphate industry saw increased demand and improved pricing worldwide which led to increased production in 2002. In 2001, the phosphate industry experienced a second year of a worldwide slowdown due to overcapacity and reduced usage that contributed to temporary facility closures during the year and the permanent closure of one phosphate processing facility. The company's phosphate customers have indicated that they expect to vary production to maintain stable prices in 2003. Revenues from phosphate sales represented slightly less than 3

percent of base revenues in 2002 and 2001. Non-phosphate industrial sales increased in 2002 and 2001, primarily reflecting continued economic growth in the area.

Base rates for all customers were unchanged in 2002. However, Tampa Electric refunded $6.4 million to customers in 2002 related to 1999 revenues held subject to refund under agreements between the Florida Public Service Commission (FPSC), the Office of Public Counsel and Tampa Electric. Fuel-related revenues increased in 2002 under the FPSC approved fuel adjustment clause due to the recovery of a previous underrecovery of fuel expense in 2001 and increased customer usage. (See the **Regulation** section.)

Sales to other utilities for resale declined in 2002, primarily as a result of lower coal-fired generating unit availability due to more planned maintenance outages.

Based on expected growth from continued population increases and business expansion, Tampa Electric expects retail energy sales growth of approximately 2.5 percent annually over the next five years, with combined energy sales growth in the residential and commercial sectors of more than 3 percent annually. Tampa Electric's forecasts indicate that summer retail demand growth is expected to average more than 100 megawatts per year for the next five years.

These growth projections assume continued local area economic growth even in the current national economic climate, normal weather and a continuation of the current market structure. (See the **Investment Considerations** section.)

Megawatt-Hour Sales

(thousands)	*2002*	*Change*	*2001*	*Change*	*2000*
Residential	8,046	6.0%	7,594	3.1%	7,369
Commercial	5,832	2.6%	5,685	2.6%	5,541
Industrial	2,612	12.2%	2,329	-2.6%	2,390
Other	1,435	4.9%	1,368	2.2%	1,338
Total retail	17,925	5.6%	16,976	2.0%	16,638
Sales for resale	1,084	-27.7%	1,499	-41.5%	2,564
Total energy sold	19,009	2.9%	18,475	-3.8%	19,202
Retail customers (average)	590.2	2.5%	575.8	2.8%	560.1

Tampa Electric Operating Expenses

Operating expenses increased almost 16 percent in 2002, reflecting higher fuel costs from an increased amount of power generated with higher-cost oil and natural gas, increased purchased power due to lower unit availability, higher Other operating expenses due to higher employee benefit costs and costs associated with a 7 percent reduction in the workforce, higher depreciation from normal plant additions to serve the growing customer base and the addition of a new peaking combustion turbine at the Polk Power Station in mid-2002, and accelerated depreciation associated with phasing out coal-related assets at the Gannon Power Station.

Operating expenses increased 6 percent in 2001, reflecting higher fuel costs from higher coal prices, increased purchased power costs due to lower unit availability, higher maintenance expenses associated with increased planned outages on coal-fired generating units, and higher depreciation from normal plant additions and accelerated depreciation associated with phasing out coal-related assets at the Gannon Power Station.

Non-fuel operations and maintenance expenses are expected to decrease in 2003 as a result of workforce reductions in 2002 and the repowering of the Gannon Station to natural gas with its lower manpower and maintenance requirements.

Depreciation expense is projected to increase in 2003, and in the future, from normal plant additions and the first phase of the Gannon to Bayside repowering project entering service in mid-2003. (See the **Environmental Compliance** section.)

Fuel costs increased 22 percent in 2002 despite lower coal costs, reflecting primarily increased generation with oil and natural gas due to lower coal unit availability. Natural gas and oil prices increased significantly in the second half of 2002. Average coal costs, on a cents-per-million Btu basis, decreased 6 percent in 2002 after a 7 percent increase in 2001. Purchased power expense increased in 2002 due to lower unit availability, primarily as a result of planned maintenance outages on base load generating units and unplanned outages during peak load periods. The effects of higher fuel and purchased power costs are also reflected in the higher operating revenues, as these costs are recovered through the fuel adjustment clause.

Nearly all of Tampa Electric's own generation over the last three years has been produced from coal, and the fuel mix is expected to continue to be substantially comprised of coal until mid-year 2003, when the first of two repowered units at Bayside is scheduled to begin operating on natural gas. (See the **Environmental Compliance** section.) On a total energy supply basis, company generation accounted for 83 percent, 84 percent and 92 percent of the total system energy requirements in 2002, 2001 and 2000, respectively.

Peoples Gas System

PGS is the largest investor-owned gas distribution utility in Florida. It serves more than 280,000 customers in all of the major metropolitan areas of Florida.

PGS net income rose almost 5 percent in 2002. Contributing to these results were 4.1 percent customer growth, operations and maintenance expenses which were essentially unchanged from 2001, and higher volumes sold for off-system sales and higher volumes transported for power generation customers which more than offset the impact of mild winter weather.

Lower gas prices in the first half of 2002 made the use of natural gas more attractive for large customers than during the period of high prices in the first half of 2001. Gas prices increased in the second half of 2002 and into early 2003, but the differential between natural gas and other fuels has remained relatively constant, therefore, fuel switching is not expected to the same degree as was experienced in 2001.

PGS' net income rose 6 percent in 2001 from 4 percent customer growth and increased gas transported for off-system sales. The high cost of gas early in 2001 had a negative impact on sales to larger interruptible and power generation customers, many of whom have the ability to switch to alternative fuels or to alter consumption patterns.

Historically the natural gas market in Florida has been underserved with the lowest market penetration in the southeastern U.S. PGS is expanding its gas distribution system into areas of Florida not previously served and within areas currently served.

Summary of Operating Results

(millions)	*2002*	*Change*	*2001*	*Change*	*2000*
Revenues	$ 318.1	-9.9%	$ 352.9	12.2%	$ 314.5
Cost of gas sold	149.0	-20.1%	186.4	18.7%	157.0
Operating expenses	115.6	.2%	115.4	4.4%	110.5
Operating income	$ 53.5	4.7%	$ 51.1	8.7%	$ 47.0
Net Income	$ 24.2	4.8%	$ 23.1	6.0%	$ 21.8
Therms sold - by customer segment					
Residential	60.2	2.4%	58.8	2.1%	57.6
Commercial	327.6	6.0%	308.9	5.8%	292.1
Industrial	423.8	22.3%	346.5	-7.4%	374.1
Power Generation	492.6	22.1%	403.5	-3.6%	418.6
Total	1,304.2	16.7%	1,117.7	-2.2%	1,142.4
Therms sold - by sales type					
System Supply	332.5	13.8%	292.2	-8.9%	320.6
Transportation	971.7	17.7%	825.5	.4%	821.8
Total	1,304.2	16.7%	1,117.7	-2.2%	1,142.4
Customers (thousands) - average	277.5	4.1%	266.6	4.1%	256.2

Residential and commercial therm sales increased from more than 4 percent customer growth in 2002, more than offsetting mild winter weather. Therm sales to large industrial and power generation customers also increased, primarily from significantly lower gas prices in the first half of 2002.

Residential therm sales increased in 2001, the result of more than 4 percent customer growth and increased per-customer usage. Commercial therm sales also increased, primarily from increased per-customer use.

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a Purchased Gas Adjustment (PGA) clause approved by the Florida Public Service Commission annually.

In Florida, natural gas service is unbundled for all non-residential customers, affording these customers the opportunity to purchase gas from any provider. The net result of this unbundling is a shift from commodity sales to transportation sales. Because commodity sales are included in operating revenues at the cost of the gas on a pass-through basis, there is no net financial impact to the company when a customer shifts to transportation-only sales. PGS markets its services to these customers through its "NaturalChoice" program. At year-end 2002, 9,500 customers had elected to take service under this program

Operating expenses were essentially unchanged from 2001 levels. This achievement represents significant cost reduction efforts in all areas of the company to offset the effect of the mild winter weather.

In 2001, operation and maintenance expenses were essentially unchanged from 2000 levels, while depreciation expense increased 8 percent, in line with the increased capital expenditures made over the past several years to expand the system.

On June 27, 2002, PGS requested a $22.6-million annual base revenue increase. On Dec. 17, 2002, the FPSC authorized PGS to increase annual base revenues by $12.05 million. The new rates allow for a return on equity range of 10.25 to 12.25 percent with an 11.25 percent midpoint, which is the same as its previously allowed return on equity, and a capital structure of 57.43 percent equity. The increase went into effect on Jan. 16, 2003. Since its last rate increase 10 years ago, PGS has added more than 100,000 customers and expanded its pipeline system from 5,000 miles to 9,000 miles.

In May 2002, Gulfstream Natural Gas Pipeline initiated service. This interstate pipeline starts in Mobile Bay, Alabama, crosses the Gulf of Mexico and comes ashore in Florida just south of Tampa. Gulfstream is the first new pipeline serving peninsular Florida since 1959. This pipeline increases gas transportation capacity into Florida by 50 percent. PGS entered into a service agreement for capacity in 2002, which grows in 2003 and 2004. The addition of the Gulfstream pipeline enhances reliability of service and helps to meet the capacity needs for PGS' growing customer base.

PGS expects increases in sales volumes and corresponding revenues in 2003, and continued customer additions and related revenues from its expansion efforts throughout the state. These growth projections assume continued local economic growth, normal weather and other factors. (See the **Investment Considerations** section.)

TECO Power Services

Net income increased almost 27 percent in 2002 to $34.1 million from higher earnings from construction-related and loan agreements with Panda Energy International (Panda), a full year of ownership of the Frontera Power Station and higher capacity payments due to higher prices and generation at the Guatemalan generating units. The improved results were partially offset by a $5.8-million after-tax charge related to the proposed sale of its minority interest in generating assets in the Czech Republic, higher operations and maintenance expense, lower energy prices and sales from the Commonwealth Chesapeake Station and higher financing costs.

Net income increased 18 percent in 2001 to $26.9 million from higher earnings from the Hamakua, Commonwealth Chesapeake, and Guatemalan generating stations and higher returns on TPS' investment through Panda in the Texas Independent Energy (TIE) projects. The improved operating performance was partially offset by weak results at the Frontera Station, which was acquired in March 2001, due to low power prices in the Texas market; increased financing costs; higher development costs; and a $6.1-million after-tax valuation reserve recognized in connection with the sale of TPS' minority interest in EGI, which owns small generating projects in Central America.

Summary of Operating Results

(millions)	*2002*	*Change*	*2001*	*Change*	*2000*
Revenues	**$309.8**	7.9%	$ 287.1	44.2%	$ 199.1
Operations, maintenance and A&G	**73.1**	8.9%	67.1	24.3%	54.0
Purchase power pass through	**31.1**	4.4%	29.8	-1.0%	30.1
Depreciation	**28.1**	-1.1%	28.4	53.5%	18.5
Taxes, other than income	**8.4**	15.1%	7.3	135.5%	3.1
Non-fuel operating expenses	**140.7**	6.1%	132.6	25.4%	105.7
Fuel	**118.6**	8.1%	109.7	60.9%	68.2
Total operating expense	**259.3**	7.0%	242.3	39.3%	173.9
Operating income	**$ 50.5**	12.7%	$ 44.8	77.8%	$ 25.2
Net income	**$ 34.1**	26.8%	$ 26.9	18.0%	$ 22.8
Generation					
Megawatt hours *(thousands)*	**3,411**	10.4%	3,089	89.2%	1,633

Increases in energy generation reflect incremental new capacity coming into service either in phases or part year in 2000 and 2001 or acquired in 2001 with full year results reflected in 2002. Increases in operations, maintenance and administrative and general (A&G) expenses reflect the increased manpower and facilities and a full year of operations of the energy marketing and management group. Increases in these expenses over the three-year period reflect the increased size of the generating portfolio, which increased from three operating plants in January 2000 to five at Dec. 31, 2002.

Increases in income and operating expenses related to the Union and Gila River power stations in 2003 and 2004 are expected to be reflected in TPS financial results on a net basis assuming these facilities continue to be accounted for as unconsolidated affiliates. (See the **Off-Balance Sheet Financing** section.) However, operations, maintenance and A&G expenses are expected to increase because of increased staffing in the energy marketing and management group related to these two plants.

TPS Project Summary

Project	Location	Size MW	TPS Economic Interest	TPS Net Size MW	In Service/ Participation Date[1]
Operating:					
Hardee Power Station	Florida	370	100%	370	1/93, 5/00
Alborada Power Station	Guatemala	78	96%	75	9/95
Empresa Eléctrica de Guatemala S.A.(EEGSA) (a distribution utility)	Guatemala		24%		9/98[4]
San José Power Station	Guatemala	120	100%	120	1/00
Hamakua Energy Project	Hawaii	60	50%	30	8/00, 12/00
Frontera Power Station	Texas	477	100%	477	5/00, 3/01[4]
Odessa and Guadalupe	Texas	2,000	(2)	750	9/00, 8/01
Commonwealth Chesapeake Power Station	Virginia	315	100%	315	9/00, 8/01
Sub-total operating		3,420		2,137	
Under Construction:					
Union	Arkansas	2,200	(3)	1,650	1/03-6/03
Gila River	Arizona	2,145	(3)	1,609	2/03-8/03
Sub-total construction		4,345		3,259	
Total		7,765		5,396	
Suspended:					
Dell	Arkansas	599	100%		
McAdams	Mississippi	599	100%		
		1,198			

(1) Unless otherwise indicated, each date appearing in this column is an in-service date. When more than one in-service date appears, it indicates when different phases of the project went into operation. For projects under construction, a range of dates indicates when the first and last phases are expected to enter service under TECO Energy's current plans.
(2) Based on the effect of the preferred return, the effective economic interest is estimated at 75 percent of Panda's 50-percent interest in these projects over the life of the projects.
(3) Based on the effect of the preferred return, the effective economic interest is estimated at 75 percent over the life of the project.
(4) Dates on which TPS acquired its economic interest in the project.

Construction Activities

In 2000, TPS focused its efforts on the development or acquisition of domestic energy projects. TPS has net ownership interest in almost 5,400 megawatts of projects either operating or under construction.

In September 2000, TPS invested $93 million in the form of a loan to Panda's TIE, which are the Odessa and Guadalupe power stations. An additional $44 million was loaned to Panda in the first quarter of 2002 bringing the total investment to $137 million. The interest earned on the loan to TIE is reflected in 2002, 2001 and 2000 earnings.

These loans converted in accordance with their terms into an ownership interest on Jan. 3, 2003 which is expected to be accounted for under the equity method. The conversion gives TPS an opportunity to have an effective economic interest estimated at 75 percent of Panda's 50-percent interest in these projects over the life of the projects. Based on information available from the other owners of these projects, these projects have realized lower than expected earnings and cash flows due to over capacity in the Texas market, uneconomic dispatch, and market design, and that trend is expected to continue in 2003. TPS is evaluating its options relative to its ownership position in these projects and is targeting to structure its interest in such a manner that it will cover its cash costs in 2003 and mitigate any impact on earnings.

In October 2000, TPS acquired two 599-megawatt, natural gas-fired, combined-cycle projects, Dell and McAdams, located in Arkansas and Mississippi, respectively. Construction commenced on these projects in 2001 but was suspended at the end of 2002 due to projected low energy prices in the markets that these plants were expected to serve. Interest will not be capitalize during the construction postponement period. The carrying costs associated with these suspended plants are expected to reduce TPS earnings in 2003. Market conditions will be monitored to determine when these plants will be completed. At the time of suspension, approximately $690 million had been invested in these plants. It is currently estimated that the cost to complete these projects will be approximately $100 million.

In November 2000, TPS entered into a 50/50 joint venture with Panda to build, own and operate the 2,200-megawatt Union Power Station in Arkansas and the 2,145-megawatt Gila River Power Station in Arizona. The partnership agreement calls for TPS to contribute all project equity and for TPS to earn a preferred return on the investment in these projects, which, over the project's life, could give TPS an effective economic interest estimated at 75 percent. Construction commenced on these projects in 2001. Each of these projects is expected to begin operation in four power blocks, beginning with the first 550-megawatt power block of Union which began operating in January 2003 and ending with the 540-megawatt final power block of Gila River expected in August of 2003. At Dec. 31, 2002, the TPS investment in these projects was $1.2 billion of project equity including the remaining $375 million equity bridge loan balance and $55 million already contributed related to the TECO Energy construction undertaking, described below. At Dec. 31, 2001, TPS had invested $624 million in these projects including $500 million of the equity bridge loan.

In December 2001, Enron Corp., a large energy trading and services company, filed for protection under the U.S. Bankruptcy Code. An Enron subsidiary, NEPCO, was serving as the construction contractor for the Union, Gila River, Dell and McAdams power stations. Enron guaranteed certain of NEPCO's obligations under the construction contracts. The Union and Gila River power stations, have financing in place with a syndicate of banks. The Dell and McAdams power stations, are wholly owned by TPS and have not been financed.

As part of Enron's centralized cash management procedure, Enron swept NEPCO's cash before it was applied to pay project costs. Enron's bankruptcy permitted the project lenders to stop funding construction costs for the Union and Gila River projects until the condition was cured or waived. TPS received approval from the project lenders on a plan that allowed funding to resume.

The plan involved TECO Energy replacing Enron as the guarantor of certain of NEPCO's obligations under the construction contracts for these two projects, including payment by the company of any project cost overruns (estimated at $62 million remaining at Dec. 31, 2002, against which TECO Energy could offset the unused construction contingency amount remaining after completion of construction) and guaranteeing the completion of construction. The plan also provided for TECO Energy to replace the letter of credit furnished by Enron that had been drawn upon and acceleration of project cash commitments to mid-year 2002, resulting in TECO Energy's total investment essentially being complete by the end of 2002 rather than mid-2003 as originally planned.

Under a series of agreements with TECO Panda Generating Co. (TPGC), NEPCO continued construction and engineering of all four plants until SNC Lavalin Constructors Inc., a large Canadian engineering and construction firm, replaced it as the contractor in May 2002. SNC Lavalin hired essentially all of NEPCO's management and staff, and construction continued without interruption. The agreements with SNC Lavalin provide for the projects to be completed on a cost-plus-fee basis, with the fee portion at-risk until the projects are completed.

In February 2002, the TPS and Panda affiliates that comprise the joint venture that owns the Union and Gila River projects entered into a purchase arrangement for TPS to purchase and Panda to sell Panda's interest in the joint venture in 2007 for $60 million. Panda has the right to cancel the purchase arrangement by paying TPS $20 million, or a lesser amount under certain circumstances. The purchase arrangement could result in TPS' purchase of the interest prior to 2007 if Panda defaults on a bank loan made to Panda using the purchase arrangement as collateral or if TECO Energy permits its debt-to-capital ratio to exceed 65.0 percent, permits its EBITDA/interest ratio to fall below 1.5 times or it defaults on the payment of indebtedness in

excess of $50 million. TECO Energy's debt-to-capital ratio at Dec. 31, 2002 was 55.9 percent and its EBITDA/interest ratio was 3.6 times.

In March 2001, TPS acquired the Frontera Power Station located near McAllen, Texas. This 477-megawatt, natural gas-fired, combined-cycle plant, began combined-cycle operation in May 2000 and has a 150-megawatt transmission connection to the Federal Electricity Commission of Mexico. In the second and third quarters of 2002, the facility sold energy and ancillary services to the Electric Reliability Council of Texas (ERCOT). During the fourth quarter the facility provided reliability-must-run (RMR) services under contract to ERCOT. Since the RMR contract was not renewed for the first quarter of 2003, the plant was shut down for scheduled maintenance. The first quarter is expected to have lower opportunities than other quarters for sales to ERCOT, Mexico or other customers due to weather.

In February 1999, TPS invested in EGI, a company with energy interests in Latin America. In the first quarter 2001, TPS recognized a $6.1-million after-tax charge as part of the sale of its interest in EGI. TPS no longer has any ownership interest in EGI.

Energy Markets

The power plants that TPS is operating and constructing are located in markets with a history of high load growth. However, the general U. S. economic slowdown in 2001 and 2002 slowed the growth in demand for power in some of these markets. In addition, the slowdown of electricity deregulation initiatives across the United States, including the markets that TPS will be serving, caused by the failure of deregulation in California, has allowed the traditional, incumbent utilities to continue to operate older, less efficient generating facilities in lieu of purchasing power from newer, more efficient independent power plants. These factors have combined with aggressive plans by the independent power industry to add merchant power facilities to cause excess generating capacity that is either being built or has come on line in many markets. This excess supply has depressed both spot and forward wholesale power prices. Based on current forward curve prices for 2003, the combined returns for the Union and Gila River power stations are expected to be below earnings break-even, but are anticipated to be close to covering cash costs. If cash costs are not covered, the non-recourse project finance lenders are required to fund the payments of these costs with additional non-recourse debt up to $80 million through a debt-service reserve. The forward curve prices represent the market price for on-peak energy that a seller would expect to receive if future energy was sold today. The forward curve for electricity prices reflects the price for energy that is delivered on a standard schedule. Because TPS' assets can be dispatched with some flexibility and sales of ancillary services are possible, the forward curve price may understate the realized price or profit margin.

Studies by numerous outside groups, such as Cambridge Energy Research Associates, Standard & Poor's and others, present conflicting outlooks on power price improvement. Some experts indicate that 2003 should be the low point for power prices while others indicate that power prices may remain low beyond 2004. Continued low power prices for the output from TPS' merchant plants in 2004 would decrease net income at TPS from 2003 levels, and could require cash payments to cover any fixed costs of the plants not covered by the project debt-service reserves or cash generated at the projects.

TPS' ultimate long-term strategy for selling the output of these plants is to enter into three- to five-year contracts with load serving entities, or ultimate customers where it is allowed, for up to 50 percent of the output of the plants. TPS would contract another 25 percent of the output in the shorter term (less than one-year market) with the remaining 25 percent sold in the spot market. In the meantime, until longer-term contracts can be signed, TPS is selling the output of these plants under a mix of spot market sales and shorter-term transactions. The shorter-term transactions are primarily forward sales of on-peak energy at prices reflective of current forward curves. TECO Energy's policy is to balance power contract commitments with necessary purchases of natural gas so as to know the margins for such sales at the time of commitment. These sales usually do not include the value for capacity payments, ancillary services, dispatchability and the premium associated with owning physical assets. These incremental value components are often captured in the spot market at the time of physical sales or through more structured transactions.

In 2001, TPS activated its TECO EnergySource (TES) subsidiary to enter into power marketing and fuel procurement transactions for the longer-term contracts. Initially, TPS retained power marketers, such as Aquila for the Union and Gila River power stations, to market the output planned for the spot market. Aquila has decided to exit the power marketing business and TPS intends to assume full responsibility for the output marketing and fuel procurement transactions. TES is actively seeking both short- and long-term contracts with purchasers for the output from the Union and Gila River power stations and the Frontera Power Station.

TES is contracting to purchase or supply electricity and natural gas, primarily at specified delivery points and specified future dates (i.e., fixed-price forward sales and purchase contracts). In some cases TES is utilizing financial instruments such as futures and contracts traded on the NYMEX and swaps and other types of financial instruments traded in the over-the-counter markets to manage its exposure to electricity and natural gas price fluctuations.

The use of these types of contracts allows TPS to manage and hedge its contractual commitments and to reduce its exposure relative to the volatility of spot market prices. TPS' and TES' use of futures, options, swaps or other financial instruments was minimal in 2002 due to the low volume of energy sales.

TPS normally balances its fixed-price physical and financial fuel purchase and energy sales contracts in terms of contract volumes and the timing of performance and delivery obligations. Net open positions may exist for short periods due to the origination of new transactions. When net open positions exist, TPS will be exposed to fluctuating market prices. All fuel purchase and energy sales contracts and open positions are monitored closely by the TECO Energy risk management function, which is independent of the TPS' energy management group.

In addition to price risk, credit risk is inherent in TPS' energy risk management activities. The marketing business may be exposed to counterparty credit risk from a counterparty not fulfilling its obligations. Credit policies and procedures, administered by TECO Energy, attempt to limit overall credit risk. The credit procedures include a thorough review of potential counterparties' financial position, collateral requirements under certain circumstances, monitoring net exposure to each counterparty and the use of standardized agreements.

TPS is currently not required to post cash collateral for fuel purchases or as a counterparty for energy sales. In the event of a TECO Energy credit downgrade to non-investment grade, TPS would be required to post cash collateral for energy management activities. Dec. 31, 2002 positions would require the posting of $9.3 million of cash collateral in the event of a downgrade.

Significant factors that could influence results at TPS include construction of its new projects on schedule and on budget, energy prices in its markets, the ability to earn a premium above forward curve prices, weather, domestic economic conditions and commodity price changes. (See the **Investment Considerations** section.)

TECO Transport

Net income declined 24 percent in 2002 to $21.0 million, compared with $27.6 million in 2001. TECO Transport's results reflect continued weakness in the U.S. economy as low levels of imported raw materials reduced northbound river shipments and drove pricing lower for all river shipments. These conditions also reduced volumes of petroleum coke and steel-related product volumes through the transfer terminal. These conditions combined to more than offset increased ocean-going phosphate shipments and lower repair and fuel costs.

Net income declined 6 percent in 2001. Increased phosphate and other product shipments, higher revenue from outside services at TECO Barge Line, and lower fuel prices were more than offset by lower U.S. government grain program shipments, higher costs primarily related to depreciation, and lower shipments of steel-related products handled by TECO Bulk Terminal. Results for 2000 included an after-tax gain of approximately $1.5 million associated with the disposition of an ocean-going asset.

After a late start to U.S. government grain shipments in 2002, volume and pricing improved in the fourth quarter. The pattern of an intense but short annual period for moving grain ship-

ments in the fall and winter is expected to repeat in 2003. Northbound river shipments of steel-related raw materials are expected to improve in 2003 as the U.S. economy improves. Southbound river shipments of grain products are expected to increase slightly in 2003, with a small increase in pricing expected. Even with the expected price increase, grain freight rates are expected to remain below historical levels, which will impact the pricing for all commodities moved on the rivers. In the meantime, TECO Transport expects to move increased volumes of fertilizers and petroleum coke northbound on the river system.

The phosphate fertilizer industry experienced an increase in worldwide demand in 2002 after a period of reduced demand in 2001 and 2000, which resulted in increased shipments of raw phosphate rock between Tampa and Louisiana. The outlook for TECO Ocean Shipping is for a slight increase in phosphate demand in 2003. Lower shipments for Tampa Electric and higher fuel and employee-related health care and pension costs are expected in 2003.

TECO Transport expects to continue diversifying into new markets and cargoes. Future growth at TECO Transport is dependent on improved pricing, higher asset utilization, and asset additions at both the river and ocean-going businesses. Significant factors that could influence results include weather, bulk commodity prices, fuel prices and domestic and international economic conditions. (See the **Investment Considerations** section.)

TECO Coal

Net income increased 30 percent in 2002, to $76.5 million, driven primarily by better margins and higher synthetic fuel (synfuel) production and sales and the resulting higher Section 29 tax credits. Production of synthetic fuel at TECO Coal qualifies for Section 29 tax credits for non-conventional fuel production.

Synfuel production increased to 3.8 million tons in 2002 compared with 3.2 million tons and 1.9 million tons in 2001 and 2000, respectively. The net benefit increased to approximately $77 million in 2002 compared with $58 million in 2001 and approximately $30 million in 2000. Synfuel production displaced some of the conventional coal production in all years.

Net income at TECO Coal increased 76 percent in 2001, driven primarily by better margins and higher synfuel production, increased coal production from Perry County Coal, Inc.'s mining facilities acquired in late 2000, and higher metallurgical coal prices in the second half of the year. 2001 was the first full year of production for the synfuel production facilities which entered service late in the second quarter of 2000.

In 2002, coal sales, including synfuel, decreased to 9.3 million tons from 10.1 million tons in 2001 due to soft market conditions. In 2003, total coal sales are expected to increase slightly due to more normal supply and demand in the market. Synfuel volumes are expected to increase to more than 5 million tons and conventional coal production is expected to decline to offset the higher synfuel production in 2003. In 2003, TECO Coal intends to sell the majority of its interest in the synfuel production facilities, but retain responsibility for operating the facilities. (See the **Strategy and Outlook** section.)

Metallurgical coal contracts, which normally renew in the first quarter of the year, resulted in lower prices in 2002 after a strong pricing environment in 2001. Prices are expected to remain near current levels in 2003. Steam coal pricing declined industry wide in the first quarter of 2002, due to high utility inventory levels as a result of the mild winter weather. TECO Coal, however, contracts much of its steam coal production for the coming year late in the preceding year and was less affected by the price declines than those companies that sell a higher percentage in the spot markets. Later in the year, after inventories were reduced to more normal levels, coal prices strengthened and contract renewals for 2003 were achieved at prices only slightly lower than 2002 levels.

In January 2000, TECO Coal purchased synfuel facilities from Headwaters Technologies, Inc. The facilities were relocated to the company's Premier Elkhorn and Clintwood Elkhorn mines in Kentucky, and were producing by the second quarter of 2000. These facilities produce synfuel from coal, coal fines and waste coal using a technology licensed from Headwaters.

TECO Coal has received private letter rulings from the Internal Revenue Service regarding the production of synfuel from its facilities. The private letter rulings confirm that the facilities are located properly and produce a qualified fuel eligible for Section 29 tax credits which are available for the production of such non-conventional fuels through 2007.

Significant factors that could influence TECO Coal's results include weather, general economic conditions, commodity price changes, continued generation of Section 29 tax credits, the sale of interest in the synfuel production facilities, the ability to use Section 29 tax credits and changes in laws, regulations or administration. (See the **Investment Considerations** section.)

Other Unregulated Companies

In 2002, net income for the other unregulated companies increased 70 percent to $6.8 million driven primarily by the full-year results of Prior Energy Corp., TECO Energy's end-use gas marketing company acquired in November 2001. In 2001, net income increased due to a full year of results from BCH Mechanical, which was acquired in September 2000.

Other unregulated companies include TECO Energy Services (formerly TECO BGA, Inc., and BCH Mechanical, Inc. and its affiliated companies), TECO Gas Services, TECO Properties, Prior Energy Corp., TECO Propane Ventures (TPV), TECO Partners and TECO Investments. Except for TECO Investments, these operating companies are organized under TECO Solutions, which was formed to offer customers (primarily in Florida) a comprehensive package of energy services and products including energy-efficient engineering and construction and gas management services.

In November 2001, TECO Solutions acquired Prior Energy Corp., a leading natural gas management company. Serving customers throughout the Southeast, Prior Energy handles all facets of natural gas energy management services for large industrial, power generation utility, municipal and other governmental agency customers, including natural gas acquisition and supply management, transportation management, asset management and consulting services.

TPV holds the company's propane business investment. In 2000, TECO Energy combined its propane operations with three other southeastern propane companies to form U.S. Propane. In a series of transactions, U.S. Propane combined with Heritage Holdings, Inc. As a result, TPV owns a 38-percent interest in the general partner that manages Heritage Propane Partners, L.P. (NYSE:HPG) and that general partner owns an approximate 29-percent limited partnership interest in Heritage Propane Partners.

Liquidity, Capital Resources

Sources of cash for TECO Energy and its operating companies in 2002 totaled $3.4 billion, including operating cash flows of $656 million and proceeds from the sale of debt and equity securities of $2.8 billion. Cash was used to fund $1.7 billion of capital spending (net of $103 million from asset sales), debt maturities of $788 million and refinancings of $162 million, net reduction of short-term debt of $278 million and dividends to common shareholders of $216 million. The company began the year with $109 million in cash and cash equivalents and ended the year with $411 million in cash and cash equivalents and $460 million of unused capacity available under the bank credit facilities at TECO Energy and Tampa Electric. The increased year-end cash position was attributable in part to the conversion of the TECO Energy bank credit facility to a term loan and other cash generating activities.

The company met 2001 cash needs with a mix of internally generated funds, short- and long-term borrowings and proceeds from the sale of equity. Cash from operations was $503 million, and net cash from financing was $614 million after common dividends of $184 million. Capital spending totaled $1.1 billion in 2001.

In light of the accelerated equity commitments for the Union and Gila River projects under the bank financing plan, an unexpected deterioration in the bank project finance market which caused a planned financing to not materialize, and the capital requirements for committed regulated and unregulated projects, TECO Energy took several steps to strengthen its balance sheet in 2002 and provide cash for its construction program. In January 2002, the company reduced its previous capital expenditure forecast for 2002 through 2004 by about $700 million, primari-

ly by delaying indefinitely generation projects that were not yet under construction for TPS and Tampa Electric, including the Bayside Units 3 and 4 repowering projects announced in the fall of 2001.

In September 2002, the company announced additional plans to meet its 2003 construction commitments without raising incremental debt, identifying a total amount required of $900 million. By the end of 2002, the company had completed 70 percent of its $900 million target by: 1) reducing by $250 million capital spending projections (which included amounts higher than earlier estimates); 2) selling the TECO Coalbed Methane gas assets for $140 million, with $42 million received in December and the remainder received in January 2003; 3) realizing $55 million of cash from repatriation and additional cash from non-recourse-financing of the Guatemalan generating assets; and 4) raising $207 million from the sale of common equity in October.

Tampa Electric has signed a letter of intent for the sale of its gasifier unit, and TECO Coal is continuing discussions with potential buyers of interests in its synthetic fuel production facilities. Completion of these activities, which will complete the 2003 funding plan, is expected late in the first quarter or early in the second quarter of 2003.

Estimated cash needs for 2003 include capital spending of $727 million for normal renewal and replacement capital as well as project commitments of Tampa Electric and TPS, including $375 million related to payment of the Union and Gila River projects equity bridge loan. (See the **Summary of Contractual Obligations** section.) Long-term debt maturities of $127 million are due in 2003, and a bank term loan of $350 million matures in November. TECO Energy expects to rely on cash on hand and internally generated cash from operations and from asset sales to fund these cash needs and the payment of dividends to shareholders. (See the **Bank Credit Facilities** and **Covenants in Financing Agreements** sections.) Based on its cash flow forecasts, the company expects to have at least $600 million of cash and capacity under the bank credit facilities at the end of the first, second and third quarters of 2003 and, if it renews its bank facilities in full, at the end of 2003.

The company has identified in this Management's Discussion & Analysis (including in **Investment Considerations**), several factors that could cause its operating cash flow to be lower than forecasted. One of these factors is the margins the company may realize for production from its merchant power facilities. Because of the company's expansion in the merchant power business, the company's cash flow has become increasingly dependent upon power margins.

TECO Energy has not made a contribution to its defined benefit pension plan since the 1995 plan year because investment returns have been more than sufficient to cover liability growth. Negative stock market returns over the past three years have reduced the over-funding of the defined benefit plan. Based on plan asset values at Jan. 1, 2003, it is estimated that TECO Energy will be required to make a $15 million contribution to its defined benefit plan in September 2004. (See **Note K, to the Consolidated Financial Statements.**)

Bank Credit Facilities

At Dec. 31, 2002, TECO Energy had a bank credit facility of $350 million, and Tampa Electric had a bank credit facility of $300 million, with maturity dates of November 2004 and November 2003, respectively. Both were undrawn at Dec. 31, 2002, except for outstanding letters of credit under the TECO Energy facility. In November 2002, TECO Energy converted another $350 million bank credit line then in effect into a one-year term loan due November 2003. TECO Energy expects to have discussions with the bank-lending group with the objective of renewing the facility before the loan matures.

The TECO Energy bank credit facility maturing November 2004 includes a $250 million sublimit for letters of credit capacity. At Dec. 31, 2002, $180 million of letters of credit were outstanding against that line, primarily related to the construction of the Union and Gila River power stations. These letters of credit of $62 million and $88 million for Union and Gila River, respectively, were replacements for the letters of credit posted by Enron and drawn by the TPS/Panda joint venture following Enron's bankruptcy filing. In addition, at Dec. 31, 2002, TECO Energy and its subsidiaries had $5 million of letters of credit outside of its bank credit line facility outstanding. (See the **Covenants in Financing Agreements** section.)

The Tampa Electric bank credit facility requires commitment fees of 15 basis points, and drawn amounts are charged interest at LIBOR plus 85-97.5 basis points at current credit ratings. The TECO Energy credit facility requires commitment fees of 15-20 basis points and drawn amounts incur interest expense at LIBOR plus 35-60 basis points at current credit ratings. TECO Energy expects that the cost of its facility will increase upon renewal.

The September 2002 downgrade by Standard & Poor's Ratings Service (S&P) of TECO Energy's commercial paper program to A-3 eliminated TECO Energy's access to the commercial paper market. Tampa Electric continues to have access to the commercial paper market with its A2/P1/F2 rated commercial paper program and had $11 million of commercial paper outstanding at Dec. 31, 2002. The lack of access to the commercial paper market has caused TECO Energy to utilize its bank credit facilities for short-term borrowing needs.

Credit Ratings/Senior Unsecured Debt

	Fitch	*Moody's*	*Standard & Poor's*
Tampa Electric	A-	A2	BBB
TECO Finance / TECO Energy	BBB	Baa2	BBB-

In September 2002, Moody's Investor Services, Inc. (Moody's), S&P and Fitch Investor Services, Inc (Fitch), lowered the ratings on the senior unsecured debt securities of TECO Energy, TECO Finance and Tampa Electric. The outlook assigned to TECO Energy by Moody's and S&P is negative while the outlook assigned by Fitch is stable. The ratings actions were attributed to increased debt levels and the changing risk profile associated with the expansion of TECO Energy's investment in merchant generation facilities through TPS, as well as the required capital outlays of Tampa Electric, the outlook for low power prices in the merchant energy sector and the negative impacts on earnings and cash flow, and the additional risks and obligations undertaken by TECO Energy with respect to the Union and Gila River power stations. These downgrades followed downgrades in 2001 and 2000 by all of the rating agencies due to the changing risk profile of TECO Energy related to the increased emphasis on merchant power.

These downgrades and any future downgrades may affect TECO Energy's ability to borrow and may increase financing costs, which may decrease earnings. TECO Energy's interest expense is likely to increase when maturing debt is replaced with new debt with higher interest rates due to the lower credit ratings.

Summary of Contractual Obligations

The following table lists the obligations of TECO Energy and its subsidiaries for cash payments to repay debt, lease payments and unconditional commitments related to capital expenditures. This table does not include contingent obligations discussed in the following table.

Contractual Obligations

		Payments Due by Period			
(millions)	*Total*	*2003*	*2004*	*2005-2007*	*After 2007*
Long-term debt	$3,426.1	$ 101.8	$ 31.9	$ 1,048.9	$2,243.5
Capital lease obligation	25.3	25.3	—	—	—
Operating leases/rentals	230.4	27.8	26.9	63.0	112.7
Unconditional purchase obligations/commitments[1]	563.0	461.6	41.4	60.0[3]	—
Other long-term obligations[2]	649.1	—	—	449.1	200.0
Total contractual obligations	$4,893.9	$ 616.5	$100.2	$ 1,621.0	$2,556.2

(1) Includes the expected repayment of $375 million on the TECO Energy guaranteed equity bridge loan at TPS for the construction of the Union and Gila River power stations.
(2) Includes the expected redemption of company preferred securities held as assets of TECO Capital Trusts I and II.
(3) TPS' obligation to purchase Panda's interest in the Union and Gila River power stations in 2007, unless Panda buys out that purchase agreement in advance. (See the **TECO Power Services – Construction Activities** section.)

Summary of Contingent Obligations

The following table summarizes the letters of credit and guarantees outstanding that are not included in the Summary of Contractual Obligations table above and not otherwise included in the company's Consolidated Financial Statements.

		Commitment Expiration			
(millions)	*Total*[2]	*2003*	*2004*	*2005-2007*	*After 2007*
Letters of Credit[1]	$185.0	$128.0	$27.1	$ —	$29.9
Guarantees:					
Debt related	23.7	—	—	—	23.7
Construction undertaking[3]	60.0	60.0	—	—	—

(1) Expected final expiration date with annual renewals.
(2) Expected maximum exposure.
(3) The construction undertaking of $60 million reflected in the table represents the estimated maximum probable exposure associated with completing construction of the Union and Gila River power stations if actual costs exceed current estimates and in-service dates are delayed beyond current estimates. This contingent obligation estimate is net of retainage letters of credit posted for these projects. This estimate will decline rapidly as construction progresses and units are brought into service. (See the **TECO Power Services – Construction Activities** section.)

Covenants in Financing Agreements

In order to utilize their respective bank credit facilities, TECO Energy and Tampa Electric must meet certain financial tests. TECO Energy's credit facilities and the financing arrangements of TPS' Union and Gila River power stations require that at each quarter-end TECO Energy's debt-to-capital ratio, as defined in the applicable agreements, not exceed 65%. Under Tampa Electric's 364-day credit facility, renewed in November 2002, its debt-to-capital ratio may not exceed 60 percent at the end of the applicable quarter and its earnings before interest, taxes, depreciation and amortization (EBITDA) to interest coverage ratio (as defined in the agreement) can not be less than 2.5 times. Certain long-term debt at PGS contains a prohibition on the incurrence of funded debt if Tampa Electric's debt-to-capital ratio, as defined in the applicable agreement, exceeds 65%. The PGS debt also contains a Tampa Electric interest coverage requirement, as defined in the applicable agreement, of 2.0 times or greater for four consecutive quarters, and certain TPS financing arrangements require a TECO Energy consolidated interest coverage, as defined in the applicable agreement, equal to or exceeding 3.0 times for the twelve-month period ended each quarter. At Dec. 31, 2002, TECO Energy's and Tampa Electric's debt-to-capital ratios, as applicable, were 55.9 percent and 43.9 percent, respectively, and interest coverage, as applicable, was 3.6 times and 7.8 times, respectively. The company expects that renewal of TECO Energy's facility will require covenants similar to Tampa Electric's.

The TECO Energy guarantees of the Union and Gila River power stations equity bridge financing, equity contribution agreement and construction undertaking require that TECO Energy maintain senior unsecured credit ratings of not less than BBB and Baa3 or BBB- and Baa2. The company's current ratings are at the minimum required level. A further downgrade from either S&P or Moody's would trigger a failure to meet that requirement, thereby requiring the delivery of letters of credit, which the company currently estimates could approximate $450 million, to secure the obligations. In the event of a downgrade, under the terms of the construction contract guarantees, TECO Energy is required to deliver letters of credit in an amount equal to the full construction contract price and any change orders and cost overruns or such lesser amount satisfactory to the majority of the lenders for the Gila River and Union power stations. TECO Energy believes that the amounts required would be based on the estimated amounts reasonably necessary to cover the remaining payment and performance obligations under the construction contracts. As of January 2002, when documenting the construction contract guarantees with the lenders for the Gila River and Union power projects, the maximum amount necessary to cover the payment and performance obligations of the contractor was estimated to be approximately $310 million, net of approximately $150 million in letters of credit previously issued to the lenders as security for the projects. Based on the construction status as of Dec. 31, 2002, TECO Energy estimates the maximum amount necessary to cover the payment and performance obligations of the contractor to be approximately $60 million, net of the approximately $150 million in letters of credit previously issued as security. This $60 million is included in the $450 million amount referenced above. The amount of the letters of credit that would be required to be delivered declines as equity is contributed to the projects, the bridge loan is repaid and the levels of construction completion increase.

The 10.5% 5-year notes issued in November 2002 contain covenants that will, among other things, in the event of certain ratings downgrades, limit TECO Energy's ability to pay dividends or distributions or make certain investments, incur additional liens or issue additional indebtedness. The covenants apply only if either the notes are rated non-investment grade by either S&P or Moody's or the notes are rated below the levels required by the equity bridge loan and Union and Gila River construction undertaking while those obligations are outstanding. If these covenants become applicable, they would restrict the company from paying dividends or distributions or making certain investments unless cumulative EBITDA to interest coverage is at least 1.7 times.

Capital Investments

	Actual	*Forecast*			
$ (millions)	*2002*	*2003*	*2004*	*2005-2007*	*2003-2007 Total*
Florida Operations	$ 662	$272	$266	$725	$1,263
Independent Power	1,027	424	25	75	524
Transportation	25	15	21	61	97
Other	50	16	23	55	94
Total	$1,764	$727	$335	$916	$1,978

TECO Energy's 2002 capital investments of $1,764 million (without reduction for asset sale proceeds of $103 million) included $597 million for Tampa Electric (excluding $35 million of AFUDC), $54 million for PGS and $11 million for the unregulated Florida operations. Tampa Electric's electric division capital investments in 2002 were $169 million for equipment and facilities to meet its growing customer base and generating equipment maintenance, $343 million for the repowering and conversion of the coal-fired Gannon Station to the natural gas-fired Bayside Station (see the **Environmental Compliance** section), and $85 million for the 180 MW Polk Unit 3 peaking combustion turbine and future generation expansion requirements. Capital expenditures for PGS were approximately $39 million for system expansion and approximately $12 million for maintenance of the existing system. TECO Transport invested $25 million in 2002 for river barge replacements and capitalized maintenance of ocean-going vessels. TECO Coal's capital expenditures included $48 million for the expansion of production at Perry County and Clintwood as well as normal equipment replacements. TPS' capital investments totaled $1,027 million primarily related to the Union, Gila River, Dell and McAdams power stations. This $1,027 million includes $672 million classified as Other Non-Current Investments, shown as notes receivable from TPGC (see the **Transactions With Related and Certain Other Parties** section), which represents TECO Energy's equity contributions for the Union and Gila River projects. The Union and Gila River contributions are initially made in the form of loans to TECO-Panda Generating Company (TPGC) and become equity as the units' specified phases come into service.

TPS expenditures represent the equity funding of project costs and exclude amounts funded by non-recourse project financing for the Union and Gila River power stations, which amounted to $627 million in 2002. (see **TECO Power Services – Construction Activity** section.)

Asset sale proceeds of $103 million in 2002 included proceeds from the sale of TECO Coalbed Methane's assets, real estate sales, and TECO Transport's sale and lease-back of vessels and barges accounted for as an operating lease.

TECO Energy estimates capital spending for ongoing operations, without reduction for pro-

ceeds from asset sales, to be $727 million for 2003, $335 million for 2004 and $916 million during the 2005-2007 period. TECO Energy's funding plan for these expenditures includes the asset sales described in the **Strategy and Outlook** section.

For 2003, Tampa Electric, electric division, expects to spend $232 million consisting of $78 million for the repowering project at the Gannon Station and $154 million to support system growth and generation reliability. At the end of 2002, Tampa Electric had outstanding commitments of about $119 million for the Gannon Power Station repowering project. Tampa Electric's total capital expenditures over the 2004-2007 period are projected to be $841 million, including $67 million for the repowering project and $141 million for compliance with the Environmental Consent Decree. (See the **Environmental Compliance** section.)

Capital expenditures for PGS are expected to be about $40 million in 2003 and $160 million during the 2004-2007 period. Included in these amounts are approximately $25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety.

TPS expects to invest $424 million in 2003 primarily for the completion of the Union and Gila River power stations. These investments include $375 million to repay the outstanding amounts due under the project company's equity bridge loan guaranteed by TECO Energy, which is expected to be repaid in three $125 million installments in the second, third and fourth quarters.

The other unregulated companies expect to invest $31 million in 2003 and $160 million during the 2004-2007 period. Included in these amounts is normal renewal and replacement capital including coal mining equipment.

Financing Activity

TECO Energy's 2002 year-end capital structure, excluding the effect of unearned compensation, was 53.7 percent debt, 9.1 percent company preferred securities and 37.2 percent common equity. TPS typically finances its power projects with non-recourse project debt. Excluding this non-recourse debt of $232.4 million, the year-end capital structure was 52.1 percent debt, 9.4 percent company preferred securities and 38.5 percent common equity.

In 2002, TECO Energy was active in the debt and equity capital markets raising $1 billion through the sale of equity or equity-linked securities and issuing $1.8 billion of debt to refinance $788 million of maturing debt, to refinance $162 million of higher-cost debt, to reduce short-term borrowing by $278 million and to fund capital investments at the operating companies. These transactions and financings in 2002 and 2001 are detailed in the following table.

Date	*Security*	*Company*	*Net Proceeds (millions)*	*Coupon*	*Use*
Dec. 2002	7-year non-recourse bank loan	TECO Power Services	$30	6%	Refinance Alborada Power Station and general corporate purposes
Nov. 2002	5-year notes	TECO Energy	$352	10.5%	Repay short- and long-term debt, and general corporate purposes
Oct. 2002	Common equity	TECO Energy	$207	—	Repay short-term debt
Aug. 2002	5-year notes	Tampa Electric	$149	5.375%	Repay maturing long-and short-term debt, and general corporate purposes
Aug. 2002	10-year notes	Tampa Electric	$394	6.375%	Repay maturing long-and short-term debt, and general corporate purposes
Jun. 2002	Pollution control bonds	Tampa Electric	$61	5.1%	Refinance higher cost debt
Jun. 2002	Pollution control bonds	Tampa Electric	$86	5.5%	Refinance higher cost debt
Jun. 2002	Common equity	TECO Energy	$346	—	Repay short-term debt, and general corporate purposes
May 2002	5-year notes	TECO Energy	$297	6.125%	Repay maturing short-term debt, and general corporate purposes
May 2002	10-year notes	TECO Energy	$397	7.0%	Repay maturing short-term debt, and general corporate purposes
Jan. 2002	Mandatorily convertible equity units	TECO Energy	$436	9.5%	Repay short-term debt, and general corporate purposes
Oct. 2001	Common equity	TECO Energy	$93	—	General corporate purposes
Sept. 2001	10-year notes	TECO Energy	$206	7.2 %	Repay maturing debt, and general corporate purposes
Jun. 2001	11-year notes	Tampa Electric	$247	6.875%	Repay long- and short-term debt, and general corporate purposes
May 2001	1-year notes	TECO Energy	$399	Variable	Repay short-term debt
May 2001	10-year notes	TECO Energy	$396	7.2%	Repay short-term debt, and general corporate purposes
Apr. 2001	6-year notes	TECO Transport	$111	5.0%	Convert floating rate debt to fixed rate debt
Mar. 2001	Common equity	TECO Energy	$232	—	Repay short-term debt, and general corporate purposes

Off-Balance Sheet Financing

Unconsolidated affiliates in which TPS has a 50% ownership interest or less have non-recourse project debt balances as follows at Dec. 31, 2002. This debt is recourse only to the unconsolidated affiliate, and TECO Energy has no debt payment obligations with respect to these financings. Although TECO Energy is not obligated on the debt, TECO Energy's equity interest in those unconsolidated affiliates and its commitments with respect to those power projects are at risk if those projects are not successfully developed.

Affiliate	*Affiliate Debt Balance (millions)*	*TPS Ownership Interest*
Union & Gila River	$1,175	50%
EEGSA	$ 200	24%
Hamakua	$ 86	50%

The equity method of accounting is used to account for investments in partnership and corporate entities in which TECO Energy or its subsidiary companies do not have either a majority ownership or exercise control. On Jan. 17, 2003, the Financial Accounting Standards Board issued FASB Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*, which requires a new approach in determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as variable interest entities or VIEs. Based on a preliminary review, TECO Energy believes it is reasonably possible that FIN 46 may impact certain unconsolidated affiliates. (See the **Other Accounting Standards – Variable Interest Entities** section.)

In June 2001, TPS and its joint venture partner, Panda, closed on a $2.175 billion syndicated bank financing for the construction of the Union and Gila River power stations. The financing includes $1.675 billion in five-year non-recourse debt (including facilities for letters of credit) and $500 million in equity bridge loans guaranteed by TECO Energy of which $125 million was repaid in 2002. Pricing for the non-recourse segment is 162.5 basis points over LIBOR during the construction period and increases to 175 basis points for year one of operation and 200 basis points for years two and three.

The TPGC debt balance is expected to reach $1.4 billion upon completion of construction of the Union and Gila River power stations in 2003.

In addition, TECO Energy has other debt-related items totaling $23.7 million. These facilities are not included in liabilities on TECO Energy's consolidated balance sheet, but do represent payment obligations of the company.

In March 2001, TPS converted the third-party construction financing for the Hamakua Power Station into a synthetic equipment operating lease with a term of five years. The lessor is an unaffiliated entity.

Critical Accounting Policies and Estimates

The following accounting policies are considered critical in the view of management. These critical accounting policies require that critical estimates be made based on the assumptions and judgment of management. The preparation of consolidated financial statements requires management to make various estimates and assumptions that affect revenues, expenses, assets, liabilities and disclosure of contingencies. The policies and estimates identified below are the more significant accounting policies and estimates used in the preparation of TECO Energy's consolidated financial statements. These estimates and assumptions are based on historical experience and on various other factors that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and judgments under different assumptions or conditions.

See the **Notes to the Consolidated Financial Statements** for a description of TECO Energy's accounting policies and the estimates and assumptions used in the preparation of the **Consolidated Financial Statements**.

Asset Impairments

TECO Energy and its subsidiaries periodically evaluate whether there has been a permanent impairment of an asset as follows:

- Long-lived assets, when indicators of impairment exist, in accordance with Financial Accounting Standard No. (FAS) 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*, and beginning in 2002, with FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*; and
- Recognized goodwill and other intangible assets with indefinite lives, annually in accordance with FAS 142. (See **Goodwill and Other Intangible Assets** section.)

The company believes that the accounting estimate related to asset impairments is a critical estimate for the following reasons: 1) it is highly susceptible to change each reporting period as management is required to make assumptions based on expectations of the results of operations for significant/indefinite future periods and/or the then-current market conditions in such periods; (2) electricity markets continue to experience significant price uncertainty with respect to market fundamentals; 3) the ongoing expectations of management regarding the future use of the asset; and 4) the impact of an impairment on reported assets and earnings would be material. The company's assumptions relating to future results of operations are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities. (See **Notes A, C** and **S** to the **Consolidated Financial Statements**.)

Long-Lived Assets

TECO Energy adopted FAS 144, with no significant impact on earnings, effective Jan. 1, 2001. During the year ended Dec. 31, 2002, the company evaluated certain merchant generation plants for impairment in accordance with FAS 144. The company concluded that the sum of the undiscounted expected future cash flows (excluding interest charges) from each individual plant exceeded the then-current carrying value of the plant. In accordance with FAS 144, the company did not recognize an impairment charge. If an impairment charge were required to be recognized, the amount of the loss would be determined by calculating the difference of the fair value and the then-current carrying value of the asset.

Goodwill and Other Intangible Assets

Prior to 2002, goodwill was amortized each year. As of Dec. 31, 2001, TECO Energy had $166 million of goodwill, net of accumulated amortization of $10 million. The adoption of FAS 142 on Jan. 1, 2002 resulted in the elimination of approximately $5 million of annual amortization. (See **Notes C** and **S** to the **Consolidated Financial Statements**.)

In accordance with the transition provisions of FAS 142, TECO Energy evaluated all reporting units where goodwill is recorded for impairment. Reporting units are generally determined as one level below the operating segment level; however, reporting units with similar characteristics may be grouped under the accounting standard for the purpose of determining the impairment, if any, of goodwill and other intangible assets. For each reporting unit evaluated, the fair value exceeded the carrying value, including goodwill, as of the valuation date, Jan. 1, 2002. During 2002, in accordance with the ongoing requirements of the standard, the company evaluated all reporting units where goodwill is recorded for impairment. The fair value for the reporting units evaluated was generally determined using discounted cash flow models appropriate for the business model of each significant group of assets within each reporting unit. No impairment loss was recorded during 2002 for goodwill or other intangible assets with indefinite lives.

Asset Retirement Obligations

In July 2001, the FASB issued FAS 143, Accounting for Asset Retirement Obligations, which requires the recognition of a liability at fair value for an asset retirement obligation in the period in which it is incurred. Retirement obligations associated with long-lived assets included within the scope of FAS 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are included in the scope of the standard only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its future value. The corresponding amount capitalized at inception is depreciated over the useful life of the asset. The liability must be revalued each period based on current market prices. FAS 143 is effective for fiscal years beginning after June 15, 2002. The company estimates that the adoption of FAS 143 will result in a non-cash increase to net property, plant and equipment of approximately $8 million, a non-cash increase to asset retirement obligation of approximately $10 million, and, as a cumulative effect of change in accounting principle, a non-cash pretax charge of approximately $2 million.

Asset retirement obligations are comprised of significant estimates which, if different, could materially impact the results of TECO Energy. The company believes these are critical estimates because: 1) the fair value of the costs associated with meeting the obligation are impacted by assumptions on discount rates and estimated profit mark-ups by third-party contractors; 2) probability factors associated with the future sale, abandonment or retirement of an asset must be forecasted and considered in the calculations; 3) the expectations and intent of management regarding the future use of long-lived assets; and 4) the impact of the recognition of an asset impairment obligation could be significant. Upon adoption, effective Jan. 1, 2003, TECO Energy and affiliates are maintaining controls and periodically reviewing all new legal arrangements and contractual commitments to ensure that any new potential asset retirement obligations are reviewed and recognized as appropriate. (See **Note A** to the **Consolidated Financial Statements.**)

Unconsolidated Affiliates

The company has investments in unconsolidated affiliates that are accounted for using the equity method of accounting. See the **Other Accounting Standards** section for a detailed discussion of the accounting policies for unconsolidated affiliates, the anticipated impact of the adoption of a new accounting policy (FIN 46)for consolidation of certain legal entities, and critical assumptions and judgments which must be made regarding the application of the accounting policies. (See **Note A** to the **Consolidated Financial Statements.**)

Employee Postretirement Benefits

The company has a funded non-contributory defined benefit retirement plan covering substantially all employees. The company's policy is to fund the plan based on actuarially determined contributions within the guidelines set by the Employee Retirement Income Security Act of 1974, as amended (ERISA), for the minimum annual contribution and the maximum allowable as a tax deduction by the IRS. Plan assets are invested in a mix of equity and fixed income securities. In addition, TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. In addition, the company has unfunded supplemental executive retirement benefit plans—non-qualified, non-contributory defined benefit retirement plans available to certain senior management.

The determination of the benefit expense is a critical estimate due to the following factors: 1) management must make significant assumptions regarding the discount rate, return on assets, rate of salary increases and health care cost trend rates; 2) costs are based on actual employee demographics, including the turnover rate, retirement rate, mortality rate, employment periods, compensation levels and age, each of which are subject to change in any given period; 3) the plan provisions may be changed by management action in future periods; and 4) the impact of changes in any of these assumptions is likely to result in a material impact on the recorded pension obligation and expense. Management reviews these assumptions periodically to reflect the company's actual experience.

The discount rate for pension cost purposes is the rate at which the pension obligations could be effectively settled. At Dec. 31, 2002, the discount rate used for actuarial purposes was 6.75%, as determined by reference to Moody's Aa bond rate as of Sep. 30, 2002. A hypothetical 25 basis point change in the discount rate would impact pension expense by approximately $2 million.

The assumed rate of return on assets is the weighted average of expected long-term asset return assumptions. In selecting an assumed rate of return on plan assets, the company considers past performance and economic forecasts for the types of investments held by the plan. At Dec. 31, 2002 the return on assets used for actuarial purposes was 9%. A hypothetical 25 basis point change in the return on assets would impact pension expense by approximately $1 million.

The assumed health care cost trend rate was 12.5% in 2002 and decreases to 5.0% in 2013 and thereafter. A 100 basis point increase in the trend rate would impact the aggregate service and interest cost by $1.1 million for 2002 and the accumulated postretirement benefit obligation by $9.5 million, and a 100 basis point decrease in the trend rate would impact the aggregate service and interest cost by ($0.5) million for 2002 and the accumulated postretirement benefit obligation by ($5.0) million, as of Sept. 30, 2002. (See **Note K** to the **Consolidated Financial Statements.**)

Derivative Instruments and Hedging

From time to time, TECO Energy enters into derivative instruments to reduce the exposure to market risks. The company does not enter into derivatives for speculative purposes. See the **Quantitative and Qualitative Disclosures About Market Risk** section for a discussion of the accounting policy for derivatives and hedging activities, variables used in estimating the fair value of derivative instruments, assumptions made with respect to forecasted transactions, and a discussion of the strategy and objectives related to the use of energy derivatives to mitigate various exposures to risk and uncertainty. (See **Notes A** and **B** to the **Consolidated Financial Statements.**)

Deferred Income Taxes

TECO Energy uses the liability method in the measurement of deferred income taxes. Under the liability method, the company estimates its current tax exposure and assesses the temporary differences resulting from differing treatment of items, such as depreciation for financial statement and tax purposes. These differences are reported as deferred taxes measured at current rates in the consolidated financial statements. The company assesses the likelihood that deferred tax assets will be recovered from future taxable income and to the extent recovery of some portion or all of the deferred tax asset is not believed to be likely, the company would establish a valuation allowance.

At Dec. 31, 2002, TECO Energy had deferred income tax assets of $340 million attributable primarily to alternative minimum tax credit carryover of Section 29 non-conventional fuels tax credits and property-related items. The carrying value of the company's deferred income tax assets assumes that the company will be able to realize this asset as an offset to future income taxes payable. The company periodically reviews the deferred income tax assets and, to the extent that recovery would be determined to be unlikely, a valuation reserve would be charged to income. The company believes that the accounting estimate related to deferred income taxes, and any related valuation allowance, is a critical estimate for the following reasons: 1) recoverability of future Section 29 non-conventional fuel tax credits is dependent on the generation of sufficient taxable income to use these credits; and 2) administrative actions of the Internal Revenue Service or the U.S. Treasury or changes in law or regulation could eliminate or reduce the availability of Section 29 tax credits. A change in the recoverability of Section 29 tax

credits could have a material impact on reported assets and results of operations. (See **Notes A** and **M** to the **Consolidated Financial Statements.**)

Cost Capitalization

During 2002, TECO Energy devoted resources to the completion and construction of additional generation capacity at Tampa Electric and TPS, extension of the transmission network and enhancement to the system's reliability at Tampa Electric, expansion of the pipeline distribution infrastructure at PGS, normal river barge replacement at TECO Transport and expansion of production capacity at TECO Coal. The cost of additions, including improvements and replacements of property is charged to plant. TECO Energy capitalizes direct costs and certain indirect costs, including the cost of debt and equity capital as appropriate, associated with its construction and retirement activity as prescribed by generally accepted accounting principles and recognized policies prescribed or permitted by the FPSC and/or the FERC. (See the **Regulation** section.)

The amount of capitalized overhead construction costs is based upon analysis of company and affiliate construction activity. Costs are capitalized based on the activity level of resources allocated to construction activities. As a result, the company's net income could be impacted by the manner and timing of the deployment of resources to construction activities. However, total cash flow is not impacted by the allocation of these costs to the various construction or maintenance activities. Due to the magnitude of construction undertakings, fluctuations in net income, as a result of cost capitalization, could be significant. Capitalized costs will be expensed as a component of depreciation when the assets are placed in service. (See **Notes A** and **D** to the **Consolidated Financial Statements.**)

Depreciation Expense

TECO Energy provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage, of depreciable property over its estimated service life. The provision for utility plant in service, expressed as a percentage of the original cost of depreciable property, was 4.2% for 2001 and 2002. The company believes the estimated service life corresponds to the anticipated physical life for most assets. However, the company's estimation of service life is a critical estimate for the following reasons: 1) forecasting the salvage value for long-lived assets over a long timeframe is subjective; 2) changes may take place that could render a technology obsolete or uneconomical; and 3) a change in the useful life of a long-lived asset could have a material impact on reported results of operations and reported assets. Although it is difficult to predict values far into the future, TECO Energy has a long history of actual costs and values that are considered in reaching a conclusion as to the appropriate useful life of an asset. (See **Note A** to the **Consolidated Financial Statements.**)

Regulatory Accounting

Tampa Electric's and PGS' retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the FERC. (See the **Regulation** section.) As a result, the regulated utilities qualify for the application of FAS 71, *Accounting for the Effects of Certain Types of Regulation*. This statement recognizes that the actions of a regulator can provide reasonable assurance of the existence of an asset or liability. Regulatory assets and liabilities arise as a result of a difference between generally accepted accounting principles and the accounting principles imposed by the regulatory authorities. Regulatory assets generally represent incurred costs that have been deferred as they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers from previous collections for costs that are not likely to be incurred.

TECO Energy periodically assesses whether the regulatory assets are probable of future recovery by considering factors such as regulatory environment changes, recent rate orders to other regulated entities in the same jurisdiction, the current political climate in the state, and the status of any pending or potential deregulation legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered by rates. A change in these assumptions may result in a material impact on reported assets and the results of operations. (See **Notes A** and **D** to the **Consolidated Financial Statements.**)

Revenue Recognition

TECO Energy and its subsidiaries recognize revenues, except as discussed below, on a gross basis when the risks and rewards of ownership have transferred to the buyer and the products are physically delivered or services provided. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The determination of the physical delivery of energy sales to individual customers is based on the reading of meters, which occurs on a regular basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading may be estimated and the corresponding unbilled revenue is estimated. Unbilled revenue is estimated each month primarily based on historical experience, customer-specific factors, customer rates, and daily generation volumes, as applicable. These revenues are subsequently adjusted to reflect actual results.

Revenues for regulated activities at Tampa Electric and PGS are subject to the actions of regulatory agencies. (See the **Regulation** section.)

The percentage of completion method is used to recognize revenues for certain transportation services at TECO Transport and for long-term engineering or construction-type contracts at TECO Energy Services (formerly known as TECO BGA and BCH Mechanical). The percentage of completion method requires management to make estimates regarding the distance traveled and/or time elapsed for TECO Transport and total costs and work-in-progress for TECO Energy Services. Revenue is recognized by comparing the estimated current total distance traveled or work completed with the total distance or cost estimate for each project. Each month, revenue recognition and realized profit are adjusted to reflect only the percentage of distance traveled or work completed.

Revenues for energy marketing services at Prior Energy and TECO Gas Services are presented on a net basis in accordance with Emerging Issues Task Force No. (EITF) 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*, to reflect the nature of the contractual relationships with customers and suppliers. Revenues for risk management and merchant power sales at TPS are reported on a gross basis, except for gains or losses related to hedge accounting, which are reported net of the hedged item or transaction.

TECO Energy estimates certain amounts related to revenues on a variety of factors, as described above. Actual results may be different from these estimates. (See the **Note A** to the **Consolidated Financial Statements.**)

Other Accounting Standards

Business Combinations

In June 2001, the FASB issued FAS 141, *Business Combinations*. FAS 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. TECO Energy has applied the provisions of FAS 141 since June 30, 2001 to all business combinations initiated after that date. (See the **Goodwill and Other Intangible Assets** section and **Note S** to the **Consolidated Financial Statements.**)

Lease Accounting Amendment

In April 2002, the FASB issued FAS 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. In addition to rescinding the aforementioned statements, FAS 145 amends FAS 13, *Accounting for Leases*, to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their appli-

cability under changed conditions. The implementation of FAS 145 has not had a significant impact on the company's results.

Exit or Disposal Costs

In July 2002, the FASB issued FAS 146, *Accounting for Costs Associated with Exit or Disposal Activities*, which addresses the accounting for costs under certain circumstances, including costs to terminate a contract that is not a capital lease, costs to consolidate facilities or relocate employees, and termination benefits provided to employees that are involuntarily terminated under the terms of a one-time benefit arrangement that is not an ongoing benefit arrangement or an individual deferred compensation contract. FAS 146 is effective for disposal activities initiated after Dec. 31, 2002 with early adoption allowed.

Gains and Losses on Energy Trading Contracts

On Oct. 25, 2002, the Emerging Issues Task Force issued EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, which eliminates mark-to-market accounting for certain energy trading contracts and changes the presentation of gains and losses for certain derivative contracts. The measurement provisions of the issue are effective for all fiscal periods beginning after Dec. 15, 2002. The net presentation provisions are effective for all financial statements issued after Dec. 15, 2002. In accordance with the recommended transition provisions, TECO Energy reclassified certain amounts in prior periods to present gains and losses on a net basis. (See **Note A** to the **Consolidated Financial Statements.**) The adoption of the measurement provisions is not expected to have a material impact.

Guarantor's Accounting and Disclosure Requirements for Guarantees

In November 2002, the FASB issued FIN 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Guarantees of Indebtedness of Others (an interpretation of FAS No. 5, 57 and 107 and rescission of FAS Interpretation No. 34)*, which modifies the accounting and enhances the disclosure of certain types of guarantees. FIN 45 requires that upon issuance of certain guarantees, the guarantor must recognize a liability for the fair value of the obligation it assumes under the guarantee. FIN 45's provisions for the initial recognition and measurement are to be applied to guarantees issued or modified after Dec. 31, 2002. The disclosure requirements are effective for financial statements of annual periods that end after Dec. 15, 2002. (See **Note R** to the **Consolidated Financial Statements.**)

Stock-Based Compensation

In December 2002, the FASB issued FAS 148, *Accounting for Stock-Based Compensation – Transition and Disclosure*, an amendment of FASB Statement No. 123. This standard amends FAS 123, *Accounting for Stock-Based Compensation*, to provide alternative methods of transition for companies that voluntarily change to the fair value based method of accounting for stock-based employee compensation. It also requires prominent disclosure about the effects on reported net income of the company's accounting policy decisions with respect to stock-based employee compensation in both annual and interim financial statements. The transition provisions and annual disclosure requirements are effective for all fiscal years ending after Dec. 15, 2002, while the interim period disclosure requirements are effective for all interim periods beginning after Dec. 15, 2002. TECO Energy does not anticipate the adoption of the disclosure provisions of this standard to have a material impact. (See **Note I** to the **Consolidated Financial Statements.**)

Variable Interest Entities

The equity method of accounting is used to account for investments in partnership and corporate entities in which TECO Energy or its subsidiary companies do not have either a majority ownership or exercise control. On Jan. 17, 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*, which requires a new approach in determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as variable interest entities or VIEs. A legal entity is considered a VIE if it does not have sufficient equity at risk to finance its own activities without relying on financial support from other parties. If the legal entity is a VIE, then the reporting entity that is the primary beneficiary must consolidate it. Even if a reporting entity is not obligated to consolidate a VIE, then certain disclosures must be made about the VIE if the reporting entity has a significant variable interest. Certain transition disclosures are required for all financial statements issued after Jan. 31, 2003. The on-going disclosure and consolidation requirements are effective for all interim financial periods beginning after Jun. 15, 2003.

The determination of the applicability of FIN 46 is complex and requires management to make significant assumptions related to: 1) the reasonable possibility that an entity may be a VIE in which the company has a significant variable interest at Dec. 31, 2002; 2) the rights, obligations, and activities of all other equity investors in the potential VIE; 3) the anticipated variability in the potential VIE's net income or loss, the fair value of its assets not already included in net income or loss, and certain fees paid to related and unrelated third parties; and 4) the magnitude of the company's variable interest as compared to the variable interests of all other variable interest holders. Each of these assumptions could significantly impact the conclusion of the company to consolidate the legal entity.

Based on a preliminary review, TECO Energy believes it is reasonably possible that FIN 46 may impact certain unconsolidated affiliates. Management is continuing to assess the extent of the relationships and obtain adequate information upon which to base appropriate conclusions. Below is a discussion of the legal entities existing as of Dec. 31, 2002 that the company considers to be possibly subject to either: 1) additional disclosure requirements; or 2) consolidation by the company, in accordance with FIN 46.

TPS entered into a joint venture, TPGC, to build, own and operate the Union and Gila River power stations. As of Dec. 31, 2002, TPGC is a development stage partnership that may meet the definition of a VIE. The third-party debt financing at TPGC is non-recourse and does not create an estimated loss exposure to TECO Energy. The estimated maximum theoretical loss exposure is approximately the current and guaranteed equity investment in the partnership. (See the **TECO Power Services – Construction Activities** section, the **Capital Investments** section, **Project Financing of Unconsolidated Affiliates** section and **Notes A, N** and **R** to the **Consolidated Financial Statements.**)

TPS completed a transaction whereby certain equipment at the Hardee Power Station was sold to a third party (the Lessor) and leased back under an operating lease agreement with an initial term of 12 years. The original cost of the equipment was $46.6 million. The sole purpose of the Lessor is to own and lease back the equipment to Hardee Power. The lease financing arrangement includes $41.6 million of subordinated debt and $1.4 million of equity contributed by an unrelated third party. If the Lessor were to be consolidated, TPS estimates that it would incur after-tax incremental expenses of approximately $9.5 million over the 12-year term of the lease. (See **Note R** to the **Consolidated Financial Statements.**)

TECO Properties formed two limited liability companies with project developers which may meet the definition of a VIE. Hernando Oaks, LLC was formed by TECO Properties with the Pensacola Group to buy and develop a residential community in Hernando County, Florida. Hernando Oaks, LLC had total assets at Dec. 31, 2002 of $18.9 million. TECO Properties' estimated maximum theoretical loss exposure is its equity investment in this project of approximately $9.7 million.

B-T One, LLC is a limited liability company formed by TECO Properties with Boyd Development Co., the project developer, to develop a residential community. B-T One, LLC had total assets at Dec. 31, 2002 of $13.1 million. TECO Properties' estimated maximum theoretical loss exposure is its equity investment in this project of approximately $7.5 million.

TECO Propane Ventures (TPV) has an investment in a partnership formed to combine propane operations with the propane operations of three third-party entities. At Dec. 31, 2002, the estimated maximum theoretical loss exposure faced by TPV is its equity investment of

approximately $35.1 million and $9.5 million of other potential liabilities. (See the **Other Unregulated Companies** section and **Note S** to the **Consolidated Financial Statements**.)

TECO Transport entered into two separate sale-leaseback transactions for certain vessels which were recognized as sales at the time of each transaction, and are currently recognized as operating leases for the assets. The sale-leaseback transactions were entered into with a third party that may meet the definition of a VIE. TECO Transport currently leases two ocean-going tugboats, four ocean-going barges, five river towboats and 49 river barges. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable equipment to meet contractual obligations. (See **Note R** to the **Consolidated Financial Statements**.)

TECO Energy Services formed a partnership to construct, own and operate a water cooling plant to produce and distribute chilled water to customers via a local distribution loop for use, primarily, in air conditioning systems. The partnership may meet the definition of a VIE in accordance with FIN 46. The estimated maximum theoretical loss exposure associated with this partnership is its equity investment of approximately $3.6 million.

In November 2000, TECO Energy established TECO Capital Trust I (Trust I) for the sole purpose of issuing Trust Preferred Securities (TRuPS) and using the proceeds to purchase company preferred securities from TECO Funding Company I, LLC (TECO Funding). Trust I may be a VIE in accordance with FIN 46. TECO Energy has guaranteed the payments to the holders of the company preferred securities and indirectly, the payments to the holders of the TRuPS, as a result of their beneficial interest in the company preferred securities. In January 2002, TECO Energy sold 17.965 million units of mandatorily convertible equity units in the form of 9.5% equity units at $25 per unit. Each equity unit consisted of $25 in principal amount of a trust preferred security of TECO Capital Trust II (Trust II), a Delaware business trust formed for the purpose of issuing these securities and using the proceeds to purchase company preferred securities from TECO Funding Company II, LLC. Trust II may meet the definition of a VIE in accordance with FIN 46. The estimated maximum loss exposure is not expected to be incrementally significant to obligations currently recognized by TECO Energy for activities associated with Trust I or Trust II. (See **Note G** to the **Consolidated Financial Statements**.)

As a result of the conversion of a loan to a Panda subsidiary on Jan. 3, 2003, TPS has an equity interest in the TIE projects. (See the **TECO Power Services — Construction Activities** section.) The estimated maximum theoretical loss exposure is TPS' equity investment of $137 million. (See **Note N** to the **Consolidated Financial Statements**.)

Quantitative and Qualitative Disclosures About Market Risk

Risk Management Infrastructure

TECO Energy and its affiliates are subject to various types of market risk in the course of daily operations, as discussed below. The company has adopted an enterprise-wide approach to the management and control of market and credit risk. Middle Office risk management functions, including credit risk management and risk control, are independent of each transacting entity (Front Office) and report to the Chief Financial Officer of TECO Energy. Front Office functions report to the various operating company presidents responsible for energy transaction activities.

The TECO Energy Risk Management Policy (Policy) governs all energy transacting activity at TECO Energy. The Policy is approved by the TECO Energy Board of Directors and administered by a Risk Authorizing Committee (RAC) that is comprised of senior management, chaired by TECO Energy's Chief Executive Officer (CEO), and advised by the Vice President of Energy Risk Management. Within the bounds of the Policy, the RAC approves specific hedging strategies, new transaction types or products, limits, and transacting authorities. The Policy further requires that, for all merchant generation asset management activities, power sales and gas purchases must be substantially matched, and that the volume of power sales commitments is limited to the volume of owned and available generating capacity. Transaction activity is reported daily and measured against limits. For all other commodity risk management activities, derivative transaction volumes are limited to the anticipated volume for customer sales or supplier procurement activities.

The TECO Energy Authorizing Committee, directed by the CEO of TECO Energy, administers the risk management policy with respect to interest rate risk exposures. Under the policy for interest rate risk management the committee operates and oversees transaction activity. Interest rate derivative transaction activity is directly correlated to borrowing activities.

Risk Management Objectives

The Front Office is responsible for reducing and mitigating the market risk exposures which arise from the ownership of physical assets and contractual obligations, such as merchant power plants, debt instruments and firm customer sales contracts. The primary objectives of the risk management organization, the Middle Office, is to quantify, measure and monitor the market risk exposures arising from the activities of the Front Office and the ownership of physical assets. In addition, the Middle Office is responsible for enforcing the limits and procedures established under the approved risk management policies. Based on the policies approved by the company's Board of Directors and the procedures established by the RAC, from time to time TECO Energy enters into futures, forwards, swaps and option contracts for the following purposes:

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric, PGS, TECO Gas Services and Prior Energy;
- To limit the exposure to interest rate fluctuations on debt issuances at TECO Energy and its other affiliates;
- To limit the exposure to electricity, natural gas and fuel oil price fluctuations related to the operations of natural gas-fired and fuel oil-fired power plants at TPS; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport.

TECO Energy uses derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers. For unregulated operations, the company uses derivative instruments primarily to optimize the value of physical assets, primarily including generation capacity and natural gas delivery.

Derivative and Hedge Accounting

Effective Jan. 1, 2001, TECO Energy adopted FAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as subsequently amended and interpreted. FAS 133 requires TECO Energy and its affiliates to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of other comprehensive income (OCI) or in net income, depending on the designation of those instruments. The effect of the adoption of FAS 133, at Jan. 1, 2001 on continuing operations was not material.

The accounting literature establishes specific criteria and requirements in order to apply hedge accounting. Due to the strict criteria and extensive requirements, certain derivatives do not qualify for hedge accounting, even though the derivative may efficiently and economically reduce the exposure to a particular type of risk. For accounting purposes, a derivative may only be designated as one of the following, resulting in the prescribed treatment in the financial statements:

Non-hedge: derivative must be recorded on the balance sheet at fair value; changes in the fair value of the derivative are recorded as a net gain or loss in earnings.

Cash Flow Hedge: derivative must be recorded on the balance sheet at fair value; changes in the fair value of the derivative are initially recorded in OCI; when the hedged item or anticipated hedged transaction impacts earnings, the current deferred gain or loss recorded in OCI is reclassified to earnings as an offset to the revenue or cost of the hedged item or anticipated hedged transaction.

Fair Value Hedge: derivative must be recorded on the balance sheet at fair value; changes in the fair value of the derivative are recorded in earnings; the hedged item is adjusted on the balance sheet to reflect the change in fair value from the hedge designation date; changes in the fair value of the hedged item are recorded as an offset to the change in fair value of the derivative recorded in earnings.

The designation of a derivative as either a cash flow or fair value hedge is dependent on the effectiveness of the derivative at offsetting the changes in future cash flows or fair value of the designated hedged transaction or item. The majority of the company's derivatives are used to reduce the variability in cash flows for anticipated sales or purchases of energy as a result of subsequent price movements (cash flow hedges). For example, a derivative to purchase natural gas at a fixed price may be designated as a cash flow hedge of the variability of future cash flows associated with an anticipated purchase of natural gas for the same time period. When the forecasted physical purchases of natural gas occurs, the gain or loss on the derivative, which has been deferred in OCI, will be reclassified to the income statement to adjust the actual purchase price to the committed fixed price of natural gas under the derivative instrument. Amounts recorded in OCI related to an effective designated cash flow hedge must be reclassified to current earnings if the anticipated hedged transaction is no longer probable of occurring.

Designation of a hedging relationship requires management to make assumptions about the future probability of the timing and amount of the transaction, and the future effectiveness of the derivative instrument in offsetting the change in fair value or cash flows of the hedged item or transaction. The determination of fair value is dependent upon certain assumptions and judgments. (See **Unregulated Companies** section below, and **Notes A** and **B** to the **Consolidated Financial Statements.**)

Interest Rate Risk

TECO Energy is exposed to changes in interest rates primarily as a result of its borrowing activities. TECO Energy or its affiliates may enter into futures, swaps and option contracts, in accordance with the approved risk management policies and procedures, to moderate this exposure to interest rate changes and achieve a desired level of fixed and variable rate debt. As of Dec. 31, 2002, a hypothetical 10% increase in TECO Energy's weighted average interest rate on its variable rate debt during 2003, as compared to 2002, would not result in a material impact on pretax earnings. Comparatively, as of Dec. 31, 2001 a hypothetical 10% increase in TECO Energy's weighted average interest rate on its variable rate debt and required refinancings during 2002, as compared to 2001, would have resulted in an estimated $3.2 million decrease in pretax earnings. These amounts were determined based on the variable rate obligations existing on the indicated date at TECO Energy and its subsidiaries. The reduction of the sensitivity to hypothetical interest rate movements is due to the amount of variable rate debt outstanding and substantially lower debt maturities. Due to the uncertainty of future events, as discussed in the **Investment Considerations** section, and management's responses to those events, the sensitivities assume no changes to TECO Energy's financing structure. A hypothetical 10% change in interest rates would increase the fair value of long-term debt 5.6 percent at Dec. 31, 2002. A hypothetical 10% change in interest rates would not have a significant impact on the estimated fair value of TECO Energy's long-term debt at Dec. 31, 2001. (See **Financing Activity** section, and **Notes E** and **F** to the **Consolidated Financial Statements.**)

Credit Risk

TECO Energy has adopted a rigorous process for the establishment of new trading counterparties. This process includes an evaluation of each counterparty's financial statements with particular attention paid to liquidity and capital resources, establishment of counterparty-specific credit limits, optimization of credit terms, and execution of standardized enabling agreements. TECO Energy's Credit Guidelines require transactions with counterparties below investment grade to be collateralized. The Credit Guidelines are administered and monitored within the Middle Office, independent of the Front Office.

Financial instability and significant uncertainties relating to liquidity in the entire merchant energy sector have increased the perceived credit risk. Credit exposures for merchant generation activities are calculated, compared to limits and reported to management on a daily basis. Contracts with different legal entities of the same counterparty are consolidated and managed as appropriate, considering the legal structure and any netting agreements in place. Below is a summary of TECO Energy's credit risk exposure on energy contracts related to merchant generation activities at Dec. 31, 2002.

Rating[1]	*Exposure Before Credit Collateral*[2]	*Credit Collateral*[3]	*Net Exposure*	*Number of Counterparties >10%*[4]	*Net Exposure Counterparties >10%*[4]
Investment grade	$13.1	—	$13.1	4	$12.7
Split rating	—	—	—	—	—
Non-investment grade	—	—	—	—	—
No external ratings (internally rated)					
Investment grade	<0.1	—	<0.1	—	—
Non-investment grade	—	2.5	—	—	—
Total	$13.1	$2.5	$13.1	4	$12.7

(1) Ratings are principally determined based on publicly available credit ratings, as determined by independent ratings agencies. If the counterparty has provided a guarantee by a higher rated entity, the assigned rating is that of the guarantor. Included in Investment grade are those counterparties with a minimum S&P or Fitch's rating of BBB- or higher and a Moody's rating of Baa3 or higher.

(2) Exposure before credit collateral includes the fair value of net energy contract assets for open positions and the net account receivable for realized energy contracts. Exposures are offset by a legal counterparty where legally enforceable netting and setoff arrangements are in place.

(3) Credit collateral is required from time-to-time based on contractual provisions and may generally include cash deposits and letters of credit. At Dec. 31, 2002, credit collateral was required from two non-investment grade counterparties. However, TECO EnergySource was not exposed to these counterparties based on the unrealized fair value of the open energy contracts at Dec. 31, 2002.

(4) The number of counterparties that individually, after considering legally enforceable netting arrangements, represent a significant concentration of credit risk (i.e., more than 10% of the total credit exposure) at TECO EnergySource. Also, the combined exposure, less credit collateral, if any, of each significant concentration.

Commodity Risk

TECO Energy and its affiliates face varying degrees of exposure to commodity risks—including coal, natural gas, fuel oil and other energy commodity prices. Any changes in prices could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. The company assesses and monitors risk using a variety of state-of-the-art measurement tools. Management uses different risk measurement and monitoring tools based on the degree of exposure of each operating company to commodity risk.

Regulated Utilities

At Tampa Electric, fuel costs used for generation are currently most affected by the cost of coal. Future fuel costs will be impacted by the cost of natural gas, in addition to coal, as the repowering of the Gannon Station is completed. (See the **Environmental Compliance** section.) PGS is primarily subject to costs for purchased gas and pipeline capacity. Increasing costs for the regulated utilities impact their competitive position in the marketplace versus other energy sources and suppliers.

Currently, Tampa Electric and PGS are subject to relatively little commodity price risk exposure. This is primarily due to the fact that commodity price increases due to changes in market conditions for fuel, purchased power and natural gas are recovered through cost recovery clauses, with no anticipated effect on earnings. Commodity price risk is mitigated by the use of long-term fuel supply agreements, prudent operation of plant facilities to reduce the reliance on purchased power, and derivative instruments designated as cash flow hedges of anticipated

purchases of natural gas. At Dec. 31, 2002 and 2001, a change in commodity prices would not have a material impact on earnings for Tampa Electric or PGS.

Unregulated Companies

Most of the unregulated subsidiaries at TECO Energy are subject to significant commodity risk. These include TECO Coal, TECO Transport, TECO Gas Services, Prior Energy and TPS. The unregulated companies do not speculate using derivative instruments. However, not all derivative instruments receive hedge accounting treatment due to the strict requirements and narrow applicability of the accounting literature to dynamic transactions, as discussed above in the **Derivative and Hedge Accounting** section.

TECO Coal is exposed to commodity price risk through coal sales as a part of its daily operations. Fixed price sales agreements are used, where possible and economical, to mitigate the variability in coal prices. At Dec. 31, 2002 and 2001, a hypothetical 10% change in the average annual market price of coal for each year would have resulted in a decrease to pretax earnings of approximately $5 million and $15 million, respectively.

Fuel price risk exists at TECO Transport as a result of periodic purchases of diesel fuel. Haulage and freight agreements often include fuel price adjustments to transfer the risk of market fuel price movements to the customer. TECO Transport also utilizes derivative instruments to reduce the risk of price variability for anticipated fuel purchases in excess of purchases subject to fuel adjustment clauses. As of Dec. 31, 2002, substantially all of the projected fuel price risk for 2003 was removed via price adjustment clauses and a derivative instrument. As a result, a hypothetical 10% change in the average annual market price of fuel would not result in a material impact on pretax earnings as of Dec. 31, 2002 and would have resulted in an impact to pretax earnings of approximately $1 million as of Dec. 31, 2001.

Prior Energy and TECO Gas Services are exposed to variability in natural gas prices as a result of their commitments to purchase from suppliers and deliver physical natural gas to customers. Prior Energy and TECO Gas Services generally enter into fixed price agreements to provide procurement and fuel optimization services to customers. At the same time, derivative instruments and fixed price purchase agreements from suppliers are used to meet customers' requirements. As a result, a hypothetical change in natural gas prices would not have had a material impact for such operations as of Dec. 31, 2002 and 2001.

Prior Energy also provides hedge management and storage solutions for customers. Derivative instruments are carefully used to reduce or eliminate natural gas price risk associated with these activities. As of Dec. 31, 2002 and 2001, a hypothetical 10% change in natural gas prices would not result in a material impact on earnings.

For TPS, results of operations are impacted primarily by changes in the market prices for electricity and natural gas. The profitability of merchant power plants is heavily dependent on the spread between electric and gas prices (spark spread) in the markets they serve.

The spark spread calculates the relative profitability of converting gas into electricity, which exists as the best indicator of a gas-fired plant's profitability. The variable cost of producing electricity is primarily a function of gas commodity prices and the heat rate of the plant. The heat rate is the measure of efficiency in converting the input fuel into electricity. When the conversion price equals the market price, the spark spread would be zero. A power plant operating at this level would theoretically break even with respect to variable costs.

Wholesale power prices are set by the market assuming a cost for the input energy and conversion efficiency, but the fixed costs are not necessarily reflected in the market-observed spark spread. TPS uses derivative instruments to reduce the commodity price risk exposure of the merchant plants. The commodity price risk of each plant is managed on both a portfolio and asset-specific basis. The following table summarizes the impact of a hypothetical 10% change in commodity prices on the fair value of merchant energy derivative contracts at Dec. 31, 2002 and Dec. 31, 2001.

Sensitivity of the Fair Value of Merchant Energy Derivative Contracts

(millions)	*Dec. 31, 2002*	*Dec. 31, 2001*
Change in Fair Value due to a 10%[1]:		
Decrease in natural gas prices	**$(16.9)**	$ (4.0)
Increase in electricity prices	**(24.4)**	—[2]
Increase in electricity and natural gas prices	**(7.5)**	—[2]

(1) Reflects the fair value associated with merchant energy derivative contracts only. The change shown for the contracts due to price movements would be more than offset by a change in the fair value of the underlying physical plant assets.
(2) No material impact.

Below is a summary of the percentage of merchant plant output and fuel requirements hedged.

Estimated Merchant Plant Hedging Information

	2003	*2004*
Forecasted plant output and fuel requirements hedged	37%	15%

The following tables summarize the changes in and the fair value balances of energy derivative assets (liabilities) for the years ended Dec. 31, 2001 and 2002.

Changes in Fair Value of Energy Derivatives *(millions)*

Net fair value of derivatives as of Dec. 31, 2000	$ (19.0)
Net change in unrealized fair value of derivatives	(29.2)
Changes in valuation techniques and assumptions	—
Realized net settlement of derivatives	21.1
Net fair value of derivatives as of Dec. 31, 2001	(27.1)
Net change in unrealized fair value of derivatives	4.7
Changes in valuation techniques and assumptions	—
Realized net settlement of derivatives	30.8
Net fair value of derivatives as of Dec. 31, 2002	$ 8.4

Roll-Forward of Energy Derivatives Net Assets (Liabilities) *(millions)*

Total energy contracts net assets (liabilities) as of Dec. 31, 2000	$ (19.0)
Change in fair value of net derivative assets (liabilities):	
Recorded in OCI	(1.2)
Recorded in earnings	21.1
Net option premium payments	2.3
Net purchase (sale) of existing contracts	(30.3)
Total energy contracts net assets (liabilities) as of Dec. 31, 2001	(27.1)
Change in fair value of net derivative assets (liabilities):	
Recorded in OCI	4.7
Recorded in earnings	30.8
Net option premium payments	—
Net purchase (sale) of existing contracts	—
Net fair value of derivatives as of Dec. 31, 2002	$ 8.4

When available, the company uses quoted market prices to record the fair value of energy derivative contracts. However, certain energy derivative contracts are not exchange-traded, but rather, are traded in the over-the-counter (OTC) market, through multiple-party on-line trading platforms, or in the bilateral market. TECO Energy uses industry-accepted valuation techniques based on pricing models or matrix pricing for energy derivative contracts when third-party price data is infrequent or not available. Prices, inputs, assumptions and the results of valuation techniques are validated by the Middle Office, independently of the Front Office, on a

daily basis. Significant inputs and assumptions used by the company to determine the fair value of energy derivative contracts are: 1) the physical delivery location of the commodity; 2) the correlation between different basis points and/or different commodities; 3) rational, economic behavior in the markets and by counterparties; 4) on- and off-peak curve shapes and correlations; 5) observed market information; and 6) volatility forecasts for and between commodities. Mathematical approaches are applied on a frequent basis to validate and corroborate the results of valuation calculations.

Below is a summary table of sources of fair value, by maturity period, for energy derivative contracts at Dec. 31, 2002.

Maturity and Source of Energy Derivative Contracts Net Assets(Liabilities) at Dec. 31, 2002

Contracts Maturing in	*2003*	*2004*	*Total fair Value*
Source of Fair Value *(millions)*			
Actively quoted prices	$ 8.7	$ 0.1	$ 8.8
Other external sources[1]	(0.3)	(0.1)	(0.4)
Model Prices[2]	—	—	—
Total	$ 8.4	$—	$ 8.4

(1) Information from external sources includes information obtained from over-the-counter brokers, industry price services or surveys and multiple-party on-line platforms.
(2) Model prices are used for determining the fair value of energy derivatives where price quotes are infrequent or the market is illiquid. Significant inputs to the models are derived from market observable data and actual historical experience.

For all unrealized energy derivative contracts, the valuation is an estimate based on the best available information. Actual cash flows could be materially different from the estimated value upon maturity.

Non-Operating Items Impacting Net Income From Continuing Operations

2002 Items

In 2002, TECO Energy's results included a $3.0-million after-tax charge at TECO Investments related to an aircraft leased to US Airways, which has filed for bankruptcy. Results at TPS include a $5.8-million after-tax asset valuation adjustment for the proposed sale of its interests in generating facilities in the Czech Republic. Results at TECO Energy include a $34.1-million pretax ($20.9-million after-tax) charge related to a debt refinancing.

2001 Items

In 2001, TECO Energy's results included charges to adjust asset valuations totaling $7.2 million after-tax. The adjustments included a $6.1-million after-tax adjustment related to the sale of TPS' minority interests in EGI, which owns smaller power generation projects in Central America, and a $1.1-million after-tax charge related to the sale of leveraged leases at TECO Investments.

2000 Items

In 2000, TECO Energy's results included an $8.3-million after-tax gain from the US Propane and Heritage Propane transactions offset by after-tax charges of $5.2 million to adjust the value of leveraged leases and $3.8 million to adjust property values at TECO Properties.

Discontinued Operations

In September 2002, as a component of its cash raising plans, TECO Energy initiated activities to sell the TECO Coalbed Methane gas assets. That sale was substantially completed in December 2002 to the Municipal Gas Authority of Georgia. Proceeds from the sale were $140 million, of which $42 million was paid in cash at closing and $98 million was paid in January 2003. TECO Coalbed Methane's results are accounted for as discontinued operations for all periods reported.

TECO Coalbed Methane's 2002 net income was $31.4 million including a $7.7-million after-tax net gain on the $42 million portion of the sale proceeds. These results reflect production of 14.2 billion cubic feet (Bcf), compared to 15 Bcf in 2001 at an effective gas price, including the effects of hedging, of about $2.80 per thousand cubic feet (Mcf), an almost 20 percent lower realized price than in 2001.

2001 net income increased as a result of higher gas prices which more than offset naturally declining production. Effective gas prices, including the effects of hedging, increased 33 percent to $3.66 per Mcf and production was 15 Bcf. Effective Jan. 1, 2001, the company had derivatives in place at TECO Coalbed Methane that qualified for cash flow hedge accounting treatment under FAS 133. As a result of the adoption of FAS 133, the company recorded an initial derivative liability of $19.0 million and an after-tax reduction to OCI of $12.6 million.

Production from TECO Coalbed Methane's reserves was eligible for Section 29 non-conventional fuels tax credits through 2002. The credit is estimated to be $1.10 for 2002 and was $1.08 per million Btu in 2001, $1.06 in 2000. This rate escalated with inflation but could be limited by domestic oil prices. In 2002, domestic oil prices would have had to exceed $49 per barrel for this limitation to have been effective. In 2002, TECO Coalbed Methane's Section 29 tax credits were $15.9 million, compared to $16.1 million in 2001.

Other Income (Expense)

In 2002, Other Income (Expense) of $47.2 million included $60.7 million from construction-related and loan agreements with Panda Energy and earnings on the equity investment in EEGSA at TPS, and income from the investment in TPV, partially offset by the $9.4 million pretax ($5.8 million after-tax) asset valuation charge for TPS' proposed sale of its minority interest in generating facilities in the Czech Republic and a $34.1 million ($20.9 million after-tax) pretax charge related to a TECO Energy debt refinancing completed in 2002.

In 2001, Other Income (Expense) of $51.9 million included $27.1 million from construction-related and loan agreements with Panda Energy and earnings on the equity investment in EEGSA at TPS, and income from the investment in TPV, partially offset by a $9.9 million pretax ($6.1 million after-tax) charge for TPS' sale of its minority interest in EGI.

Equity AFUDC at Tampa Electric, which is included in Other Income, was $24.9 million in 2002, $6.6 million in 2001 and $1.6 million in 2000. AFUDC is expected to be about $20 million in 2003 before declining in 2004, primarily reflecting Tampa Electric's growing investment in the Gannon to Bayside repowering. With the conversion of the loan to Panda Energy related to the TIE projects to an ownership interest, (see the **TECO Power Services – Construction Activities** section) the interest income related to these loans will be eliminated in 2003.

Interest Charges

Interest expense was $147.1 million in 2002 compared with $164.0 million in 2001 and $167.6 million in 2000. The decline in 2002 was primarily because of lower short-term debt rates and balances and a favorable settlement with the Internal Revenue Service regarding disputed income tax amounts for which interest had been previously paid, partially offset by higher distributions on preferred securities due to the issuance of mandatorily convertible equity units in January 2002. The slight decrease in 2001 was primarily because of lower short-term debt rates.

Income Taxes

Income taxes decreased in 2002, reflecting greater non-taxable AFUDC equity and a substantial increase in tax credits associated with the production of non-conventional fuels. In 2001 income tax expense decreased, reflecting higher taxable income offset by an increase in tax credits associated with the production of non-conventional fuels. Income tax expense as a percentage of income from continuing operations before taxes was –14.8 percent in 2002, –0.8 percent in 2001 and 11.4 percent in 2000.

The cash payment for federal income taxes, as required by the alternative minimum tax rules, was $71.9 million, $52.4 million and $83.9 million in 2002, 2001 and 2000, respectively.

Total income tax expense was reduced by the Federal tax credit related to the production of non-conventional fuels, under Section 29 of the Internal Revenue Code. This tax credit totaled $107.3 million in 2002, $86.2 million in 2001 and $52.1 million in 2000. These tax credits are generated annually on qualified production at TECO Coal through Dec. 31, 2007, subject to changes in law, regulation or administration that could impact the qualification of Section 29 tax credits.

The tax credit is determined annually and is estimated to be $1.08 for 2002 and was $1.08 per million Btu in 2001 and $1.06 in 2000. This rate escalates with inflation but could be limited by domestic oil prices. In 2002, domestic oil prices would have had to exceed $49 per barrel for this limitation to have been effective.

In 2002, 2001 and 2000, the decreased income tax expense also reflected the impact of increased overseas operations with deferred U.S. tax structures. The decrease related to these deferrals was $8.1 million, $7.2 million and $9.3 million for 2002, 2001 and 2000, respectively.

The income tax effect of gains and losses from the discontinued operations of TECO Coalbed Methane is shown as a component of results from discontinued operations.

Enron Related Matters

TPS has filed a claim in the Enron bankruptcy proceeding associated with the NEPCO "swept cash" (see the **TECO Power Services – Construction Activities** section) for the four projects in the amount of $214 million. This is a gross amount and does not take into account efficiencies in the projects and other similar credits. The bankruptcy judge appointed an examiner in October 2002 to evaluate whether the "swept cash" lost by all NEPCO customers at the time of the bankruptcy can be traced from NEPCO to Enron and then to Enron's use of the funds. That report is expected by the end of the first quarter, and if it is favorable, the judge should require that the amount of the traceable funds be returned to the bankrupt estate of NEPCO. This result would improve significantly TPS' likelihood of recovering most of the cash. Since the appointment of the examiner, TPS and others have filed adversary proceedings in the bankruptcy.

TECO Energy has negotiated an agreement with Enron, pending approval of the Creditors Committee, to settle the previously reported $3.5 million of potential trade payables exposure as a result of the Enron bankruptcy. Action by the Creditors Committee is expected by the end of March 2003. The net financial impact of the agreement is reflected in consolidated net income and no future financial impact is expected.

Environmental Compliance

Consent Decree

Tampa Electric Company, in cooperation with the Environmental Protection Agency (EPA) and the U.S. Department of Justice, signed a Consent Decree which became effective Oct. 5, 2000, and a Consent Final Judgment with the Florida Department of Environmental Protection (FDEP), effective Dec. 7, 1999. Pursuant to these agreements, allegations of violations of New Source Review requirements of the Clean Air Act were resolved, provision was made for environmental controls and pollution reductions, and Tampa Electric began implementing a comprehensive program that will dramatically decrease emissions from the company's power plants.

The emission reduction requirements included specific detail with respect to the availability of the flue gas desulfurization systems (scrubbers) to help reduce sulfur dioxide (SO2), projects for nitrogen oxides (NOx) reduction efforts on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Station to natural gas. When these units are repowered, the station will be renamed the Bayside Power Station and will have total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled electric generation. Tampa Electric anticipates commercial operation for the first repowered Bayside unit by May 1, 2003. The repowering of the second unit is scheduled for completion by May 1, 2004. By May 1, 2005, Tampa Electric must decide whether to install NOx controls, repower, or shutdown Big Bend Unit 4, and it must implement the chosen methodology by Jan. 1, 2007. By May 1, 2007, Tampa Electric will decide whether to install NOx controls, repower, or shutdown Big Bend Units 1, 2 and 3 and it must implement the chosen methodology beginning in 2008. Tampa Electric's capital investment forecast includes amounts in the 2006 and 2007 period for compliance with the NOx reduction requirements.

Emission Reductions

Since 1998, Tampa Electric has reduced annual SO2, NOx, and particulate matter (PM) emissions from its facilities by 105,418 tons, 11,206 tons, and 1,113 tons, respectively.

Reductions in SO2 emissions were primarily accomplished through the installation of scrubber systems on Big Bend Units 1 and 2. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3. Currently, the scrubbers at Big Bend Station remove more than 95 percent of the SO2 emissions from the flue gas streams. In addition, reductions in NOx have been accomplished through combustion tuning and optimization projects at Big Bend and Gannon Stations.

Particulate matter is controlled at Big Bend and Gannon Stations through the use of electrostatic precipitators, which remove more than 99.9 percent of the PM generated during the combustion process.

Significant reductions in emissions outlined in the consent decree and consent final judgment will result from the ongoing repowering of the Gannon to Bayside Power Station and, should Tampa Electric decide to continue to burn coal, the installation of additional NOx emissions controls on all Big Bend Units. By 2010, these projects will result in the additional phased reduction of SO2 by 47,467 tons per year, NOx by 50,488 tons per year, and PM by 1,981 tons per year. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO2, NOx, and PM emissions by 87 percent, 89 percent, and 60 percent, respectively, below 1998 levels. With these improvements in place, Tampa Electric's facilities will meet the same standards required of new power generating facilities and help to significantly enhance the quality of the air in the community.

In November 2000, the FPSC approved recovery, through the Environmental Cost Recovery Clause of costs incurred to improve the availability and removal efficiency for its Big Bend 1, 2 and 3 scrubbers, to reduce PM emissions, and for early NOx emissions reduction projects. The approved cost recovery for these various environmental projects through customers' bills started in January 2001.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2002, Tampa Electric Company has estimated its ultimate financial liability to be approximately $20 million, and this amount has been reflected in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors, or the company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other potentially responsible parties (PRPs) is based on each parties' relative ownership interest in or usage of a site. Accordingly, Tampa Electric Company's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Regulation

Tampa Electric Rate Stabilization Strategy

Tampa Electric's objectives of stabilizing prices from 1996 through 1999 and securing fair earnings opportunities during this period were accomplished through a series of agreements entered into in 1996 with Florida's Office of Public Counsel (OPC) and the Florida Industrial Power Users Group (FIPUG), which were approved by the FPSC. Prior to these agreements, the FPSC approved a plan submitted by Tampa Electric to defer certain 1995 revenues.

In general, under these agreements Tampa Electric was allowed to defer revenues in 1995 and 1996 during the construction of Polk Unit 1 and recognize these revenues in 1997 and 1998 after commercial operation of the unit. Other components of the agreements were a base rate freeze through 1999 and refunds to customers totaling $50 million during the period from October 1996 through December 1998, while Tampa Electric was allowed recovery of the capital costs incurred for the Polk Unit 1 project.

In October 2000, the FPSC staff recommended a refund of $6.1 million for the final year of the agreements. OPC objected to certain interest expenses recognized in 1999 that were associated with prior years' tax positions and used to calculate the amount to be refunded. Following a review by the FPSC staff, the FPSC agreed in December 2000 that the original $6.1 million was to be refunded to customers. In February 2001, OPC protested the FPSC's decision. The FPSC held hearings on the issue in August 2001 and upheld its original decision. In January 2002, the OPC filed a motion with the FPSC asking for reconsideration of its decision, alleging the FPSC relied on erroneous information. This was not granted, and Tampa Electric made refunds of about $6.4 million associated with 1999 in 2002.

Since the expiration of the agreements, Tampa Electric is not under a new stipulation. Therefore, its rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue earning within its allowed ROE range.

Peoples Gas Rate Proceeding

On Jun. 27, 2002, PGS filed a petition with the FPSC to increase its service rates. The requested rates would have resulted in a $22.6 million annual base revenue increase, reflecting a ROE midpoint of 11.75 percent.

On the date of the FPSC hearing, PGS agreed to a settlement with all parties involved, and a final Commission order was granted on Dec. 17, 2002. The company received authorization to increase annual base revenues by $12.05 million. The new rates allow for an 11.25 percent midpoint ROE and a capital structure with 57.43 percent equity and were effective after Jan. 16, 2003.

Cost Recovery Clauses

In September 2002, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery clause rates for the period January through December 2003. In November, the FPSC approved Tampa Electric's requested changes. Accordingly, Tampa Electric's residential customer rate per 1,000-kilowatt hours decreased by $4.26 to $89.68. The rates include projected costs associated with environmental projects required under the EPA Consent Decree and the FDEP Consent Final Judgment. They also reflect natural gas purchases for the company's repowered Bayside Unit 1.

During 2002, PGS' purchased gas adjustment remained stable, as no significant natural gas spikes occurred. The actual purchased gas adjustment rate paid by consumers was significantly lower than the FPSC approved cap. In December 2002, PGS' purchased gas adjustment cap for 2003 was approved as filed.

Utility Competition: Electric

Tampa Electric's retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of self-generation available to larger users of electric energy. Such users may seek to expand their alternatives through various initiatives, including legislative and/or regulatory changes that would permit competition at the retail level. Tampa Electric intends to retain and expand its retail business by managing costs and providing high-quality service to retail customers.

There is presently active competition in Florida's wholesale power markets, increasing largely as a result of the Energy Policy Act of 1992 and related federal initiatives. However, the state's Power Plant Siting Act, which sets the state's electric energy and environmental policy and governs the building of new generation involving steam capacity of 75 megawatts or more, requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits.

In February 2002, the FPSC began holding workshops to discuss suggested changes to an associated rule originally adopted by the FPSC in 1994, requiring investor-owned electric utilities (IOUs) to issue Requests for Proposals (RFP) prior to filing a petition for Determination of Need. The RFP process has been used as a tool to measure the cost-effectiveness of new generation. After a series of workshops, a rule hearing was held in December 2002 and, as a result, the FPSC made modifications to the rule that provide a mechanism for expedited dispute resolution; allow bidders to submit new bids whenever the IOU revises its costs estimates for its self-build option; require IOUs to disclose the methodology and criteria to be used to evaluate the bids; and provide more stringent standards for the IOUs to recover costs overruns in the event the self-build option is deemed the most cost-effective. The new rule will become effective for requests for proposal for applicable capacity additions, prospectively.

Regional Transmission Organization (RTO)

In December 1999, the Federal Energy Regulatory Commission (FERC) issued Order No. 2000, encouraging the development of RTOs. This rule was driven by the FERC's continuing effort to increase open access to transmission facilities in large, regional markets.

The peninsular Florida IOUs made joint RTO filings to the FERC in October and December 2000. In the filing, Tampa Electric agreed with the other Florida IOUs to form an RTO to be known as GridFlorida LLC. GridFlorida would independently control the transmission assets of the filing utilities, as well as other utilities in the region that choose to join. The RTO would be an independent, investor-owned organization that would have control of the planning and operations of the bulk power transmission systems of the utilities within peninsular Florida. In addition, GridFlorida was proposed to be a transmission company that would own transmission assets. Tampa Electric planned to contribute its transmission assets to GridFlorida in exchange for a passive interest.

In March 2001, the FERC conditionally approved GridFlorida. In May 2001, the FPSC decided to investigate whether the peninsular Florida IOUs were prudent in complying with FERC's Order No. 2000. In October 2001, the FPSC ruled that, while the companies were prudent in forming GridFlorida, the FPSC was not satisfied with the transmission-owning features of the GridFlorida filing nor with the proposal that any of the filing utilities transfer ownership of their assets to GridFlorida. Accordingly, the FPSC ordered the companies to develop a new RTO model.

In September 2002, the FPSC issued an order which gave final approval to some aspects of the latest GridFlorida proposal; set some items for further discussion by parties and the FPSC; and set a hearing to address market design. The applicants filed joint testimony that addressed the principles for developing a Florida-specific market design that is consistent with the prin-

ciples identified in the FERC's proposed order on standard market design.

In October 2002, the process was held in abeyance after the OPC filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the IOUs and by approving GridFlorida, they were doing just that. Tampa Electric and the other peninsular IOUs will take varying roles to support the FPSC and their prudence determinations. Oral arguments are expected during the first half of 2003, and a decision by the Supreme Court is not expected until late 2003. All activity in development of GridFlorida has ceased pending the outcome of the case and the resolution of certain issues by the FPSC subsequent to that outcome.

Federal Energy Regulatory Commission (FERC) Restructuring Initiatives

The FERC has increased its focus on creating a more efficient electric industry, and it has begun several key initiatives since its RTO order in late 1999 (see the Regional Transmission Organization section). These include the development of a Standard Market Design (SMD) for electric wholesale markets; standard generator interconnection terms, conditions and pricing; enhanced affiliate standards of conduct; and more comprehensive public information initiatives. The most significant of these initiatives relates to development of a SMD through rulemaking that will provide certain structural changes to how transmission service is provided, accessed and priced. A final rule in this matter is expected sometime in 2003. TECO Energy, through its appropriate operating companies, is active in providing comments on all initiatives and plans to remain active in ensuring its positions are fairly represented. Many of the initiatives being proposed by the FERC would be beneficial both to Tampa Electric and TPS.

TPS Federal and State Regulatory and Legislative Involvement

Along with TECO Energy's active involvement in restructuring initiatives, TPS has been proactively involved in regulatory and legislative forums in the markets in which it competes including Arizona, Texas, Arkansas, Mississippi, and Louisiana. This has included repeal in part and sometimes in total of wholesale and retail deregulation rules and laws in Arizona and Arkansas.

Arizona Public Service (APS), the largest investor-owned electric utility in the state, filed with the Arizona Corporation Commission (ACC) a request for a partial variance from the state's competition rules established in 1999. APS requested that it be exempt from its obligation, beginning on Jan. 1, 2003, to purchase at least 50 percent (about 3,000 MW) of its load requirements through a formal, arms-length, competitive procurement process and sought instead to purchase almost all of its load requirements from its unregulated affiliate, Pinnacle West Energy Corporation (PWEC). APS asserted that, due to the California crisis and the Enron collapse, the competitive wholesale market was not mature or reliable enough to meet its needs, so it should be permitted to execute a 28-year power purchase agreement between itself and PWEC. Tucson Electric Power Company (TEP) filed a similar variance request with the ACC, although it only sought a postponement of the implementation date, not a long-term power purchase agreement with an affiliated entity. The two requests were stayed by the ACC in late April 2002, and a docket was opened to review the future of competition in Arizona. In August 2002, the Commission ordered APS not to divest its current rate-based generating facilities to its affiliate, and to continue to participate in a parallel proceeding to determine what portion of its needs will be competitively bid for delivery beginning in the summer of 2003.

Regarding the competitive procurement process, the ACC Staff held numerous workshops, followed by a hearing in November 2002 to determine the amount and procedures for APS' and TEP's acquisition of their power requirements. TPS has been active in all aspects of the state's proceedings. A final determination is expected during the first quarter of 2003 with the competitive procurement process slated to begin by spring.

During this year's legislative session, the Arkansas Legislature will consider repealing its earlier legislation, which was to initiate retail electric deregulation in Arkansas sometime between October 2003 and October 2005. The incumbent IOUs are advocating a complete repeal of retail deregulation and/or a ten-year postponement of its implementation date. The large consumers and the independent power producers are lobbying for a recommitment to wholesale deregulation in Arkansas, access to the state's transmission grid, and a "pilot" project for large customers to be able to shop for power in the interim. TPS is supporting this approach while also aligning with other independent power producers to analyze the beneficial impacts to ratepayers from implementing a region-wide, security-constrained, economic dispatch, with consideration given for units' efficiency and environmental characteristics, including emissions. This is a strategy for displacing the region's older, less efficient, more polluting generating units so that state-of-the-art, gas-fired, combined-cycle units, such as Union Power Partners, can serve the growing needs of the area. This is a strategy that TPS has advanced at the federal level and other markets it serves.

In Texas, TPS has taken an active role on ERCOT committees, in proceedings at the Public Utility Commission of Texas (PUCT) and in the Legislature, whose session begins in mid-January. Transmission congestion is a major concern in the ERCOT market, and has negatively affected Frontera's ability to economically operate. Several initiatives within the ERCOT committees and at the PUCT are underway to address these ongoing congestion problems.

Frontera appealed specific ERCOT protocols with the PUCT, because of inadequate compensation for ERCOT's high usage levels of Frontera's units during times of regional congestion. Originally, the intent of the protocols was to allow ERCOT to acquire energy and capacity, when only critically necessary and on an infrequent basis from the region's existing generating units. Due to local transmission congestion in the Rio Grande Valley, Frontera was frequently requested by ERCOT to start-up and relieve the region's congestion. Frontera, however was not compensated sufficiently for providing this ancillary service in 2002. The appeal process is underway and is expected to be concluded by the end of the first quarter of 2003.

Transmission Rates

In October 2002, Tampa Electric submitted a FERC filing to change its transmission and ancillary services rates under the company's open access transmission tariff. These rates apply to wholesale transmission users of Tampa Electric's transmission system and do not affect retail service rates. In December, the FERC accepted the filing and set the matter for settlement negotiations and a potential hearing should the settlement process fail. Settlement discussions began in January 2003.

Utility Competition: Gas

Although PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity.

In Florida, gas service is unbundled for all non-residential customers. In November 2000, PGS implemented its "NaturalChoice" program offering unbundled transportation service to all eligible customers. This means that non-residential customers can purchase commodity gas from a third party but continue to pay PGS for the transportation of the gas.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by companies seeking to sell gas directly, by transporting gas through other facilities, thereby bypassing PGS facilities. In response to this competition, various programs have been developed including the provision of transportation services at discounted rates.

In general, PGS faces competition from other energy source suppliers offering fuel oil, electricity and in some cases, propane. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high-quality service to customers.

In March 2000, the City of Lakeland (City) filed suit against PGS and sought a declaration that it had the right to purchase PGS facilities located within the city limits. In October 2002, the City came to the conclusion that it no longer desired to pursue owning the gas utility in Lakeland and agreed to voluntarily dismiss the lawsuit. The City and PGS entered into a new

10-year franchise agreement, similar in terms and conditions to the majority of the agreements PGS has with other municipalities.

Corporate Governance

Recently, legislation, rules and proposed rules and guidelines were issued by the United States Congress, the Securities and Exchange Commission (SEC), the New York Stock Exchange (NYSE) and other interested groups designed to ensure corporate accountability, improve corporate governance and restore investor confidence. In 2002, the NYSE issued proposed standards for listed companies; the SEC issued the requirement that the largest public companies certify quarterly financial reports, one of 18 directives issued from December 2001 through December 2002. Also in 2002, the President signed the Sarbanes-Oxley Act which, among other things, requires certification of financial statements with criminal penalties for filing false statements.

These rules and proposals require independence by the Board of Directors, define committees of the Board of Directors with charters and review processes, require an internal audit function, a code of ethics for senior financial officers, adequate internal controls to detect fraud, adequate training for members of the Board of Directors, increased oversight of financial disclosure by the Audit Committee of the Board, shorter time period to report insider selling of company shares and other important items.

For many years, TECO Energy's Board of Directors has primarily consisted of independent directors, the committee structures recommended in the various proposals were already in place and the company has an effective internal audit function. In addition, the company has had a code of ethics for all officers and employees, and it was expanded to include the Board of Directors in 2002. TECO Energy has always had controls for full and complete financial reporting and disclosure, and in response to the new requirements, they have been formalized and are reviewed for effectiveness quarterly.

TECO Energy's CEO and CFO certified its first and second quarter Reports on Form 10-Q for 2002, all interim Reports on Form 8-K and its Annual Report on Form 10-K for 2001 as required by the SEC in August 2002. The certifications, which contained no exceptions, attested to the accuracy of the reports and was signed following a review by the Audit Committee of the company's Board of Directors. In compliance with the Sarbanes-Oxley Act, certifications of second and third quarter Reports on Form 10-Q have been filed with the SEC.

In addition, the CEO and CFO evaluated the effectiveness of the company's disclosure controls and procedures in conjunction with the filing of quarterly financial statement certifications, as required under the new legislation, and found that the disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the company required to be included in the company's reports. Processes are in place to meet these requirements on a quarterly basis.

Transactions with Related and Certain Other Parties

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests that are reported in TECO Energy's annual proxy statement and Tampa Electric's annual regulatory filings. These transactions, primarily for legal services, were not material for the periods ended Dec. 31, 2002 and 2001. There are no material transactions of this type where the payments are in excess of those that would be paid under an arms-length transaction. TECO Energy has interests in unconsolidated affiliates, which are discussed in the **TECO Power Services**, **Other Unregulated Companies** and **Off-Balance Sheet Financing** sections.

TPS Arkansas Operations Company and TPS Arizona Operations Company, both wholly-owned subsidiaries of TPS, had a combined receivable from Union and Gila River of $0.8 million as of Dec. 31, 2002.

In addition, TPS recognized income on the non-TPS portion of notes receivable from unconsolidated affiliates in which TPS holds joint venture interests and from credit support for the TPGC joint venture (see **Notes A** and **N** to the **Consolidated Financial Statements**). The notes receivable from unconsolidated affiliates include:

($ millions)	*Rate*	*Dec. 31, 2002*	*Dec. 31, 2001*
Notes receivable from:			
Panda Energy	14%	**$ 137.0**	$ 92.7
Energeticke Centrum Kladno	6%	**1.4**	—
Mosbacher Power Partners L.P.	12%	**—**	13.1
Mosbacher Power Partners L.P.	9%	**13.7**	21.1
Mosbacher Power Partners L.P.	12%	**—**	6.2
EEGSA	6.81%(1)	**11.1**	10.9
TPGC - Gila River	7.79%(1)	**369.5**	37.5
TPGC - Union Power	6.58%(1)	**426.3**	86.7

(1) Current rate at Dec. 31, 2002.

TPS' position in the Odessa and Guadalupe power stations in Texas was in the form of a $137 million loan to a Panda Energy International subsidiary, which is a partner in TIE at Dec. 31, 2002. This loan converted into an ownership interest on Jan. 3, 2003. The conversion gives TPS an opportunity to have an effective economic interest estimated at 75 percent of Panda's 50-percent interest in these projects (approximately 1,000 MW) over the life of the projects. TPS is evaluating its options relative to its ownership position in these projects and is targeting to structure its interest in such a manner that it will cover its cash costs in 2003 and mitigate any impact on earnings at TPS in 2003. (See **Strategy and Outlook** section.)

In February 2002, the TPS and Panda affiliates that comprise the joint venture that owns the Union and Gila River projects entered into an arrangement obligating TPS to purchase and Panda to sell Panda's interest in the joint venture in 2007 for $60 million. Panda has the right to cancel the purchase arrangement by paying TPS $20 million or a lesser amount under certain circumstances. The purchase arrangement can result in TPS' purchase of the interest prior to 2007 if Panda defaults on a bank loan made to Panda using the purchase arrangement as collateral or if TECO Energy permits its debt-to-capital ratio to exceed 65.0 percent, permits its EBITDA/interest ratio to fall below 1.5 times or it defaults on the payment of indebtedness in excess of $50 million. TECO Energy's debt-to-capital ratio at Dec. 31, 2002 was 55.9 percent and its EBITDA/interest ratio was 3.6 times.

Investment Considerations

The following are certain factors that could affect TECO Energy's future results. They should be considered in connection with evaluating forward-looking statements contained in this report and otherwise made by or on behalf of TECO Energy because these factors could cause actual results and conditions to differ materially from those projected in those forward-looking statements.

Financing Risks

TECO Energy has substantial indebtedness, which could adversely affect its financial condition and financial flexibility.

In recent years, TECO Energy has significantly expanded its indebtedness. This increase in debt levels has increased the amount of fixed charges TECO Energy is obligated to pay. The level of indebtedness and restrictive covenants contained in its debt obligations could limit its ability to obtain additional financing or refinance existing debt.

Some of TECO Energy's debt obligations contain financial covenants related to debt-to-capital ratios and interest coverage that could prevent the repayment of subordinated debt and the

payment of dividends if those payments would cause a violation of the covenants. (See Covenants in Financing Agreements section.) TECO Energy's failure to comply with any of these covenants, as well as its ratings maintenance covenants discussed below, or to meet its payment obligations, could result in an event of default which, if not cured or waived, could result in the acceleration of other outstanding debt obligations. TECO Energy may not have sufficient working capital or liquidity to satisfy its debt obligations in the event of an acceleration of all or a significant portion of its outstanding obligations. Additionally, such an acceleration would also affect the company's ability to pay dividends. Furthermore, if TECO Energy had to defer interest payments on its subordinated notes that support the distributions on its outstanding trust preferred securities, TECO Energy would be prohibited from paying cash dividends on its common stock until all unpaid distributions on the subordinated notes were made.

TECO Energy also incurs obligations in connection with the operations of its subsidiaries and affiliates, which do not appear on the balance sheet, including in connection with the development of power projects by unconsolidated affiliates. These obligations take the form of guarantees, letters of credit and contractual commitments, as are described in the sections titled **Off-Balance Sheet Financing** and **Liquidity, Capital Resources**. In addition, TECO Energy's unconsolidated affiliates from time to time incur non-recourse debt to finance their power projects. Although TECO Energy is not obligated on that debt, its investments in those unconsolidated affiliates and its commitments with respect to those power projects are at risk if the projects are not successfully developed.

TECO Energy's financial condition and ability to access capital and pay dividends may be materially adversely affected by further ratings downgrades.

In September 2002, Moody's, S&P, Inc. and Fitch, lowered their ratings on the senior unsecured debt securities of TECO Energy.

Those downgrades and any future downgrades may affect TECO Energy's ability to borrow and may increase its financing costs, which may decrease earnings. TECO Energy is also likely to experience greater interest expense than it may have otherwise if, in future periods, it replaces maturing debt with new debt bearing higher interest rate spreads due to its lower credit ratings. In addition, such downgrades could adversely affect TECO Energy's relationships with customers and counterparties.

In addition to affecting the cost of borrowing, lower credit ratings may affect the amount of indebtedness, types of financing structures and debt markets that are available. Finally, TECO Energy's failure to comply with its ratings maintenance covenants could result in an event of default under certain of its debt obligations, which if not cured or waived, could result in the acceleration of other outstanding debt obligations and would affect its ability to pay dividends. (See the **Bank Credit Facilities** and **Covenants in Financing Agreements** sections.)

If TECO Energy is unable to reduce capital expenditures or successfully complete planned asset sales and other transactions to the extent anticipated, its financial condition and results could be adversely affected.

Part of the business plan for 2003 includes reducing previously anticipated capital expenditures by approximately $250 million in order to maximize cash flows and reduce the need for external financings. TECO Energy cannot be sure that it will be successful in achieving reductions in that amount. The business plan also includes the sale of the majority of its interest in facilities that produce synthetic fuel which qualifies for Section 29 tax credits at TECO Coal, and Tampa Electric's Polk Power Station's coal gasification unit. TECO Energy cannot be certain, however, that it will find purchasers or realize the expected value of these transactions with the anticipated impact on its cash flow position. Depending on the success of these planned expenditure reductions and asset sales transactions, TECO Energy may need to seek external financings, which, in the case of debt financings, could adversely affect the balance sheet strength and apply downward pressure on the credit ratings, and, in the case of equity financings, could have a dilutive effect to equity holders and earnings-per-share results.

Because TECO Energy is a holding company, it is dependent on cash flow from its subsidiaries, which may not be available in the amounts and at the times it is needed.

TECO Energy is a holding company and dependent on cash flow from its subsidiaries to meet its cash requirements that are not satisfied from external funding sources. Some subsidiaries have indebtedness containing restrictive covenants which, if violated, would prevent them from making cash distributions to TECO Energy. In particular, Tampa Electric's first mortgage bonds indenture contain restrictions on distributions on its common stock, and certain long-term debt at Tampa Electric's PGS division prohibits payment of dividends to TECO Energy if Tampa Electric Company's consolidated shareholders' equity is not at least $500 million. At Dec. 31, 2002, Tampa Electric's unrestricted retained earnings available for dividends on its common stock were approximately $189 million and its consolidated shareholders' equity was approximately $1.8 billion. Also, TECO Energy's wholly-owned subsidiary, TECO Diversified, the holding company for TECO Transport, TECO Coal and TECO Solutions, has a guarantee related to a coal supply agreement that could limit the payment of dividends to TECO Energy.

TECO Energy is vulnerable to interest rate changes and may not have access to capital at favorable rates, if at all.

Changes in interest rates and capital markets generally affect TECO Energy's cost of borrowing and access to these markets. TECO Energy cannot be sure that it will be able to accurately predict the effect those changes will have on the cost of borrowing or access to capital markets.

Independent Power Project Risks

TPS' existing and planned power plants are affected by market conditions, and it may not be able to sell power at prices that enable it to recover its investments in the plants.

TPS is currently operating, constructing and investing in power plants that do not currently have long-term contracts for the sale of power. These power plants may sell at least a portion of their power based on market conditions at the time of sale, so TPS cannot predict with certainty:

- the amount or timing of revenue it may receive from power sales from operating plants;
- the differential between the cost of operations (in particular, natural gas prices) and power sales revenue;
- the effect of competition from other suppliers of power;
- regulatory actions that may affect market behavior, such as price limitations or bidding rules imposed by the FERC or reimposition of regulation in power markets;
- the demand for power in a market served by its plants relative to available supply;
- the availability of transmission to accommodate the sale of power; or
- whether TPS will recover its initial investment in these plants.

At present, several of the wholesale markets supplied by so-called "merchant" power plants are experiencing significant pricing declines due to excess supply and weak economies. Consequently, only a portion of the projected output of TPS' plants has been hedged for 2003 and 2004. TPS' results could be adversely affected if it is unable to sufficiently sell the output of its plants at a premium to forward curve prices or if TECO Energy needs to write off any capital already invested in projects.

TECO Energy's forecast assumes that TPS will manage these risks by:

- optimizing amongst a mix of forward on-peak energy sales, daily and hourly spot market sales of capacity, energy and ancillary services, and longer-term structured transactions;
- avoiding short positions; and
- retaining flexibility to defer, if and where possible and advisable, construction of output capacity in a market that has become oversupplied.

However, TECO Energy cannot be sure how successfully it will be able to implement these risk management measures. For instance, in oversupplied markets, entering into forward contracts could be difficult.

TPS may be unable to successfully complete and finance current and future projects on schedule and within budget.

TPS currently has new power generating facilities under construction. The construction of these facilities, as well as any future construction projects, involves risks of shortages and inconsistent qualities of equipment and material, labor shortages and disputes, engineering problems, work stoppages, unanticipated cost increases, and environmental or geological problems. In addition, the development of independent power plants involves considerable risks, including successful siting, permitting, financing and construction, contracting for necessary services, fuel supplies and power sales and performance by project partners. Any of these events could delay a project's construction schedule or increase its costs, which may impact TPS' ability to generate sufficient cash flow and service its related non-recourse project debt.

TPS marketing and risk management policies may not work as planned, and it may suffer economic losses despite such policies.

TPS actively manages the market risk inherent in its energy and fuel positions. Nonetheless, adverse changes in energy and fuel prices may result in losses in earnings or cash flows and adversely affect the balance sheet. TPS marketing and risk management procedures may not always be followed or may not work as planned. As a result, it cannot predict with precision the impact that its marketing, trading and risk management decisions may have on its business, operating results or financial position. In addition, to the extent it does not cover the entire exposure of assets or positions to market price volatility, or the hedging procedures do not work as planned, fluctuating commodity prices could cause sales and net income to be volatile.

TPS' marketing and risk management activities also are exposed to the credit risk that counterparties to its transactions will not perform their obligations. Should counterparties to these arrangements fail to perform, TPS may be forced to enter into alternative hedging arrangements, honor underlying commitments at then-current market prices or otherwise satisfy its obligations on unfavorable terms. In that event, its financial results would likely be adversely affected.

General Business and Operational Risks

General economic conditions may adversely affect TECO Energy's businesses.

TECO Energy's businesses are affected by general economic conditions. In particular, the projected growth in Tampa Electric's service area and in Florida is important to the realization of Tampa Electric's and PGS' forecasts for annual energy sales growth. An unanticipated downturn in the local area's or Florida's economy could adversely affect Tampa Electric's or PGS' expected performance.

TECO Energy's unregulated businesses, particularly TECO Transport, TECO Coal and TPS, are also affected by general economic conditions in the industries and geographic areas they serve, both nationally and internationally. TPS' investment in Empresa Eléctrica de Guatemala, S.A. depends on growth in the relevant service areas and in annual energy sales.

Potential competitive changes may adversely affect TECO Energy's gas and electricity businesses.

The U.S. electric power industry has been undergoing restructuring. Competition in wholesale power sales has been introduced on a national level. Some states have mandated or encouraged competition at the retail level and, in some situations, required divestiture of generating assets. While there is active wholesale competition in Florida, the retail electric business has remained substantially free from direct competition. Changes in the competitive environment occasioned by legislation, regulation, market conditions or initiatives of other electric power providers, particularly with respect to retail competition, could adversely affect Tampa Electric's business and its performance.

The gas distribution industry has been subject to competitive forces for several years. Gas services provided by PGS are now unbundled for all non-residential customers. Because PGS earns margins on distribution of gas, but not on the commodity itself, unbundling has not negatively impacted PGS results. However, future structural changes that cannot be predicted could adversely affect PGS.

TECO Energy's gas and electricity businesses, both utility and independent, are highly regulated and any changes in regulatory structures could lower revenues or increase costs or competition.

Tampa Electric, TPS and PGS operate in highly regulated industries. Retail operations, including the prices charged, are regulated by the FPSC, and Tampa Electric's and TPS' wholesale power sales and transmission services are subject to regulation by the FERC. Changes in regulatory requirements or adverse regulatory actions could have an adverse effect on their performance by, for example, increasing competition or costs, threatening investment recovery or impacting rate structure.

TECO Energy's businesses are sensitive to variations in weather and have seasonal variations.

Most of TECO Energy's businesses are affected by variations in general weather conditions and unusually severe weather. Tampa Electric's, PGS' and TPS' energy sales are particularly sensitive to variations in weather conditions. Those companies forecast energy sales on the basis of normal weather, which represents a long-term historical average. Significant variations from normal weather could have a material impact on energy sales. Unusual weather, such as hurricanes, could adversely affect operating costs and sales.

PGS, which has a single winter peak period, is more weather sensitive than Tampa Electric, which has both summer and winter peak periods. Mild winter weather in Florida can be expected to negatively impact results at PGS.

Variations in weather conditions also affect the demand and prices for the commodities sold by TECO Coal, as well as electric power sales from TPS' merchant power plants. TECO Transport is also impacted by weather because of its effects on the supply of and demand for the products transported. Severe weather conditions could interrupt or slow service and increase operating costs of those businesses.

Electric power marketing may be seasonal. For example, in some parts of the country, demand for, and market prices of, electricity peak during the hot summer months, while in other parts of the country such peaks occur in the cold winter months. As a result, power marketing results may fluctuate on a seasonal basis. The pattern of this fluctuation may change depending on the nature and location of the facilities operated and the terms under which they sell electricity.

Commodity price changes may affect the operating costs and competitive positions of TECO Energy's businesses.

Most of TECO Energy's businesses are sensitive to changes in coal, gas, oil and other commodity prices. Any changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services.

In the case of Tampa Electric, currently fuel costs used for generation are mostly affected by the cost of coal. Future fuel costs will be impacted by the cost of natural gas as well as coal. Tampa Electric is able to recover the cost of fuel through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

Regarding wholesale sales of electricity, the ability to make sales and margins on power sales is currently affected by the cost of coal to Tampa Electric, particularly as it compares to the cost of gas and oil to other power producers.

In the case of TPS, results are impacted by changes in the market price for electricity. The profitability of merchant power plants is heavily dependent on the price for power in the mar-

kets they serve. Wholesale power prices are set by the market assuming a cost for the input energy and conversion efficiency, but the fixed costs may not be reflected in the price for spot, or excess power.

In the case of PGS, costs for purchased gas and pipeline capacity are recovered through retail customers' bills, but increases in gas costs affect total retail prices and therefore, the competitive position of PGS relative to electricity, other forms of energy and other gas suppliers.

TECO Energy relies on some transmission and distribution assets that it does not own or control to deliver wholesale electricity as well as natural gas. If transmission is disrupted, or if capacity is inadequate, its ability to sell and deliver power and natural gas may be hindered.

TECO Energy depends on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity and natural gas it sells to the wholesale market, as well as the natural gas it sells and purchases for use in its electric generation facilities. If transmission is disrupted, or if capacity is inadequate, the ability to sell and deliver products and satisfy contractual and service obligations may be hindered.

The FERC has issued regulations that require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, there is the potential that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electric power as desired. TECO Energy cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities in specific markets.

In addition, the independent system operators that oversee the transmission systems in certain wholesale power markets have from time to time been authorized to impose price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the profitability of TECO Energy's wholesale power marketing business.

The uncertain outcome regarding the creation of regional transmission organizations, or RTOs, may impact operations, cash flows or financial condition.

Tampa Electric is continuing to make progress towards the development of its RTO, which would independently control the transmission assets of participating utilities in peninsular Florida. Given the regulatory uncertainty of the ultimate timing, structure and operations of GridFlorida or an alternate combined transmission structure, TECO Energy cannot predict what effect its creation will have on future consolidated results of operations, cash flow or financial condition.

TECO Energy may be unable to take advantage of its existing tax credits.

TECO Energy derives a portion of its net income from Section 29 tax credits related to the production of non-conventional fuels. Although TECO Energy currently plans to sell a significant portion of the production facilities, until and unless TECO Energy successfully does so, the use of these tax credits is dependent on the generation of sufficient taxable income against which to use the credits. TECO Energy's forecast assumes that it will generate sufficient taxable income to use these credits. These credits, and their sale value, could be impacted by or become unavailable due to administrative actions of the Internal Revenue Service or the U.S. Treasury or changes in law, regulation or administration.

Problems with operations could cause TECO Energy to incur substantial costs.

Each of TECO Energy's subsidiaries is subject to various operational risks, including accidents or equipment breakdown or failure and operations below expected levels of performance or efficiency. As operators of power generation facilities, Tampa Electric and TPS could incur problems such as the breakdown or failure of power generation equipment, transmission lines, pipelines or other equipment or processes which would result in performance below assumed levels of output or efficiency. TECO Energy's forecast assumes normal operations and normal maintenance periods for its subsidiaries' facilities.

The international projects and operations of TPS and TECO Ocean Shipping are subject to risks that could result in losses or increased costs.

TPS is involved in several international projects. These projects involve numerous risks that are not present in domestic projects, including expropriation, political instability, currency exchange rate fluctuations, repatriation restrictions, and regulatory and legal uncertainties. TECO Energy's forecast assumes that TPS will manage these risks through a variety of risk mitigation measures, including specific contractual provisions, teaming with strong international and local partners, obtaining non-recourse financing and obtaining political risk insurance where appropriate.

TECO Ocean Shipping is exposed to operational risks in international ports, primarily in the form of its need to obtain suitable labor and equipment to safely discharge its cargoes in a timely manner. TECO Energy's forecast assumes that TECO Ocean Shipping will manage these risks through a variety of risk mitigation measures, including retaining agents with local knowledge and experience in successfully discharging cargoes and vessels similar to those used.

Changes in the environmental laws and regulations to which TECO Energy's regulated businesses are subject could increase costs or curtail activities.

TECO Energy's businesses are subject to regulation by various governmental authorities dealing with air, water and other environmental matters. Changes in compliance requirements or the interpretation by governmental authorities of existing requirements may impose additional costs or require curtailment of some businesses' activities.

Consolidated Financial Statements

Consolidated Balance Sheets

Assets *(millions)* Dec. 31,	2002	2001
Current assets		
Cash and cash equivalents	$ 411.1	$ 108.5
Restricted cash	1.6	1.6
Receivables, less allowance for uncollectibles of $6.6 million and $7.1 million at Dec. 31, 2002 and 2001, respectively	422.7	358.6
Current notes receivable	235.1	92.7
Inventories, at average cost		
Fuel	113.7	87.3
Materials and supplies	96.1	83.2
Prepayments and other current assets	42.9	44.4
Total current assets	1,323.2	776.3
Property, plant and equipment		
Utility plant in service		
Electric	5,054.4	4,861.1
Gas	746.7	699.4
Construction work in progress	1,556.8	897.0
Other property	857.4	865.1
Property, plant and equipment, at original cost	8,215.3	7,322.6
Accumulated depreciation	(2,751.3)	(2,572.0)
	5,464.0	4,750.6
Property held for sale (net)	—	87.6
Total property, plant and equipment (net)	5,464.0	4,838.2
Other assets		
Other investments	845.3	210.4
Investment in unconsolidated affiliates	149.2	172.9
Goodwill	193.7	165.8
Deferred income taxes	340.2	242.0
Regulatory assets	163.2	198.3
Deferred charges and other assets	159.0	159.5
Total other assets	1,850.6	1,148.9
Total assets	$8,637.8	$6,763.4

Liabilities and Capital *(millions)* Dec. 31,	2002	2001
Current liabilities		
Long-term debt due within one year	$ 127.1	$ 788.8
Notes payable	360.5	638.9
Accounts payable	377.4	267.4
Current derivative liability	3.9	33.5
Customer deposits	94.6	86.3
Interest accrued	49.8	35.6
Taxes accrued	95.9	71.7
Total current liabilities	1,109.2	1,922.2
Other liabilities		
Deferred income taxes	495.0	498.7
Investment tax credits	27.5	32.3
Regulatory liabilities	98.1	106.2
Deferred credits and other liabilities	322.9	189.9
Long-term debt, less amount due within one year	3,324.3	1,842.5
Total other liabilities	4,267.8	2,669.6
Preferred securities		
Company preferred securities	649.1	200.0
Capital		
Common equity (400 million shares authorized; 175.8 million and 139.6 million outstanding at Dec. 31, 2002 and 2001, respectively)	175.8	139.6
Additional paid in capital	1,094.5	600.7
Retained earnings	1,413.7	1,298.0
Accumulated other comprehensive (loss) income	(41.2)	(22.4)
Common equity	2,642.8	2,015.9
Unearned compensation	(31.1)	(44.3)
Total capital	2,611.7	1,971.6
Total liabilities and capital	$8,637.8	$6,763.4

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statements of Income

(millions, except per share amounts)	*Year Ended Dec. 31,*	*2002*	*2001*	*2000*
Revenues	Regulated electric and gas (includes franchise fee and gross receipts taxes of $73.8 million in 2002, $71.1 million in 2001 and $59.7 million in 2000)	**$1,867.0**	$1,733.0	$1,635.9
	Unregulated	**808.8**	755.1	587.2
	Total revenues	**2,675.8**	2,488.1	2,223.1
Expenses	Regulated operations			
	Fuel	**312.7**	218.2	201.2
	Purchased power	**202.3**	144.7	124.5
	Cost of natural gas sold	**148.9**	186.4	157.0
	Other	**273.8**	250.0	247.1
	Other operations	**710.4**	689.8	546.9
	Maintenance	**162.1**	151.3	140.0
	Depreciation	**303.4**	288.2	258.0
	Taxes, other than income	**173.2**	161.3	147.9
	Total expenses	**2,286.8**	2,089.9	1,822.6
Income from operations		**389.0**	398.2	400.5
Other income (expense)	Allowance for other funds used during construction	**24.9**	6.6	1.6
	Other income (expense)	**62.4**	38.6	13.9
	Loss on debt refinancing	**(34.1)**	—	—
	Earnings from equity investments	**(6.0)**	6.7	7.7
	Total other income (expense)	**47.2**	51.9	23.2
Interest charges	Interest expense	**147.1**	164.0	167.6
	Distribution on preferred securities	**38.9**	17.0	—
	Allowance for borrowed funds used during construction	**(9.6)**	(2.6)	(0.7)
	Total interest charges	**176.4**	178.4	166.9
Income before provision for income taxes		**259.8**	271.7	256.8
Provision (benefit) for income taxes		**(38.4)**	(2.1)	29.3
Net income from continuing operations		**298.2**	273.8	227.5
Discontinued operations	Income from discontinued operations	**26.1**	21.9	12.6
	Income tax benefit	**(5.8)**	(8.0)	(10.8)
	Total discontinued operations	**31.9**	29.9	23.4
Net income		**$ 330.1**	$ 303.7	$ 250.9
Average common shares outstanding during year	– Basic	**153.2**	134.5	125.9
	– Diluted	**153.3**	135.4	126.3
Earnings per average common share outstanding	From continuing operations – Basic	**$ 1.95**	$ 2.04	$ 1.81
	– Diluted	**$ 1.95**	$ 2.02	$ 1.79
	Net income – Basic	**$ 2.15**	$ 2.26	$ 1.99
	– Diluted	**$ 2.15**	$ 2.24	$ 1.97

Consolidated Statements of Comprehensive Income

(millions)	*Year Ended Dec. 31,*	*2002*	*2001*	*2000*
Net income		**$ 330.1**	$ 303.7	$ 250.9
Other comprehensive (loss) income, net of tax	Foreign currency translation adjustments	**(1.2)**	—	—
	Net unrealized losses on cash flow hedges	**(13.2)**	(19.2)	—
	Minimum pension liability adjustments	**(4.4)**	0.3	2.0
	Other comprehensive (loss) income, net of tax	**(18.8)**	(18.9)	2.0
Comprehensive income		**$ 311.3**	$ 284.8	$ 252.9

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statements of Cash Flows

(millions)	*Year Ended Dec. 31,*	*2002*	*2001*	*2000*
Cash flows from operating activities	Net income	$ 330.1	$ 303.7	$ 250.9
	Adjustments to reconcile net income to net cash from operating activities:			
	Depreciation	303.4	288.2	258.0
	Deferred income taxes	(96.5)	(102.9)	(77.6)
	Investment tax credits, net	(4.8)	(4.9)	(4.8)
	Allowance for funds used during construction	(34.5)	(9.2)	(2.3)
	Amortization of unearned compensation	13.9	9.7	9.2
	Gain on asset sales, pretax	(15.1)	—	(13.6)
	Equity in earnings of unconsolidated affiliates	15.3	(3.1)	(7.6)
	Asset valuation adjustment, pretax	14.1	11.1	14.2
	Deferred recovery clause	72.2	(19.0)	(68.7)
	Refund to customers	(6.4)	—	(13.2)
	Receivables, less allowance for uncollectibles	(64.1)	57.1	(95.5)
	Inventories	(39.4)	(22.8)	7.5
	Taxes accrued	24.1	16.4	17.6
	Interest accrued	14.2	(6.3)	25.5
	Accounts payable	98.3	(51.3)	42.6
	Other	30.9	36.0	44.1
	Cash flows from operating activities	655.7	502.7	386.3
Cash flows from investing activities	Capital expenditures	(1,065.2)	(965.9)	(688.4)
	Allowance for funds used during construction	34.5	9.2	2.3
	Purchase of minority interest	(9.9)	—	(52.6)
	Purchase of business	—	(315.8)	(31.3)
	Net proceeds from sales of assets	103.3	43.2	61.3
	Investment in unconsolidated affiliates	(7.6)	27.6	(7.7)
	Other non-current investments	(715.6)	95.7	(333.4)
	Cash flows from investing activities	(1,660.5)	(1,106.0)	(1,049.8)
Cash flows from financing activities	Dividends	(215.8)	(184.2)	(167.4)
	Common stock	572.6	348.4	18.3
	Purchase of treasury stock	—	—	(29.9)
	Proceeds from long-term debt	1,758.4	1,255.9	394.9
	Repayment of long-term debt	(949.7)	(236.5)	(145.6)
	Net increase (decrease) in short-term debt	(278.4)	(570.0)	395.3
	Issuance of preferred securities	435.6	—	200.0
	Equity contract adjustment payments	(15.3)	—	—
	Cash flows from financing activities	1,307.4	613.6	665.6
	Net increase in cash and cash equivalents	302.6	10.3	2.1
	Cash and cash equivalents at beginning of year	108.5	98.2	96.1
	Cash and cash equivalents at end of year	$ 411.1	$ 108.5	$ 98.2
Supplemental disclosure of cash flow information	Cash paid during the year for			
	Interest (net of amounts capitalized)	$ 160.2	$ 178.1	$ 166.7
	Income taxes	$ 71.9	$ 52.4	$ 83.9

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statements of Common Equity

(millions)	Shares[1]	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Unearned Compensation	Total Common Equity
Balance, Dec. 31, 1999	126.7	$ 132.1	$ 368.9	$(114.8)	$ 1,091.8	$ (5.5)	$ (54.7)	$ 1,417.8
Net income for 2000					250.9			250.9
Other comprehensive income, after tax						2.0		2.0
Common stock issued	1.2	1.2	26.8				(3.9)	24.1
Treasury shares purchased	(1.6)			(29.9)				(29.9)
Cash dividends declared					(167.4)			(167.4)
Amortization of unearned compensation							9.2	9.2
Tax benefits–ESOP dividends and stock options			1.6		1.8			3.4
Performance shares							(3.2)	(3.2)
Balance, Dec. 31, 2000	126.3	133.3	397.3	(144.7)	1,177.1	(3.5)	(52.6)	1,506.9
Net income for 2001					303.7			303.7
Other comprehensive (loss) income, after tax						(18.9)		(18.9)
Common stock issued	13.3	6.3	203.2	144.7			(5.8)	348.4
Cash dividends declared					(184.2)			(184.2)
Amortization of unearned compensation							9.7	9.7
Tax benefits–ESOP dividends and stock options			0.2		1.4			1.6
Performance shares							4.4	4.4
Balance, Dec. 31, 2001	139.6	139.6	600.7	—	1,298.0	(22.4)	(44.3)	1,971.6
Net income for 2002					330.1			330.1
Other comprehensive (loss) income, after tax						(18.8)		(18.8)
Common stock issued	36.2	36.2	544.4				(8.0)	572.6
Cash dividends declared					(215.8)			(215.8)
Amortization of unearned compensation							13.9	13.9
Convertible preferred stock – present value of contract adjustment payments			(53.1)					(53.1)
Tax benefits–ESOP dividends and stock options			2.5		1.4			3.9
Performance shares							7.3	7.3
Balance, Dec. 31, 2002	175.8	$ 175.8	$ 1,094.5	$ —	$ 1,413.7	$ (41.2)	$ (31.1)	$ 2,611.7

The accompanying notes are an integral part of the consolidated financial statements.
(1) TECO Energy had 400 million shares of $1 par value common stock authorized in 2002, 2001 and 2000.

Notes to Consolidated Financial Statements

A. Summary of Significant Accounting Policies

The significant accounting policies for both utility and diversified operations are as follows:

Principles of Consolidation

The consolidated financial statements include the accounts of TECO Energy, Inc. (TECO Energy or the company) and its wholly-owned subsidiaries.

The equity method of accounting is used to account for investments in partnership arrangements in which TECO Energy or its subsidiary companies do not have majority ownership or exercise control.

The proportional share of expenses, revenues and assets reflecting TECO Coalbed Methane's undivided interest in joint venture property is included in the consolidated financial statements. Results of operations for TECO Coalbed Methane are included in discontinued operations.

All significant intercompany balances and intercompany transactions have been eliminated in consolidation.

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles.

Cash Equivalents

Cash equivalents are highly liquid, high-quality investments purchased with an original maturity of three months or less. The carrying amount of cash equivalents approximated fair market value because of the short maturity of these instruments.

Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates are accounted for using the equity method of accounting. At Dec. 31, 2002, these investments included TECO Propane Ventures' (TPV) 38 percent ownership interest in US Propane, TECO Power Services' (TPS) 24 percent ownership interest in Empresa Eléctrica de Guatemala, S.A. (EEGSA), the Guatemalan electric utility, TPS' 50 percent voting interest in the TECO-Panda Generating Company, L.P. (TPGC), TPS' 50 percent ownership interest in the Hamakua Power Station in Hawaii, TECO Energy Services' 50 percent ownership interest in a chiller plant project, TECO Partners' 65 percent ownership interest in Litestream Technologies, a fiber optic cable project, and TECO Properties' 50 percent ownership interest in four real estate projects (See Note T). At Dec. 31, 2001, the investment in unconsolidated affiliates included the US Propane, EEGSA, TPGC, Hamakua and real estate investments.

Summary financial information for TPGC, a development stage enterprise, as of Dec. 31, 2002 and 2001 is presented in the following table. Results from operations were primarily attributable to financing and general administrative costs associated with construction activities.

Summary Financial Information for TPGC

(millions) Dec. 31,	*2002*	*2001*
Current assets	$ 50.1	$ 102.6
Non-current assets	$ 3,117.1	$ 1,854.1
Current liabilities	$ 584.0	$ 372.8
Non-current liabilities	$ 2,732.4	$ 1,686.6

(millions) For the year ended Dec. 31,	*2002*	*2001*
Net revenues	$ 0.7	$ 0.5
Operating loss	$ (22.0)	$ (5.4)
Loss available for allocation to partners	$ (22.0)	$ (5.4)

Other Investments

Other investments, which include longer-term passive investments, at Dec. 31, 2002 and 2001 were as follows:

Other Investments

(millions) Dec. 31,	*Rate*	*Due Date*	*2002*	*2001*
Notes receivable from:				
Panda Energy[1]	14.00%	1/3/03	$ 137.0	$ 92.7
Energeticke Centrum Kladno	6.00%	10/31/10	1.4	—
Mosbacher Power Partners L.P.	12.00%	5/16/02	—	13.1
Mosbacher Power Partners L.P.	9.00%	8/1/08	13.7	21.1
Mosbacher Power Partners L.P.	12.00%	5/16/02	—	6.2
EEGSA	6.81%[2]	9/11/07	11.1	10.9
TECO-Panda Generating Company, L.P.	7.79%[2]	11/30/04	369.5	37.5
TECO-Panda Generating Company, L.P.	6.58%[2]	11/30/04	426.3	86.7
Municipal Gas Authority of Georgia[3]	1.38%	3/31/03	98.1	—
Investment in Energy Center Kladno Generating (ECKG)[4]	—	—	13.6	18.2
Continuing Investments in Leveraged Leases	—	—	9.4	15.6
Other investments	—	—	0.3	1.1
			1,080.4	303.1
Current notes receivable			235.1	92.7
Other non-current investments			$ 845.3	$ 210.4

(1) On Jan. 3, 2003, this note receivable converted to an ownership interest (see Note N).
(2) Current rate at Dec. 31, 2002.
(3) Received payment of this note receivable on Jan. 30, 2003 (see Note U).
(4) 13.35% ownership interest in an electric generating power project in the Czech Republic.

These financial investments have no quoted market prices and, accordingly, a reasonable estimate of fair market value could not be made without incurring excessive costs. However, the company believes by reference to stated interest rates and security description, the fair value of these assets would not differ significantly from the carrying value.

Deferred Credits and Other Liabilities

Other deferred credits primarily include the accrued post-retirement benefit liability, the pension liability, deferred gains and the liability for future contract adjustment payments related to the mandatorily convertible equity securities.

Revenue Recognition

TECO Energy recognizes revenues in accordance with the Securities and Exchange Commission's Staff Accounting Bulletin (SAB) 101, *Revenue Recognition in Financial Statements*. The criteria outlined in SAB 101 are that a) there is persuasive evidence that an arrangement exists; b) delivery has occurred or services have been rendered; c) the fee is fixed and determinable; and d) collectibility is reasonably assured. Except as discussed below, TECO Energy and its subsidiaries recognize revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The regulated utilities' (Tampa Electric Company and Peoples Gas System) retail businesses and the prices charged to customers are regulated by the Florida Public Service Commission (FPSC). Tampa Electric's wholesale business is regulated by the Federal Energy Regulatory Commission (FERC). As a result, the regulated utilities qualify for the application of Financial Accounting Standard No. (FAS) 71, *Accounting for the Effects of Certain Types of Regulation*. See Note D for a discussion of the applicability of FAS 71 to the company. Revenues for certain transportation services at TECO Transport are recognized using the percentage of completion method, which includes estimates of the distance traveled and/or the time elapsed, compared to the total estimated contract.

Revenues for long-term engineering or construction-type contracts at TECO Energy Services (formerly TECO BGA and BCH Mechanical) are recognized on a percentage of completion basis, which includes estimates of the total costs for the project compared to the estimated work progress already completed for the contract. Each month, revenue recognition and realized profit are adjusted to reflect only the percentage of the estimated costs that have been completed.

Revenues for energy marketing operations at Prior Energy and TECO Gas Services are presented on a net basis in accordance with Emerging Issues Task Force No. (EITF), 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent* and EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, to reflect the nature of the contractual relationships with customers and suppliers. As a result, costs netted against revenues were $539.4 million, $105.5 million and $28.4 million, respectively, for 2002, 2001 and 2000.

Revenues and Fuel Costs

Revenues include amounts resulting from cost recovery clauses which provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs for Tampa Electric and purchased gas, interstate pipeline capacity and conservation costs for Peoples Gas System (PGS). These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over-recovery or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. Over-recoveries of costs are recorded as deferred credits, and under-recoveries of costs are recorded as deferred charges.

In 1994, Tampa Electric bought out a long-term coal supply contract which would have expired in 2004 for a lump sum payment of $25.5 million. In February 1995, the FPSC authorized the recovery of this buy-out amount plus carrying costs through the Fuel and Purchased Power Cost Recovery Clause over the 10-year period beginning April 1, 1995. In each of the years 2002, 2001 and 2000, $2.7 million of buy-out costs were amortized to expense.

Certain other costs incurred by the regulated utilities are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed.

The regulated utilities accrue base revenues for services rendered but unbilled to provide a closer matching of revenues and expenses.

Tampa Electric's objectives of stabilizing prices from 1996 through 1999 and securing fair earnings opportunities during this period were accomplished through a series of agreements entered into in 1996 with Florida's Office of Public Counsel (OPC) and the Florida Industrial Power Users Group which were approved by the FPSC. Prior to these agreements, the FPSC approved a plan submitted by Tampa Electric to defer certain 1995 revenues.

In general, under these agreements Tampa Electric was allowed to defer revenues in 1995 and 1996 during the construction of Polk Unit 1 and recognize these revenues in 1997 and 1998 after commercial operation of the unit. Other components of the agreements were a base rate freeze through 1999 and refunds to customers totaling $50 million during the period October 1996 through December 1998 while Tampa Electric was allowed recovery of the capital costs incurred for the Polk Unit 1 project.

In October 2000, the FPSC staff recommended a refund of $6.1 million for the final year of the agreements. OPC objected to certain interest expenses recognized in 1999 that were associated with prior years' tax positions and used to calculate the amount to be refunded. Following a review by the FPSC staff, the FPSC agreed in December 2000 that the original $6.1 million was to be refunded to customers. In February 2001, OPC protested the FPSC's decision. The FPSC held hearings on the issue in August 2001 and upheld its original decision. In January 2002, the OPC filed a motion with the FPSC asking for reconsideration of its decision, alleging the FPSC relied on erroneous information. This was not granted and Tampa Electric made refunds associated with 1999 earnings in 2002. Over the terms of the agreements, the company refunded in total about $69 million.

Since the expiration of the agreements, Tampa Electric is not under a new stipulation. Therefore its rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue earning within its allowed ROE range.

On June 27, 2002, PGS filed a petition with the FPSC to increase its service rates. The requested rates would have resulted in a $22.6 million annual base revenue increase, reflecting a ROE midpoint of 11.75 percent.

On the date of the FPSC hearing, PGS agreed to a settlement with all parties involved, and a final FPSC order was granted on Dec. 17, 2002. PGS received authorization to increase annual base revenues by $12.05 million. The new rates allow for an ROE range of 10.25 to 12.25 percent with an 11.25 percent midpoint ROE and a capital structure with 57.43 percent equity. The increase went into effect on Jan. 16, 2003.

Purchased Power

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. For the years ended Dec. 31, 2002, 2001 and 2000, Tampa Electric purchased power of $202.3 million, $144.7 million and $124.5 million, respectively. These purchased power costs are recoverable through an FPSC-approved cost recovery clause.

TPS, through its wholly-owned subsidiary, Hardee Power Partners (Hardee), has agreements with Seminole Electric Cooperative and Tampa Electric to supply all the power and capacity of its Hardee Power Station for 20 years beginning in 1993. Under the Seminole agreement, Hardee agreed to supply Seminole with an additional 145 megawatts of capacity during the first 10 years of the contract, which ended on Dec. 31, 2002. This additional capacity was purchased

from Tampa Electric's Big Bend Unit 4 for resale to Seminole. To meet other firm commitment contracts, TPS' merchant plants may also purchase power from time to time. Total unregulated purchased power for 2002, 2001 and 2000 was $51.3 million, $34.0 million and $30.1 million, respectively.

Planned Major Maintenance

TECO Energy accounts for planned maintenance projects by expensing the costs as incurred. Planned major maintenance projects that do not increase the overall life or value of the related assets are expensed. When the major maintenance materially increases the life or value of the underlying asset, the cost is capitalized. While normal maintenance outages covering various components of the plants generally occur on at least a yearly basis, major overhauls occur less frequently.

Tampa Electric expenses major maintenance costs as incurred. Concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with FPSC and FERC regulations.

At TPS, each of the San José and Alborada plants in Guatemala has a long-term power purchase agreement (PPA) with EEGSA. A major maintenance revenue recovery component is implicit in the capacity payment portion of the PPA for each plant. Accordingly, a portion of each monthly fixed capacity payment is deferred to recognize the portion that reflects recovery of future planned major maintenance expenses. Actual maintenance costs are expensed when incurred with a like amount of deferred recovery revenue recognized at the same time. All other TPS operating projects expense major maintenance costs when incurred.

Depreciation

TECO Energy provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage, of depreciable property over its estimated service life. The provision for utility plant in service, expressed as a percentage of the original cost of depreciable property, was 4.2% for 2002 and 2001, and 4.1% for 2000.

The original cost of utility plant retired or otherwise disposed of and the cost of removal less salvage are charged to accumulated depreciation.

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

TECO Coal and TECO Transport incur most of TECO Energy's total excise taxes, which are accrued as an expense and reconciled to the actual cash payment of excise taxes. As general expenses, they are not specifically recovered through revenues. Excise taxes paid by the regulated utilities are not material and are expensed when incurred.

The regulated utilities are allowed to recover certain costs incurred from customers through prices approved by the regulatory process. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statement of Income. These amounts totaled $73.8 million, $71.1 million and $59.7 million, respectively, for 2002, 2001 and 2000. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statement of Income in Taxes, other than income. For 2002, 2001 and 2000 these totaled $73.7 million, $71.0 million and $59.8 million, respectively.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2002, 2001 and 2000. Total AFUDC for 2002, 2001 and 2000 was $34.5 million, $9.2 million, and $2.3 million, respectively. The base on which AFUDC is calculated excludes construction work in progress which has been included in rate base.

Interest Capitalized

Interest costs for the construction of non-utility facilities are capitalized and depreciated over the service lives of the related property. TECO Energy capitalized $63.2 million, $23.0 million and $6.5 million of interest costs in 2002, 2001 and 2000, respectively.

Deferred Income Taxes

TECO Energy utilizes the liability method in the measurement of deferred income taxes. Under the liability method, the temporary differences between the financial statement and tax bases of assets and liabilities are reported as deferred taxes measured at current tax rates. Tampa Electric and PGS are regulated, and their books and records reflect approved regulatory treatment, including certain adjustments to accumulated deferred income taxes and the establishment of a corresponding regulatory tax liability reflecting the amount payable to customers through future rates.

Investment Tax Credits

Investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property.

Asset Impairments

Effective Jan. 1, 2002, TECO Energy and its subsidiaries adopted FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which supersedes FAS 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*. FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a segment of a business.

The company periodically assesses whether there has been a permanent impairment of its long-lived assets and certain intangibles held and used by the company, in accordance with FAS 144, and prior to 2002 with FAS 121.

TECO Energy recorded after-tax charges of $8.8 million, $7.2 million and $9.0 million in 2002, 2001 and 2000, respectively, to adjust asset valuations (see Note L).

Reporting on the Costs of Start-up Activities

In 1998, the AICPA issued Statement of Position (SOP) 98-5, *Reporting on the Costs of Start-up Activities*. It requires costs of start-up activities and organization costs to be expensed as incurred. Start-up activities are broadly defined as those one-time activities related to events such as opening a new facility, conducting business in a new territory and organizing a new entity. Some costs, such as the costs of acquiring or constructing long-lived assets and bringing them into service, are not subject to SOP 98-5. Start-up costs, as defined by SOP 98-5, are expensed as incurred.

Foreign Operations

The functional currency of the company's foreign investments is primarily the U.S. dollar. Transactions in the local currency are remeasured to the U.S. dollar for financial reporting purposes. The aggregate remeasurement gains or losses included in net income in 2002, 2001 and 2000 were not significant.

The investments are generally protected from any significant currency gains or losses by the terms of the power sales agreements and other related contracts, in which payments are defined in U.S. dollars.

Restrictions on Dividend Payments and Transfer of Assets

Dividends on TECO Energy's common stock are at the discretion of its Board of Directors. Should TECO Energy exercise its right to defer payments on its subordinated notes issued in connection with the issuance of trust preferred securities by TECO Capital Trust I or TECO Capital Trust II, TECO Energy would be prohibited from paying cash dividends on its common

stock until the unpaid distributions on the subordinated notes are made. TECO Energy has not exercised that right. In addition, TECO Energy's $380 million note indenture contains covenants which would apply only if either 1) notes are rated below BBB- by Standard & Poor's (S&P) or below Baa3 by Moody's or 2) notes are rated below Special Ratings Trigger (minimum of BBB- by S&P and Baa2 by Moody's or BBB by S&P and Baa3 by Moody's) if TECO Energy construction undertakings for the TECO/Panda projects are not discharged. These covenants include limitation on restricted payments, limitations on certain liens and limitation on indebtedness.

The primary sources of funds to pay dividends on TECO Energy's common stock are dividends from its operating companies. Tampa Electric's first mortgage bond indenture and certain long-term debt at PGS contain restrictions that limit the payment of dividends on the common stock of Tampa Electric. Tampa Electric's first mortgage bond indenture does not limit loans or advances. In addition, TECO Diversified, Inc., a wholly-owned subsidiary of TECO Energy and the holding company for TECO Transport, TECO Coal, TECO Coalbed Methane and TECO Solutions, has a guarantee related to a coal supply agreement that limits the payment of dividends to its common shareholder, but does not limit loans or advances. As of Dec. 31, 2002 and 2001, the balances restricted as to transfers to the parent company in the form of loans, advances or cash dividends were less than 25 percent of consolidated common equity. (See Note R.)

Lease Accounting Amendment

In April 2002, the Financial Accounting Standards Board (FASB) issued FAS 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. In addition to rescinding the aforementioned statements, FAS 145 amends FAS 13, *Accounting for Leases*, to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The implementation of FAS 145 has not had a significant impact on the company's results.

Reclassifications

Certain prior year amounts were reclassified to conform with current year presentation.

B. Derivatives and Hedging

From time to time, TECO Energy enters into futures, forwards, swaps and option contracts for the following purposes:

- To hedge the selling price for the physical production of natural gas at TECO Coalbed Methane;
- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric, PGS and Prior Energy;
- To limit the exposure to interest rate fluctuations on debt issuances at TECO Energy and its other affiliates;
- To limit the exposure to electricity, natural gas and fuel oil price fluctuations related to the operations of natural gas-fired and fuel oil-fired power plants at TPS; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport.

TECO Energy uses derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers. For unregulated operations, the company uses derivative instruments primarily to optimize the value of physical assets, including generation capacity, natural gas production, and natural gas delivery.

The risk management policies adopted by TECO Energy provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operating companies.

Effective Jan. 1, 2001, the company adopted FAS 133, *Accounting for Derivative Instruments and Hedging Activities*. The new standard requires companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of other comprehensive income (OCI) or in net income, depending on the designation of those instruments. The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or the loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of its reclassification. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the amount paid or received on the underlying physical transaction. Additionally, amounts defined in OCI related to an effective designated cash flow hedge must be reclassified to current earnings if the anticipated hedged transaction is no longer probable of occurring. At adoption, the company had derivatives in place at TECO Coalbed Methane that qualified for cash flow hedge accounting treatment under FAS 133, and recorded an opening swap liability of $19.0 million and an after-tax reduction to OCI of $12.6 million.

At Dec. 31, 2002, the company had derivative assets totaling $12.5 million and liabilities totaling $4.1 million. At Dec. 31, 2001, the company had derivative assets totaling $9.9 million and liabilities totaling $37.0 million. At Dec. 31, 2002 and 2001, accumulated OCI included $32.4 million and $19.2 million, respectively, of unrealized after-tax losses, representing the fair value of cash flow hedges whose transactions will occur in the future, including an unrealized loss of $37.3 million and $11.2 million for 2002 and 2001, respectively, on an equity investee's interest rate swap and other fuel hedges designated as cash flow hedges. Amounts recorded in OCI reflect the value of derivative instruments designated as hedges, based on market prices as of the balance sheet date. These amounts are expected to fluctuate with movements in market prices and may or may not be realized as a loss upon future reclassification from OCI.

As of Dec. 31, 2002, TECO Energy had transactions in place to hedge commodity price risk and interest rate risk that qualify for cash flow hedge accounting treatment under FAS 133. During 2002, TECO Energy reclassified net pretax losses of $29.0 million to earnings for cash flow hedges, compared to pretax losses of $19.7 million in 2001. Amounts reclassified from OCI were primarily related to cash flow hedges of physical purchases of natural gas and physical sales of electricity. For these types of hedge relationships, the loss on the derivative, reclassified from OCI to earnings, is offset by the reduced expense arising from lower prices paid for spot purchases of natural gas. Conversely, reclassification of a gain from OCI to earnings is offset by the increased cost of spot purchases of natural gas.

As a result of 1) the suspension of construction on the Dell and McAdams power plants at TPS, and 2) the maintenance activity on the Frontera Power Station at TPS in early 2003, the company discontinued hedge accounting for purchases of natural gas and sales of electricity which are no longer anticipated to take place within two months of the originally designated time period for delivery. The discontinuation of hedge accounting resulted in a reclassification of a pretax gain of $0.2 million from OCI to earnings, reflecting the fair value of the related derivatives as of the discontinuation date. This gain is included in the net pretax loss reported above for 2002. Gains and losses on these derivative instruments subsequent to the discontinuation of hedge accounting treatment were recorded in earnings.

Based on the fair values at Dec. 31, 2002, pretax gains of $7.1 million are expected to be reversed from OCI to the Consolidated Statement of Income within the next twelve months. However, these gains and other future reclassifications from OCI, will fluctuate with movements in the underlying market price of the derivative instruments. Excluding interest rate risk exposures, the company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2004.

At Dec. 31, 2002 and 2001, TECO Energy had transactions in place to hedge gas storage inventory that qualify for fair value hedge accounting treatment under FAS 133. During 2002,

the company recognized pretax gains of $0.7 million compared to $0.1 million in 2001. For the years ended Dec. 31, 2002 and 2001, the company also recognized pretax losses of $2.4 million and $1.5 million, respectively, relating to derivatives that do not qualify for cash flow or fair value hedge treatment that are marked to market.

C. Goodwill and Other Intangible Assets

Effective Jan. 1, 2002, TECO Energy and its subsidiaries adopted FAS 141, *Business Combinations*, and FAS 142, *Goodwill and Other Intangible Assets*. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting. With the adoption of FAS 142, goodwill is no longer subject to amortization. Rather, goodwill is subject to an annual assessment for impairment by applying a fair-value-based test. Under the new rules, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented, or exchanged, regardless of the acquiror's intent to do so. These intangible assets are required to be amortized over their useful lives.

The amount of goodwill included on the consolidated balance sheets at Dec. 31, 2002 and 2001 was $193.7 million and $165.8 million, respectively, net of accumulated amortization of $9.5 million. Amortization of goodwill ceased effective Jan. 1, 2002 with the adoption of FAS 142, resulting in savings of approximately $5 million of annual amortization expense. Results for 2001 and 2000 included $4.8 million and $2.7 million of goodwill amortization expense, respectively.

The amount of intangible assets included in deferred charges and other assets on the Consolidated Balance Sheet at Dec. 31, 2002 was $11.1 million, which is net of accumulated amortization of $35.4 million, and at Dec. 31, 2001 was $28.5 million, which was net of accumulated amortization of $12.3 million. Amortizable intangible assets of $4.4 million at Dec. 31, 2002 represent customer backlog and supply agreements related to the Prior Energy acquisition in November 2001. The company is amortizing these intangibles over the current year period. Amortization expense of $23.1 million and $12.3 million, respectively, was recorded in 2002 and 2001. There were no intangible assets at Dec. 31, 2000. Unamortizable intangible assets of $6.7 million at Dec. 31, 2002 represent licenses held by TPS related to gasification technologies.

TECO Energy continues to review recorded goodwill and intangibles as required under FAS 142, and has not identified any impairments. The reconciliation of reported net income and earnings per share to adjusted net income excluding goodwill amortization expense for 2002, 2001 and 2000 follows:

Pro Forma Effect of FAS 142 Adoption

(millions, except per share amounts)	*2002*	*2001*	*2000*
Net income:			
As reported	$330.1	$303.7	$250.9
Add: Goodwill amortized, net of tax	—	3.7	2.4
Adjusted net income	$330.1	$307.4	$253.3
Earnings per share – basic:			
As reported	$ 2.15	$ 2.26	$ 1.99
Add: Goodwill amortized, net of tax	—	.03	.02
Adjusted basic earnings per share	$ 2.15	$ 2.29	$ 2.01
Earnings per share – diluted:			
As reported	$ 2.15	$ 2.24	$ 1.97
Add: Goodwill amortized, net of tax	—	.03	.02
Adjusted diluted earnings per share	$ 2.15	$ 2.27	$ 1.99

D. Regulatory Assets and Liabilities

Tampa Electric and PGS maintain their accounts in accordance with recognized policies of the FPSC. In addition, Tampa Electric maintains its accounts in accordance with recognized policies prescribed or permitted by the FERC. These policies conform with generally accepted accounting principles in all material respects.

Tampa Electric and PGS apply the accounting treatment permitted by FAS 71, *Accounting for the Effects of Certain Types of Regulation*. Areas of applicability include: deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel; purchased power, conservation and environmental costs; and deferral of costs as regulatory assets when cost recovery is ordered over a period longer than a fiscal year, to the period that the regulatory agency recognizes them. Details of the regulatory assets and liabilities as of Dec. 31, 2002 and 2001 are presented in the following table:

Regulatory Assets and Liabilities

(millions) Dec. 31,		*2002*	*2001*
Regulatory assets:	Regulatory tax asset [1]	$ 54.9	$ 41.3
	Other:		
	Cost recovery clauses	34.7	105.2
	Coal contract buy-out [2]	5.4	8.1
	Unamortized refinancing costs [3]	35.9	13.7
	Environmental remediation	20.3	22.3
	Competitive rate adjustment	7.4	5.9
	Other	4.6	1.8
		108.3	157.0
Total regulatory assets		$163.2	$198.3
Regulatory liabilities:	Regulatory tax liability [1]	$ 36.6	$ 43.1
	Other:		
	Deferred allowance auction credits	2.1	1.1
	Cost recovery clauses	2.2	0.5
	Revenue refund	—	6.3
	Environmental remediation	20.3	22.3
	Transmission and distribution storm reserve	36.0	32.0
	Deferred gain on property sales [4]	0.9	0.9
		61.5	63.1
Total regulatory liabilities		$ 98.1	$106.2

(1) Related primarily to plant life. Includes excess deferred taxes of $20.9 million and $24.6 million as of Dec. 31, 2002 and 2001, respectively.

(2) Amortized over a 10-year period ending December 2004.

(3) Unamortized refinancing costs:

Related to debt transactions as follows *(millions)*:	Amortized until:
$155.0	2003
$51.6	2005
$22.1	2007
$25.0	2011
$50.0	2011
$150.0	2012
$150.0	2012
$85.9	2014
$25.0	2021
$100.0	2022

(4) Amortized over a 5-year period with various ending dates

E. Long-Term Debt *(millions)* *Dec. 31,*

		Due	2002	2001
TECO Energy	Notes: 5.31% for 2001[1]	2002	$ —	$ 200.0
	Notes: 7.2% (effective rate of 7.38%)[2]	2011	600.0	600.0
	Floating rate notes: 5.2% for 2001[1]	2002	—	400.0
	Notes: 6.125%(effective rate of 6.31%)[2]	2007	300.0	—
	Notes: 7%(effective rate of 7.08%)[2]	2012	400.0	—
	Notes: 10.5%(effective rate of 12.29%)[2]	2007	380.0	—
			1,680.0	1,200.0
Tampa Electric	First mortgage bonds (issuable in series):			
	7.75% (effective rate of 7.96%)	2022	75.0	75.0
	6.125% (effective rate of 6.61%)	2003	75.0	75.0
	Installment contracts payable[3]:			
	5.75%	2002	—	22.5
	7.875% Refunding bonds[4]	2002	—	25.0
	8% Refunding bonds[5]	2002	—	100.0
	6.25% Refunding bonds (effective rate of 6.81%)[6]	2034	86.0	86.0
	5.85% (effective rate of 5.88%)	2030	75.0	75.0
	5.1% Refunding bonds (effective rate of 5.78%)[6]	2013	60.7	—
	5.5% Refunding bonds (effective rate of 6.35%)[6]	2023	86.4	—
	4% for 2002 (effective rate of 4.21%) and variable rate of 1.45% for 2001[1][7]	2025	51.6	51.6
	4% for 2002 (effective rate of 4.16%) and variable rate of 1.47% for 2001[1][7]	2018	54.2	54.2
	4.25% for 2002 (effective rate of 4.43%) and variable rate of 1.52% for 2001[1][7]	2020	20.0	20.0
	Notes: 5.86%[1]	2002	—	100.0
	Notes: 6.875% (effective rate of 6.98%)[2]	2012	210.0	210.0
	Notes: 6.375% (effective rate of 7.34%)[2]	2012	330.0	—
	Notes: 5.375% (effective rate of 5.58%)[2]	2007	125.0	—
			1,248.9	894.3
Peoples Gas System	Senior Notes[8]			
	10.35%	2007	4.2	5.0
	10.33%	2008	5.6	6.4
	10.3%	2009	7.2	7.8
	9.93%	2010	7.4	8.0
	8%	2012	25.4	27.5
	Notes: 5.86%[1]	2002	—	50.0
	Notes: 6.875% (effective rate of 6.98%)[2]	2012	40.0	40.0
	Notes: 6.375% (effective rate of 7.34%)[2]	2012	70.0	—
	Notes: 5.375% (effective rate of 5.58%)[2]	2007	25.0	—
			184.8	144.7
Diversified companies	Dock and wharf bonds, 5%[9]	2007	110.6	110.6
	Non-recourse secured facility notes, Series A: 7.8%	2003-2012	111.0	118.5
	Non-recourse secured facility notes: 9.875%	2002	—	17.1
	Non-recourse secured facility notes, variable rate: 4.63% for 2002 and 5.43% for 2001[1]	2003-2007	50.1	57.9
	Non-recourse secured facility notes: 10.1%	2003-2009	16.4	16.9
	Non-recourse secured facility notes: 9.629%	2003-2010	24.8	28.0
	Non-recourse secured facility note, variable rate: 6.88% for 2002[1]	2004-2009	16.0	—
	Non-recourse secured facility note, variable rate: 5% for 2002 [1]	2004-2009	14.0	—
	Capital lease: implicit rate of 8.5%	2003	25.3	27.6
			368.2	376.6
TECO Finance	Medium-term notes payable: 7.54% for 2001[10]	2002	—	9.0
	Unamortized debt premium (discount), net		(30.5)	6.7
			3,451.4	2,631.3
	Less amount due within one year[9]		127.1	788.8
Total long-term debt			$3,324.3	$1,842.5

(1) Composite year-end interest rate.
(2) These notes are subject to redemption in whole or in part, at any time, at the option of the company.
(3) Tax-exempt securities.
(4) Proceeds of these bonds were used to refund bonds with interest rates of 11.625%–12.625%. For accounting purposes, interest expense has been recorded using blended rates of 8.28%–8.66% on the original and refunding bonds, consistent with regulatory treatment.
(5) Proceeds of these bonds were used to refund bonds with an interest rate of 9.9% in February 1995. For accounting purposes, interest expense has been recorded using a blended rate of 6.52% on the original and refunding bonds, consistent with regulatory treatment.
(6) Proceeds of these bonds were used to refund bonds with interest rates of 5.75%–8%.
(7) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002.
(8) These long-term debt agreements contain various restrictive covenants, including provisions related to interest coverage, maximum levels of debt to total capitalization and limitations on dividends.
(9) Of the amount due in 2003, $0.8 million may be satisfied by the substitution of property in lieu of cash payments.

TECO Transport entered into a capital lease agreement with Midwest Marine Management Company in March 1998 for the charter of additional capacity. This lease covers 110 river barges and three towboats, classified as property, plant and equipment on the balance sheet; the corresponding $35 million five-year lease commitment was recorded as long-term debt on the balance sheet. The future minimum lease payments under the capitalized lease as of Dec. 31, 2002 are $25.8. This represents $25.3 million present value of net minimum lease payments and $0.5 million of interest, all due in 2003.

Substantially all of the property, plant and equipment of Tampa Electric is pledged as collateral to secure its first mortgage bonds and certain pollution control equipment is pledged to secure certain installment contracts payable. TECO Energy's maturities and annual sinking fund requirements of long-term debt for the years 2004, 2005, 2006 and 2007 are $31.9 million, $35.7 million, $38.0 million and $975.2 million, respectively. Of these amounts $0.8 million per year for 2004 through 2007 may be satisfied by the substitution of property in lieu of cash payments.

At Dec. 31, 2002, total long-term debt had a carrying amount of $3,324.3 million and an estimated fair market value of $3,288.7 million. The estimated fair market value of long-term debt was based on quoted market prices for the same or similar issues, on the current rates offered for debt of the same remaining maturities, or for long-term debt issues with variable rates that approximate market rates, at carrying amounts. The carrying amount of long-term debt due within one year approximated fair market value because of the short maturity of these instruments.

F. Short-Term Debt

At Dec. 31, 2002 and 2001, notes payable consisted of the following:

Notes Payable

(millions) Dec. 31,	*2002*	*2001*
Credit facilities outstanding	$350.0	$ —
Commercial paper	10.5	638.9
Total notes payable	$360.5	$638.9

The weighted average interest rate on outstanding notes payable at Dec. 31, 2002 and 2001 was 1.88% and 1.99%, respectively.

At Dec. 31, 2002 and 2001, the following credit facilities and related borrowings existed:

Credit Facilities

	Dec. 31, 2002			*Dec. 31, 2001*		
(millions)	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*
Tampa Electric						
1-year facility	$ 300.0	$ —	$ —	$ 300.0	$ —	$ —
TECO Energy						
1-year facility	350.0	350.0	—	350.0	—	—
TECO Energy						
3-year facility	350.0	—	179.8	350.0	—	—
Totals	$1,000.0	$350.0	$179.8	$1,000.0	$ —	$ —

Tampa Electric's credit facility has a maturity date of November 2003. TECO Energy's one-year facility also matures in November 2003 and its 3-year facility matures in November 2004. These credit facilities require facility fees ranging from 15 to 20 basis points. Within its 3-year facility, TECO Energy has $250 million of capacity to issue letters of credit. These letters of credit require issuance fees of 12.5 basis points and lenders fees of 55 basis points

In order to utilize the credit facilities, TECO Energy's debt-to-capital ratio, as defined in the credit agreement, may not exceed 65.0% at the end of the applicable quarter. At Dec. 31, 2002, TECO Energy's debt-to-capital ratio was 55.9%. Under Tampa Electric's credit facility, Tampa Electric's debt-to-capital ratio may not exceed 60.0% measured at the end of the applicable quarter and its earnings before interest, taxes, depreciation and amortization (EBITDA) to interest coverage ratio must be at least 2.5 times. At Dec. 31, 2002, Tampa Electric's debt-to-capital ratio was 43.9% and its EBITDA to interest coverage ratio was 7.8 times. (See Note R.)

G. Preferred Securities

In November 2000, TECO Energy established TECO Capital Trust I (the Trust) for the sole purpose of issuing Trust Preferred Securities (TRuPS) and using the proceeds to purchase company preferred securities from TECO Funding Company I, LLC (TECO Funding). On Dec. 20, 2000, the Trust issued 8 million shares of $25 par, 8.5% TRuPS, due 2041, with an aggregate liquidation value of $200 million. Currently, all 8 million shares of the TRuPS are outstanding. Each TRuPS represents an undivided beneficial interest in the assets of the Trust. The Trust used the proceeds from the sale of the TRuPS to purchase a corresponding amount of company preferred securities of TECO Funding. TECO Funding used the proceeds from the sale of the company preferred securities to the Trust of $200 million and the sale of $6.2 million of its common securities to TECO Energy, to purchase $206.2 million of 8.5% junior subordinated notes of TECO Energy, due 2041. The junior subordinated notes are the sole assets of TECO Funding and the company preferred securities are the sole assets of the Trust. TECO Energy's proceeds from the sale of the junior subordinated notes were used to reduce the commercial paper balances of TECO Finance and for general corporate purposes. TECO Energy has guaranteed the payments to the holders of the company preferred securities and indirectly, the payments to the holders of the TRuPS, as a result of their beneficial interest in the company preferred securities. Distributions are payable quarterly in arrears on January 31, April 30, July 31, and October 31 of each year. Distributions were $17.0 million and $14.6 million in 2002 and 2001, respectively. No distributions were made in 2000.

The junior subordinated notes may be redeemed at the option of TECO Energy at any time on or after Dec. 20, 2005 at 100% of their principal amount plus accrued interest through the redemption date. If TECO Energy redeems the junior subordinated notes in full before their maturity date, then TECO Funding is required to redeem the company preferred securities and common securities, in accordance with their terms. If TECO Energy redeems the junior subordinated notes in part but not in full before their maturity date, then TECO Funding will redeem the company preferred securities in full prior to any payment being made on the common securities. Upon any liquidation of the company preferred securities, holders of the TRuPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends through the date of redemption.

In January 2002, TECO Energy sold 17.965 million mandatorily convertible equity security units in the form of 9.5% equity units at $25 per unit resulting in $436 million of net proceeds. Each equity unit consisted of $25 in principal amount of a trust preferred security of TECO Capital Trust II, a Delaware business trust formed for the purpose of issuing these securities, with a stated liquidation amount of $25 and a contract to purchase shares of common stock of TECO Energy in January 2005 at a price per share of between $26.29 and $30.10 based on the market price at that time. The equity units represent an indirect interest in a corresponding amount of TECO Energy 5.11% subordinated debt. The holders of these contracts are entitled to quarterly contract adjustment payments at the annualized rate of 4.39% of the stated amount of $25 per year through and including Jan. 15, 2005. The net proceeds from the offering were used to repay short-term debt and for general corporate purposes.

H. Preferred Stock

Preferred stock of TECO Energy – $1 par 10 million shares authorized, none outstanding.
Preference stock of Tampa Electric – no par 2.5 million shares authorized, none outstanding.
Preferred stock of Tampa Electric – no par 2.5 million shares authorized, none outstanding.
Preferred Stock of Tampa Electric – $100 par value 1.5 million shares authorized, none outstanding.

1. Common Stock

Stock-Based Compensation

In April 1996, the shareholders approved the 1996 Equity Incentive Plan (the "1996 Plan"). The 1996 Plan superseded the 1990 Equity Incentive Plan (the "1990 Plan"), and no additional grants will be made under the 1990 Plan. The rights of the holders of outstanding options under the 1990 Plan were not affected. The purpose of the 1996 Plan is to attract and retain key employees of the company, to provide an incentive for them to achieve long-range performance goals and to enable them to participate in the long-term growth of the company. The 1996 Plan amended the 1990 Plan to increase the number of shares of common stock subject to grants by 3,750,000 shares, expand the types of awards available to be granted and specify a limit on the maximum number of shares with respect to which stock options and stock appreciation rights may be made to any participant under the plan. Under the 1996 Plan, the Compensation Committee of the Board of Directors may award stock grants, stock options and/or stock equivalents to officers and key employees of TECO Energy and its subsidiaries.

The Compensation Committee has discretion to determine the terms and conditions of each award, which may be subject to conditions relating to continued employment, restrictions on transfer or performance criteria.

In 2002, under the 1996 Plan, 1,769,880 stock options were granted, with a weighted average option price of $27.97 and a maximum term of 10 years. In addition, 255,242 shares of restricted stock were awarded, each with a weighted average fair value of $27.97. Compensation expense recognized for stock grants awarded under the 1996 Plan was $1.7 million, $2.8 million and $4.6 million in 2002, 2001 and 2000, respectively. Half the stock grants awarded in 2002 and all of the stock grants awarded in 2001 and 2000 are performance shares, restricted subject to meeting specified total shareholder return goals, vesting in three years with final payout ranging from zero to 200% of the original grant. Adjustments are made to reflect contingent shares which could be issuable based on current period results. The consolidated balance sheets at Dec. 31, 2002 and 2001 reflected a ($6.3) million and a $1.1 million liability respectively, classified as other deferred credits, for these contingent shares. The remaining stock grants are restricted subject generally to continued employment, with the 2002 stock grants vesting in three years, the 1998 stock grants vesting in five years, and the 1997 and 1996 stock grants vesting at normal retirement age.

In April 2001, the shareholders approved an amendment to the 1996 Plan, to increase the number of shares of common stock subject to grants by 6.3 million.

Stock option transactions during the last three years under the 1996 Plan and the 1990 Plan (collectively referred to as the "Equity Plans") are summarized as follows:

Stock Options - Equity Plans

	Option Shares (thousands)	*Weighted Avg. Option Price*
Balance at Dec. 31, 1999	3,827	$22.64
Granted	1,264	$21.33
Exercised	(488)	$20.15
Cancelled	(44)	$23.61
Balance at Dec. 31, 2000	4,559	$22.54
Granted	1,268	$31.39
Exercised	(605)	$21.53
Cancelled	(32)	$26.88
Balance at Dec. 31, 2001	5,190	$24.79
Granted	1,770	$27.97
Exercised	(487)	$20.93
Cancelled	(57)	$27.03
Balance at Dec. 31, 2002	6,416	$25.94
Exercisable at Dec. 31, 2002	0	—
Available for future grant at Dec. 31, 2002	4,288	

As of Dec. 31, 2002, the 6.4 million options outstanding under the Equity Plans are summarized below.

Stock Options Outstanding at Dec. 31, 2002

Option Shares (thousands)	*Range of Option Prices*	*Weighted Avg. Option Price*	*Weighted Avg. Remaining Contractual Life*
2,099	$19.44-$22.48	$21.16	6 Years
705	$23.55-$25.97	$24.07	4 Years
3,612	$27.56-$31.58	$29.08	8 Years

In April 1997, the Shareholders approved the 1997 Director Equity Plan (the "1997 Plan"), as an amendment and restatement of the 1991 Director Stock Option Plan (the "1991 Plan"). The 1997 Plan supersedes the 1991 Plan, and no additional grants will be made under the 1991 Plan. The rights of the holders of outstanding options under the 1991 Plan will not be affected. The purpose of the 1997 Plan is to attract and retain highly qualified non-employee directors of the company and to encourage them to own shares of TECO Energy common stock. The 1997 Plan is administered by the Board of Directors. The 1997 Plan amended the 1991 Plan to increase the number of shares of common stock subject to grants by 250,000 shares, expanded the types of awards available to be granted and replaced the current fixed formula grant by giving the Board discretionary authority to determine the amount and timing of awards under the Plan.

In 2002, 27,500 options were granted, with a weighted average option price of $27.97. Transactions during the last three years under the 1997 Plan are summarized as follows:

Stock Options - Director Equity Plans

	Option Shares (thousands)	*Weighted Avg. Option Price*
Balance at Dec. 31, 1999	273	$21.25
Granted	30	$23.49
Exercised	(33)	$18.57
Cancelled	(12)	$25.15
Balance at Dec. 31, 2000	258	$21.68
Granted	35	$31.26
Exercised	(91)	$19.12
Cancelled	—	—
Balance at Dec. 31, 2001	202	$24.49
Granted	28	$27.97
Exercised	(22)	$20.95
Cancelled	(2)	$27.56
Balance at Dec. 31, 2002	206	$25.31
Exercisable at Dec. 31, 2002	0	—
Available for future grant at Dec. 31, 2002	270	

As of Dec. 31, 2002, the 206,000 options outstanding under the 1997 Plan with option prices of $19.81-$31.575, had a weighted average option price of $25.31 and a weighted average remaining contractual life of six years.

TECO Energy has adopted the disclosure-only provisions of FAS 123, *Accounting for Stock-Based Compensation*, but applies Accounting Principles Board Opinion No. 25 and related interpretations in accounting for its plans. Therefore, since stock options are granted with an option price greater than or equal to the fair value on date of grant, no compensation expense has been recognized for stock options granted under the 1996 Plan and the 1997 Plan. If the company had elected to recognize compensation expense for stock options based on the fair value at grant date, consistent with the method prescribed by FAS 123, net income and earnings per share would have been reduced to the pro forma amounts as follows. These pro forma

amounts were determined using the Black-Scholes valuation model with weighted average assumptions as follows:

Pro Forma Disclosure – Stock Options

		2002	2001	2000
Net income from continuing operations *(millions)*	As reported	$298.2	$ 273.8	$227.5
	Pro forma expense[1]	5.1	4.3	2.6
	Pro forma	$293.1	$ 269.5	$224.9
Net income *(millions)*	As reported	$330.1	$ 303.7	$250.9
	Pro forma expense[1]	5.1	4.3	2.6
	Pro forma	$325.0	$ 299.4	$248.3
Net income from continuing operations – EPS basic	As reported	$ 1.95	$ 2.04	$ 1.81
	Pro forma	$ 1.91	$ 2.00	$ 1.79
Net income – EPS basic	As reported	$ 2.15	$ 2.26	$ 1.99
	Pro forma	$ 2.12	$ 2.23	$ 1.97
Assumptions				
Risk-free interest rate		5.09%	4.86%	6.24%
Expected lives (in years)		6	6	6
Expected stock volatility		25.92%	27.45%	22.93%
Dividend yield		5.47%	5.46%	5.15%

(1) Compensation expense for stock options determined under fair-value based method, after-tax.

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan (DRP). TECO Energy raised $11.2 million, $8.6 million and $8.1 million of common equity from this plan in 2002, 2001 and 2000, respectively.

Common Stock and Treasury Stock

In September 1999, TECO Energy began a program to repurchase up to $150 million of its outstanding common stock. Shares acquired constituted treasury shares. In 1999 and 2000, the company acquired 7.0 million shares of its outstanding common stock at a cost of $144.7 million, or an average per share price of $20.55. The company's share repurchase program favorably impacted earnings in 2000 by approximately $0.06 per share.

On March 12, 2001, the company completed a public offering of 8.625 million common shares at $27.75 per share, 7.0 million shares of which were reissued from treasury shares. On Oct. 4, 2001, S&P announced the inclusion of TECO Energy shares in the S&P 500 Index effective as of the market close on Oct. 9, 2001. On Oct. 12, 2001, TECO Energy issued 3.5 million additional common shares at $26.72 per share. The sales of the common shares resulted in total net proceeds to TECO Energy of $325.5 million in 2001, which were used to fund capital expenditures, for working capital requirements, general corporate purposes and to repay short-term debt.

In June 2002, the company completed a public offering of 15.525 million common shares at a price to the public of $23.00 per share. The sale of these shares resulted in net proceeds to the company of approximately $346.4 million, which were used to repay short-term debt and for general corporate purposes. In October 2002, the company issued 19.385 million common shares at a price to the public of $11.00 per share. The sale of these shares resulted in net proceeds to the company of approximately $206.8 million, which were used to repay short-term debt.

Shareholder Rights Plan

In accordance with the company's Shareholder Rights Plan, a Right to purchase one additional share of the company's common stock at a price of $90 per share is attached to each outstanding share of the company's common stock. The Rights expire in May 2009, subject to extension. The Rights will become exercisable 10 business days after a person acquires 10 percent or more of the company's outstanding common stock or commences a tender offer that would result in such person owning 10 percent or more of such stock. If any person acquires 10 percent or more of the outstanding common stock, the rights of holders, other than the acquiring person, become rights to buy shares of common stock of the company (or of the acquiring company if the company is involved in a merger or other business combination and is not the surviving corporation) having a market value of twice the exercise price of each Right.

The company may redeem the Rights at a nominal price per Right until 10 business days after a person acquires 10 percent or more of the outstanding common stock.

Employee Stock Ownership Plan

Effective Jan. 1, 1990, TECO Energy amended the TECO Energy Group Retirement Savings Plan, a tax-qualified benefit plan available to substantially all employees, to include an employee stock ownership plan (ESOP). During 1990, the ESOP purchased 7 million shares of TECO Energy common stock on the open market for $100 million. The share purchase was financed through a loan from TECO Energy to the ESOP. This loan is at a fixed interest rate of 9.3% and will be repaid from dividends on ESOP shares and from TECO Energy's contributions to the ESOP.

TECO Energy's contributions to the ESOP were $13.6 million, $5.6 million and $6.8 million in 2002, 2001 and 2000, respectively. TECO Energy's annual contribution equals the interest accrued on the loan during the year plus additional principal payments needed to meet the matching allocation requirements under the plan, less dividends received on the ESOP shares. The components of net ESOP expense recognized for the past three years are as follows:

ESOP Expense

(millions)	2002	2001	2000
Interest expense	$ 4.3	$5.2	$6.0
Compensation expense	12.2	7.4	6.9
Dividends	(8.5)	(8.5)	(8.5)
Net ESOP expense	$ 8.0	$4.1	$4.4

Compensation expense was determined by the shares allocated method.

At Dec. 31, 2002, the ESOP had 4.0 million allocated shares, 0.3 million committed-to-be-released shares, and 1.7 million unallocated shares. Shares are released to provide employees with the company match in accordance with the terms of the TECO Energy Group Retirement Savings Plan and in lieu of dividends on allocated ESOP shares. The dividends received by the ESOP are used to pay debt service on the loan between TECO Energy and the ESOP.

For financial statement purposes, the unallocated shares of TECO Energy stock are reflected as a reduction of common equity, classified as unearned compensation. Dividends on all ESOP shares are recorded as a reduction of retained earnings, as are dividends on all TECO Energy common stock. The tax benefit related to the dividends paid to the ESOP for allocated shares is a reduction of income tax expense and for unallocated shares is an increase in retained earnings. All ESOP shares are considered outstanding for earnings per share computations.

J. Comprehensive Income

FAS 130, *Reporting Comprehensive Income*, requires that comprehensive income, which includes net income as well as certain changes in assets and liabilities recorded in common equity, be reported in the financial statements. TECO Energy reported the following comprehensive income (loss) in 2002, 2001 and 2000 related to changes in the fair value of cash flow hedges, foreign currency adjustments and adjustments to the minimum pension liability associated with the company's supplemental executive retirement plan:

Comprehensive Income (loss)

(millions)	*Gross*	*Tax*	*Net*
2002			
Unrealized (loss) gain on cash flow hedges	$ (8.7)	$ (4.0)	$ (4.7)
Less: Loss (gain) reclassified to net income	29.0	11.4	17.6
Gain (loss) on cash flow hedges	20.3	7.4	12.9
Portion of equity investee's loss on cash flow hedges	(42.5)	(16.4)	(26.1)
Foreign currency adjustments	(1.2)	—	(1.2)
Pension adjustments	(7.2)	(2.8)	(4.4)
Total other comprehensive income (loss)	$(30.6)	$(11.8)	$(18.8)
2001			
Initial adoption of FAS 133	$(19.0)	$ (7.3)	$(11.7)
Unrealized (loss) gain on cash flow hedges	(13.9)	(5.5)	(8.4)
Less: Loss (gain) reclassified to net income	19.7	7.6	12.1
Gain (loss) on cash flow hedges	(13.2)	(5.2)	(8.0)
Portion of equity investee's loss on cash flow hedges	(18.2)	(7.0)	(11.2)
Pension adjustments	0.5	0.2	0.3
Total other comprehensive income (loss)	$(30.9)	$(12.0)	$(18.9)
2000			
Pension adjustments	$ 3.3	$ 1.3	$ 2.0
Total other comprehensive income (loss)	$ 3.3	$ 1.3	$ 2.0

K. Employee Postretirement Benefits

Pension Benefits

TECO Energy has a non-contributory defined benefit retirement plan which covers substantially all employees. Benefits are based on employees' age, years of service and final average earnings. On April 1, 2000, the plan was amended to provide for benefits to be earned and payable substantially on a lump sum basis through an age and service credit schedule for eligible participants leaving the company on or after July 1, 2001. Other significant provisions of the plan, such as eligibility, definitions of credited service, final average earnings, etc., were largely unchanged. This amendment resulted in decreased pension expense of approximately $.8 million and $2.0 million in 2001 and 2000, respectively, and a reduction of benefit obligation of $6.2 million and $14.4 million at Sept. 30, 2001 and Dec. 31, 2000, respectively.

The company's policy is to fund the plan within the guidelines set by ERISA for the minimum annual contribution and the maximum allowable as a tax deduction by the IRS. About 53 percent of plan assets were invested in common stock and 47 percent in fixed income investments at Sept. 30, 2002.

Amounts shown also include the unfunded obligations for the supplemental executive retirement plans, non-qualified, non-contributory defined benefit retirement plans available to certain senior management. TECO Energy reported other comprehensive loss of $4.4 million in 2002 and other comprehensive income of $0.3 million and $2 million in 2001 and 2000, respectively, related to adjustments to the minimum pension liability associated with the supplemental executive retirement plans.

In 2001, TECO Energy elected to change the measurement date for pension obligations and plan assets from Dec. 31 to Sept. 30. The effect of this accounting change was not material.

Other Postretirement Benefits

TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. The company contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and June 30, 2001, is limited to a defined dollar benefit based on years of service. On April 1, 2000, the company adopted changes to this program for participants retiring from the company on or after July 1, 2001. The company contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after July 1, 2001, is limited to a defined dollar benefit based on an age and service schedule. The impact of this amendment, including a change in the company's commitment for future retirees combined with a grandfathering provision for current retired participants, resulted in a reduction in the benefit obligation of $1.4 million in 2001. Postretirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify the plans in whole or in part at any time.

In 2001, TECO Energy elected to change the measurement date for benefit obligations from Dec. 31 to Sept. 30. The effect of this accounting change was not material.

The following charts summarize the income statement and balance sheet impact, as well as the benefit obligations, assets, funded status and rate assumptions associated with the pension and other postretirement benefits.

Benefit Expense

	Pension Benefits			*Other Postretirement Benefits*		
(millions)	*2002*	*2001*	*2000*	*2002*	*2001*	*2000*
Components of net periodic benefit expense						
Service cost (benefits earned during the period)	$ 11.8	$ 11.2	$ 10.7	$ 3.5	$ 3.4	$ 3.0
Interest cost on projected benefit obligations	28.7	27.9	27.5	11.2	10.9	8.9
Expected return on assets	(42.9)	(42.0)	(40.8)	—	—	—
Amortization of:						
Transition obligation (asset)	(1.1)	(1.1)	(1.0)	2.7	2.7	2.7
Prior service cost (benefit)	(0.5)	(0.5)	0.2	1.9	2.0	1.7
Actuarial (gain) loss	(3.7)	(4.4)	(5.6)	0.1	0.4	(0.2)
Pension expense (benefit)	(7.7)	(8.9)	(9.0)	19.4	19.4	16.1
Special termination benefit charge	2.7	—	1.1	0.6	—	0.2
Additional amounts recognized	—	—	—	—	—	0.9
Net pension expense (benefit) recognized in the Consolidated Statements of Income	$ (5.0)	$ (8.9)	$ (7.9)	$ 20.0	$ 19.4	$ 17.2

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for non-qualified pension plans with accumulated benefit obligations in excess of plan assets were $41.3 million, $32.8 million and $0, respectively, as of Sept. 30, 2002 and $27.3 million, $23.5 million and $0, respectively, as of Sept. 30, 2001.

(millions)	Pension Benefits 2002	Pension Benefits 2001	Other Postretirement Benefits 2002	Other Postretirement Benefits 2001
Change in benefit obligation				
Net benefit obligation at prior measurement date	$382.3	$379.9	$ 150.2	$ 130.8
Service cost	11.8	11.2	3.5	3.4
Interest cost	28.7	27.9	11.2	10.9
Plan participants' contributions	—	—	1.0	0.9
Actuarial (gain) loss	58.3	(8.7)	25.6	11.6
Plan amendments	1.1	(6.2)	—	(1.4)
Special termination benefits	2.7	—	0.6	—
Gross benefits paid	(29.8)	(21.8)	(7.5)	(6.0)
Net benefit obligation at measurement date	$455.1	$382.3	$ 184.6	$ 150.2
Change in plan assets				
Fair value of plan assets at prior measurement date	$428.0	$493.8	$ —	$ —
Actual return on plan assets	(24.9)	(43.7)	—	—
Employer contributions	1.7	2.1	6.5	5.1
Plan participants' contributions	—	—	1.0	0.9
Gross benefits paid (including expenses)	(32.9)	(24.2)	(7.5)	(6.0)
Fair value of plan assets at measurement date	$371.9	$428.0	$ —	$ —
Funded status				
Funded status at measurement date	$ (83.2)	$ 45.7	$(184.6)	$(150.2)
Net contributions after measurement date	0.4	0.4	1.9	1.7
Unrecognized net actuarial (gain) loss	88.9	(44.0)	42.4	16.9
Unrecognized prior service cost (benefit)	(7.4)	(9.0)	22.4	24.3
Unrecognized net transition obligation (asset)	(2.5)	(3.6)	27.4	30.1
Accrued liability at end of year	$ (3.8)	$ (10.5)	$ (90.5)	$ (77.2)
Amounts recognized in the statement of financial position				
Prepaid benefit cost	$ 14.7	$ 6.3	$ —	$ —
Accrued benefit cost	(18.5)	(16.8)	(90.5)	(77.2)
Additional minimum liability	(13.8)	(6.2)	—	—
Intangible asset	1.5	1.1	—	—
Accumulated other comprehensive income	12.3	5.1	—	—
Net amount recognized at end of year	$ (3.8)	$ (10.5)	$ (90.5)	$ (77.2)
Assumptions used in determining actuarial valuations				
Discount rate to determine projected benefit obligation	6.75%	7.5%	6.75%	7.5%
Rate of increase in compensation levels	4.8%	4.7%		
Plan asset growth rate through time	9.0%	9.0%		

The assumed health care cost trend rate for medical costs was 12.5% in 2002 and decreases to 5.0% in 2013 and thereafter.

A 100 basis point increase in the medical trend rates would produce a 7 percent ($1.1 million) increase in the aggregate service and interest cost for 2002 and a 5 percent ($9.5 million) increase in the accumulated postretirement benefit obligation as of Sept. 30, 2002.

A 100 basis point decrease in the medical trend rates would produce a 3 percent ($0.5 million) decrease in the aggregate service and interest cost for 2002 and a 3 percent ($5.0 million) decrease in the accumulated postretirement benefit obligation as of Sept. 30, 2002.

L. Other Non-Operating Items Affecting Net Income

2002

In 2002, TECO Energy recorded $8.8 million after-tax charges ($14.1 million pretax) to adjust asset valuations. The adjustments included a $5.8 million after-tax adjustment ($9.2 million pretax) related to the proposed sale of TPS' investment in the ECKG project, and a $3.0 million after-tax charge ($4.9 million pretax) at TECO Investments related to an aircraft leased to US Airways, which has filed for bankruptcy.

In November 2002, the proceeds from the issuance of TECO Energy notes were used, in part, to pay the $34.1 million option premium associated with the refinancing of $200 million of notes. The $34.1 million option premium ($20.9 million after-tax) was recognized as a charge in 2002.

2001

In the first quarter of 2001, TECO Energy recorded $7.2 million of after-tax charges ($11.1 million pretax) to adjust asset valuations. The adjustments included a $6.1 million after-tax adjustment ($9.3 million pretax) related to the sale of TPS' minority interests in Energía Global International, Ltd. (EGI) which owned smaller power generation projects in Central America, and a $1.1 million after-tax adjustment ($1.8 million pretax) to adjust the carrying value of leveraged leases at TECO Investments.

2000

In 2000, TECO Energy's results included an $8.3-million, after-tax gain from the US Propane and Heritage Propane transactions offset by after-tax charges of $5.2 million to adjust the value of leveraged leases and $3.8 million to adjust property values at TECO Properties. Because of the offsetting nature of these items, there was no significant effect on earnings in 2000.

M. Income Tax Expense

Income tax expense consists of the following components:

Income Tax Expense

(millions)	*Federal*	*State*	*Total*
2002			
Currently payable	$ 41.1	$ 14.0	$ 55.1
Deferred	(81.7)	(7.0)	(88.7)
Amortization of investment tax credits	(4.8)	—	(4.8)
Income tax benefit from continuing operations	(45.4)	7.0	(38.4)
Currently payable	—	2.0	2.0
Deferred	(7.4)	(0.4)	(7.8)
Income tax benefit from discontinued operations	(7.4)	1.6	(5.8)
Total income tax expense (benefit)	$ (52.8)	$ 8.6	$ (44.2)
2001			
Currently payable	$ 85.7	$ 18.3	$ 104.0
Deferred	(94.1)	(7.1)	(101.2)
Amortization of investment tax credits	(4.9)	—	(4.9)
Income tax benefit from continuing operations	(13.3)	11.2	(2.1)
Currently payable	(7.9)	1.6	(6.3)
Deferred	(1.4)	(0.3)	(1.7)
Income tax benefit from discontinued operations	(9.3)	1.3	(8.0)
Total income tax expense (benefit)	$ (22.6)	$ 12.5	$ (10.1)
2000			
Currently payable	$ 103.3	$ 8.4	$ 111.7
Deferred	(79.5)	2.0	(77.5)
Amortization of investment tax credits	(4.9)	—	(4.9)
Income tax expense from continuing operations	18.9	10.4	29.3
Currently payable	(10.7)	—	(10.7)
Deferred	(1.6)	1.5	(0.1)
Income tax benefit from discontinued operations	(12.3)	1.5	(10.8)
Total income tax expense (benefit)	$ 6.6	$ 11.9	$ 18.5

Deferred taxes result from temporary differences in the recognition of certain liabilities or assets for tax and financial reporting purposes. The principal components of the company's deferred tax assets and liabilities recognized in the balance sheet are as follows:

Deferred Income Tax Assets and Liabilities

(millions) Dec. 31,	*2002*	*2001*
Deferred income tax assets[1]		
Property related	$ 86.8	$ 87.7
Basis differences in oil and gas producing properties	(0.1)	1.2
Alternative minimum tax credit carry forward	201.3	105.5
Other	52.2	47.6
Total deferred income tax assets	340.2	242.0
Deferred income tax liabilities[1]		
Property related	(565.3)	(522.8)
Basis differences in oil and gas producing properties	(13.9)	(8.9)
Other	84.2	33.0
Total deferred income tax liabilities	(495.0)	(498.7)
Accumulated deferred income taxes	$ (154.8)	$ (256.7)

(1) Certain property related assets and liabilities have been netted.

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes for the following reasons:

Effective Income Tax Rate

(millions)	*2002*	*2001*	*2000*
Net income from continuing operations	$ 298.2	$ 273.8	$ 227.5
Total income tax provision (benefit)	(38.4)	(2.1)	29.3
Income from continuing operations before income taxes	$ 259.8	$ 271.7	$ 256.8
Income taxes on above at federal statutory rate of 35%	$ 90.9	$ 95.1	$ 89.9
Increase (Decrease) due to			
State income tax, net of federal income tax	4.6	7.3	7.5
Amortization of investment tax credits	(4.8)	(4.9)	(4.9)
Non-conventional fuels tax credit	(107.3)	(86.2)	(52.1)
Permanent reinvestment-foreign income	(8.1)	(7.2)	(9.3)
AFUDC Equity	(8.7)	(2.3)	(0.6)
Other	(5.0)	(3.9)	(1.2)
Total income tax provision from continuing operations	$ (38.4)	$ (2.1)	$ 29.3
Provision for income taxes as a percent of income from continuing operations, before income taxes	-14.8%	-0.8%	11.4%

The provision for income taxes as a percent of income from discontinued operations was -22.4%, -36.5% and -46.1%, respectively, in 2002, 2001 and 2000. The total effective income tax rate differs from the federal statutory rate due to state income tax, net of federal income tax, the non-conventional fuels tax credit and other miscellaneous items. The actual cash paid for income taxes as required by the alternative minimum tax rules in 2002, 2001, and 2000 was $71.9 million, $52.4 million and $83.9 million, respectively.

N. Related Parties

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests. These transactions, primarily for legal services, were not material for 2002, 2001 and 2000. No material balances were payable as of Dec. 31, 2002 or 2001.

TPS recognized income on the non-TPS portion of notes receivable from unconsolidated affiliates in which TPS holds joint venture interests and from credit support for the TPGC joint venture. The notes receivable from unconsolidated affiliates are as follows:

Notes Receivable From Related Parties

(millions) Dec. 31,	*Rate*	*2002*	*2001*
Panda Energy	14.00%	$ 137.0	$ 92.7
Energeticke Centrum Kladno	6.00%	1.4	—
Mosbacher Power Partners L.P.	12.00%	—	13.1
Mosbacher Power Partners L.P.	9.00%	13.7	21.1
Mosbacher Power Partners L.P.	12.00%	—	6.2
EEGSA	6.81%[1]	11.1	10.9
TPGC - Gila River	7.79%[1]	369.5	37.5
TPGC - Union Power	6.58%[1]	426.3	86.7

(1) Current rate at Dec. 31, 2002

Other Income (Expense) included pretax income from construction-related and loan agreements with Panda Energy, and interest income of $78.9 million and $32.8 million for 2002 and 2001, respectively from the other notes receivable shown on the preceeding table.

At Dec. 31, 2002, TPS' position in the Odessa and Guadalupe power stations in Texas was in the form of a $137 million loan to a Panda Energy International subsidiary, which is a partner in Texas Independent Energy (TIE). On Jan. 3, 2003 the loan converted to an ownership interest in these projects.

TPS Arkansas Operations Company and TPS Arizona Operations Company, both wholly-owned subsidiaries of TPS, have a combined receivable from TPGC of $0.8 million as of Dec. 31, 2002.

TPS has agreed to purchase the interests of Panda Energy in the TPGC projects in 2007 for $60 million, and TECO Energy has guaranteed payment of TPS' purchase obligation. This obligation may be accelerated if Panda Energy defaults on a bank loan for which the TPS purchase obligation is collateral or if TECO Energy permits its debt-to-capital ratio to exceed 65.0%, permits its EBITDA/interest ratio to fall below 1.5 times or defaults on the payment of indebtedness in excess of $50 million. TECO Energy's debt-to-capital ratio at Dec. 31, 2002, was 55.9% and its EBITDA/interest ratio was 3.6 times (See Note R). Panda Energy may cancel the purchase obligation at any time prior to 2007 by paying TPS a cancellation fee that ranges from $8 million to $20 million based on the time of such cancellation.

O. Discontinued Operations

TECO Coalbed Methane, a subsidiary of TECO Energy, had developed jointly the natural gas potential in a portion of Alabama's Black Warrior Basin. In September 2002, the company announced its intent to sell the TECO Coalbed Methane gas assets. On Dec. 20, 2002, TECO Energy sold substantially all of its coalbed methane assets in Alabama to the Municipal Gas Authority of Georgia. Proceeds from the sale were $140 million, $42 million paid in cash at closing, and a $98 million note receivable, which was paid in January 2003 (See **Note U**). TECO Coalbed Methane's results were accounted for as discontinued operations for all periods reported. The gas assets are included in Property held for sale net of accumulated depreciation on the Consolidated Balance Sheets as of Dec. 31, 2001. Operating revenues from TECO Coalbed Methane were $39.7 million, $55.0 million and $43.0 million, and pretax operating income was $14.9 million, $24.3 million and $12.6 million for the years ended Dec. 31, 2002, 2001 and 2000, respectively.

TECO Coalbed Methane utilized the successful efforts method to account for its gas operations, in which expenditures for unsuccessful exploration activities were expensed currently.

Capitalized costs were amortized on the unit-of-production method using estimates of proven reserves. Investments in unproven properties and major development projects were not amortized until proven reserves associated with the projects could be determined or until impairment occurred.

Aggregate capitalized costs related to producing wells at Dec. 31, 2001 were $220.8 million. Net proven reserves at Dec. 31, 2001 were as follows:

Net Proven Reserves - Coalbed Methane Gas

(billion cubic feet)	*2001*
Proven reserves, beginning of year	181.7
Production	(15.0)
Revisions of previous estimates	0.4
Proven reserves, end of year	167.1
Number of wells	682

P. Earnings Per Share

In 1997, the FASB issued FAS 128, *Earnings per Share*, which requires disclosure of basic and diluted earnings per share and a reconciliation (where different) of the numerator and denominator from basic to diluted earnings per share. The reconciliation of basic and diluted earnings per share is shown as follows:

Earnings Per Share

(millions, except per share amounts)	*2002*	*2001*	*2000*
Numerator			
Net Income from continuing operations, basic	$ 298.2	$273.8	$227.5
Effect of contingent performance shares	—	—	(1.9)
Net Income from continuing operations, diluted	$ 298.2	$273.8	$225.6
Net Income, basic	$ 330.1	$303.7	$250.9
Effect of contingent performance shares	—	—	(1.9)
Net Income, diluted	$ 330.1	$303.7	$249.0
Denominator			
Average number of shares outstanding - basic	153.2	134.5	125.9
Plus: incremental shares for assumed conversions:			
Stock options at end of period and contingent performance shares	2.1	4.2	3.3
Less: Treasury shares which could be purchased	(2.0)	(3.3)	(2.9)
Average number of shares outstanding - diluted	153.3	135.4	126.3
Earnings per share from continuing operations			
Basic	$ 1.95	$ 2.04	$ 1.81
Diluted	$ 1.95	$ 2.02	$ 1.79
Earnings per share			
Basic	$ 2.15	$ 2.26	$ 1.99
Diluted	$ 2.15	$ 2.24	$ 1.97

For the year ended Dec. 31, 2002, stock options for 4.5 million shares and 14.9 million common shares issuable under the purchase contract associated with the mandatorily convertible equity units issued in January 2002 were excluded from the computation of diluted earnings per share due to their antidilutive effect. For the year ended Dec. 31, 2001, stock options for 1.2 million shares were excluded from the computation of diluted earnings per share due to their antidilutive effect.

Q. Segment Information

TECO Energy is an electric and gas utility holding company with significant diversified activities. The management of TECO Energy determined its reportable segments based on each subsidiary's contribution of revenues, net income and total assets. All significant intercompany transactions are eliminated in the consolidated financial statements of TECO Energy but are included in determining reportable segments in accordance with FAS 131, *Disclosures about Segments of an Enterprise and Related Information*. In December 2002, TECO Energy sold the assets of TECO Coalbed Methane. Information presented here excludes TECO Coalbed Methane's results, which are reflected in the consolidated financial statements as discontinued operations.

Segment Information

(millions)		Revenues[1][2][3]	Net Income[1][2][3]	Depreciation[1]	Assets at Dec. 31,	Capital Expenditures
2002	Tampa Electric	$1,583.2[4]	$171.8[9]	$189.8	$3,737.0	$ 632.2
	Peoples Gas System	318.1	24.2[10]	30.5	571.7	53.5
	TECO Power Services	309.8[5]	34.1[11]	28.1	2,875.0[15][16]	299.9
	TECO Transport	254.6[6]	21.0[12]	22.3	355.1	25.2
	TECO Coal	317.1[7]	76.5[13]	31.4	283.5	48.2
	Other unregulated businesses	122.1[8]	6.8[14]	1.3	312.4[17][18]	3.0
		2,904.9	334.4	303.4	8,134.7	1,062.0
	Other and eliminations	(229.1)	(36.2)	—	503.1[19]	3.2[19]
	TECO Energy consolidated	$2,675.8	$298.2	$303.4	$8,637.8	$1,065.2
2001	Tampa Electric	$1,412.7[4]	$154.0[9]	$173.4	$3,315.5	$ 426.3
	Peoples Gas System	352.9	23.1[10]	27.9	528.9	73.0
	TECO Power Services	287.1[5]	26.9[11]	28.4	1,935.4[15][16]	397.5
	TECO Transport	274.9[6]	27.6[12]	24.1	333.1	38.8
	TECO Coal	303.4[7]	59.0[13]	28.3	258.5	25.8
	Other unregulated businesses	106.9[8]	4.0[14]	6.1	295.5[17][18]	(0.1)
		2,737.9	294.6	288.2	6,666.9	961.3
	Other and eliminations	(249.8)	(20.8)	—	96.5[19]	4.6[19]
	TECO Energy consolidated	$2,488.1	$273.8	$288.2	$6,763.4	$ 965.9
2000	Tampa Electric	$1,353.8[4]	$144.5[9]	$161.6	$2,997.1	$ 267.1
	Peoples Gas System	314.5	21.8[10]	25.8	513.3	82.2
	TECO Power Services	199.1[5]	22.8[11]	18.5	1,350.6[15][16]	243.5
	TECO Transport	269.8[6]	29.2[12]	22.0	311.3	21.1
	TECO Coal	232.8[7]	33.5[13]	26.9	246.3	64.0
	Other unregulated businesses	81.8[8]	1.2[14]	3.2	213.3[17][18]	6.9
		2,451.8	253.0	258.0	5,631.9	684.8
	Other and eliminations	(228.7)	(25.5)	—	142.4[19]	3.6[19]
	TECO Energy consolidated	$2,223.1	$227.5	$258.0	$5,774.3	$ 688.4

(1) From continuing operations. Revenues, net income and depreciation for all periods have been adjusted to reflect the reclassification of TECO Coalbed Methane results as discontinued operations.

(2) Revenues for all periods have been adjusted to reflect the presentation of energy marketing related revenues on a net basis and the reclassification of earnings from equity investments from Revenues to Other income.

(3) Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated costs for 2002, 2001, and 2000 were at pretax rates of 7%, 7%, and 6.75%, respectively, based on the average investment in each subsidiary.

(4) Revenues from sales to affiliates were $ 34.4 million, $32.6 million and $32.4 million in 2002, 2001 and 2000, respectively.

(5) Revenues from sales to affiliates were $ 51.4 million, $65.0 million and $67.6 million in 2002, 2001 and 2000, respectively.

(6) Revenues from sales to affiliates were $110.7 million, $123.2 million and $118.0 million in 2002, 2001 and 2000, respectively.

(7) Revenues from sales to affiliates were $0.7 million, $5.1 million and $4.3 million in 2002, 2001 and 2000, respectively.

(8) Revenues from sales to affiliates were $31.9 million, $23.8 million and $6.5 million in 2002, 2001 and 2000, respectively.

(9) Net income includes net interest expense of $51.5 million, $60.8 million and $67.4 million in 2002, 2001 and 2000, respectively. Net income also includes provisions for income taxes of $85.7 million, $83.4 million and $82.5 million, respectively, for the same periods.

(10) Net income includes net interest expense of $14.7 million, $14.3 million and $12.6 million in 2002, 2001 and 2000, respectively. Net income also includes provisions for income taxes of $14.7 million, $14.2 million and $13.3 million, respectively, for the same periods.

(11) Net income includes net interest expense of $57.2 million, $51.8 million and $23.0 million for 2002, 2001 and 2000, respectively, of which $102.6 million, $54.1 million and $23.0 million for the same periods was internally allocated financing costs (see Note A). Net income also includes provisions for income taxes of $9.2 million and $0.7 million for 2002 and 2001, respectively, and an income tax benefit of $0.6 million for 2000.

(12) Net income includes net interest expense of $6.3 million, $8.9 million and $6.5 million for 2002, 2001 and 2000, respectively, of which $1.7 million, $0.7 million and $0.9 million for the same periods was internally allocated financing income. Net income also includes provisions for income taxes of $10.8 million, $14.2 million and $16.2 million, respectively for the same periods.

(13) Net income includes internally allocated financing costs of $8.1 million, $7.6 million and $6.5 million for 2002, 2001 and 2000, respectively. Net income also includes income tax benefits of $22.9 million, $19.0 million and $14.8 million, respectively, for the same periods.

(14) Net income includes internally allocated financing costs of $4.5 million, $4.4 million and $2.7 million for 2002, 2001 and 2000, respectively. Net income also includes provisions for income taxes of $0.3 million, $3.1 million and $0.9 million, respectively, for the same periods.

(15) Total assets include $97.4 million, $120.4 million and $145.5 million in investments in unconsolidated affiliates at Dec. 31, 2002, 2001 and 2000, respectively. Total assets also includes $972.6 million, $286.4 and $383.1 million in other non-current investments at Dec. 31, 2002, 2001 and 2000, respectively.

(16) Total assets include $154.5 million, $129.4 million and $65.7 million in goodwill net of amortization at Dec. 31, 2002, 2001 and 2000, respectively.

(17) Total assets include $51.8 million, $52.5 million and $50.4 million in investments in unconsolidated affiliates at Dec. 31, 2002, 2001 and 2000, respectively.

(18) Total assets include $39.1 million, $36.4 million and $27.4 million in goodwill net of amortization at Dec. 31, 2002, 2001 and 2000, respectively.

(19) Total assets and capital expenditures for all periods include amounts for the discontinued operations of TECO Coalbed Methane.

Tampa Electric Company provides retail electric utility services to almost 598,000 customers in West Central Florida. Its Peoples Gas System division is engaged in the purchase, distribution and marketing of natural gas for more than 281,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

TECO Transport, through its wholly-owned subsidiaries, transports, stores and transfers coal and other dry bulk commodities for third parties and Tampa Electric. TECO Transport's subsidiaries operate on the Mississippi, Ohio and Illinois rivers, in the Gulf of Mexico and worldwide.

TECO Coal, through its wholly-owned subsidiaries, owns mineral rights, and owns or operates surface and underground mines and coal processing and loading facilities in Kentucky, Tennessee and Virginia. In 2000, these subsidiaries began operating two synthetic fuel processing facilities, whose production qualifies for the non-conventional fuels tax credit. With plans to continue growth in the production and sales of synfuel, TECO Coal has formed a new LLC and has transferred the synfuel units into this LLC effective Jan. 1, 2003. Selling partial interest in the LLC will facilitate efforts to maximize production as well as increase overall cash flow. TECO Coal's subsidiaries sell their coal production to third parties.

TPS has subsidiaries that have interests in independent power projects in Florida, Virginia, Texas, Arkansas, Mississippi, Arizona, Hawaii and Guatemala, and transmission and distribution facilities in Guatemala. TPS also has investments in unconsolidated affiliates that participate in independent power projects in other parts of the U.S. and the world.

TECO Energy's other diversified businesses are engaged in natural gas production from coalbeds, the marketing of natural gas, and energy services and engineering. Also included is the company's investment in the propane business.

Foreign Operations

TPS has independent power operations and investments in Guatemala.

TPS, through its subsidiaries, has a 96 percent ownership interest and operates a 78-megawatt power station that supplies energy to EEGSA, an electric utility in Guatemala, under a U.S. dollar-denominated power sales agreement.

At Dec. 31, 2002, TPS, through a wholly-owned subsidiary, had a 100 percent ownership interest in a 120-megawatt power station and in transmission facilities in Guatemala. The plant provides capacity under a U.S. dollar-denominated power sales agreement to EEGSA.

TPS, through a subsidiary, owns a 30 percent interest in a consortium that includes Iberdrola, an electric utility in Spain, and Electricidade de Portugal, an electric utility in Portugal. The consortium owns an 80.9 percent interest in EEGSA.

Total assets at Dec. 31, 2002, 2001 and 2000 included $415.9 million, $454.2 million and $442.6 million, respectively, related to these Guatemalan operations and investments. Revenues included $88.5 million, $79.9 million and $69.0 million for the years ended Dec. 31, 2002, 2001 and 2000, respectively, and operating income included $33.0 million, $38.0 million and $23.7 million for the same periods from these Guatemalan operations and investments.

R. Commitments and Contingencies

Capital Investments

TECO Energy has made certain commitments in connection with its continuing capital improvements program. At Dec. 31, 2002, these forecasted capital investments total approximately $2.0 billion for the years 2003 through 2007 and are summarized as follows.

Forecasted-Capital Investments

(millions)	*2003*	*2004*	*2005 – 2007*	*Total 2003-2007*
Florida operations	$272	$266	$725	$1,263
Independent power	424	25	75	524
Transportation	15	21	61	97
Other	16	23	55	94
	$727	$335	$916	$1,978

For 2003, Tampa Electric expects to spend $232 million, consisting of $78 million for the repowering project at the Gannon Station, and $154 million to support system growth and generation reliability. Tampa Electric's estimated capital expenditures over the 2004-2007 period are projected to be $841 million, including $67 for the Gannon repowering project. At the end of 2002, Tampa Electric had outstanding commitments of about $119 million for the Gannon repowering project.

Capital expenditures for PGS are expected to be about $40 million in 2003 and $160 million during the 2004-2007 period. Included in these amounts are approximately $25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing maintenance and system safety.

TPS expects to invest $424 million in 2003 for completion of the Union and Gila River power stations and $100 million in 2004 through 2006, mainly for the completion of the Dell and McAdams power stations. Estimates for TPS include net contributions to projects of unconsolidated affiliates and other investments of $393 million. TPS had outstanding commitments at Dec. 31, 2002 of approximately $384 million related to the Union and Gila River power stations.

The other unregulated companies expect to invest $31 million in 2003 and $160 million during 2004 through 2007, mainly for normal renewal and replacement capital.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2002, Tampa Electric has estimated its ultimate financial liability to be $20 million, and this amount has been accrued in

the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric. The estimates to perform the work are based on actual estimates obtained from contractors, or the company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric and other potentially responsible parties (PRPs) is based on each parties relative ownership interest in or usage of a site. Accordingly, Tampa Electric's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Long Term Operating Lease Commitments

TECO Energy has commitments under long-term operating leases, primarily for building space, office equipment and heavy equipment, marine assets at TECO Transport, and certain equipment at TPS' Hardee Power Station. On Dec. 30, 2002 TECO Transport completed a sales leaseback transaction to be accounted for as an operating lease covering one ocean-going tug and barge, five river towboats and 49 river barges. On Dec. 21, 2001, TECO Transport sold three ocean-going barges and one ocean-going tug boat in a sales leaseback transaction to be accounted for as an operating lease. Both lease terms are 12 years with early buyout options after 5 years. TPS completed a transaction on Dec. 29, 2000, where certain equipment at its Hardee Power Station was sold to a third party and leased back under a 12-year operating lease. Total rental expense for these operating leases, included in the Consolidated Statements of Income for the years ended Dec. 31, 2002, 2001 and 2000 was $26.1 million, $20.4 million and $17.6 million, respectively. The following is a schedule of future minimum lease payments at Dec. 31, 2002 for all operating leases with noncancelable lease terms in excess of one year:

Future Minimum Lease Payments For Operating Leases

Year ended Dec. 31:	*Amount (millions)*
2003	$ 27.4
2004	26.5
2005	23.3
2006	20.7
2007	17.9
Later Years	107.1
Total minimum lease payments	$222.9

Guarantees and Letters of Credit

The company has outstanding letters of credit of $185.0 million at Dec. 31, 2002, which guarantee performance to third parties related to debt service, major maintenance requirements and various trade activities. The company also has financial guarantees of $755.6 million at Dec. 31, 2002, primarily for fuel purchases, energy management and construction related debt for projects in which TPS is a participant. Most of the guarantees are renewable annually. In addition, TECO Energy has guaranteed a $375 million equity bridge loan and the $60 million construction undertaking related to the Gila River and Union power stations. A summary of TECO Energy's letters of credit and guarantees are as follows:

Letters of Credit and Guarantees

(millions)							
Letters of Credit and Guarantees for the Benefit of:		*2003*	*2004*	*2005-2007*	*After 2007*	*Total*	*Liabilities Recognized at Dec. 31, 2002*
Tampa Electric	Letters of credit	$ —	$ —	$—	$ 0.9	$ 0.9	$ —
TECO Power Services	Letters of credit	128.0	27.1		24.7	179.8	
	Guarantees:						
	Debt related				15.7	15.7	
	Fuel purchase/energy management				443.9	443.9	10.0
	Construction/Investment related	435.0		60.0	5.0	500.0	
		563.0	27.1	60.0	489.3	1,139.4	10.0
TECO Transport	Letters of credit	—	—	—	1.5	1.5	—
TECO Coal	Letters of credit				0.1	0.1	
	Guarantees: Fuel purchase related				1.5	1.5	1.5
		—	—	—	1.6	1.6	1.5
Other unregulated subsidiaries	Letters of credit				2.7	2.7	
	Guarantees:						
	Debt related				8.0	8.0	
	Fuel purchase/energy management				221.5	221.5	46.4
		—	—	—	232.2	232.2	46.4
		$563.0	$ 27.1	$60.0	$ 725.5	$ 1,375.6	$ 57.9

Financial Covenants

A summary of TECO Energy's significant financial covenants is as follows:

TECO Energy Significant Financial Covenants

(millions)	*Instrument*	*Financial Covenant*[1]	*Requirement/ Restriction*	*Calculation at Dec. 31, 2002*
Tampa Electric	Mortgage bond indenture	Dividend restriction	Cumulative distributions cannot exceed cumulative net income plus $4	$189 unrestricted
	PGS senior notes	EBIT/interest	Minimum of 2.0 times	3.7 times
		Restricted payments	Shareholder equity at least $500	$1,838
		Funded debt/capital	Cannot exceed 65%	44.8%
		Sale of assets	Less than 20% of total assets	0%
	Credit facility	Debt/capital	Cannot exceed 60%	43.9%
		EBITDA/interest	Minimum of 2.5 times	7.8 times
TECO Energy	Credit facilities	Debt/capital	Cannot exceed 65%	55.9%
	$380 million note indenture[2]	Various	—	—
	TECO/Panda guarantees[3]	Debt/capital	Cannot exceed 65%	55.9%
		EBITDA/interest	Minimum of 3.0 times	3.6 times
		Minimum ratings	BBB and Baa3, or BBB- and Baa2	BBB- and Baa2
	TPS purchase obligation guarantee	Debt/capital	Cannot exceed 65%	55.9%
		EBITDA/interest	Minimum of 1.5 times	3.6 times
TECO Diversified	Energy management services agreement guarantee	Consolidated tangible net worth	Minimum of $200	$575
		Consolidated funded debt	Cannot exceed 60%	19.1%
	Coal supply agreement guarantee	Dividend restriction	Net worth not less than $200 or $446 (40% of tangible net assets)	$536

(1) As defined in applicable instrument.
(2) Indenture contains covenants which would apply only if either (a) Notes are rated below BBB- by S&P or below Baa3 by Moody's or (b) Notes are rated below Special Ratings Trigger (minimum of BBB- by S&P and Baa2 by Moody's or BBB by S&P and Baa3 by Moody's) if TECO Energy Construction Undertakings for the TECO/Panda projects are not discharged. These covenants include Limitation on Restricted Payments, Limitations on Certain Liens and Limitation on Indebtedness.
(3) Includes Equity Bridge, Equity Contribution and Construction Undertaking Guarantees related to the TPGC projects.

Other Contingencies

In December 2001, Enron Corp., a large energy trading and services company, filed for protection under the U.S. Bankruptcy Code. TECO Energy announced it believed it had exposure in operations from trade payables and other trading positions due to the Enron bankruptcy of $3.5 million or less after-tax at its subsidiaries TPS, PGS and Prior Energy. TECO Energy has negotiated an agreement with Enron, pending approval of the Creditors Committee, to settle the previously reported $3.5 million of potential trade payables exposure as a result of the Enron bankruptcy. The net financial impact of the agreement is reflected in consolidated net income and no future financial impact is expected.

5. Mergers and Acquisitions

In May 2002, TPS purchased Mosbacher Power Partners' interest in TM Power Ventures (TMPV) for $29.3 million. The majority of the purchase price was allocated to TMPV's investment in the 312-megawatt Commonwealth Chesapeake Power Station located on the Delmarva Peninsula in Virginia, and has been recorded as an increase in goodwill. The acquisition increased TPS' ownership interest in TMPV to 100 percent.

In November 2001, TECO Solutions acquired Prior Energy Corporation, a leading natural gas management company serving customers in Alabama, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee and Texas. Prior Energy handles all facets of natural gas energy management services, including natural gas purchasing and marketing. The company has an established market base in the Southeast and one of the top customer service reputations in the region. The acquisition was accounted for by the purchase method of accounting and, accordingly, the results of operations of Prior Energy are included as part of TECO Solutions' results beginning Nov. 1, 2001. The final working capital adjustment and purchase price allocation was completed in 2002. The total cost of the acquisition was $23.0 million plus a net working capital payment of $6.4 million. Goodwill of $9.6 million was recorded, representing the excess of purchase price over the fair market value of assets acquired. Under FAS 141, effective for all business combinations initiated after June 30, 2001, goodwill is no longer subject to amortization. Net intangible assets of $39.8 million were recorded, representing the value of customer backlog and supply agreements as well as the open cash flow hedges as of Nov. 1, 2001, which are being amortized over 2001 through 2004.

In March 2001, TPS acquired the Frontera Power Station located near McAllen, Texas, accounting for the transaction using the purchase method of accounting. This 477-megawatt, natural gas-fired combined-cycle plant, originally developed by CSW Energy (CSW), began commercial operation in May 2000. As a condition of the merger of Central & South West Corporation, CSW's parent company, with American Electric Power Company, Inc., the FERC required CSW to divest its ownership in this facility. The total cost of the acquisition was $265.3 million. Goodwill of $70.4 million, representing the excess of purchase price over the fair market value of assets acquired, was recorded, and was amortized on a straight-line basis over 40 years until the requirements of FAS 141 became effective on Jan. 1, 2002 (See Note C). The results of operations of Frontera Power Station are included as part of TPS' results beginning March 16, 2001.

The following pro forma disclosures include Prior Energy and the Frontera Power Station as if they had been included in TECO Energy's financial statements for the years ended Dec. 31, 2001 and 2000.

Pro Forma Disclosure — Mergers and Acquisitions

	Actual	*Pro Forma*	
Year ended Dec. 31,	*2002*	*2001*	*2000*
Revenues *(millions)*	$2,675.8	$2,557.4	$2,308.6
Net income from continuing operations *(millions)*	$ 298.2	$ 270.4	$ 230.5
Earnings per share from continuing operations – basic	$ 1.95	$ 2.01	$ 1.83

This pro forma information is not necessarily indicative of the operating results that would have occurred had the acquisitions been completed as of the dates indicated, nor are they indicative of future operating results.

In October 2001, TECO BGA, a unit of TECO Solutions, purchased a district cooling business from FPL Energy Services, a subsidiary of FPL Group. The acquisition includes a 12,000-ton design capacity cooling plant located in downtown Miami. This acquisition provides TECO BGA with a stronger presence in the growing South Florida energy market, long-term contract business, a franchise agreement with the city of Miami and the potential for expansion. The acquisition was accounted for by the purchase method of accounting and, accordingly, its results of operations are included as part of TECO BGA's results beginning Oct. 25, 2001. The total cost of the acquisition was $12.5 million. No goodwill was recorded for the acquisition. The acquisition was not material to the financial statements; no pro forma disclosures are presented.

On Nov. 1, 2000, TECO Coal acquired all of the outstanding stock of Perry County Coal for $14.9 million, comprised of $12.1 million in cash and $2.8 million in notes. Perry County Coal owns or controls more than 23 million tons of low-sulfur reserves, and operates both deep and surface contract mines. The acquisition was accounted for by the purchase method of accounting and, accordingly, the results of operations and assets of Perry County Coal are included as part of TECO Coal's results beginning Nov. 1, 2000. The acquisition was not material to the financial statements; no pro forma disclosures are presented.

In September 2000, TECO Energy acquired BCH Mechanical, Inc. and its affiliated companies ("BCH") accounting for the transaction using the purchase method of accounting. BCH is one of the leading mechanical contracting firms in Florida. TECO Energy purchased a combination of stock and assets of the BCH companies for $34.8 million, comprised of $26.1 million in cash, $2.9 million in notes, and 233,819 shares of TECO Energy common stock. Goodwill of $25.9 million representing the excess of purchase price over the fair market value of assets acquired was recorded, and was amortized on a straight-line basis over 20 years, until the requirements of FAS 141 became effective on Jan. 1, 2002 (See **Note C**). The result of operations of BCH are included as part of TECO Energy's results beginning Sept. 1, 2000. The acquisition was not material to the financial statements; no pro forma disclosures are presented.

In connection with this transaction, TECO Solutions was formed to support TECO Energy's strategy of offering customers a comprehensive and competitive package of energy services and products. Operating companies under TECO Solutions include TECO Energy Services (formerly TECO BGA and BCH Mechanical), TECO Partners, TPV, TECO Gas Services, Prior Energy and TECO Properties.

In February 2000, TECO Energy entered into an agreement to form US Propane, a joint venture to combine its Peoples Gas Company (PGC) propane operations with the propane operations of Atmos Energy Corporation, AGL Resources Inc. and Piedmont Natural Gas Company, Inc. Through a series of transactions completed Aug. 10, 2000, US Propane combined its propane operations with those of Heritage Propane Partners, L.P. US Propane now owns the general partner interest and 29 percent of the limited partnership interests of Heritage Propane Partners. TECO Energy through its wholly-owned subsidiary TPV, is accounting for its interest in US Propane under the equity method of accounting. As a result of these transactions, TPV also received $19.3 million in cash and recognized a pretax gain of $13.6 million ($8.3 million after-tax) on the sale of PGC assets and liabilities to the extent acquired by US Propane and Heritage Propane Partners.

T. New Accounting Pronouncements

Accounting for Asset Retirement Obligations

In July 2001, the FASB issued FAS 143, *Accounting for Asset Retirement Obligations*, which requires the recognition of a liability at fair value for an asset retirement obligation in the period in which it is incurred. Retirement obligations associated with long-lived assets included within the scope of FAS 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are included in the scope of the standard only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its future value. The corresponding amount capitalized at inception is depreciated over the useful life of the asset. The liability must be revalued each period based on current market prices. FAS 143 is effective for fiscal years beginning after June 15, 2002. The company estimates that the adoption of FAS 143 will result in a non-cash increase to net property, plant and equipment of approximately $8.0 million, a non-cash net increase to asset retirement obligation of approximately $10.0 million, and as a cumulative effect of change in accounting principle, a non-cash pretax charge of approximately $2.0 million.

Exit or Disposal Costs

In July 2002, the FASB issued FAS 146, *Accounting for Costs Associated with Exit or Disposal Activities*, which addresses the accounting for costs under certain circumstances, including costs to terminate a contract that is not a capital lease, costs to consolidate facilities or relocate employees, and termination benefits provided to employees that are involuntarily terminated under the terms of a one-time benefit arrangement that is not an ongoing benefit arrangement or an individual deferred compensation contract. FAS 146 is effective for disposal activities initiated after Dec. 31, 2002 with early adoption allowed.

Gains and Losses on Energy Trading Contracts

On Oct. 25, 2002, the Emerging Issues Task Force released EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, which 1) precludes mark-to-market accounting for energy trading contracts that are not derivatives pursuant to FAS 133, 2) requires that gains and losses on all derivative instruments within the scope of FAS 133 be presented on a net basis in the income statement if held for trading purposes, and 3) limits the circumstances in which a reporting entity may recognize a "day one" gain or loss on a derivative contract. The measurement provisions of the issue are effective for all fiscal periods beginning after Dec. 15, 2002. The net presentation provisions are effective for all financial statements issued after Dec. 15, 2002. In accordance with the recommended transition provisions, TECO Energy reclassified certain amounts in prior periods to present gains and losses on a net basis (see **Note A**). The adoption of the measurement provisions is not anticipated to have a material impact.

Guarantees

In November 2002, the FASB issued Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of others (an interpretation of FAS No. 5, 57, and 107 and rescission of FAS Interpretation No. 34)*, which modifies the accounting and enhances the disclosure of certain types of guarantees. FIN 45 requires that upon issuance of certain guarantees, the guarantor must recognize a liability for the fair value of the obligation it assumes under the guarantee. FIN 45's provisions for the initial recognition and measurement are to be applied to guarantees issued or modified after Dec. 31, 2002. The disclosure requirements are effective for financial statements of annual periods that end after Dec. 15, 2002 (see **Note R**).

Stock-Based Compensation

In December 2002, the FASB issued FAS 148, *Accounting for Stock-Based Compensation – Transition and Disclosure*, an amendment of FASB Statement No. 123. This standard amends FAS 123, *Accounting for Stock-Based Compensation*, to provide alternative methods of transition for companies that voluntarily change to the fair value based method of accounting for stock-based employee compensation. It also requires prominent disclosure about the effects on reported net income of the company's accounting policy decisions with respect to stock-

based employee compensation in both annual and interim financial statements. The transition provisions and annual disclosure requirements are effective for all fiscal years ending after Dec. 15, 2002, while the interim period disclosure requirements are effective for all interim periods beginning after Dec. 15, 2002. The adoption of the disclosure provisions of this standard does not have a material impact.

Consolidation of Variable Interest Entities

The equity method of accounting is used to account for investments in partnership arrangements in which TECO Energy or its subsidiary companies do not have a majority ownership or exercise control. On Jan. 17, 2003, the FASB issued FASB Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*, which imposes a new approach in determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as variable interest entities or VIEs. A legal entity is considered a VIE if it does not have sufficient equity at risk to finance its own activities without relying on financial support from other parties. Additional criteria must be applied to determine if this condition is met or if the equity holders, as a group, lack any one of three stipulated characteristics of a controlling financial interest. If the legal entity is a VIE, then the reporting entity determined to be the primary beneficiary must consolidate it. Even if a reporting entity is not obligated to consolidate a VIE, then certain disclosures must be made about the VIE if the reporting entity has a significant variable interest. Certain transition disclosures are required for all financial statements issued after Jan. 31, 2003. The on-going disclosure and consolidation requirements are effective for all interim financial periods beginning after June 15, 2003.

Based on a preliminary review, TECO Energy believes it is reasonably possible that FIN 46 may impact certain unconsolidated affiliates. Management is continuing to assess the extent of the relationships and obtain adequate information upon which to base appropriate conclusions. Below is a discussion of the legal entities existing as of Dec. 31, 2002 that TECO Energy considers to be possibly subject to either 1) additional disclosure requirements or 2) consolidation by the company, in accordance with FIN 46.

TPS entered into a joint venture, TPGC, to build, own and operate the Union and Gila River power stations. As of Dec. 31, 2002, TPGC is a development stage partnership that may meet the definition of a VIE in accordance with FIN 46. The third-party debt financing at TPGC is nonrecourse and does not create an estimated loss exposure to TECO Energy. The estimated maximum loss exposure is approximately the current and guaranteed equity investment in the partnership. (See **Notes A, N** and R.)

TPS completed a transaction whereby certain equipment at the Hardee Power Station was sold to a third party (the Lessor) and leased back under an operating lease agreement with an initial term of 12 years. The original cost of the equipment was $46.6 million. The sole purpose of the Lessor is to own and lease back the equipment to Hardee Power. The Lessor may be a VIE in accordance with FIN 46. The lease financing arrangement includes $41.6 million of subordinated debt and $1.4 million of equity contributed by an unrelated third party. If the Lessor were to be consolidated, TPS estimates that it would incur after-tax incremental expenses of approximately $9.5 million over the 12 year term of the lease. (See **Note R.**)

TECO Properties formed two limited liability companies with project developers which may meet the definition of a VIE. Hernando Oaks, LLC was formed by TECO Properties with the Pensacola Group to buy and develop 627 acres of land in Hernando County, Florida into a residential golf community comprised of an 18-hole golf course and 975 single-family lots for sale to homebuilders. Hernando Oaks, LLC had total assets at Dec. 31, 2002 of $18.9 million. TECO Properties' estimated maximum loss exposure in this project is approximately $9.7 million.

B-T One, LLC is a limited liability company formed by TECO Properties with Boyd Development Co., the project developer, to buy 592 acres of land in Ocala, Florida and to develop and sell 585 single-family lots to homebuilders. B-T One, LLC had total assets at Dec. 31, 2002 of $13.1 million. TECO Properties' estimated maximum loss exposure in this project is approximately $7.5 million.

TECO Propane Ventures (TPV) has an investment in a partnership formed to combine propane operations with the propane operations of three third-party entities. The partnership may meet the definition of a VIE as established in FIN 46. At Dec. 31, 2002, the estimated maximum loss exposure faced by TPV is approximately $44.6 million. (See **Note S.**)

TECO Transport entered into two separate sale-leaseback transactions for certain vessels which were recognized as sales at the time of each transaction, and are currently recognized as operating leases for the assets. The sale-leaseback transactions were entered into with a third party that may meet the definition of a VIE. TECO Transport currently leases two ocean-going tugboats, four ocean-going barges, five river towboats and 49 river barges. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable equipment to meet contractual obligations. (See **Note R.**)

TECO Energy Services (formerly TECO BGA) formed a partnership to construct, own and operate a water cooling plant to produce and distribute chilled water to customers via a local distribution loop for use, primarily, in air conditioning systems. The partnership may meet the definition of a VIE in accordance FIN 46. The estimated maximum loss exposure associated with this partnership is approximately $3.6 million as of Dec. 31, 2002.

In November 2000, TECO Energy established TECO Capital Trust I (Trust I) for the sole purpose of issuing Trust Preferred Securities (TRuPS) and using the proceeds to purchase company preferred securities from TECO Funding. Trust I may be a VIE in accordance with FIN 46. TECO Energy has guaranteed the payments to the holders of the company preferred securities and indirectly, the payments to the holders of the TRuPS, as a result of their beneficial interest in the company preferred securities.

Subsequently, in January 2002, TECO Energy sold 17.965 million units of mandatorily convertible equity units in the form of 9.5% equity units at $25 per unit. Each equity unit consisted of $25 in principal amount of a trust preferred security of TECO Capital Trust II (Trust II), a Delaware business trust formed for the purpose of issuing these securities. Trust II may meet the definition of a VIE in accordance with FIN 46. The estimated maximum loss exposure is not expected to be incrementally significant to obligations currently recognized by TECO Energy for the activities of either Trust I or Trust II. (See **Note G.**)

As a result of the conversion of a loan to a Panda Energy International subsidiary on Jan. 3, 2003, TPS has an equity interest in the TIE partnership (See **Note N**). The TIE partnership owns and operates the Odessa and Guadalupe power stations in Texas. The partnership may be a VIE in accordance with FIN 46. The estimated maximum loss exposure is approximately $137 million, representing TPS' equity investment as of Jan. 3, 2003.

U. Subsequent Event

On Jan. 30, 2003, TECO Energy received $98.1 million in cash for the repayment of a note receivable from the Municipal Gas Authority of Georgia, related to the sale of its coalbed methane assets on Dec. 20, 2002.

V. Quarterly Data *(unaudited)*

Financial data by quarter is as follows:

Quarter ended	*March 31*	*June 30*	*Sept. 30*	*Dec. 31*
2002				
Revenues[1]	$ 606.6	$ 677.7	$ 731.0	$ 660.5
Income from operations[1]	$ 89.2	$ 97.8	$ 142.5	$ 59.5
Net income[1]				
Net income from continuing operations	$ 69.9	$ 80.9	$ 112.8	$ 34.6
Net income	$ 75.4	$ 85.7	$ 118.9	$ 50.1
Earnings per share (EPS)- basic				
EPS from continuing operations	$ 0.50	$ 0.56	$ 0.72	$ 0.20
EPS	$ 0.54	$ 0.59	$ 0.76	$ 0.29
Earnings per share (EPS) - diluted				
EPS from continuing operations	$ 0.50	$ 0.56	$ 0.72	$ 0.20
EPS	$ 0.54	$ 0.59	$ 0.76	$ 0.29
Dividends paid per common share[2]	$ 0.345	$ 0.355	$ 0.355	$ 0.355
Stock price per common share[3]				
High	$ 28.940	$ 29.050	$ 24.710	$ 16.480
Low	$ 23.400	$ 22.700	$ 14.200	$ 10.020
Close	$ 28.630	$ 24.750	$ 15.880	$ 15.470
2001				
Revenues[1]	$ 641.3	$ 613.2	$ 659.6	$ 574.0
Income from operations[1]	$ 103.0	$ 95.4	$ 131.7	$ 68.1
Net income[1]				
Net income from continuing operations	$ 62.1	$ 61.8	$ 90.8	$ 59.1
Net income	$ 69.7	$ 71.9	$ 97.3	$ 64.8
Earnings per share (EPS)- basic				
EPS from continuing operations	$ 0.48	$ 0.46	$ 0.67	$ 0.43
EPS	$ 0.54	$ 0.53	$ 0.72	$ 0.47
Earnings per share (EPS) - diluted				
EPS from continuing operations	$ 0.47	$ 0.44	$ 0.66	$ 0.42
EPS	$ 0.53	$ 0.52	$ 0.71	$ 0.47
Dividends paid per common share[2]	$ 0.335	$ 0.345	$ 0.345	$ 0.345
Stock price per common share[3]				
High	$ 32.125	$ 32.970	$ 31.650	$ 28.300
Low	$ 26.100	$ 28.780	$ 25.530	$ 24.750
Close	$ 29.960	$ 30.500	$ 27.100	$ 26.240

(1) Millions.
(2) Dividend paid on TECO Energy common stock.
(3) Trading prices for common shares.

Report of Independent Certified Public Accountants

To the Board of Directors and Shareholders of TECO Energy, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common equity and cash flows present fairly, in all material respects, the financial position of TECO Energy, Inc. and its subsidiaries at Dec. 31, 2002 and Dec. 31, 2001, and the results of their operations and their cash flows for each of the three years in the period ended Dec. 31, 2002, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the **Notes C** and **B** to the **Financial Statements**, the Company adopted the provisions of Financial Accounting Standard 142, *Goodwill and Other Intangible Assets*, on Jan. 1, 2002 and Financial Accounting Standard 133, *Accounting for Derivative Instruments and Hedging*, on Jan. 1, 2001, respectively.

PricewaterhouseCoopers LLP

Tampa, Florida, Jan. 22, 2003, except for the information in Note U as to which the date is Jan. 30, 2003.

Selected Financial Data

(Millions, except per share amounts)	*Year ended Dec. 31,*	*2002*	*2001*	*2000*	*1999*	*1998*
	Revenues	$ 2,675.8	$ 2,488.1	$ 2,223.1	$ 1,932.6	$ 1,905.1
	Net income from continuing operations	$ 298.2[1]	$ 273.8[1]	$ 227.5[1]	$ 179.2[2]	$ 179.2[3]
	Income from discontinued operations	26.1	21.9	12.6	(16.3)	10.3
	Income tax benefit – discontinued operations	(5.8)	(8.0)	(10.8)	(23.2)	(17.0)
	Net income from discontinued operations	31.9	29.9	23.4	6.9	27.3
	Net income	$ 330.1[1]	$ 303.7[1]	$ 250.9[1]	$ 186.1[2]	$ 206.5[3]
	Total assets	$ 8,637.8	$ 6,763.4	$ 5,774.3	$ 4,733.0	$ 4,218.3
	Long-term debt	$ 3,324.3	$ 1,842.5	$ 1,374.6	$ 1,207.8	$ 1,279.6
	Earnings per share (EPS) – basic					
	From continuing operations	$ 1.95[1]	$ 2.04[1]	$ 1.81[1]	$ 1.37[2]	$ 1.36[3]
	From discontinued operations	.20	.22	.18	.05	.21
	EPS basic	$ 2.15[1]	$ 2.26[1]	$ 1.99[1]	$ 1.42[2]	$ 1.57[3]
	Dividends paid per common share[4]	$ 1.41	$ 1.37	$ 1.33	$ 1.285	$ 1.225

(1) Includes other non-operating items affecting net income (see Note L).
(2) Includes the effect of charges, which reduced net income by $19.6 million and earnings per share by $0.15 in 1999.
(3) Includes the effect of charges, which reduced net income by $19.6 million and earnings per share by $0.15 in 1998.
(4) Dividend paid on TECO Energy common stock.

Corporate Directory

TECO Energy Executive Officers

Robert D. Fagan	Chairman of the Board, President and Chief Executive Officer
John B. Ramil	Executive Vice President – TECO Energy and President, Tampa Electric
William N. Cantrell	President, Peoples Gas System and TECO Solutions
Royston K. Eustace	Senior Vice President – Business Development
Gordon L. Gillette	Senior Vice President – Finance and Chief Financial Officer
Richard Lehfeldt	Senior Vice President – External Affairs
Richard E. Ludwig	President, TECO Power Services
Sheila M. McDevitt	Senior Vice President – General Counsel
D. Jeffrey Rankin	President, TECO Transport
J.J. Shackleford	President, TECO Coal

TECO Energy Staff Officers

Charles A. Attal III	Vice President and Deputy General Counsel
Paul R. Bogenrieder	Vice President – Energy Risk Management
Deirdre A. Brown	Vice President – Regulatory Affairs
Sandra W. Callahan	Vice President – Treasury and Risk Management (Treasurer)
Clinton E. Childress	Chief Human Resources Officer
Margarita N. Dominguez	Chief Information Officer
Charles O. Hinson III	Vice President – State Government Affairs
Wayne W. Hopkins	Vice President – Corporate Communications
Burnis L. Kilpatrick, Jr.	Corporate Compliance Officer
Shirley A. Myers	Vice President – Corporate Accounting and Tax (Chief Accounting Officer)
David E. Schwartz	Vice President, Assistant General Counsel and Corporate Secretary
Janet L. Sena	Vice President – Federal Affairs

Board of Directors

Robert D. Fagan[3]	Chairman of the Board, President and Chief Executive Officer, TECO Energy, Inc., Tampa, Florida
DuBose Ausley[3]	Chairman, Ausley & McMullen (attorneys), Tallahassee, Florida
Sara L. Baldwin[2]	Private Investor, former Vice President, Baldwin and Sons, Inc. (insurance agency), Tampa, Florida
James L. Ferman, Jr.[1][4]	President, Ferman Motor Car Company, Inc. (automobile dealerships), Tampa, Florida
Luis Guinot, Jr.[2]	Partner, Shapiro Sher & Guinot, P.A. (attorneys), Washington, D.C., former United States Ambassador to the Republic of Costa Rica
Ira D. Hall[2]	President and Chief Executive Officer, Utendahl Capital Management, L.P. (money management), New York, New York, former Treasurer, Texaco, Inc. (integrated oil company), White Plains, New York
Sherrill W. Hudson[1]	Former Managing Partner for South Florida, Deloitte & Touche LLP (public accounting), Miami, Florida
Tom L. Rankin[1][3]	Independent Investment Manager, Tampa, Florida, former Chief Executive Officer, Lykes Energy, Inc. (the former holding company for Peoples Gas System)
William D. Rockford[3]	President, Private Power, LLC (power generation), Oak Brook, Illinois, former Managing Director, Chase Securities Inc. (financial services), New York, New York
William P. Sovey[2][4]	Chairman of the Board and former Chief Executive Officer, Newell Rubbermaid, Inc. (consumer products), Freeport, Illinois
J. Thomas Touchton[3][4]	Managing Partner, The Witt-Touchton Company (private investment partnership), Tampa, Florida
John A. Urquhart[2][3][4]	President, John A. Urquhart Associates (management consultants), Fairfield, Connecticut, former Senior Vice President/ Executive Vice President, G.E. Industrial & Power Systems, General Electric Company
James O. Welch, Jr.[2]	Former Vice Chairman, RJR Nabisco, Inc. and former Chairman, Nabisco Brands, Inc. (tobacco and food products), East Hanover, New Jersey

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Finance Committee
(4) Member of the Governance and Nominating Committee

Information for Investors

Internet
Current information about TECO Energy is on the Internet at www.tecoenergy.com

TECO Energy is listed on the New York Stock Exchange symbol: TE

TECO Energy Offices
TECO Plaza
702 N. Franklin Street
Tampa, FL 33602
813-228-1111
Fax 813-228-1670

Auditors
PricewaterhouseCoopers LLP
Tampa, FL

Annual Meeting
The Annual Meeting of Shareholders will be held on April 22, 2003, 11:30 a.m. at:
TECO Plaza
702 N. Franklin Street
Tampa, FL 33602

Shareholder Inquiries
Communication concerning transfer requirements, lost certificates, dividends and change of address should be directed to the Transfer Agent.

Transfer Agent & Registrar
Equiserve
P.O. Box 43010
Providence, RI 02940
800-650-9222
www.equiserve.com

Dividend Reinvestment
The company offers a Dividend Reinvestment and Common Stock Purchase Plan which allows common shareholders of record to purchase additional shares of common stock at the current market price. All correspondence concerning this Plan should be directed to the Plan Agent:
Equiserve
P.O. Box 9223
Chelsea, MA 02150

Form 10-K Available
TECO Energy's Annual Report on Form 10-K, which is filed with the Securities and Exchange Commission, is available to shareholders at no charge on the Internet at www.sec.gov or through the Investor Relations page at www.tecoenergy.com. Requests should be addressed to:
TECO Energy, Inc.
Investor Relations
P.O. Box 111
Tampa, FL 33601
813-228-1326
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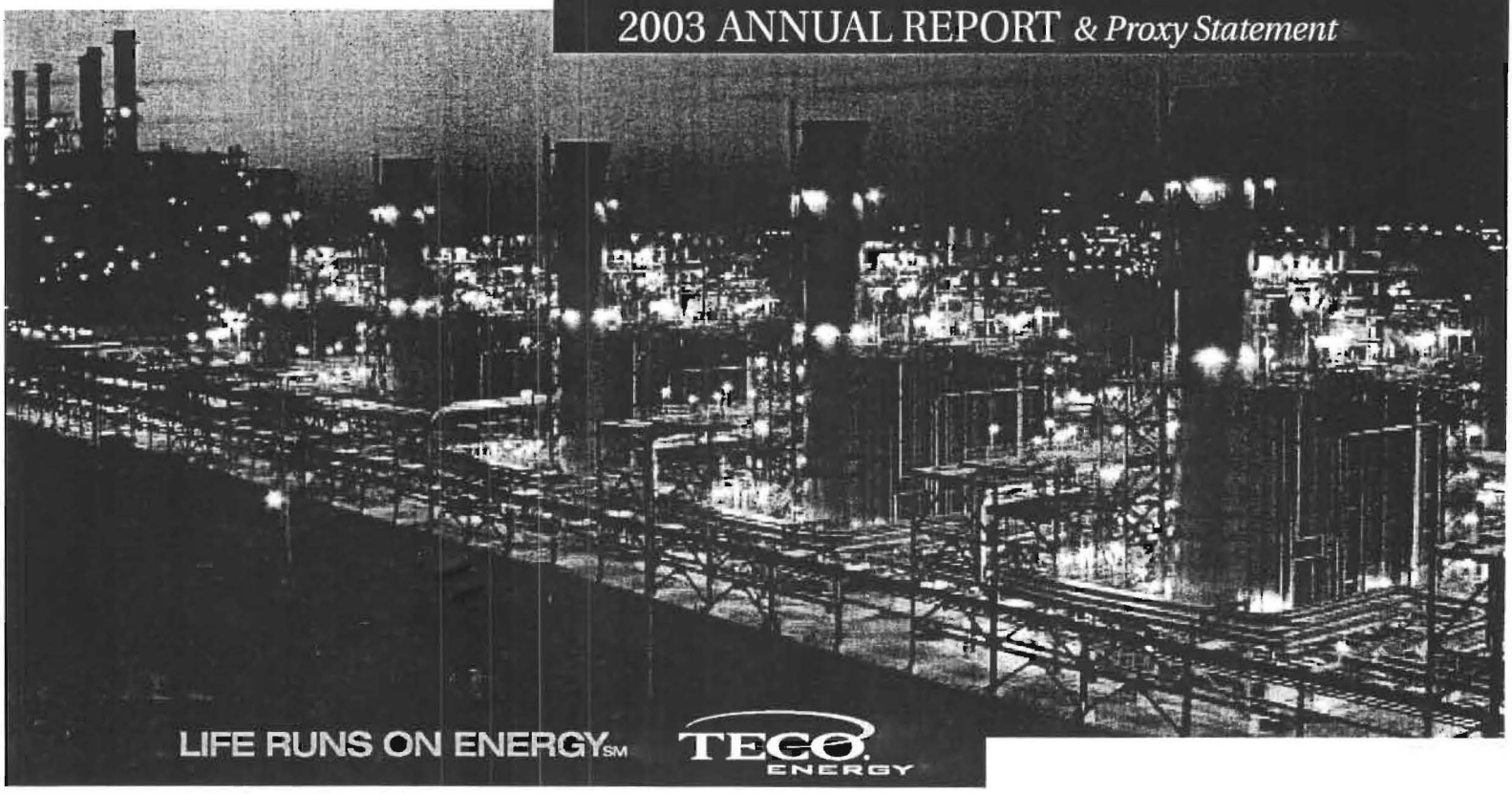
2003 ANNUAL REPORT *& Proxy Statement*



LIFE RUNS ON ENERGY℠

TECO ENERGY

TECO *Energy, Inc.*

TECO Energy, Inc. (NYSE: TE) is an integrated energy provider with core businesses in the utility sector, complemented by a family of unregulated businesses. In addition to the regulated operations of Tampa Electric and Peoples Gas System, TECO Energy has interests in waterborne transportation, coal and synthetic fuel production and independent power.

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(Cover) Tampa Electric's natural gas-fired Bayside Power Station.

LETTER *to Shareholders*

March 25, 2004

Dear Fellow Shareholders:

The year 2003 was a turning point for TECO Energy, as we changed course from the strategy we embarked on in 1999.

Then, markets were opening to electric competition, and investors paid premiums for companies with prospects for growth through independent power. National environmental policy was poised to change the nation's electric generating fleet through stringent regulations that would force the retirement of older, more polluting facilities. Against this backdrop, scores of new, more efficient, environmentally friendly power facilities were built to take the place of older, less efficient plants.

The competitive marketplace most had anticipated, for a variety of reasons, has not yet emerged. But what has emerged is TECO Energy's need to reduce risk to earnings and cash flow and rebuild shareholder value. Given current market conditions, there was really only one way to start down that road. In April 2003, we announced TECO Energy's new strategic direction – to return our company to its utility roots and focus on our regulated Florida operations.

Throughout the year, we worked diligently to limit our exposure to the merchant energy business and to address investor concerns regarding our financial condition. Unfortunately, a very difficult step toward restoring our financial health was the April 2003 dividend reduction. While this was an unpleasant step for me, and for the Board of Directors, it was a step we took to maintain TECO Energy's financial integrity.

This month, TECO Energy took its most significant step toward implementing our "back to basics" utility-focused strategy. We made the decision to exit our two largest independent power projects, Union and Gila River, through a sale to either the project lending banks or a third party. We have entered into a letter of intent with the banks regarding the transfer of these projects.

The decision to end TECO Energy's ownership of these projects and cease further funding is not, however, dependent on reaching final agreement with lenders. As such, we no longer take a long-term view of Union or Gila River, and we took a fourth-quarter 2003 write-off of $762 million (after tax), which clearly impacted our results for the quarter, and the year.

But, in any event, these charges are behind us, and we've begun to return to our roots, which are centered in the State of Florida. Our Florida energy market continues to grow and thrive, and in that market, we've renewed our emphasis on our regulated utilities, Tampa Electric and Peoples Gas. The regulated utility model is a business model that provides more sustainable growth at substantially lower risk.

In the future, we expect that you will see a different TECO Energy, but one that is familiar to long-time shareholders – a strong holding company with valuable Florida utilities that have profitable electric and gas operations. Both Tampa Electric and Peoples Gas have strong, sustainable growth.

And, we expect to continue to benefit from stable earnings and cash flow from our long-term unregulated transportation and coal businesses. While we may continue to have some investments in independent power projects, we expect that these remaining projects will have long-term contracts or otherwise be self-sustaining.

Our capital expenditure program at Tampa Electric and the independent power facilities is now complete. TECO Energy has no significant corporate debt maturities until 2007, and we expect free cash flow generated between now and then to reduce the company's levels of debt outstanding.

As you know, we took decisive steps during 2003 to improve our financial position. We will continue to seek to position ourselves for a return to a stronger financial position, and a return to earnings growth in the future.

As we enter 2004, I would like to take this opportunity to thank John A. "Jack" Urquhart for his service as a member of TECO Energy's Board of Directors. Effective April 28, 2004, Jack is retiring, after more than 13 years of service to the company.

And as always, thank you for your investment in TECO Energy.

Sincerely,

Robert D. Fagan
Chairman, President and Chief Executive Officer

MANAGEMENT'S *Discussion & Analysis*

of Financial Condition & Results of Operations

*This Management's Discussion and Analysis contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. These forward-looking statements include references to TECO Energy's anticipated capital investments, financing requirements, future transactions and other plans. Certain factors that could cause actual results to differ materially from those projected in these forward-looking statements include the following: energy price changes affecting the merchant plants at TECO Wholesale Generation, Inc. (formerly known as TECO Power Services) (TWG); TECO Energy's ability to complete the transfer of the ownership of the Union and Gila River power plants to the lending banks as described below or otherwise insulate itself from the adverse financial impact of those plants; TWG's ability to sell the output of its remaining merchant plants in the spot markets or to obtain power contracts to reduce earnings volatility; any unanticipated need for additional debt or equity capital that might result from lower than expected cash flow or higher than projected capital requirements; and TECO Coal's ability to successfully complete the sale of its synthetic fuel production facilities and to successfully operate its synthetic fuel production facilities in a manner qualifying for Section 29 federal tax credits which could be impacted by changes in law, regulation or administration. Other factors include: general economic conditions, particularly those in Tampa Electric's service area affecting energy sales; weather variations affecting energy sales and operating costs; regulatory actions affecting Tampa Electric, Peoples Gas System or TWG; commodity price changes affecting the competitive positions of Tampa Electric and Peoples Gas System, as well as the margins at TECO Coal; changes in and compliance with environmental regulations that may impose additional costs or curtail some activities; TWG's ability to successfully operate its projects; the ability of TECO Energy's subsidiaries to operate equipment without undue accidents, breakdowns or failures; and, interest rates, credit ratings and other factors that could impact TECO Energy's ability to obtain access to sufficient capital on satisfactory terms. Some of these factors and others are discussed more fully under "**Investment Considerations.**"*

TECO Energy, Inc. is a holding company, and all of its business is conducted through its subsidiaries. In this Management's Discussion and Analysis "we," "our," "ours," and "us" refer to TECO Energy, Inc. and its consolidated group of companies unless the context otherwise requires.

Overview

Our results and many of our activities in 2003 were driven by the capital requirements to complete the construction of the Union and Gila River power stations and the Tampa Electric Bayside Station repowering; the initial operations of Union and Gila River power stations and the poor financial performance of these two large plants; the generally poor financial results from our other merchant power plants; and our decision to exit our ownership of the Union and Gila River power stations, (see the **TECO Wholesale Generation** company section). (Merchant power plants are power plants that do not have long-term contracts for the majority of their output. Most of the power from a merchant power plant is sold under short-term agreements or in the more volatile spot markets.) At the same time, we were focused on implementing plans that included the completion of our cash generation plan announced in September 2002 and the sale of common stock, debt securities and certain assets to provide adequate liquidity in 2003 and beyond.

In April, we announced that our strategy for the future was to return to basics and to focus on our regulated utility operations in the high-growth Florida markets and to minimize the risks from the merchant power plants. Our results in 2003 reflect the significant changes made in our strategic direction with respect to our merchant operations.

Driven by the poor financial performance of the Union and Gila River power plants, the diminished prospects for power price improvement in the near term, and increased rating agency concerns regarding our exposure to the merchant energy sector, in October, we announced that we would invest little, if any, additional cash in the merchant generation portfolio. Following this announcement we entered into negotiations with the Union and Gila River lending bank group. These negotiations resulted in a non-binding letter of intent containing a binding settlement agreement in February 2004 to transfer ownership to the lenders through a purchase and sale, or other, agreement. The letter of intent is described in the TECO Wholesale Generation company discussion.

Results Summary

Our financial results for 2003 reflect the write-offs associated with our decision to exit from our ownership of the two large merchant plants, which are included as discontinued operations, and losses incurred at the merchant plants. The net loss in 2003 was $909.4 million, primarily due to $1,084.1 million of charges detailed in the following table. These losses were partially offset by gains from the sale of Hardee Power Partners and the second installment on the sale of TECO Coalbed Methane. The net loss from continuing operations was $14.7 million, compared with net income from continuing operations of $277.2 million in 2002. Non-GAAP net income from continuing operations excluding the effects of Hardee Power Partners (HPP) and charges was $164.8 million in 2003, compared with $305.8 million in 2002. Results in 2003 from discontinued operations reflect the results from the Union and Gila River power stations and the associated charges; the results at the coalbed methane business, which was sold in December 2002; the results of Prior Energy, which was in the process of being sold at Dec. 31, 2003 and closed in February 2004 and the results of TECO Gas Services, whose gas marketing book of business was sold in the third quarter of 2003.

Results from continuing operations were lower primarily due to charges associated with rationalizing our remaining merchant portfolio, restructuring charges associated with a corporate restructuring and staffing reductions, valuation adjustments at the energy services companies and limitations on the use of tax credits. (See the table **2003 Non-operating Items Affecting Net Income.**) Results from continuing operations excluding charges were lower due to higher depreciation expense at Tampa Electric, as a result of a regulatory decision related to the timing of the shutdown of the Gannon Station and higher interest expense associated with the debt incurred to fund Tampa Electric's Bayside repowering project, continued weak results at TECO Transport due to lower coal tonnage for Tampa Electric due to the Bayside repowering to natural gas and continued weakness in the river business; higher interest expense associated with the debt incurred to fund the construction of the TWG power projects; lower results from TWG's Frontera Station in Texas due to power prices in that market; and the elimination of interest and support income from

Panda Energy related to the TIE projects. These results were partially offset by the gain on the sale of HPP and higher operating results at TECO Coal from increased synthetic fuel production and sales and the sale of the 49.5% interest in the synthetic fuel production facilities.

The net loss on a per-share basis was $5.05 in 2003, compared with earnings of $2.15 per share in 2002. The loss from continuing operations on a per-share basis was $0.08 in 2003, including charges and gains totaling $1.00 per share detailed below, compared with earnings per share from continuing operations of $1.81 per share in 2002, including charges totaling $0.18 per share. The number of average shares outstanding at Dec. 31, 2003 was more than 17 percent higher than at Dec. 31, 2002.

In 2002, net income was $330.1 million. Net income from continuing operations was $277.2 million, compared with $265.5 million in 2001. The 2002 results reflect continued customer growth and increased energy usage in the Florida utility operations, higher allowance for funds used during construction (AFUDC – a non-cash credit to income with a corresponding increase in utility plant which represents the cost of borrowed funds and a reasonable return on the equity funds used for construction) at Tampa Electric, the results at TWG, and increased synthetic fuel production and sales at TECO Coal. These improvements were partially offset by lower results at TECO Transport. Revenues in 2002 increased 7 percent to $2.7 billion.

Included in the 2002 results from continuing operations were a $20.9 million after-tax charge related to a debt refinancing, a $10.9 million after-tax charge associated with an employee staffing reduction program at Tampa Electric and others, and a $5.8 million after-tax asset valuation charge related to the sale of TWG's minority interest in power generating facilities in the Czech Republic.

In 2002, earnings per share from continuing operations were $1.81 per share, compared with $1.98 per share in 2001. The number of average shares outstanding at Dec. 31, 2002 was almost 14 percent higher than at Dec. 31, 2001. Total non-GAAP net income and earnings per share in 2002, excluding the restructuring, debt refinancing and asset valuation charges, the impact of HPP operations and the $7.7 million gain on the sale of TECO Coalbed Methane, were $305.8 million and $1.99 per share, respectively.

Our 2003 results reflect the gain on the sale of HPP and the 2003 net income from HPP's operations through the date of sale in continuing operations. The gain on the sale and the operations were originally reported in discontinued operations for the quarter ended Sept. 30, 2003. A re-evaluation of the accounting originally applied to the sale, by us and our independent auditors caused us to reclassify the results from HPP to continuing operations and record the gain on the sale in the fourth quarter. This change did not impact our overall results for 2003. See **Note 24** to the **Consolidated Financial Statements** for a comparison of revised results to previously reported results.

2003 Earnings Summary

(millions)	*2003*	*2002*	*2001*
Consolidated revenues	**$2,740.0**	$2,664.9	$2,483.3
Earnings (loss) per share – basic			
Earnings per share	**$ (5.05)**	$ 2.15	$ 2.26
Less: Discontinued operations	**(4.95)**	0.34	0.28
Cumulative effect of change in accounting principle	**(0.02)**	–	–
Earnings from continuing operations before cumulative effect of change in accounting principle	**$ (0.08)**	$ 1.81	$ 1.98
Less: Charges and gains from continuing operations	**(1.00)**	(0.18)	–
Earnings per share from continuing operations before charges and gains	**$ 0.92**	$ 1.99	$ 1.98
Earnings (loss) per share – diluted			
Earnings per share	**$ (5.05)**	$ 2.15	$ 2.24
Less: Discontinued operations	**(4.95)**	0.34	0.28
Cumulative effect of change in accounting principle	**(0.02)**	–	–
Earnings from continuing operations before cumulative effect of change in accounting principle	**$ (0.08)**	$ 1.81	$ 1.96
Less: Charges and gains from continuing operations	**(1.00)**	(0.18)	–
Earnings per share from continuing operations before charges and gains	**$ 0.92**	$ 1.99	$ 1.96
Net income (loss)	**$ (909.4)**	$ 330.1	$ 303.7
Less: Net income (loss) from discontinued operations	**(890.4)**	52.9	38.2
Cumulative effect of change in accounting principle	**(4.3)**	–	–
Charges and gains from continuing operations	**(179.5)**	(28.6)	9.0
Net income from continuing operations before charges and gains	**$ 164.8**	$ 305.8	$ 256.5
Average common shares outstanding			
Basic	**179.9**[3]	153.2[2]	134.5[1]
Diluted	**179.9**[3]	153.3[2]	135.4[1]

(1) Average shares outstanding for 2001 reflects the issuance of 8.625 million shares in March 2001 and 3.5 million shares in October 2001.
(2) Average shares outstanding for 2002 reflects the issuance of 15.525 million shares in June 2002 and 19.385 million shares in October 2002.
(3) Average shares outstanding for 2003 reflects the issuance of 11 million shares in September 2003.

2003 Non-operating Items Affecting Net Income

Net income impact (millions)	*Tampa Electric*	*TWG*	*Peoples Gas*	*TECO Transport*	*TECO Coal*	*Coalbed Methane*	*Other Unregulated*	*TECO Energy*	*Total*
Merchant power valuation [1]	$ –	$762.0	$ –	$ –	$ –	$ –	$ –	$ –	$ 762.0
Turbine valuations	48.9	–	–	–	–	–	28.5	–	77.4
Goodwill impairment	–	61.2	–	–	–	–	12.8	–	74.0
Loss on joint venture termination [1]	–	94.7	–	–	–	–	–	–	94.7
TMDP arbitration reserve	–	26.7	–	–	–	–	–	–	26.7
Restructuring costs	6.1	0.3	2.6	1.0	–	–	3.6	1.6	15.2
Project cancellation costs	–	–	–	–	–	–	9.0	–	9.0
Valuation adjustment	–	–	–	–	–	–	11.1	–	11.1
Tax credit reversals	–	–	–	–	7.0	–	2.7	–	9.7
Change in accounting	–	–	–	0.8	0.3	–	–	3.2	4.3
Total Charges	$ 55.0	$944.9	$ 2.6	$ 1.8	$7.3	$ –	$67.7	$ 4.8	$1,084.1
Gain on Asset sales	$ –	$ –	$ –	$ 3.5	$ –	$23.5 [1]	$35.2	$ –	$ 62.2

(1) Included in discontinued operations.

The table below reconciles GAAP net income to non-GAAP net income after elimination of Hardee Power Partners and the charges referred to above that are not expected to recur. Management believes that this non-GAAP presentation provides useful supplemental information by providing a measure that is more closely related to the company's ongoing operations.

Net Income Reconciliation

(millions)	*2003*	*2002*	*2001*
GAAP net income (loss)	$ (909.4)	$ 330.1	$ 303.7
Add change in accounting	4.3	–	–
Exclude discontinued operations	(890.4)	52.9	38.2
GAAP net income (loss) from continuing operations	$ (14.7)	$ 277.2	$ 265.5
Add: Tax credit reversals	9.7	–	–
Project cancellation costs	9.0	–	–
TECO Solutions valuation adjustment	7.9	–	–
Hamakua FIN 46 accounting valuation adjustment	3.2	–	–
Restructuring costs	15.2	10.9	–
TMDP arbitration reserve	26.7	–	–
Debt extinguishment costs	–	20.9	–
ECKG valuation adjustment	–	5.8	–
Goodwill impairments	74.0	–	–
Turbine valuations	77.4	–	–
Subtract: Hardee gain on sale	(34.6)	–	–
Hardee operating results	(9.0)	(9.0)	(9.0)
Non-GAAP net income from continuing operations [1][2]	$ 164.8	$ 305.8	$ 256.5

(1) Excludes adoption of FAS 143, FAS 142 adjustments and items noted in table above.
(2) A non-GAAP financial measure is a numerical measure of historical or future financial performance, financial position or cash flow that includes that amounts, or is subject to adjustments that have the effect of including amounts, that are excluded from the most directly comparable measure GAAP so calculated and presented.

Strategy and Outlook

In late 1999, TECO Energy announced a three-pronged business strategy which was to focus on its Florida operations, which included Tampa Electric, Peoples Gas System (PGS) and the Florida energy services businesses, TECO Solutions; to expand its domestic independent power operations at TWG; and to use the returns of its family of other profitable unregulated businesses to support growth. Since that time, the company undertook a number of initiatives to advance the announced strategy. These initiatives included continued development of the regulated electric and gas businesses in Florida, including significant additions to Tampa Electric's electric generation facilities, development of independent power generation projects in the Sunbelt of the United States and continued good operations and returns on investments from the other unregulated businesses.

However, conditions in energy markets and the independent power business have changed since the announcement of this strategy, which have dramatically changed the prospects for the investments in the domestic independent power generation facilities. Starting in 2001, future wholesale power prices declined significantly in markets across the country driven by high profile events such as the failure of deregulation in California and the Enron bankruptcy combined with a general slowing of wholesale electric competition; less than full economic dispatch in some areas of the country; the U.S. economic slowdown; and the large amount of new generating capacity that came online in 2002 and 2003 that contributed to significant excess generating capacity in many areas of the country. While wholesale power prices improved in a few markets in 2003, in general they remained weak and the prospects for long-term price recovery remained uncertain for the next several years in markets where we had made major investments. In addition to the impacts of lower prices, potential buyers of firm power under long-term contracts have been unwilling to enter into such longer-term contracts for a variety of reasons, including the current excess capacity in many areas. The low power prices and lack of long-term contracts have caused weaker earnings and cash flow expectations from merchant power projects and caused us, and other developers, to cancel or delay projects in some markets.

In April 2003, we announced that we were ceasing any new

development activities in the independent power business, and that we were changing our strategy to refocus on the regulated utility operations. At the time of the decision to expand the independent power operations, our announced strategy was to construct facilities and sign contracts for the majority of the output and have only a small percentage of the output in the spot, or merchant market. This is not consistent with the current wholesale power market model, where most transactions are short term agreements and spot sales. The weakened wholesale power markets and the changing market dynamics resulted in a change in our strategy.

Following the completion of the large Union and Gila River power stations, in the face of weak conditions in the merchant energy markets, in October 2003, we announced that we would invest little, if any, additional cash in the existing merchant generating plants. Following a thorough review of the outlook for the non-recourse project-financed Union and Gila River power plants, and assessment of our ability to continue to support the plants, we determined to cease providing equity funding to the projects, and to sell our ownership interest in these projects to the lending banks or others.

With the reduction of business risk and elimination of the associated losses expected from these plants over the next several years, we will be positioned to focus on our electric and gas utilities, which operate in one of the best energy markets in the country, the high-growth Florida market. In addition, we will have the earnings and cash flow from our long-term profitable unregulated coal and transportation businesses and those wholesale power generating plants with contracts.

Over the last two years, we have taken significant steps, including asset sales, dividend reduction and capital markets transactions to meet our cash and liquidity needs associated with our large construction program. As discussed in the **Liquidity and Capital Resource** section, we have made significant progress in improving our liquidity position over the past few years and look forward in 2004 to having to meet our needs for significantly lower levels of capital expenditures which should result in positive cash flow. Accordingly, the strong cash-producing assets previously considered for potential sale, TECO Transport and the Guatemalan assets, are not being offered for sale. It is possible, however, that unforeseen cash shortfalls or increased capital spending requirements could cause us to revisit our liquidity plans. (See the **Investment Considerations** section.)

Without the losses from the large merchant power projects we expect improved financial results primarily from our regulated businesses, Tampa Electric and PGS. Our major capital expenditure program is complete, and capital expenditures are expected to be at maintenance levels for the next several years. We have no significant corporate debt maturities due until 2007. We expect to use free cash flow generated in the 2004 through 2006 period to reduce the levels of debt outstanding and therefore the refinancing needs in 2007. We continue to take steps as necessary to position ourselves for a return to a stronger financial position and a return to earnings growth in the future.

Operating Results

Management's Discussion & Analysis of Financial Condition and Results of Operations utilizes TECO Energy's consolidated financial statements, which have been prepared in accordance with GAAP, to analyze the financial condition of the company.

TECO Energy's reported operating results are affected by a number of critical accounting estimates such as those involved in our accounting for regulated activities, asset impairment testing, accounting for unconsolidated affiliates and others. (See the **Critical Accounting Policies and Estimates** section.)

The following table shows the unconsolidated revenues, net income and earnings per share contributions from continuing operations of the significant business segments (as we have redefined them). (See **Note 19** to the **Consolidated Financial Statements**.)

(millions) Except per share amounts		*2003*	*2002*	*2001*
Unconsolidated Revenues [1]				
Regulated Companies	Tampa Electric	$1,586.1	$1,583.2	$1,412.7
	Peoples Gas System	408.4	318.1	352.9
Total Regulated		$1,994.5	$1,901.3	$1,765.6
Unregulated Companies	TWG	$ 95.9	$ 111.1	$ 81.8
	TECO Transport	260.6	254.6	274.9
	TECO Coal	296.3	317.1	303.5
	Other unregulated businesses	263.5	297.7	298.8
Total Unregulated		$ 916.3	$ 980.5	$ 959.0
Net Income [2]				
Regulated Companies	Tampa Electric	$ 98.9	$ 171.8	$ 154.0
	Peoples Gas System	24.5	24.2	23.1
Total Regulated		$ 123.4	$ 196.0	$ 177.1
Unregulated Companies	TWG	$ (147.6)	$ (7.9)	0.5
	TECO Transport	15.3	21.0	27.6
	TECO Coal	77.1	76.4	59.0
	Other unregulated businesses	(5.4)	27.8	22.1
Total Unregulated		(60.6)	117.3	109.2
Financing/Other		(77.5)	(36.1)	(20.8)
Net income (loss) from continuing operations		(14.7)	277.2	265.5
Discontinued operations		(890.4)	52.9	38.2
Net income (loss) before cumulative effect of change in accounting principle		(905.1)	330.1	303.7
Cumulative effect of a change in accounting principle		(4.3)	–	–
Net income		$ (909.4)	$ 330.1	$ 303.7
Earnings per Share - Basic [2]				
Regulated Companies	Tampa Electric	$ 0.55	$ 1.12	$ 1.15
	Peoples Gas System	0.14	0.16	0.17
Total Regulated		0.69	$ 1.28	$ 1.32
Unregulated Companies	TWG	$ (0.82)	$ (0.05)	$ 0.00
	TECO Transport	0.08	0.14	0.20
	TECO Coal	0.43	0.50	0.44
	Other unregulated businesses	(0.03)	0.18	0.17
Total Unregulated		(0.34)	0.77	0.81
Financing/Other		(0.43)	(0.24)	(.15)
Earnings (loss) per share from continuing operations		(0.08)	1.81	1.98
Discontinued operations		(4.95)	0.34	0.28
Earnings (loss) per share before cumulative effect of change in accounting principle		(5.03)	2.15	2.26
Cumulative effect of a change in accounting principle		(0.02)	–	–
EPS Total		$ (5.05)	$ 2.15	$ 2.26

(1) Revenues for all periods have been adjusted to reflect the presentation of energy marketing related revenues on a net basis, the reclassification of TECO Coalbed Methane, Hardee Power Partners, Prior Energy and TECO Gas Services results to discontinued operations, and the reclassification of earnings from equity investments from Revenues to Other Income.

(2) Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated finance costs for 2003, 2002 and 2001 were at pre-tax rates of 8%, 7%, and 7%, respectively, based on the average investment in each subsidiary.

Tampa Electric - Electric Operations Results

Tampa Electric's net income decreased 42 percent in 2003 to $98.9 million, reflecting a $48.9 million after-tax write-off associated with combustion turbine purchase cancellations, accelerated depreciation related to Gannon Station coal fired assets of $15.6 million after tax, a $5.1 million after-tax disallowance by the Florida Public Service Commission (FPSC) in the November 2003 fuel adjustment hearings for operations and maintenance expenses for the Gannon Station (see the **Regulation** section), lower AFUDC equity, a $6.1 million after-tax restructuring charge associated with a staffing reduction program and higher interest expense. Tampa Electric's net income before the restructuring and turbine cancellation charges was $153.9 million. The expense items previously noted and lower sales to other utilities and decreased sales to phosphate customers more than offset continued good residential and commercial customer growth, lower operations and maintenance expenses and more favorable summer weather. The equity component of AFUDC, primarily from the Gannon to Bayside Units 1 and 2 repowering project, decreased to $19.8 million, compared to $24.9 million in 2002.

Tampa Electric's net income increased almost 12 percent in 2002, reflecting good customer growth, slightly higher residential and commercial per-customer energy usage, and a favorable customer mix, lower interest expense and higher AFUDC equity, primarily from the Gannon to Bayside Units 1 and 2 repowering project, partially offset by higher operations, maintenance and depreciation expenses. AFUDC equity increased to $24.9 million, compared with $6.6 million in 2001. Net income increased in 2002 while operating income decreased, due to higher AFUDC and lower interest expense which affect net income but not operating income.

Summary of Operating Results – Tampa Electric

(millions)	*2003*	*Change*	*2002*	*Change*	*2001*
Revenues	$1,586.1	0.2%	$1,583.2	12.1%	$1,412.7
Other operating expenses	202.8	-4.5%	212.3	11.3%	190.7
Maintenance	90.8	-16.4%	108.7	9.2%	99.5
Depreciation	210.3	10.8%	189.8	9.5%	173.4
Taxes, other than income	112.6	0.3%	112.3	7.2%	104.8
Non-fuel operating expenses	616.5	-1.1%	623.1	9.6%	568.4
Fuel	443.3	4.5%	424.1	22.4%	346.5
Purchased power	234.9	-7.4%	253.7	21.0%	209.7
Total fuel expense	678.2	0.1%	677.8	21.9%	556.2
Turbine valuation adjustment	79.6	–	–	–	–
Total operating expenses	$1,374.3	5.6%	$1,300.9	15.7%	$1,124.6
Operating income	$ 211.8	-25.0%	$ 282.3	-2.0%	$ 288.1
Net income	$ 98.9	-42.4%	$ 171.8	11.6%	$ 154.0
Turbine cancellation charges after tax	48.9	–	–	–	–
Restructuring charges after tax	6.1	–	10.3	–	–
Net income before charges	$ 153.9	-15.5%	$ 182.1	18.2%	$ 154.0

Tampa Electric Operating Revenues

Retail megawatt hour sales rose 1.8 percent in 2003, primarily from increased residential and commercial sales from customer growth and higher per-customer usage among residential customers. Electricity sales to the lower-margin industrial customers in the phosphate industry decreased 7.4 percent in 2003 after an 18.2 percent increase in 2002. Low prices for phosphate fertilizers and high raw material costs contributed to temporary closures of phosphate production facilities during the year. Domestic phosphate consumption is expected to remain relatively stable for the next several years with increased demand from China driving the export market. The company's phosphate customers have indicated that prices have improved from the low levels experienced in 2003, but production may vary to maintain stable prices in 2004. Base revenues from phosphate sales represented slightly less than 3 percent of base revenues in 2003 and 2002. Non-phosphate industrial sales increased in 2003 and 2002, primarily reflecting continued economic growth in the area.

Base rates for all customers were unchanged in 2003. Fuel-related revenues increased in 2003 under the FPSC approved fuel adjustment clause due to the recovery of a previous under recovery of fuel expense in 2002 and higher natural gas prices starting in late 2002 and continuing in 2003. Rates under the fuel adjustment clause will increase in 2004 under the rates approved by the FPSC in November 2003 to reflect the increased use and higher cost of natural gas with the completion of the Bayside Power Station repowering to natural gas.

Sales to other utilities for resale declined in 2003, primarily as a result of lower coal-fired generating unit availability due to the shut down of the Gannon Station coal fired generation in preparation of the conversion to natural gas, and the scheduled Jan. 1, 2003 expiration of the Big Bend Station power sales agreement with Hardee Power Partners. Energy sales to other utilities are expected to remain stable in 2004, due to incremental generation being gas fired, which is at a higher cost due to gas prices.

Based on projected growth from continued population increases and business expansion, Tampa Electric expects average retail energy sales growth of more than 2.5 percent annually over the next five years, with combined energy sales growth in the residential and commercial sectors of 3 percent annually. Tampa Electric's forecasts indicate that summer retail demand growth is expected to average more than 100 megawatts per year for the next five years. These growth projections assume continued local area economic growth, normal weather and a continuation of the current energy market structure. (See the Investment Considerations section.)

The economy in Tampa Electric's service area continued to grow in 2003, aided by the region's relatively low labor rates, attractive cost of living and affordable housing. The Tampa metropolitan area's employment grew slightly in 2003, in spite of the continued U.S. economic slowdown in the first half of the year. The local Tampa area unemployment rate peaked in January 2003 at 4.9 percent before falling to 3.7 percent in December 2003, (compared with 4.3 percent in December 2002), and 4.7 percent for the State of Florida and 5.7 percent for the nation. The Tampa area, with its diverse service-based economy, did not experience the same drop in economic activities as those areas of the country with manufacturing-based economies. Studies by local economic development agencies have shown that the Tampa Bay region has been one of the last regions in Florida to enter a recession and one of the first to recover from an economic slowdown.

Megawatt-Hour Sales

(thousands)	*2003*	*Change*	*2002*	*Change*	*2001*
Residential	8,265	2.7%	8,046	6.0%	7,594
Commercial	5,860	0.5%	5,832	2.6%	5,685
Industrial	2,579	-1.2%	2,612	12.2%	2,329
Other	1,538	7.2%	1,435	4.9%	1,368
Total retail	18,242	1.8%	17,925	5.6%	16,976
Sales for resale	691	-36.2%	1,084	-27.7%	1,499
Total energy sold	18,933	-0.4%	19,009	2.9%	18,475
Retail customers (average)	604.9	2.5%	590.2	2.5%	575.8

Tampa Electric Operating Expenses

Total operating expenses, excluding the $79.6 million pre-tax charge for combustion turbine purchase cancellations, were almost unchanged in 2003 as lower non-fuel operations and maintenance expenses for power generation plants and lower purchased power expenses virtually offset higher fuel costs from increased use of higher cost natural gas; higher depreciation from normal plant additions and accelerated depreciation on the Gannon coal assets, which ceased operations in 2003, and increased employee benefits costs. Operating expenses increased almost 16 percent in 2002, reflecting higher fuel costs from an increased amount of power generated with higher-cost oil and natural gas, increased purchased power due to lower unit availability, higher operating expenses due to higher employee benefit costs and costs associated with a staffing reduction program which resulted in a 7 percent reduction in the workforce, higher depreciation from normal plant additions to serve the growing customer base and the addition of a new peaking combustion turbine at the Polk Power Station in mid-2002, and accelerated depreciation

associated with phasing out coal-related assets at the Gannon Power Station.

Non-fuel operations and maintenance expenses are expected to decrease in 2004 as a result of workforce reductions in 2003 and 2002 and the operation of Bayside Power Station, which has lower manpower and maintenance requirements.

Depreciation expense is projected to decrease in 2004 due to the end of the accelerated depreciation on the now retired Gannon Station coal-fired assets, partially offset by normal plant additions and the completion of the Bayside repowering project where commercial service began on the first phase in April 2003 and the second phase on Jan. 15, 2004. (See the **Environmental Compliance** section.) Accelerated depreciation on the Gannon Station coal fired assets was $25 million pre-tax in 2003.

Fuel costs increased 4.5 percent in 2003, primarily due to increased use of natural gas at the first phase of the Bayside Power Station and across the board increases for fuel costs that ranged from 5 percent per million BTU for coal to 10 percent for natural gas. Fuel costs increased 22 percent in 2002 despite lower coal costs, reflecting primarily increased generation with oil and natural gas due to lower coal unit availability. Coal prices have varied from year to year from a 5 percent increase in 2003, a 6 percent decrease in 2002 and a 7 percent increase in 2001 due to supply and demand and the prices of other fuels.

Purchased power decreased in 2003, primarily due to the operations of the first phase of the Bayside Power Station in time for summer peak loads. Purchased power expense increased in 2002 due to lower unit availability, primarily as a result of planned maintenance outages on base load generating units and unplanned outages during peak load periods. The effects of higher fuel and purchased power costs are also reflected in the higher operating revenues, as these costs are recovered through the fuel adjustment clause. Purchased power is expected to decline significantly in 2004, due to the operation of the newly repowered Bayside Station.

Prior to 2003, nearly all of Tampa Electric's own generation was produced from coal. Starting in April 2003, the mix started to shift with increased use of natural gas at the Bayside Station. Coal is expected to be more than half of the fuel in the Tampa Electric mix due to the base-load units at Big Bend and the coal gasification unit, Polk Unit One. Natural gas use is expected to increase again in 2004 with the commercial operation of the second phase of the Bayside Station on Jan. 15, 2004. (See the **Environmental Compliance** section.) On a total energy supply basis, company generation accounted for 81 percent, 83 percent and 84 percent of the total system energy requirements in 2003, 2002 and 2001, respectively.

Peoples Gas System Operations Results

PGS is the largest investor-owned gas distribution utility in Florida. It serves almost 292,000 customers in all of the major metropolitan areas of Florida.

Net income increased in 2003 from customer growth of 5.2 percent and a $12 million base revenue increase effective in January 2003, which more than offset the impact of milder than normal late winter weather, the effects of higher natural gas prices and higher operations expenses.

Gas prices rose significantly in the second half of 2002 and again in 2003 and have remained high compared to 2001 levels. The higher cost of gas has had a negative impact on sales to larger interruptible and power generation customers, especially in the second half of 2003. Many of these customers have the ability to switch to alternative fuels or to alter consumption patterns. Initially the gas price increases in 2003 did not cause significant fuel switching as the differential between natural gas and other fuels remained relatively constant; however, the persistent high natural gas prices and the forecast for continued high prices caused fuel switching to increase in the second half of 2003.

PGS net income rose almost 5 percent in 2002. Contributing to these results were 4.1 percent customer growth, operations and maintenance expenses which were essentially unchanged from 2001, and higher volumes sold for off-system sales and higher volumes transported for power generation customers which more than offset the impact of mild winter weather.

Historically, the natural gas market in Florida has been underserved with the lowest market penetration in the southeastern U.S. PGS is expanding its gas distribution system into areas of Florida not previously served and within areas currently served.

Summary of Operating Results – Peoples Gas System

(millions)		*2003*	*Change*	*2002*	*Change*	*2001*
Revenues		$ 408.4	28.4%	$ 318.1	-9.9%	$ 352.9
Cost of gas sold		224.0	50.3%	149.0	-20.1%	186.4
Operating expenses		130.0	12.5%	115.6	.2%	115.4
Operating income		$ 54.4	1.7%	$ 53.5	4.7%	$ 51.1
Net Income		$ 24.5	1.2%	$ 24.2	4.8%	$ 23.1
Restructuring charges		$ 2.6	—	$ 0.0	—	$ 0.0
Net income before charges		$ 27.1	12.0%	$ 24.2	4.8%	$ 23.1
Therms sold - by customer segment	Residential	64.2	6.6%	60.2	2.4%	58.8
	Commercial	354.8	8.3%	327.6	6.0%	308.9
	Industrial	406.3	-4.1%	423.8	22.3%	346.5
	Power Generation	363.7	-26.2%	492.6	22.1%	403.5
Total		1,189.0	-8.8%	1,304.2	16.7%	1,117.7
Therms sold - by sales type	System Supply	337.3	1.4%	332.5	13.8%	292.2
	Transportation	851.7	-12.3%	971.7	17.7%	825.5
Total		1,189.0	-8.8%	1,304.2	16.7%	1,117.7
Customers (thousands) - average		291.9	5.2%	277.5	4.1%	266.6

In 2003, residential and commercial therm sales increased from customer growth of over 5 percent in 2003, and colder than normal early winter weather. Therm sales to large industrial and power generation customers decreased, primarily from significantly higher gas prices.

Residential therm sales increased in 2002, the result of customer growth of more than 4 percent and increased per-customer usage, more than offsetting milder-than-normal weather. Commercial therm sales also increased, primarily from increased per-customer use.

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a Purchased Gas Adjustment (PGA) clause approved by the FPSC annually.

In Florida, natural gas service is unbundled for all non-residential customers, affording these customers the opportunity to purchase gas from any provider. The net result of this unbundling is a shift from commodity sales to transportation sales. Because commodity sales are included in operating revenues at the cost of the gas on a pass-through basis, there is no net financial impact to the company when a customer shifts to transportation-only sales. PGS markets its services to these customers through its "NaturalChoice" program. At year-end 2003, 10,500 customers had elected to take service under this program.

Operating expenses increased in 2003, driven primarily by higher employee-related costs, including restructuring costs. Operating expenses in 2002 were essentially unchanged from 2001 levels. Depreciation expense increased in both years, in line with the increased capital expenditures made over the past several years to expand the system.

On June 27, 2002, PGS requested a $22.6 million annual base revenue increase. On Dec. 17, 2002, the FPSC authorized PGS to increase annual base revenues by $12.05 million. The new rates allow for a return on equity range of 10.25 to 12.25 percent with an 11.25 percent midpoint, which is the same as its previously allowed return on equity, and a capital structure of 57.43 percent equity. The increase went into effect on Jan. 16, 2003. (See the **Regulation** section.)

In May 2002, Gulfstream Natural Gas Pipeline initiated service. This interstate pipeline starts in Mobile Bay, Alabama, crosses the Gulf of Mexico and comes ashore in Florida just south of Tampa. Gulfstream is the first new pipeline serving peninsular Florida since 1959. This pipeline increases gas transportation capacity into Florida by 50 percent. PGS entered into a service agreement for capacity in 2002, which increases in 2003 and 2004. The addition of the Gulfstream pipeline enhances reliability of service and helps to meet the capacity needs for PGS' growing customer base.

In 2003, PGS decreased the level of capital expenditures to expand its system into areas of Florida previously unserved by natural gas to $42 million, a level below the prior three years. PGS expansion strategy for the next several years is to take advantage of the significant capital investments in main pipeline expansions made over the past five years and connect customers to that existing infrastructure. PGS expects increases in sales volumes and corresponding revenues in 2004, and continued customer additions and related revenues from its build-out efforts throughout the state of Florida. These growth projections assume continued local economic growth, normal weather and other factors. (See the **Investment Considerations** section.)

TECO Wholesale Generation, Inc.
(Formerly TECO Power Services)

In 1999, we announced that a component of our strategy was to expand our presence in the domestic independent energy industry. (See the **Strategy and Outlook** section.) Our decision to invest in this industry was made more than three years ago, based on the outlook then for the energy markets beyond 2001. Many states were opening their markets to more competitive models, electric demand was growing with the growing economy, and we saw opportunities to earn attractive returns on our investments.

We have rethought our independent power strategy in the face of many factors. These factors include lack of support for deregulation that was originally anticipated to materialize, the existence of supply well in excess of demand, and the outlook for a continuing weak power price environment in the markets where we have built plants.

In September 2002, we announced that we had ceased all new project development at TWG. In April 2003, we announced that we would seek to increase our flexibility to be able to mitigate the risk from the merchant portfolio through a number of steps, including the termination of joint ventures with Panda Energy in the Union and Gila River power stations (TPGC) and in the Texas Independent Energy (TIE) plants. The termination of the joint venture with Panda Energy was accomplished by mid-year for the Union and Gila River projects and in the third quarter for the TIE projects .

In October 2003, we announced that we would put little if any additional cash into the merchant generation portfolio. In February 2004, we established a plan to exit from our ownership of the Union and Gila River plants that included a non-binding letter of intent with the lending banks for those projects that would allow such an exit. Completion of the plan is subject to the lender group's approval and execution of definitive agreements, which will contain customary closing conditions and require certain regulatory approvals. Definitive agreements are expected by the end of the second quarter with final closing targeted for the end of the third quarter of 2004. Until closing, TWG will continue to operate the plants consistent with previous operations and be compensated for these operations, while working with the lenders to effect a smooth transition upon change of ownership. Our decision to exit from our ownership of these projects is not dependent on reaching a final agreement with the lenders for a consensual transfer.

As part of our renewed focus on our utility operations, we have revised certain internal reporting information used for decision-making purposes. The results of TWG are now focused on the results of operations for the Frontera, Commonwealth Chesapeake, Dell and McAdams power plants, as well as the equity investment in the TIE, the Odessa and Guadalupe power plants, and TECO EnergySource, Inc. (TES), the energy marketing operation for the merchant plants. The non-merchant power assets that were formerly reported with TECO Power Services include our interest in the Hamakua Power Station in Hawaii, the Guatemalan operations (which include the San José and Alborada power stations and our interest in the Guatemalan distribution utility, EEGSA) and Hardee Power Partners, which was sold in October 2003. These are now reported with **Other Unregulated Companies.**

TWG Project Summary

	Project	Location	TWG Economic Size MW	TWG Net Interest	In Service/ Participation Size MW	Date [1]
Operating:	Frontera Power Station	Texas	477	100%	477	5/00, 3/01[2]
	Odessa and Guadalupe	Texas	2,000	50%	1,000	9/00, 8/01
	Commonwealth Chesapeake Power Station	Virginia	315	100%	315	9/00, 8/01
			2,792		1,792	
Suspended:	Dell	Arkansas	599	100%	599	
	McAdams	Mississippi	599	100%	599	
			1,198		1,198	
Held for Sale:	Union	Arkansas	2,200	100%	2,200	1/03-6/03
	Gila River	Arizona	2,145	100%	2,145	2/03-8/03
			4,345		4,345	

(1) Unless otherwise indicated, each date appearing in this column is an in-service date. When more than one in-service date appears, it indicates when different phases of the project went into operation.
(2) Dates on which TWG acquired its economic interest in the project.

Merchant Generation Facilities

Continuing operations at TWG recorded a $147.6 million loss in 2003, primarily due to its portion of the $61.2 million after-tax goodwill write-offs associated with the Frontera and Commonwealth Chesapeake plants, the $26.7 million after-tax arbitration reserve associated with the ownership of the Commonwealth Chesapeake Power Station and the operating losses from the merchant generating plants. Other factors influencing results in 2003 were the loss of interest income from the TIE plants when the loan to Panda Energy converted into an equity ownership position in January 2003, and the cessation of capitalization of interest on the Dell and McAdams plants.

The loss for the merchant portfolio in 2002 (restated to reflect continuing operations) was $7.9 million, primarily from full year of ownership of the Frontera Power Station. The results included a $5.8 million after-tax charge related to the sale of TWG's minority interest in generating assets in the Czech Republic, higher operations and maintenance expense, lower energy prices and sales from the Commonwealth Chesapeake Station and higher financing costs.

Results in 2001 included earnings from the Commonwealth Chesapeake and Frontera generating stations and higher returns on TWG's investment through Panda in the TIE projects, and a $6.1 million after-tax valuation reserve recognized in connection with the sale of TWG's minority interest in EGI, which owns small generating projects in Central America.

TWG's two investments, in the form of a loan to Panda, converted into an indirect ownership interest in TIE in early 2003, totaled $137 million. In September 2003, TWG completed the foreclosure on Panda's interest in TIE for a default on a $23 million note receivable which resulted in TWG becoming a 50-percent owner in the plants and a total investment of $160 million. In 2003, improved peak season power prices and a new power and gas manager retained to increase the energy sales from these plants resulted in improved financial performance; however, the plants still had a negative impact on earnings. The interest on the loans to TIE was reflected in 2002 and 2001 earnings.

In 2003, the 477 megawatt, natural gas-fired, combined-cycle Frontera Power Station, located near McAllen, Texas sold its output in the spot market in Texas. While prices in Texas improved during the peak summer months due to an outage at a large nuclear facility in south Texas, the plant had a negative impact on earnings due to power prices and increased maintenance expenses. In 2002, the Frontera plant facility sold energy and ancillary services to the Electric Reliability Council of Texas (ERCOT) under a reliability-must-run contract which contributed to higher earnings that year.

In 2003, weaker results for the 315 megawatt simple-cycle, oil-fired Commonwealth Chesapeake Power Station on the Delmarva Peninsula in Virginia were impacted by the mild and wet summer weather in that area of the nation, which reduced peak summer load. 2003's results also included its portion of a $61.2 million after-tax goodwill write off required under FAS 142, *Goodwill and Other Intangible Assets*, and a $26.7 million after-tax reserve for an arbitration award against TMDP, the indirect owner of this plant. This plant is a peaking plant that is designed to operate primarily in the summer and sell in the PJM market. The plant's location on the Delmarva Peninsula gives it a location advantage due to few competing generating resources in the area and transmission system constraints on the peninsula. In addition to electric energy, the plant sells ancillary services such as spinning reserve and capacity in the PJM market.

TWG owns two 599-megawatt, natural gas-fired, combined-cycle projects, Dell and McAdams, located in Arkansas and Mississippi, respectively. Construction on these projects was suspended at the end of 2002 due to projected low energy prices in the markets that these plants were expected to serve. The carrying costs, primarily due to the cessation of interest capitalization, associated with these suspended plants reduced TWG earnings in 2003. Market conditions will be monitored to determine when these plants will be completed. At the time of suspension, approximately $690 million had been invested in these plants. It is estimated that the total construction cost to complete these projects would be approximately $100 million.

Energy Markets

TWG's operating merchant power plants are located in markets with a history of high load growth. However, the general U. S. economic slowdown over the past several years slowed the growth in demand for power in some of these markets. In addition, the slowdown of electricity deregulation initiatives across the United States, including the markets that TWG serves, caused in part by the failure of deregulation in California and other events, has allowed the traditional, incumbent utilities to continue to operate older, less efficient generating facilities in lieu of purchasing power from newer, more efficient independent power plants. These factors have combined with aggressive plans by the independent power industry to add merchant power facilities to cause excess generating capacity that is either being built or has come on line in many markets. This excess supply has depressed both spot and forward wholesale power prices.

Studies by numerous outside groups, such as Cambridge Energy Research Associates, Standard & Poor's and others, present conflicting outlooks on power price improvement , but most experts indicate that while spot power prices stabilized in some markets in 2003, power prices are expected to remain low well beyond 2004.

TWG has been unable to secure long-term contracts for the output of these plants; therefore, their production has been sold under a mix of spot market sales and shorter-term transactions in 2003 and 2002. TECO Energy's policy is to balance power contract

commitments with necessary purchases of natural gas in order to know the margins for such sales at the time of commitment. These sales usually do not include the value for capacity payments, ancillary services, dispatchability and the premium associated with owning physical assets. These incremental value components are often captured in the spot market at the time of physical sales or through more structured transactions.

In 2001, TECO EnergySource (TES) began entering into power marketing and fuel procurement transactions. TES is actively seeking both short- and long-term contracts with purchasers for the output from the Frontera Power Station. Our current below investment grade credit rating limits TES' ability to hedge significant amounts of forward sales without posting collateral, which it is not doing.

The merchant operations normally balance their fixed-price physical and financial fuel purchase and energy sales contracts in terms of contract volumes and the timing of performance and delivery obligations. Net open positions may exist for short periods due to the origination of new transactions. When net open positions exist, the merchant operations will be exposed to fluctuating market prices. All fuel purchase and energy sales contracts and open positions are monitored closely by the TECO Energy risk management function, which is independent of the merchant operations.

In addition to price risk, credit risk is inherent in TWG's energy risk management activities. The marketing business may be exposed to counterparty credit risk from a counterparty not fulfilling its obligations. Credit policies and procedures, administered by TECO Energy, attempt to limit overall credit risk. The credit procedures include a thorough review of potential counterparties' financial position, collateral requirements under certain circumstances, monitoring net exposure to each counterparty and the use of standardized agreements.

Significant factors that could influence results at TWG include energy prices in its markets, weather, domestic economic conditions and commodity price changes. (See the **Investment Considerations** section.)

Union and Gila River Power Stations

In February 2004, we announced our decision to exit from our ownership of the Union and Gila River projects and to cease further funding of these plants. We, as the equity investor, and the project companies that own the two large plants have entered into a non-binding letter of intent containing a binding settlement agreement with the lenders that provided the non-recourse project financing for these projects that contemplates negotiation of an agreement for the purchase and sale or other agreement to transfer ownership of the plants to these banks. As part of the contemplated transaction, the outstanding non-recourse project debt (owed by the project companies) would be satisfied. The decision to end the ownership of the plants and cease further funding is not, however, dependent on reaching final agreement with the lenders for a consensual transfer. Even without such an agreement, the project companies, which are currently indirect subsidiaries of TECO Energy, could pursue other disposition alternatives that would ultimately end TECO Energy's ownership of the plants.

Letter of Intent

The lending group for the Union and Gila River projects approved a non-binding letter of intent containing a binding settlement agreement on Feb. 5, 2004. Under the agreement, we and the project companies will work toward a definitive agreement with the lenders for a purchase and sale or other agreement to transfer of the ownership of the projects to the lenders in exchange for a release of all obligations under the project loan agreements. The letter of intent specifies target dates for a definitive agreement by Jun. 30, 2004 and for closing by Sep. 30, 2004. The settlement agreement provides for the treatment of the $66 million of letters of credit posted by us under the Construction Undertaking, with $35 million drawn in February 2004 for the benefit of the project companies and the remaining $31 million of letters of credit to be cancelled and returned to us. Under the letter of intent, all parties have specified a target completion of due diligence for final acceptance under the construction and undertaking contracts for both projects within 45 days from Feb. 6, 2004; however, we and the project companies will remain responsible to address certain permit issues at the Gila River project. We will make no new investment in the projects. Since the projects have achieved commercial operation on all facilities at Union and Gila River, we believe that we have met all but limited warranty and final acceptance responsibilities to the project companies. We and certain of our subsidiaries plan to continue to provide services and continue to provide expertise and operating support to help the project companies operate the facilities consistent with past practices at least through the completion of the transfer of ownership. The lenders and we and our affiliates have reserved the right to assert certain claims against one another until a definitive agreement is reached.

Expiration of Suspension / Standstill Agreement

The letter of intent permits the parties to reserve their rights against each other, including with respect to our failure to comply with the 3.0 times EBITDA-to-interest ratio coverage requirement in our Construction Undertakings for the quarters ending Sep. 30 and Dec. 31, 2003 (a cross default to the non-recourse credit agreements) that were covered by the Suspension Agreement, which has expired, and the failure of the project companies to make interest payments on the non-recourse project debt and payments under interest rate swap agreements due Dec. 31, 2003 when the project lenders declined to fund the debt service reserve.

As a result, the lending group could seek to exercise remedies against the project companies due to defaults in connection with the non-recourse project debt, including accelerating the non-recourse debt, foreclosing on the project collateral and suspending further funding; subject to the defenses we may have. While there can be no assurance that the lenders group will not exercise these rights, we believe that the lenders would prefer to effect a consensual transfer of the projects in accordance with the letter of intent.

Accounting Treatment

Based on our short-term view of these projects and the efforts to dispose of them, our consolidated financial results include, as of Dec. 31, 2003, an asset impairment of $762 million, after tax, for previous investments to reflect adjustments to the value of the subsidiaries that own the interests in the two plants. These after-tax impairment charges include the asset valuation adjustments resulting in the write off of the full equity investment in the facilities, costs related to the related accelerated impact of the change in hedge accounting for interest rate swaps and a related valuation allowance for certain state tax benefits. The Union and Gila River power stations are considered "Held for Sale" and are included in discontinued operations for income statement purposes, and the assets and liabilities are separately stated as "Held for Sale" on the balance sheet. This accounting treatment could be affected in future periods, depending on the ultimate disposition of our ownership in the plants.

TECO Transport

Net income in 2003 was $15.3 million, before a $0.8 million charge for a change in accounting principle, compared with $21 million in 2002. The decrease was primarily due to lower tonnage for Tampa Electric due to the conversion of the Gannon Station from coal to the natural gas fired Bayside Station, continued weak results from the river transportation and terminal businesses due to lower northbound shipments and a very competitive pricing environment, higher labor and repair costs, and a $1.0 million

after tax restructuring charge. Results for 2003 also include a $3.5 million after-tax gain associated with the disposition of ocean-going assets no longer used by TECO Ocean Shipping and scrap river barges at TECO Barge Line.

In 2002, net income declined 24 percent from 2001. 2002 results reflected continued weakness in the U.S. economy as low levels of imported raw materials reduced northbound river shipments and drove pricing lower for all river shipments. These conditions also reduced volumes of petroleum coke and steel-related product volumes through the transfer terminal. These conditions combined to more than offset increased ocean-going phosphate shipments and lower repair and fuel costs.

Northbound river shipments of steel-related raw materials did not improve in 2003 as expected due to continued weakness in the U.S. economy and production problems for furnace coke, which is imported from China for domestic steel production. Additionally, northbound petroleum coke shipments were reduced for six months due to production problems at a major producer. Southbound river shipments of grain products increased in 2003, with much better pricing during the fall grain shipping season. The recovery of the U.S. economy is expected to increase the volumes in 2004 at the same time that consolidation in the river shipping business is expected to reduce capacity. This combination is expected to improve pricing slightly.

The phosphate fertilizer industry, an important business segment for TECO Ocean Shipping, continued its efforts to balance supply and demand to support prices in 2003. TECO Ocean Shipping expects phosphate shipments to be at 2003 levels in 2004.

TECO Transport operating companies expect to be impacted by lower shipments for Tampa Electric, but expect to replace a portion of this tonnage with increased third-party business, as well as lower operations and maintenance expenses in 2004.

TECO Transport expects to continue diversifying into new markets and cargoes. Future growth at TECO Transport is dependent on improved pricing, higher asset utilization, and asset additions at both the river and ocean-going businesses. Significant factors that could influence results include weather, bulk commodity prices, fuel prices and domestic and international economic conditions. (See the **Investment Considerations** section.)

TECO Transport has two operating leases with an aggregate value of about $100 million as a result of sale-leaseback transactions entered into in 2001 and 2002 that provide for a cross-default in the event TECO Energy or any of its affiliates defaults in the payment of certain obligations. The failure of the Union and Gila River project companies to make payments on the non-recourse project debt, could result in a cross default entitling the lessors to terminate the leases and recover certain amounts. However, we have reached agreement in principle, subject to definitive agreements being executed, with the lessors on amendments to the leases that would eliminate this possible cross-default.

TECO Coal

In 2003, net income increased slightly to $77.1 million before a $0.3 million after-tax charge for a change in accounting principle on total coal sales of almost 9.2 million tons. These results were driven by expensing $7.0 million after tax for the loss of unutilized Section 29 tax credits, lower volumes and prices for conventional coals and higher mining costs due to the use of marginal and waste coals for the production of synthetic fuel, which were more than offset by higher volumes of synthetic fuel production and sales and the sale of a 49.5% interest in the synthetic fuel production facilities. The loss of the tax credits is due to generating tax credits in excess of the company's current regular income tax expense as the tax rules only qualify synthetic fuel tax credits up to a taxpayer's current regular income tax expense.

Synthetic fuel production and sales increased to 5.8 million tons in 2003 from 3.8 million tons and 3.2 million tons in 2002 and 2001, respectively. In April 2003, TECO Coal sold a 49.5% interest in its synthetic fuel production facilities. Under this transaction, TECO Coal is paid to provide feedstock, operate the synthetic fuel production facilities and sell the output while the purchaser has the risks and rewards of ownership including being allocated 49.5% of the tax credits and operating costs. In addition to funding the operating costs of the 49.5% share, TECO Coal recognizes a gain on the sale of the facilities for each installment sale payment. The net income for the year includes $55.8 million of gain from this sale.

Net income was $76.4 million in 2002 compared with $59.0 million in 2001. The 30% increase was driven primarily by better margins and higher synthetic fuel (synfuel) production and sales and the resulting higher Section 29 tax credits. Total coal sales, including synthetic fuel, were 9.3 million tons in 2002. Synthetic fuel production displaced some of the conventional coal production in all years.

In 2004, total coal sales and synthetic fuel production are expected to remain at about 2003 levels, with virtually all planned production sold forward under a variety of contracts of varying terms. Coal prices for 2004 have improved after declining in 2003 and 2002. Higher prices for competing fuels, better balance in supply and demand, lower producer inventories and consolidation in the mining industry are contributing to the improved prices. Late in 2003 and early 2004 spot coal prices increased sharply. TECO Coal contracts much of its coal production for the coming year in the preceding year and is less affected by the rapid price changes, both upward and downward than those companies that sell a higher percentage in the spot markets.

In January 2000, TECO Coal purchased synthetic fuel facilities from Headwaters Technologies, Inc. The facilities were relocated to the company's Premier Elkhorn and Clintwood Elkhorn mines in Kentucky, and were producing by the second quarter of 2000. These facilities produce synthetic fuel from coal, coal fines and waste coal using a technology licensed from Headwaters. The facilities were subsequently sited at all three of TECO Coal's complexes.

TECO Coal has received private letter rulings (PLRs) from the Internal Revenue Service regarding the qualification of synthetic fuel production from its facilities. The PLRs confirm that the facilities are located appropriately and produce a qualified fuel eligible for Section 29 tax credits which are available for the production of such non-conventional fuels through 2007.

In June 2003, the Internal Revenue Service (IRS) suspended the issuance of PLRs to taxpayers seeking certainty regarding the use of the Section 29 tax credits for the production of synthetic fuel from coal. The suspension was due to questions raised within the IRS regarding the validity of the production of a significant chemical change in the production of synthetic fuel as required under Section 29. TECO Coal's sale of the 49.5% interest of its production facilities required an updated PLR. During the suspension period, all cash paid to TECO Coal by the purchaser was held in escrow pending resolution of the PLR issue. In October 2003, the IRS concluded its review and resumed issuing PLRs. TECO Coal received a PLR from the IRS on Oct. 31, 2003 that resolved any uncertainty related to the sale, triggered the release of $70.7 million of cash held in escrow and confirmed that the synthetic fuel produced by TECO Coal is eligible for Section 29 tax credits and that its test procedures are in compliance with the requirements of the IRS.

Significant factors that could influence TECO Coal's results include weather, general economic conditions, commodity price changes, continued generation of Section 29 tax credits, the sale of interest in the synthetic fuel production facilities, the ability to use Section 29 tax credits and changes in laws, regulations or administration. (See the **Investment Considerations** section.)

Other Unregulated Companies

Independent Power Project Summary

Project	*Location*	*Size MW*	*Economic Interest*	*Net Size MW*	*In Service/ Participation Date* [1]
Alborada Power Station	Guatemala	78	96%	75	9/95
Empresa Eléctrica de Guatemala S.A.(EEGSA) (a distribution utility)	Guatemala		24%		9/98 [2]
San José Power Station	Guatemala	120	100%	120	1/00
Hamakua Energy Project	Hawaii	60	50%	30	8/00, 12/00
Total non-merchant		258		225	

(1) Unless otherwise indicated, each date appearing in this column is an in-service date. When more than one in-service date appears, it indicates when different phases of the project went into operation.
(2) Dates on which TWG acquired its economic interest in the project.

We now include the non-merchant independent power operations in our Other Unregulated Companies segment for financial reporting purposes. These include the San José and Alborada power stations in Guatemala, our ownership interest in EEGSA, the Guatemalan distribution utility, our 50 percent ownership of the Hamakua Power Station in Hawaii, and HPP, which was sold in October 2003. Other unregulated companies include, TECO Solutions, TECO Partners and TECO Investments.

In 2003, the other unregulated companies reported a loss of $5.4 million, which included $67.7 million of after-tax charges previously discussed partially offset by the $34.6 million after-tax gain on the sale of HPP. (See the **Earning Summary** section.) Excluding charges, gains and $9.0 million of net income from nine months of operations at HPP, net income was $18.7 million which included $24.7 million from the independent power operations and a $7.0 million loss at TECO Solutions. The loss at TECO Solutions was driven primarily by project losses. Results from the independent power operations reflect higher net income from EEGSA from increased energy sales at higher prices and favorable currency translation gains, more than offset by unfavorable tax adjustments on the Guatemalan assets and increased maintenance costs for scheduled maintenance at the San José Power Station.

Many of the other unregulated companies were formed or acquired during the early stages of Florida's proposed electric industry restructuring, as a vehicle through which we could potentially expand our services to other parts of the state. The subsequent rollback of the proposed deregulation and our refocus on our core utility operations has caused us to reexamine our continued participation in these lines of business. As a result of this reexamination, in the third quarter we sold TECO Gas Services' book of business; in November we announced the sale of our interest in TECO Propane Ventures (TPV) which closed in January 2004 (see below); in December we entered into an agreement to sell our end use gas marketing company Prior Energy and closing was completed in February 2004; and, in January 2004 we sold TECO Energy Services (formerly TECO BGA) to an employee group.

TPV held the company's propane business investment. In 2000, TECO Energy combined its propane operations with three other southeastern propane companies to form U.S. Propane. In a series of transactions, U.S. Propane combined with Heritage Holdings, Inc. In January 2004, U.S. Propane completed the sale of its direct and indirect equity investments in Heritage Propane Partners, L.P. (Heritage). The sale, part of a larger transaction that involved the merging of privately held Energy Transfer Company with Heritage, was announced in November 2003. Our portion of the sale generated $49.4 million of cash and a $17.2 million pre-tax book gain.

Liquidity, Capital Resources

At Dec. 31, 2003, we had cash and cash equivalents of $108.2 million, excluding all restricted cash, and $590.1 million of availability under our bank credit facilities, net of letters of credit of $109.9 million outstanding under these facilities. The availability under the bank credit facilities included the $250 million undrawn Tampa Electric facility; the undrawn Merrill Lynch facility; and the $350 million TECO Energy multi-year facility, undrawn except for the $110.1 million of outstanding letters of credit.

Restricted cash is comprised of $15.4 million of cash held in escrow under the sale agreement for the 49.5% interest of TECO Coal's synthetic fuel production facilities to provide credit support for the company's obligations under the sale agreement due to the company's current credit rating, and $36.0 million held in escrow from the sale of Hardee Power Partners. In February 2004, $29.0 million of the Hardee escrow amounts were returned as expected.

2003 sources of cash included cash from operations of $329 million, net cash proceeds from asset sales of $245 million, and proceeds from debt and equity sales of $792 million. Cash was used to fund $638 million of capital investing, long term debt repayments of $526 million, short term debt reduction of $323 million and common dividends of $165 million.

TECO Energy met 2002 cash needs with a mix of externally and internally generated funds. Cash from operations was $656 million, and proceeds from the sale of debt and equity were $2.8 billion. Cash was used to fund $1.7 billion of capital spending (net of $103 million from asset sales), debt maturities of $788 million and refinancings of $162 million, net reduction of short term debt of $278 million and dividends to common shareholders of $216 million.

Cash from Operations

In 2003, cash flow from operations was affected by the accounting for the sale of interests in the synthetic fuel production facilities at TECO Coal, the benefits of which are recorded in financing and investing activities as described more fully below, the payment of taxes associated with asset sales in 2002 and 2003, the under recovery of fuel expense at Tampa Electric, and the impact on working capital due to the consolidation of the Union and Gila River power projects, which were previously recorded as unconsolidated joint ventures. The substantial charges for asset and goodwill impairments, loss on the Panda joint venture termination and the TWG arbitration reserve did not affect cash from operations.

In April 2003, TECO Coal sold a 49.5% interest in its synthetic fuel production facilities located at its operations in eastern

Kentucky. Cash flow from operations includes the operating losses of $9.00 - $11.00 per ton (pre-tax) associated with the production of synthetic fuel, while the cash benefits from the sale of the synthetic fuel production facilities of approximately $30 per ton (pre-tax) are included in the investing and financing activities on the Consolidated Statement of Cash Flows. Investing activity includes cash from the gain on the sale of the synthetic fuel facilities. The company expects to record a quarterly gain associated with the sale of the assets through the life of the contract. The cash paid by the owner for its portion of the operating loss from the production of synthetic fuel is included in Financing Activities as a minority interest.

TES and Prior Energy were required to post collateral to contract counterparties due to the downgrade of TECO Energy's credit rating to non-investment grade in April 2003. As of Dec. 31, 2003, collateral posted of $12 million is included in working capital as a prepaid item.

Cash from operations in 2004 will be affected by lower cash payments of income taxes and collection by Tampa Electric of the under-recovered fuel expense from 2003, offset in part by greater operating losses associated with synthetic fuel. We anticipate selling additional interests in our synthetic fuel facilities in 2004 which, as described previously, will decrease cash from operations but substantially benefit cash from investing and financing.

We have not made a contribution to our defined benefit pension plan since the 1995 plan year because investment returns had been more than sufficient to cover liability growth. Negative stock market returns in 2001 and 2002 reduced the overfunding of the plan and, based on plan asset values at Jan. 1, 2003 and 2004, it is estimated that TECO Energy will be required to make a $14.2 million contribution to its defined benefit plan in September 2004 and a cash contribution of a similar amount in 2005. (See **Note 16 to the Consolidated Financial Statements.**)

Cash from Investing Activities

Investing activities of $393 million in 2003 included capital investments totaling $638 million, reduced by net asset sales proceeds of $245 million. Asset sales included $98 million from the second installment on the sale of our coalbed methane gas production assets, $72 million from the sale of Hardee Power Partners (net of cash escrows), and installments of $35 million (net of escrows) from the sale of the 49.5% interest in TECO Coal's synthetic fuel facilities.

Capital spending in 2003 represented the completion of a substantial capital investment program both for TWG's merchant power facilities and for Tampa Electric's Bayside Station. In 2004 and for the next several years, we expect capital spending at a "maintenance" level supporting customer growth, safety and reliability, and renewal and replacement of capital. (See **Capital Investment** section.) In January 2004 we sold TECO Propane Ventures, realizing $49.4 million of proceeds, and also received $29 million from the release of escrow in February 2004 from the Hardee sale. We also closed the sale of Prior Energy in February 2004 and received total proceeds of $30 million, including payment for the value of gas inventory.

Cash from Financing Activities

Cash proceeds from long-term debt in 2003 included a $250 million Tampa Electric note issue, a $300 million TECO Energy note issue, and draws of $111 million under the Union and Gila River non-recourse bank facilities. We raised $137 million from the sale of common stock consisting primarily of the direct placement of 11 million shares to Franklin Advisors in September 2003. Debt repayments included the $375 million equity bridge loan for the Union and Gila River power projects, Tampa Electric's $75 million mortgage bond maturity, a $25 million Transport capital lease maturity, and scheduled principal installments of PGS debt and non-recourse project debt. We also reduced short-term borrowings by $323 million in 2003, including the November repayment of a $350 million bank term loan maturity.

We have no significant corporate debt maturities until 2007. Long-term debt maturities in 2004 are $31.6 million, consisting primarily of installment payments of non-recourse project debt, but excluding the project debt of the Union and Gila River power stations. (See **Note 7 to the Consolidated Financial Statements.**) Our $37.5 million drawn credit facility was repaid in February 2004. We do not expect to issue debt in 2004, except for the planned refinancing of the San José non-recourse project debt in Guatemala, expected to provide net cash proceeds of $40 million and a planned refinancing of $75 million of Tampa Electric First Mortgage Bonds with a 7.75% coupon.

Liquidity Outlook

In 2002 and 2003, our cash and liquidity needs were significant as we faced the funding obligations associated with large construction programs at TWG and Tampa Electric, significant debt maturities, and the liquidity requirements associated with a merchant power business strategy in a difficult power price market. We took significant steps in this time period to meet these needs, including selling assets, raising external capital, reducing capital spending by canceling or delaying for an extended period generation projects, reducing our exposure to merchant power and reducing our common dividend.

Our future liquidity needs will be lower because the major construction programs at TWG and Tampa Electric are now complete, we have no significant upcoming debt maturities, and our business risk will be reduced because of our planned exit from the large Union and Gila River power stations. Tampa Electric currently targets available liquidity (cash plus available undrawn credit lines) of $250 million and, in November, replaced its maturing bank credit facility with new facilities totaling $250 million. While TECO Energy has previously targeted available liquidity of $325 million, we expect to target available liquidity of approximately $200 million in the future, for the reasons described above. We expect that we will replace the expiring $350 million TECO Energy credit facility prior to its expiration with a smaller facility.

Bank Credit Facilities

At Dec. 31, 2003, we had a bank credit facility of $350 million with a maturity date of November 2004 and a $100 million credit facility with Merrill Lynch, and Tampa Electric had bank credit facilities totaling $250 million with maturity dates in November 2004 and November 2006, described below. All were undrawn at Dec. 31, 2003, except for outstanding letters of credit under the $350 million TECO Energy facility. In November 2002, we converted another $350 million bank credit line then in effect into a one-year term loan which was repaid on Nov. 13, 2003.

Our bank credit facility maturing November 2004 includes a $250 million sublimit for letters of credit. At Dec. 31, 2003, $109.9 million of letters of credit were outstanding against that line, of which $66 million related to the construction of the Union and Gila River power stations. These letters of credit represented the remaining amounts of letters of credit posted in May 2003 under the Construction Undertaking posting requirements upon our downgrade to non-investment grade in April 2003. In February 2004, by agreement of the parties, $35 million of these letters of credit were drawn by the lending banks, and the remaining $31 million were cancelled and returned to us. (See the **Covenants in Financing Agreements** section.) In addition, at Dec. 31, 2003, we and our subsidiaries had $0.2 million of letters of credit outside of our bank credit line facility outstanding, and the Union and Gila River project companies had $144.2 million outstanding under the letter of credit facilities included in their non-recourse bank financing.

At TECO Energy, we have not had access to the commercial paper market since the September 2002 downgrade by Standard & Poor's Ratings Service (S&P) of our commercial paper program to A-3. Tampa Electric continued to have access to the commercial paper market until the S&P downgrade in June 2003 of its commercial paper program to A-3. The lack of access to the commercial paper market has caused us to utilize bank credit facilities for short-term borrowing needs.

In April 2003, we entered into a $350 million unsecured credit facility with Merrill Lynch for a term of up to eighteen months. The facility contained certain financial covenants described in the **Covenants in Financing Agreements** Section. In November 2003, we amended this credit facility to allow $100 million of credit capacity to remain in place subsequent to the repayment of the $350 million bank term maturity on Nov. 13, 2003. Under the terms of the original agreement, the facility would have been extinguished upon that repayment. The amendment made the $100 million commitment of undrawn line capacity available through April 8, 2004, at which time the facility can be drawn up to $100 million and remain outstanding to Oct. 8, 2004. The $100 million facility is required to be reduced for certain asset sales and financings. As a result of cash proceeds from asset sales in early 2004, this facility has been reduced to $20.6 million.

On Dec. 19, 2003, TECO Energy and Merrill Lynch further amended the existing credit facility to put in place with Merrill and JP Morgan a contingent credit facility of $200 million. The contingent facility will become effective only if our existing $350 million bank credit facility becomes unavailable because of non-compliance with the 65% debt-to-total-capital covenant or transfer of assets covenant as a result of write-offs or disposition of TWG assets. Upon the occurrence of these certain events, we would pledge the common stock of TECO Transport Corporation as security under the amended credit facility and the commitment available under the facility would be increased to $200 million, all of which would be available for letters of credit or cash draws. If the terms of the facility change as a result of these certain events, the amended facility would mature in December 2004. The contingent facility, if activated, would replace the existing Merrill Lynch facility. See the **Covenants in Financing Agreements** section for a summary of our performance against significant financial covenant requirements.

In June 2003, we entered into a one-year $37.5 million credit facility with four banks, collateralized by 50 percent of the interests in Union and Gila River projects. The proceeds from the credit facility were used in the termination of the joint venture agreement with Panda Energy. The facility was paid in full in February, 2004.

On Nov. 7, 2003, Tampa Electric Company replaced its maturing $300 million credit facility with a $125 million one-year credit facility and a $125 million three-year credit facility maturing in November 2004 and November 2006, respectively. In addition to the financial covenants described in the **Covenants in Financing Agreements** section, the two new facilities include a covenant limiting cumulative distributions after Oct. 31, 2003 and outstanding loans to its parent to an amount representing an accumulation of net income after May 31, 2003 and capital contributions from the parent after Oct. 31, 2003, plus $450 million.

The Tampa Electric bank credit facilities require commitment fees of 20 - 25 basis points, and drawn amounts are charged interest at LIBOR plus 100 - 117.5 basis points at current credit ratings. TECO Energy's $350 million three-year credit facility requires commitment fees of 25 basis points, and drawn amounts incur interest expense at LIBOR plus 55 – 75 basis points at current ratings. The Merrill Lynch credit facility requires commitment fees of 50 basis points and drawn amounts incur interest at LIBOR plus a borrowing spread derived from the borrowing spread of our 7.2% Notes due in 2011.

We expect that the replacement TECO Energy credit facility will be at a higher cost reflecting our current credit ratings, that it will contain restrictive covenants and that it may require security.

Covenants in Financing Agreements

In order to utilize their respective bank credit facilities, TECO Energy and Tampa Electric must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, Tampa Electric and other operating companies have certain restrictive covenants in specific agreements and debt issuances. The table below lists the covenants and the performance relative to them at Dec. 31, 2003.

TECO Energy Significant Financial Covenants

(millions, unless otherwise indicated) *Instrument*	*Financial Covenant* [1]	*Requirement/Restriction*	*Calculation at Dec. 31, 2003*
Tampa Electric			
Mortgage bond indenture	Dividend restriction	Cumulative distributions cannot exceed cumulative net income plus $4	$5 unrestricted [2]
PGS senior notes	EBIT/interest [3]	Minimum of 2.0 times	3.5 times
	Restricted payments	Shareholder equity at least $500	$1,652
	Funded debt/capital	Cannot exceed 65%	50.5%
	Sale of assets	Less than 20% of total assets	–%
Credit facility	Debt/capital	Cannot exceed 60%	49.2%
	EBITDA/interest [3]	Minimum of 2.5 times	5.8 times
	Restriction on distributions	Limit on cumulative distributions and outstanding affiliate loans [4]	$483 unrestricted
6.25% senior notes	Debt/capital	Cannot exceed 60%	49.2%
	Limit on liens	Cannot exceed $787	$362
TECO Energy			
Credit facilities [5]	Debt/capital	Cannot exceed 65%	61.9%
$37.5 credit facility [6]	EBITDA/interest [3]	Minimum of 2.5 times	2.4 times
	Limit on liens	Cannot exceed 60% of fair value of assets	24.9% [7]
	Debt/capital	Cannot exceed 65%	61.9%
$380 million note indenture	Limit on restricted payments [8]	Cumulative operating cash flow in excess of 1.7 times interest	$284 unrestricted
	Limit on liens	Cannot exceed 5% of tangible assets	$206 unrestricted [9]
	Limit on indebtedness	Interest coverage at least 2.0 times	2.6 times
$300 million note indenture	Limit on liens	Cannot exceed 5% of tangible assets	$206 unrestricted [9]
TPGC guarantees [10]	Debt/capital	Cannot exceed 65%	61.9%
	EBITDA/interest [3]	Minimum of 3.0 times	(11)
TECO Diversified			
Energy management services agreement guarantee	Consolidated tangible net worth	Minimum of $200 net worth	$548
	Consolidated funded debt	Cannot exceed 60%	17.8%
Coal supply agreement guarantee	Dividend restriction	Tangible net worth not less than $200 or $424 (40% of tangible net assets)	$548

(1) As defined in each applicable instrument.
(2) Reflects the determination as of Dec. 31, 2003, after giving effect to $158 million distributed to TECO Energy as a return of capital during 2003. There were $75 million of callable bonds outstanding under the indenture at Dec. 31, 2003.
(3) EBIT generally represents earnings before interest and taxes. EBITDA generally represents EBIT before depreciation and amortization. However, in each circumstance, the term is subject to the definition prescribed under the relevant legal agreements.
(4) Limits cumulative distributions after Oct. 31, 2003 and outstanding affiliate loans to an amount representing an accumulation of net income after May 31, 2003 and capital contributions from the parent after Oct. 31, 2003, plus $450 million.
(5) One of TECO Energy's credit facilities, if drawn upon, can limit payment of dividends each quarter to $40 million, unless the company provides the lender with satisfactory liquidity projections demonstrating the company's ability to pay both the dividends contemplated and each of the three quarterly dividends next scheduled to be paid.
(6) This facility was repaid in full in February 2004 prior to a default under the agreements. (See the **Bank Credit Facilities** section.)
(7) The fair market value of the assets has not been calculated. This calculation represents total collateralized debt, including TWG non-recourse debt, divided by the book value of total assets.
(8) The limitation on restricted payments restricts the company from paying dividends or making distributions or certain investments unless there is sufficient cumulative operating cash flow, as defined, in excess of 1.7 times interest to make such distribution or investment. The operating cash flow and restricted payments are calculated on a cumulative basis since the issuance of the 10.5% Notes in the fourth quarter of 2002. This calculation, at Dec. 31, 2003, reflects the amount accumulated and available for future restricted payments, representing the accumulation of four quarters' activities.
(9) The repayment of the collateralized $37.5 million credit facility in early 2004 (see the **Bank Credit Facilities** section) increases this unrestricted amount to $244 million.
(10) Includes the Construction Undertaking Guarantees related to the TPGC projects.
(11) This calculation was not required for Sep. 30 or Dec. 31, 2003, as provided by the terms of the Suspension Agreement entered into between the lenders, the project companies and TECO Energy, as discussed in the **TECO Wholesale Generation** section. (See the **Investment Considerations, Financing Risks** section.)

Credit Ratings/Senior Unsecured Debt

(As of Feb. 10, 2004)	Fitch	Moody's	Standard & Poor's
Tampa Electric	BBB+	Baa2	BBB-
TECO Energy / TECO Finance	BB+	Ba2	BB+

In February 2004, Moody's lowered the ratings on TECO Energy's senior unsecured debt securities, and those of TECO Finance and Tampa Electric. The ratings assigned to TECO Energy and TECO Finance were below investment grade, while the rating assigned to Tampa Electric remained investment grade. These ratings changes followed actions taken by Moody's, S&P and Fitch in April and May 2003. The outlook assigned by all of the rating agencies to both TECO Energy and Tampa Electric is negative. The ratings actions were attributed to increased debt levels and the changing risk profile associated with the expansion of TECO Energy's investment in merchant generation facilities through TWG, as well as the required capital outlays of Tampa Electric, the outlook for low power prices in the merchant energy sector and the resulting impacts on earnings and cash flow, and the additional risks and obligations undertaken by TECO Energy with respect to the Union and Gila River power stations. These downgrades followed downgrades in 2002 and 2001 by all of the rating agencies due to the changing risk profile of TECO Energy related to the increased emphasis on merchant power.

The reduction in credit ratings below investment grade by Moody's in April 2003 accelerated the repayment of the outstanding $250 million balance on the equity bridge loan associated with the construction of the TPGC projects and the requirement to post letters of credit satisfactory to the lending banks under the Construction Undertaking guarantees. The company and the banks agreed that the amount of security to be posted for the remaining construction, liquidated damages for delay and performance shortfalls was $172 million. This amount was subsequently reduced to $66 million following the successful commercial operation of both power plants. (See the **Liquidity, Capital Resources** section.)

In November 2003, S&P affirmed TECO Energy's current credit ratings and removed the ratings from Credit Watch with negative implications following the resolution of the Private Letter Ruling issues related to the production of synthetic fuel at TECO Coal. (See the **TECO Coal** section.) At that time, S&P stated that future ratings stability was directly correlated with TECO Energy's exit from the merchant energy business and the use of future cash flows to reduce debt. S&P went on to state that a failure to exit the Union and Gila River power projects would result in credit rating downgrades. Such downgrades by S&P could result in Tampa Electric's S&P credit rating falling below investment grade. In February 2004, S&P stated that our announcement to exit the Union and Gila River projects was favorable for credit quality but took no ratings action and maintained its negative outlook.

Any downgrades in credit ratings may affect TECO Energy's ability to borrow and may increase financing costs, which may decrease earnings. TECO Energy's interest expense is likely to increase when maturing debt is replaced with new debt with higher interest rates due to the lower credit ratings.

Summary of Contractual Obligations

The following table lists the obligations of TECO Energy and its subsidiaries for cash payments to repay debt, lease payments and unconditional commitments related to capital expenditures. This table does not include contingent obligations discussed in the following table.

Contractual Obligations

		Payments Due by Period			
(millions)	Total	2004	2005	2006-2008	After 2008
Long-term debt:					
Recourse	$ 3,666.4	$ 6.1	$ 5.5	$ 958.3	$ 2,696.5
Non-recourse [1]	108.7	25.5	20.7	51.6	10.9
Preferred security	649.1	–	–	449.1	200.0
Operating leases/rentals [2]	169.5	24.1	21.3	44.9	79.2
Purchase obligations/commitments	9.4	9.4	–	–	–
Total contractual obligations	$ 4,603.1	$ 65.1	$ 47.5	$ 1,503.9	$ 2,986.6

(1) Excludes the non-recourse debt associated with the Union and Gila River projects which is included in liabilities associated with assets held for sale.
(2) Includes payments under the two TECO Transport operating leases discussed in the **TECO Transport** section.

Summary of Contingent Obligations

The following table summarizes the letters of credit and guarantees outstanding that are not included in the Summary of Contractual Obligations table above and not otherwise included in the company's Consolidated Financial Statements.

			Commitment Expiration			
(millions)		Total [2]	2004	2005	2006-2008	After 2008
Letters of Credit [3]		$ 110.1	$78.7 [3]	$ –	$ 4.7	$ 26.7
Guarantees:	Debt related	24.5	–	–	–	24.5
	Fuel purchase/energy management [4]	363.9	183.2 [5]	–	–	180.7
	Other	8.8	5.0	–	–	3.8

(1) Expected final expiration date with annual renewals.
(2) Expected maximum exposure.
(3) In February 2004, by agreement of the parties, $35 million of these letters of credit were drawn by the Union and Gila River non-recourse lending bank group, and the remaining $31 million cancelled and returned to TECO Energy. (See the **TWG, Union and Gila River** section.)
(4) These guarantee amounts renew annually and are shown on the basis they will continue to renew beyond 2007.
(5) As a result of the sale of Prior Energy in February 2004, $173.2 million of guarantees are expected to be eliminated in early 2004.

Capital Investments

Capital Investments

		Forecast			
$ (millions)	*Actual 2003*	*2004*	*2005*	*2006-2008*	*2004-2008 Total*
Florida Operations	$337	$224	$255	$ 916	$1,395
Independent Power	276	14	25	75	114
Transportation	20	20	20	60	100
Other	21	21	19	53	93
Total	$654	$279	$319	$1,104	$1,702

TECO Energy's 2003 capital investments of $654 million (without reduction for asset and business sale proceeds) included $289 million for Tampa Electric (including $27 million of AFUDC), $43 million for PGS and $5 million for the unregulated Florida operations. Tampa Electric's electric division capital investments in 2003 were $152 million for equipment and facilities to meet its growing customer base and generating equipment maintenance and $137 million for the repowering and conversion of the coal-fired Gannon Station to the natural gas-fired Bayside Station (see the **Environmental Compliance** section). Capital expenditures for PGS were approximately $28 million for system expansion and approximately $15 million for maintenance of the existing system. TECO Transport invested $20 million in 2003 for river barge replacements and capitalized maintenance of ocean-going vessels. TECO Coal's capital expenditures included $7 million for normal mining expansions and equipment replacements. TWG's capital investments totaled $276 million, net of $31 million received from the sale of its Enron bankruptcy claims (see the **Enron Related Matters** in the **TWG** section), primarily related to the Union and Gila River power stations. This $276 million includes $33 million classified as Other Non-Current Investments, representing the costs associated with the Panda Energy joint venture termination for Union and Gila River and $29 million classified as investment in Unconsolidated Affiliates representing the cost associated with the buyout of Panda's interest in the TIE projects (see the **Transactions With Related and Certain Other Parties** section).

Asset sale proceeds in 2003 were $245 million net of cash escrows of $51 million. Proceeds included the sale of TECO Coalbed Methane's assets, the sale of Hardee Power Partners, TECO Transport's sale of equipment no longer used at TECO Ocean Shipping, the sale of interest in the ECK Generating project in the Czech Republic, and a portion of the proceeds from TECO Coal's sale of a 49.5% interest in its synthetic fuel production facilities. (See the **TECO Coal** and **Liquidity, Capital Resources** sections.)

TECO Energy estimates capital spending for ongoing operations, without reduction for proceeds from asset sales, to be $279 million for 2004, $319 million for 2005 and $1,104 million during the 2006-2008 period.

For 2004, Tampa Electric's electric division expects to spend $183 million, consisting of $9 million for the completion of the repowering project at the Bayside Station and $174 million to support system growth and generation reliability. At the end of 2003, Tampa Electric had outstanding commitments of about $9 million for the Bayside Station repowering project. Tampa Electric's total capital expenditures over the 2005-2008 period are projected to be $1,006 million, including $221 million for compliance with the Environmental Consent Decree. The environmental compliance expenditures are eligible for recovery of depreciation and a return on investment through the Environmental Cost Recovery Clause. (See the **Environmental Compliance** section.)

Capital expenditures for PGS are expected to be about $40 million in 2004 and $160 million during the 2005-2008 period. Included in these amounts are approximately $25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety.

TWG expects to invest $14 million in 2004 for capitalized maintenance, and $100 million in the 2005-2008 period for the completion of the Dell and McAdams power stations when market conditions justify the expenditures. (See the **TECO Wholesale Generation** section.)

The other unregulated companies expect to invest $42 million in 2004 and $156 million during the 2005-2008 period. Included in these amounts is normal renewal and replacement capital, including coal mining equipment and river barge replacements.

Financing Activity

Our 2003 year-end capital structure, excluding the effect of uneamed compensation, was 71.6 percent senior debt, 7.9 percent company preferred securities and 20.5 percent common equity. TWG has typically financed its power projects with non-recourse project debt. Excluding this non-recourse debt of $2,196 million, the year-end capital structure was 61.3 percent debt, 10.7 percent company preferred securities and 28.0 percent common equity. The debt-to-total-capital ratio increased from last year primarily due to the impairment charges taken in 2003 associated with our investments in merchant power.

In 2003, we accessed the debt and equity markets on three occasions raising $792 million to provide funds for general liquidity purposes, to repay $526 million of long-term debt, and reduce short-term debt balances by $323 million. In addition, debt proceeds in 2003 included non-recourse proceeds of $111 million associated with the Union and Gila River power projects.

In 2002, we were active in the debt and equity capital markets raising $1 billion through the sale of equity or equity-linked securities and issuing $1.8 billion of debt to refinance $788 million of maturing debt, to refinance $162 million of higher-cost debt, to reduce short-term borrowing by $278 million and to fund capital investments at the operating companies.

In 2004, TECO Energy plans to remarket the Trust Preferred debt securities within TECO Capital Trust II, as required. We have been advised that other companies remarketing similar securities have not been successful due to changing company specific and market conditions. In addition, there is expected to be a large number of other issuers seeking to remarket similar securities at the same time. In the event that these securities cannot be successfully remarketed, a possible consequence could be the loss of the tax deductibility of the interest payments made on these securities retroactive to the time of issue in January 2002. The loss of this tax deduction to TECO Energy could result in a non-cash reduction in earnings of approximately $9 million for the year 2002, but due to the level of taxable income, any earnings reduction in 2003 is expected to be significantly lower. We are exploring various remarketing strategies to avoid the loss of the tax deductibility of these payments.

The following table provides details of the financing activities for the years 2003, 2002 and 2001.

Date	Security	Company	Net Proceeds (millions)	Coupon	Use
Sep. 2003	Common equity	TECO Energy	$129	–	Repay short-term debt, and general corporate purposes
Jun. 2003	7-year notes	TECO Energy	$293	7.5%	Repay short-term debt, and general corporate purposes
Apr. 2003	13-year notes	Tampa Electric	$250	6.25%	Repay maturing short-term debt, and general corporate purposes
Dec. 2002	7-year non-recourse bank loan	TECO Wholesale Generation	$30	6%	Refinance Alborada Power Station and general corporate purposes
Nov. 2002	5-year notes	TECO Energy	$352	10.5%	Repay short- and long-term debt, and general corporate purposes
Oct. 2002	Common Equity	TECO Energy	$207	–	Repay short-term debt
Aug. 2002	5-year notes	Tampa Electric	$149	5.375%	Repay maturing long-and short-term debt, and general corporate purposes
Aug. 2002	10-year notes	Tampa Electric	$394	6.375%	Repay maturing long-and short-term debt, and general corporate purposes
Jun. 2002	Pollution control bonds	Tampa Electric	$61	5.1%	Refinance higher cost debt
Jun. 2002	Pollution control bonds	Tampa Electric	$86	5.5%	Refinance higher cost debt
Jun. 2002	Common Equity	TECO Energy	$346	–	Repay short-term debt, and general corporate purposes
May 2002	5-year notes	TECO Energy	$297	6.125%	Repay maturing short-term debt, and general corporate purposes
May 2002	10-year notes	TECO Energy	$397	7.0%	Repay maturing short-term debt, and general corporate purposes
Jan. 2002	Mandatorily Convertible equity units	TECO Energy	$436	9.5%	Repay short-term debt, and general corporate purposes
Oct. 2001	Common Equity	TECO Energy	$93	–	General corporate purposes
Sep. 2001	10-year notes	TECO Energy	$206	7.2 %	Repay maturing debt, and general corporate purposes
Jun. 2001	11-year notes	Tampa Electric	$247	6.875%	Repay long- and short-term debt, and general corporate purposes
Jun. 2001	2-year equity bridge facility	Union & Gila River	$500	LIBOR + 162.5 BP	Construction of the Union and Gila River power stations
May 2001	1-year notes	TECO Energy	$399	Variable	Repay short-term debt
May 2001	10-year notes	TECO Energy	$396	7.2%	Repay short-term debt, and general corporate purposes
Apr. 2001	6-year notes	TECO Transport	$111	5.0%	Convert floating rate debt to fixed rate debt
Mar. 2001	Common Equity	TECO Energy	$232	–	Repay short-term debt, and general corporate purposes

Off-Balance Sheet Financing

Unconsolidated affiliates with a 50% ownership interest or less have project debt balances as follows at Dec. 31, 2003. TECO Energy has no debt payment obligations with respect to these financings, except as indicated by the maximum potential obligation under a related guarantee issued by TECO Energy or its consolidated subsidiaries. Although TECO Energy is not directly obligated on the debt, TECO Energy's equity interest in those unconsolidated affiliates and its commitments with respect to those projects are at risk if those projects are not successfully developed or operated.

Affiliate	Long-term Debt (millions)	Indirect Maximum Guarantee	Indirect Ownership Interest
TIE	$ 545.4	$ –	50%
EEGSA	$ 234.6	$ 15.0[1]	24%
Hamakua	$ 86.0	$ –	50%

(1) Represents a subsidiary of TECO Energy's 30% ownership interest in the guarantor.

The equity method of accounting is used to account for investments in partnership and corporate entities in which TECO Energy or its subsidiary companies do not have either a majority ownership or exercise control. On Jan. 17, 2003, the Financial Accounting Standards Board issued FASB Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*, which requires a new approach in determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as variable interest entities or VIEs. On Dec. 24, 2003, the FASB published a revision to FIN 46 (FIN 46R), to clarify some of the provisions of FIN 46 and exempt certain entities from its requirements. TECO Energy believes it is reasonably possible that FIN 46R may impact the accounting for certain unconsolidated affiliates. (See the **Other Accounting Standards – Variable Interest Entities** section.)

Critical Accounting Policies and Estimates

The preparation of consolidated financial statements requires management to make various estimates and assumptions that affect revenues, expenses, assets, liabilities and the disclosure of contingencies. The policies and estimates identified below are, in the view of management, the more significant accounting policies and estimates used in the preparation of our consolidated financial statements. These estimates and assumptions are based on historical experience and on various other factors that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and judgments under different assumptions or conditions.

(See **Note 1** to the **Consolidated Financial Statements** for a description of our significant accounting policies and the estimates and assumptions used in the preparation of the consolidated financial statements.)

Asset Impairments

We and our subsidiaries periodically evaluate whether there has been a permanent impairment of an asset as follows:

- Long-lived assets, when indicators of impairment exist or an asset group is held for sale, in accordance with Financial Accounting Standard (FAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (see the **Long-Lived Assets** section); and
- Recognized goodwill and other intangible assets with indefinite lives, at least annually, in accordance with FAS 142, *Goodwill and Other Intangible Assets* (see the **Goodwill and Other Intangible Assets** section); and
- Equity investments, when a decline in fair value below the carrying value is determined to be other than temporary, in accordance with Accounting Principles Board Opinion (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock*.

We believe that the accounting estimate related to asset impairments is a critical estimate for the following reasons: 1) it is highly susceptible to change each reporting period as management is required to make assumptions based on expectations of the results of operations for significant/indefinite future periods and/or the then-current market conditions in such periods; 2) electricity markets continue to experience significant uncertainty with respect to market fundamentals; 3) the ongoing expectations of management regarding probable future uses and holding periods of assets; and 4) the impact of an impairment on reported assets and earnings would be material. Our assumptions relating to future results of operations are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. Management's expectations regarding uses and holding periods of assets are based on internal long-term budgets and strategic plans, which give consideration to external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities. (See **Notes 1, 3 and 10** to the **Consolidated Financial Statements**.)

Long-Lived Assets

Effective Jan. 1, 2002, we and our subsidiaries adopted FAS 144, which superseded FAS 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*. FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a segment or component of a business.

In accordance with FAS 144, we assess whether there has been an other-than-temporary impairment of our long-lived assets and certain intangibles held and used by us when such indicators exist. When specific criteria are met, a disposal group, comprised of assets and liabilities expected to be transferred in a sale within one year, is classified as assets and liabilities, respectively, held for sale. Furthermore, the income associated with a disposal group may, if additional criteria are met, be presented as discontinued operations in the statement of income. Under FAS 144, the company records an asset impairment charge associated with a disposal group when the estimated fair value, less costs to sell, is less than the net carrying value of the related assets and liabilities. We recognized impairments associated with certain long-lived assets held for use and a disposal group, comprised of the assets and liabilities associated with the Union and Gila River projects. (See **Notes 1** and **10** to the **Consolidated Financial Statements**.)

Goodwill and Other Intangible Assets

In accordance with FAS 142, we continue to review goodwill and intangibles at least annually for each reporting unit. Reporting units are generally determined as one level below the operating segment level; however, reporting units with similar characteristics may be grouped under the accounting standard for the purpose of determining the impairment, if any, of goodwill and other intangible assets. For each reporting unit evaluated, the fair value exceeded the carrying value, including goodwill, as of the annual assessment date, except as indicated below. The fair value for the reporting units evaluated was generally determined using discounted cash flow models appropriate for the business model of each significant group of assets within each reporting unit. During the year ended Dec. 31, 2003, a $74.0 million after-tax ($113.9 million pre-tax) impairment charge was recorded to write off all goodwill associated with the Frontera and Commonwealth Chesapeake power stations and reduce the goodwill associated with BCH Mechanical. (See **Note 3** to the **Consolidated Financial Statements**.)

Equity Investments

We only record an impairment of an equity investment when a decline in the fair value below the carrying value of the investment is determined to be other than temporary. Management assesses other than temporary based on: 1) the magnitude of the difference of the fair value below the carrying value; 2) the period of time in which the decline in the fair value is less than the carrying value; and 3) other reasonably available qualitative or quantitative information that provides evidence to indicate that a decline in fair value is temporary. As of Dec. 31, 2003, the company did not record an other-than-temporary impairment of an equity investment.

Asset Retirement Obligations

On Jan. 1, 2003, we adopted FAS 143, *Accounting for Asset Retirement Obligations*, which requires the recognition of a liability at fair value for an asset retirement obligation in the period in which it is incurred. Retirement obligations associated with long-lived assets included within the scope of FAS 143 are those for which there is a legal obligation to settle under an existing or enacted law or statute, a written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are included in the scope of the standard only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its future value. The corresponding amount capitalized at inception is depreciated over the useful life of the asset. The liability must be revalued each period based on current market prices. FAS 143 was effective for fiscal years beginning after June 15, 2002.

Asset retirement obligations are comprised of significant estimates which, if different, could materially impact our results. We believe these are critical estimates because: 1) the fair value of the

costs associated with meeting the obligation are impacted by assumptions on discount rates and estimated profit mark-ups by third-party contractors; 2) probability factors associated with the future sale, abandonment or retirement of an asset must be forecasted and considered in the calculations; 3) the expectations and intent of management regarding the future use of long-lived assets; and 4) the impact of the recognition of an asset impairment obligation could be significant. In connection with the adoption of the guidance on Jan. 1, 2003, we and our affiliates maintain and periodically review all new legal arrangements and contractual commitments to ensure that any new potential asset retirement obligations are reviewed and recognized as appropriate. (See **Note 5 to the Consolidated Financial Statements.**)

Employee Postretirement Benefits

We have a funded non-contributory defined benefit retirement plan covering substantially all employees. Our policy is to fund the plan based on actuarially determined contributions within the guidelines set by the Employee Retirement Income Security Act of 1974, as amended (ERISA), for the minimum annual contribution and the maximum allowable as a tax deduction by the Internal Revenue Service (IRS). Plan assets are invested in a mix of equity and fixed income securities. In addition, we and our subsidiaries currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. In addition, we have unfunded supplemental executive retirement benefit plans—non-qualified, non-contributory defined benefit retirement plans available to certain senior management.

The determination of the benefit expense is a critical estimate due to the following factors: 1) management must make significant assumptions regarding the discount rate, return on assets, rate of salary increases and health care cost trend rates; 2) costs are based on actual employee demographics, including the turnover rate, retirement rate, mortality rate, employment periods, compensation levels and age, each of which are subject to change in any given period; 3) the plan provisions may be changed by management action in future periods; and 4) the impact of changes in any of these assumptions is likely to result in a material impact on the recorded pension obligation and expense. Management reviews these assumptions periodically to assure the consistency with our actual experience.

The assumed health care cost trend rate for medical costs was 11.5% in 2003 and decreases to 5.0% in 2013 and thereafter.

A 100 basis point increase in the medical trend rates would produce a 4 percent ($0.6 million) increase in the aggregate service and interest cost for 2003 and a 4 percent ($7.5 million) increase in the accumulated postretirement benefit obligation as of Sep. 30, 2003.

A 100 basis point decrease in the medical trend rates would produce a 3 percent ($0.4 million) decrease in the aggregate service and interest cost for 2003 and a 3 percent ($5.3 million) decrease in the accumulated postretirement benefit obligation as of Sep. 30, 2003.

Deferred Income Taxes

We use the liability method in the measurement of deferred income taxes. Under the liability method, we estimate our current tax exposure and assesses the temporary differences resulting from differing treatment of items, such as depreciation for financial statement and tax purposes. These differences are reported as deferred taxes measured at current rates in the consolidated financial statements. Management reviews all reasonably available current and historical information, including forward-looking information, to determine if it is more likely than not that some or all of the deferred tax asset will not be realized. If we determine that it is likely that some or all of a deferred tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

At Dec. 31, 2003, we had net deferred income tax assets of $1,051.5 million attributable primarily to property-related items and an alternative minimum tax credit carryover of Section 29 non-conventional fuel tax credits. Based primarily on historical income levels and the steady-growth expectations for future earnings of the company's core utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2003 will be realized in future periods.

We believe that the accounting estimate related to deferred income taxes, and any related valuation allowance, is a critical estimate for the following reasons: 1) administrative actions of the IRS or the U.S. Treasury or changes in law or regulation could eliminate or reduce the availability of alternative minimum tax credits arising from Section 29 tax credits; 2) realization of the deferred tax asset is dependent upon the generation of sufficient taxable income in future periods; and 3) a change in the estimated valuation reserves could have a material impact on reported assets and results of operations. (See **Note 13 to the Consolidated Financial Statements.**)

Cost Capitalization

During 2003, our subsidiaries devoted resources to the completion and construction of additional generation capacity at Tampa Electric and TWG, extension of the transmission network and enhancement to the system's reliability at Tampa Electric, expansion of the pipeline distribution infrastructure at PGS, normal ocean equipment improvements at TECO Transport and expansion of production capacity at TECO Coal. (See the **Capital Investments** section.) The cost of additions, including improvements and replacements of property, is charged to plant. We capitalize direct costs and certain indirect costs, including the cost of debt and equity capital as appropriate, associated with its construction and retirement activity as prescribed by generally accepted accounting principles and recognized policies prescribed or permitted by the FPSC and/or the FERC. The amount of capitalized overhead construction costs is based upon analysis of company and affiliate construction activity. Costs are capitalized based on the activity level of resources allocated to construction activities. As a result, our net income could be impacted by the manner and timing of the deployment of resources to construction activities. However, total cash flow is not impacted by the allocation of these costs to the various construction or maintenance activities. Due to the magnitude of construction undertakings, fluctuations in net income, as a result of cost capitalization, could be significant. Capitalized costs are expensed as a component of depreciation when the assets are placed in service. (See **Note 1 to the Consolidated Financial Statements.**)

Depreciation Expense

We provide for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage, of depreciable property over its estimated service life. The provision for utility plant in service, expressed as a percentage of the original cost of depreciable property, was 4.5% and 4.2% for the years ended Dec. 31, 2003 and 2002. We believe the estimated service life corresponds to the anticipated physical life for most assets. However, our estimation of service life is a critical estimate for the following reasons: 1) forecasting the salvage value for long-lived assets over a long timeframe is subjective; 2) changes may take place that could render a technology obsolete or uneconomical; and 3) a change in the useful life of a long-lived asset could have a material impact on reported results of operations and reported assets. Although it is difficult to predict values far into the future, we have a long history of actual costs and values that are considered in reaching a conclusion as to the appropriate useful life of an asset. (See **Note 1 to the Consolidated Financial Statements.**)

Regulatory Accounting

Tampa Electric's and PGS' retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the FERC. As a result, the regulated utilities qualify for the application of FAS 71, *Accounting for the Effects of Certain Types of Regulation*. This statement recognizes that the actions of a regulator can provide reasonable assurance of the existence of an asset or liability. Regulatory assets and liabilities arise as a result of a difference between generally accepted accounting principles and the accounting principles imposed by the regulatory authorities. Regulatory assets generally represent incurred costs that have been deferred as they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers from previous collections for costs that are not likely to be incurred.

We periodically assess whether the regulatory assets are probable of future recovery by considering factors such as regulatory environment changes, recent rate orders to other regulated entities in the same jurisdiction, the current political climate in the state, and the status of any pending or potential deregulation legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered by rates. A change in these assumptions may result in a material impact on reported assets and the results of operations. (See **Notes 1 and 4** to the **Consolidated Financial Statements**.)

Revenue Recognition

We and our subsidiaries recognize revenues, except as discussed below, on a gross basis when the risks and rewards of ownership have transferred to the buyer and the products are physically delivered or services provided. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The determination of the physical delivery of energy sales to individual customers is based on the reading of meters, which occurs on a regular basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading may be estimated and the corresponding unbilled revenue is estimated. Unbilled revenue is estimated each month primarily based on historical experience, customer-specific factors, customer rates, and daily generation volumes, as applicable. These revenues are subsequently adjusted to reflect actual results. Revenues for regulated activities at Tampa Electric and PGS are subject to the actions of regulatory agencies.

The percentage of completion method is used to recognize revenues for certain transportation services at TECO Transport and for long-term construction-type contracts. The percentage of completion method requires management to make estimates regarding the distance traveled and/or time elapsed for TECO Transport and total costs and work-in-progress for BCH Mechanical. Revenue is recognized by comparing the estimated current total distance traveled or work completed with the total distance or cost estimate for each project. Each month, revenue recognition and realized profit are adjusted to reflect only the percentage of distance traveled or work completed.

Revenues for merchant power sales and expenses for fuel purchases at TWG are reported on a gross basis, except for derivative gains or losses related to hedge accounting, which are reported net of the hedged item or transaction. Likewise, expenses arising from purchased power or revenues arising from fuel sales at TWG are reported net of power revenues and fuel expense, respectively.

We estimate certain amounts related to revenues on a variety of factors, as described above. Actual results may be different from these estimates. (See **Note 1** to the **Consolidated Financial Statements**.)

Recently Issued Accounting Standards

In accordance with recently issued accounting pronouncements, we will be required to comply with certain changes in accounting rules and regulations. (See **Note 22** to the **Consolidated Financial Statements**.)

Gains and Losses on Energy Trading Contracts

On Oct. 25, 2002, the Emerging Issues Task Force released EITF 02-3, Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17, which 1) precludes mark-to-market accounting for energy trading contracts that are not derivatives pursuant to FAS 133, 2) requires that gains and losses on all derivative instruments within the scope of FAS 133 be presented on a net basis in the income statement if held for trading purposes, and 3) limits the circumstances in which a reporting entity may recognize a "day one" gain or loss on a derivative contract. The measurement provisions of the issue are effective for all fiscal periods beginning after Dec. 15, 2002. The net presentation provisions are effective for all financial statements issued after Dec. 15, 2002. The adoption of the measurement provisions on Jan. 1, 2003 did not have a material impact. (See **Note 14** to the **Consolidated Financial Statements** for additional details of amounts presented on a net basis.)

Consolidation of Variable Interest Entities

The equity method of accounting is generally used to account for significant investments in arrangements in which we or our subsidiary companies do not have a majority ownership interest or exercise control. On Jan. 17, 2003, the FASB issued FIN 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*, which imposes a new approach in determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as variable interest entities or VIEs. On Dec. 24, 2003, the FASB published a revision to FIN 46 (FIN 46R), to clarify some of the provisions of FIN 46 and exempt certain entities from its requirements.

Under FIN 46R, a legal entity is considered a VIE, with some exemptions if specific criteria are met, if it does not have sufficient equity at risk to finance its own activities without relying on financial support from other parties. Additional criteria must be applied to determine if this condition is met or if the equity holders, as a group, lack any one of three stipulated characteristics of a controlling financial interest. If the legal entity is a VIE, then the reporting entity determined to be the primary beneficiary of the VIE must consolidate it. Even if a reporting entity is not obligated to consolidate a VIE, then certain disclosures must be made about the VIE if the reporting entity has a significant variable interest. Certain transition disclosures are required for all financial statements issued after Jan. 31, 2003. The effective date of the interpretation was modified under FIN 46R. A reporting entity is required to apply the provisions of FIN 46R to all VIEs that previously were subject to certain previously issued special purpose entity, or SPE, accounting pronouncements for all reporting periods ending after Dec. 15, 2003. For all other VIEs, a reporting entity is required to adopt the provisions of FIN 46R for all reporting periods after Mar. 15, 2004.

Based on its review under the existing approved guidance, we believe that FIN 46R will impact the accounting for certain unconsolidated affiliates. Below is a discussion of the legal entities as of Dec. 31, 2003 that we believe will be subject to either additional disclosure requirements or consolidation by the company, in accordance with FIN 46R.

In November 2000 and January 2002, respectively, we established TECO Funding I, LLC and TECO Funding II, LLC. Each of these limited-liability companies are wholly-owned subsidiaries of TECO Energy. These companies sold preferred securities to Capital Trust I and Capital Trust II, respectively. The funding com-

panies used the proceeds to purchase subordinated notes from us. The subordinated notes are not secured by specific assets of the company. The terms of these notes are similar to the terms of the preferred securities. The funding companies are expected to be considered VIEs in accordance with FIN 46R. As of Dec. 31, 2003, management expects the potential impact of the adoption of FIN 46R to not be material for the funding companies.

Pike Letcher Synfuel, LLC was established as part of the Apr. 1, 2003, sale of TECO Coal's synthetic fuel production facilities. TECO Energy's maximum loss exposure in this entity is its equity investment of approximately $10.9 million and losses related to the production costs for the future production of synthetic fuel, in the event that such production creates Section 29 non-conventional fuel tax credits in excess of our capacity to generate sufficient taxable income to use such credits.

TECO Transport entered into two separate sale-leaseback transactions for certain vessels which were recognized as sales in December 2001 and December 2002, and are currently recognized as operating leases for the assets. The sale-leaseback transactions were entered into with separate third parties that the company believes meet the definition of a VIE. TECO Transport currently leases two ocean-going tugboats, four ocean-going barges, five river towboats and 49 river barges through these two trusts. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable equipment to meet the company's contractual shipping obligations. The company does not expect to consolidate upon the effective date of FIN 46R because TECO Transport is not the primary beneficiary of the trusts.

TECO Properties formed a limited liability company with a project developer which meets the definition of a VIE. Hernando Oaks, LLC was formed by TECO Properties with the Pensacola Group to buy and develop 627 acres of land in Hernando County, Florida into a residential golf community comprised of an 18-hole golf course and 975 single-family lots for sale to homebuilders. TECO Properties has provided subordinated financial support in the form of a guarantee on behalf of the limited liability company. Hernando Oaks, LLC had total assets at Dec. 31, 2003 of $21.6 million. TECO Properties' estimated maximum loss exposure in this project is approximately $10.6 million. The company expects to consolidate Hernando Oaks, LLC for all financial reporting periods ending after Mar. 15, 2004.

TECO Solutions owns a partnership formed to construct, own and operate a water cooling plant to produce and distribute chilled water to customers via a local distribution loop primarily for use in air conditioning systems. The partnership, TECO AGC, Ltd., meets the definition of a VIE. The company is the primary beneficiary, in accordance with FIN 46R, due to subordinated financing of $3.3 million provided to the partnership as of Dec. 31, 2003, in addition to the company's equity investment. This note receivable from the partnership is collateralized by the assets in the partnership. The estimated maximum loss exposure associated with this partnership is approximately $3.8 million as of Dec. 31, 2003, representing substantially all of the assets of the partnership. The company expects to consolidate TECO AGC, Ltd. for all financial reporting periods ending after Mar. 15, 2004.

Amendment to Derivatives Accounting

In April 2003, the FASB issued FAS 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, which clarifies the definition of a derivative and modifies, as necessary, FAS 133 to reflect certain decisions made by the FASB as part of the Derivatives Implementation Group (DIG) process. The majority of the guidance was already effective and previously applied by the company in the course of the adoption of FAS 133.

In particular, FAS 149 incorporates the conclusions previously reached in 2001 under DIG Issue C10, *"Can Option Contracts and Forward Contracts with Optionality Features Qualify for the Normal Purchases and Normal Sales Exception"*, and DIG Issue C15, *"Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity"*. In limited circumstances when the criteria are met and documented, we designate option-type and forward contracts in electricity as a normal purchase or normal sale (NPNS) exception to FAS 133. A contract designated and documented as qualifying for the NPNS exception is not subject to the measurement and recognition requirements of FAS 133. The incorporation of the conclusions reached under DIG Issues C10 and C15 into the standard will not have a material impact on our consolidated financial statements.

FAS 149 establishes multiple effective dates based on the source of the guidance. For all DIG Issues previously cleared by the FASB and not modified under FAS 149, the effective date of the issue remains the same. For all other aspects of the standard, the guidance is effective for all contracts entered into or modified after June 30, 2003. We do not anticipate that the adoption of the additional guidance in FAS 149 will have a material impact on the consolidated financial statements.

Financial Instruments with Characteristics of Both Liabilities and Equity

In May 2003, the FASB issued FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*, which requires that an issuer classify certain financial instruments as a liability or an asset. Previously, many financial instruments with characteristics of both liabilities and equity were classified as equity. Financial instruments subject to FAS 150 include financial instruments with any of the following features:

- An unconditional redemption obligation at a specified or determinable date, or upon an event that is certain to occur;
- An obligation to repurchase shares, or indexed to such an obligation, and may require physical share or net cash settlement;
- An unconditional, or for new issuances conditional, obligation that may be settled by issuing a variable number of equity shares if either (a) a fixed monetary amount is known at inception, (b) the variability is indexed to something other than the fair value of the issuer's equity shares, or (c) the variability moves inversely to changes in the fair value of the issuer's shares.

The standard requires that all such instruments be classified as a liability, or an asset in certain circumstances, and initially measured at fair value. Forward contracts that require a fixed physical share settlement and mandatorily redeemable financial instruments must be subsequently re-measured at fair value on each reporting date.

This standard is effective for all financial instruments entered into or modified after May 31, 2003, and for all other financial instruments, at the beginning of the first interim period beginning after June 15, 2003. (See Note 7 to the Consolidated Financial Statements for a discussion of the impact of the adoption of this standard on July 1, 2003.)

Disclosures About Market Risk

Risk Management Infrastructure

We and our affiliates are subject to various types of market risk in the course of daily operations, as discussed below. We have adopted an enterprise-wide approach to the management and control of market and credit risk. Middle Office risk management functions, including credit risk management and risk control, are independent of each transacting entity (Front Office) and report to the senior risk officer at TECO Energy. Front Office functions report independently from the senior risk officer.

Our Risk Management Policy (Policy) governs all energy transacting activity at the TECO Energy group of companies. The Policy is approved by our Board of Directors and administered by a Risk Authorizing Committee (RAC) that is comprised of senior management, and advised by the Vice President of Energy Risk

Management. Within the bounds of the Policy, the RAC approves specific hedging strategies, new transaction types or products, limits, and transacting authorities. The Policy further requires that, for all merchant generation asset management activities, power sales and gas purchases must be substantially matched, and that the volume of power sales commitments is limited to the volume of owned and available generating capacity. Transaction activity is reported daily and measured against limits. For all other commodity risk management activities, derivative transaction volumes are limited to the anticipated volume for customer sales or supplier procurement activities.

The TECO Energy Authorizing Committee, administers the risk management policy with respect to interest rate risk exposures. Under the policy for interest rate risk management, the committee operates and oversees transaction activity. Interest rate derivative transaction activity is directly correlated to borrowing activities.

Risk Management Objectives

The Front Office is responsible for reducing and mitigating the market risk exposures which arise from the ownership of physical assets and contractual obligations, such as merchant power plants, debt instruments and firm customer sales contracts. The primary objectives of the risk management organization, the Middle Office, is to quantify, measure and monitor the market risk exposures arising from the activities of the Front Office and the ownership of physical assets. In addition, the Middle Office is responsible for enforcing the limits and procedures established under the approved risk management policies. Based on the policies approved by the company's Board of Directors and the procedures established by the RAC, from time to time members of the TECO Energy group of companies enter into futures, forwards, swaps and option contracts for the following purposes:

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric and PGS, and prior to their dispositions, TECO Gas Services and Prior Energy;
- To limit the exposure to interest rate fluctuations on debt issuances at TECO Energy and its other affiliates;
- To limit the exposure to electricity, natural gas and fuel oil price fluctuations related to the operations of natural gas-fired and fuel oil-fired power plants at TWG; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport.

The TECO Energy group of companies use derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers. For unregulated operations, the companies use derivative instruments primarily to optimize the value of physical assets, primarily generation capacity and natural gas delivery.

Derivatives and Hedge Accounting

Effective Jan. 1, 2001, we adopted FAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as subsequently amended and interpreted. FAS 133 requires us and our affiliates to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of other comprehensive income (OCI) or in net income, depending on the designation of those instruments. The effect of the adoption of FAS 133, at Jan. 1, 2001 on continuing operations was not material.

Designation of a hedging relationship requires management to make assumptions about the future probability of the timing and amount of the hedged transaction, and the future effectiveness of the derivative instrument in offsetting the change in fair value or cash flows of the hedged item or transaction. The determination of fair value is dependent upon certain assumptions and judgments, as described more fully below. (See **Unregulated Companies** section below, and **Note 2** to the **Consolidated Financial Statements**.)

Interest Rate Risk

We and our affiliates are exposed to changes in interest rates, primarily as a result of our borrowing activities. We or our affiliates may enter into futures, swaps and option contracts, in accordance with the approved risk management policies and procedures, to moderate this exposure to interest rate changes and achieve a desired level of fixed and variable rate debt. As of Dec. 31, 2003, a hypothetical 10% increase in the consolidated group's weighted average interest rate on its variable rate debt during 2004, as compared to 2003, would not result in a material impact on pre-tax earnings. Comparatively, as of Dec. 31, 2002, a hypothetical 10% increase in the consolidated group's weighted average interest rate on its variable rate debt during 2003, as compared to 2002, would not have resulted in a material impact on pre-tax earnings. These amounts were determined based on the variable rate obligations existing on the indicated dates at TECO Energy and its subsidiaries. Due to the uncertainty of future events, as discussed in the **Investment Considerations** section, and our responses to those events, the above sensitivities assume no changes to our financial structure or our affiliates. A hypothetical 10% decrease in interest rates would increase the fair value of long-term debt by approximately 3.1 percent and 5.6 percent at Dec. 31, 2003 and 2002, respectively. (See **Financing Activity** section, and **Notes 6** and **7** to the **Consolidated Financial Statements**.)

Credit Risk

We have adopted a rigorous process for the establishment of new trading counterparties. This process includes an evaluation of each counterparty's financial statements, with particular attention paid to liquidity and capital resources, establishment of counterparty-specific credit limits, optimization of credit terms, and execution of standardized enabling agreements. Our Credit Guidelines require transactions with counterparties below investment grade to be collateralized. The Credit Guidelines are administered and monitored within the Middle Office, independent of the Front Office.

Financial instability and significant uncertainties relating to liquidity in the entire merchant energy sector have increased the perceived credit risk. Credit exposures for merchant generation activities are calculated, compared to limits and reported to management on a daily basis. Contracts with different legal entities affiliated with the same counterparty are consolidated and managed as appropriate, considering the legal structure and any netting agreements in place. The following is a summary of the TECO Energy group of companies credit risk exposure on energy contracts related to merchant generation activities at Dec. 31, 2003.

(millions) Rating[1]	Exposure Before Credit Collateral[2]	Credit Collateral[3]	Net Exposure	Number of Counterparties >10%[4]	Net Exposure Counterparties >10%[4]
Investment grade	$ 24.4	$ –	$ 24.4	1	$ 7.4
Split rating	8.4	–	8.4	1	8.4
Non-investment grade	–	–	–	–	–
No external ratings (internally rated)					
Investment grade	0.8	–	0.8	–	–
Non-investment grade	–	–	–	–	–
Total	$ 33.6	$ –	$ 33.6	2	$ 15.8

(1) Ratings are principally determined based on publicly available credit ratings, as determined by independent ratings agencies. If the counterparty has provided a guarantee by a higher rated entity, the assigned rating is that of the guarantor. Included in Investment grade are those counterparties with a minimum S&P or Fitch's rating of BBB- or higher and a Moody's rating of Baa3 or higher.
(2) Exposure before credit collateral includes the fair value of net energy contract assets for open positions and the net accounts receivable for realized energy contracts. Exposures are offset by a legal counterparty where legally enforceable netting and set-off arrangements are in place.
(3) Credit collateral is required from time-to-time based on contractual provisions and may generally include cash deposits and letters of credit.
(4) The number of counterparties that individually, after considering legally enforceable netting arrangements, represent a significant concentration of credit risk (i.e., more than 10% of the total credit exposure) at TECO EnergySource. Also, the combined exposure, less credit collateral, if any, of each significant concentration.

Commodity Risk

We and our affiliates face varying degrees of exposure to commodity risks—including coal, natural gas, fuel oil and other energy commodity prices. Any changes in prices could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. We assess and monitor risk using a variety of state-of-the-art measurement tools. Management uses different risk measurement and monitoring tools based on the degree of exposure of each operating company to commodity risk.

Regulated Utilities

At Tampa Electric, fuel costs used for generation have been affected primarily by the cost of coal and, to a lesser degree, the cost of natural gas. With the completion of the repowering of the Bayside Power Station to natural gas, the use of natural gas, with its more volatile pricing, increased in 2003 and is expected to increase again in 2004. (See the Environmental Compliance section.) PGS is primarily subject to costs for purchased gas and pipeline capacity. Increasing costs for the regulated utilities impact their competitive position in the marketplace versus other energy sources and suppliers.

Currently, Tampa Electric and PGS are subject to relatively little commodity price risk exposure. This is primarily due to the fact that commodity price increases due to changes in market conditions for fuel, purchased power and natural gas are recovered through cost recovery clauses, with no anticipated effect on earnings. Commodity price risk is mitigated by the use of long-term fuel supply agreements, prudent operation of plant facilities to reduce the reliance on purchased power, and derivative instruments designated as cash flow hedges of anticipated purchases of natural gas. At Dec. 31, 2003 and 2002, a change in commodity prices would not have a material impact on earnings for Tampa Electric or PGS.

Unregulated Companies

Most of the unregulated subsidiaries at TECO Energy are subject to significant commodity risk. These include TECO Coal, TECO Transport, and TWG. The unregulated companies do not speculate using derivative instruments. However, not all derivative instruments receive hedge accounting treatment due to the strict requirements and narrow applicability of the accounting rules to dynamic transactions.

TECO Coal is exposed to commodity price risk through coal sales as a part of its daily operations. Fixed-price sales agreements are used, where possible and economical, to mitigate the variability in coal prices. At Dec. 31, 2003 and 2002, a hypothetical 10% increase in the average annual market price of coal for each year would have resulted in a decrease to pre-tax earnings of approximately $1 million and $5 million, respectively.

Fuel price risk exists at TECO Transport as a result of periodic purchases of diesel fuel. Haulage and freight agreements often include fuel price adjustments to transfer the risk of market fuel price movements to the customer. The projected fuel price risk for 2004 was reduced via price adjustment clauses. As a result, as of Dec. 31, 2003, a hypothetical 10% change in the average annual market price of fuel would result in an estimated impact on pre-tax earnings in 2004 of approximately $2.1 million. As of Dec. 31, 2002, the impact of a hypothetical 10% change in the average annual market price of fuel would not have had a material impact due to price adjustment clauses and derivative instruments used to significantly reduce the risk of price variability of anticipated fuel purchases in excess of fuel purchases subject to fuel adjustment clauses.

For TWG, results of operations are impacted primarily by changes in the market prices for electricity and natural gas. The profitability of merchant power plants is heavily dependent on the spread between electric and gas prices (spark spread) in the markets they serve.

The spark spread calculates the relative profitability of converting gas into electricity, which exists as the best indicator of a gas-fired plant's profitability. The variable cost of producing electricity is primarily a function of gas commodity prices and the heat rate of the plant. The heat rate is the measure of efficiency in converting the input fuel into electricity. When the conversion price equals the market price, the spark spread would be zero. A power plant operating at this level would theoretically break even with respect to variable costs.

Wholesale power prices are set by the market assuming a cost for the input energy and conversion efficiency, but the fixed costs are not necessarily reflected in the market-observed spark spread. TWG uses derivative instruments to reduce the commodity price risk exposure of the merchant plants. The commodity price risk of each plant is managed on both a portfolio and asset-specific basis. The following table summarizes the impact of a hypothetical 10% change in commodity prices on the fair value of merchant energy derivative contracts at Dec. 31, 2003 and Dec. 31, 2002.

Sensitivity of the Fair Value of Merchant Energy Derivative Contracts

(millions) Dec. 31,	2003	2002
Change in Fair Value due to a 10%:[1]		
Decrease in natural gas prices	$ (3.2)	$ (16.9)
Increase in electricity prices	(4.3)	(24.4)
Increase in electricity and natural gas prices	(7.5)	(7.5)

(1) Reflects the fair value associated with merchant energy derivative contracts only. The change shown for the contracts due to price movements would be more than offset by a change in the fair value of the underlying physical plant assets.

Below is a summary of the percentage of merchant plant output and fuel requirements hedged.

Estimated Merchant Plant Hedging Information	*2004*	*2005*
Forecasted plant output and fuel requirements hedged	15%	13%

The following tables summarize the changes in and the fair value balances of energy derivative assets (liabilities) for the year ended Dec. 31, 2003:

Changes in Fair Value of Energy Derivatives (millions)	
Net fair value of derivatives as of Dec. 31, 2002	$ 8.4
Net change in unrealized fair value of derivatives	1.7
Changes in valuation techniques and assumptions	–
Realized net settlement of derivatives	(1.0)
Net fair value of energy derivatives as of Dec. 31, 2003	$ 9.1

Roll-Forward of Energy Derivative Net Assets (Liabilities) (millions)	
Total energy derivative net assets (liabilities) as of Dec. 31, 2002	$ 8.4
Change in fair value of net derivative assets (liabilities):	
Recorded in OCI	12.8
Recorded in earnings	(15.5)
Net option premium payments	10.2
Net purchase (sale) of existing contracts	(6.8)
Net fair value of energy derivatives as of Dec. 31, 2003	$ 9.1

When available, the company uses quoted market prices to record the fair value of energy derivative contracts. However, certain energy derivative contracts are not exchange-traded, but rather, are traded in the over-the-counter (OTC) market, through multiple-party on-line trading platforms, or in the bilateral market. We use industry-accepted valuation techniques based on pricing models or matrix pricing for energy derivative contracts when third-party price data is infrequent or not available. Prices, inputs, assumptions and the results of valuation techniques are validated by the Middle Office, independently of the Front Office, on a daily basis. Significant inputs and assumptions used by the company to determine the fair value of energy derivative contracts are: 1) the physical delivery location of the commodity; 2) the correlation between different basis points and/or different commodities; 3) rational, economic behavior in the markets and by counterparties; 4) on- and off-peak curve shapes and correlations; 5) observed market information; and 6) volatility forecasts and estimates for and between commodities. Mathematical approaches are applied on a frequent basis to validate and corroborate the results of valuation calculations.

The following is a summary table of sources of fair value, by maturity period, for energy derivative contracts at Dec. 31, 2003.

Maturity and Source of Energy Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2003

Contracts Maturing in	*Current*	*Non-current*	*Total Fair Value*
Source of fair value (millions)			
Actively quoted prices	$ 13.8	$ –	$ 13.8
Other external sources [1]	(4.9)	–	(4.9)
Model prices [2]	2.0	(1.8)	0.2
Total	$ 10.9	$(1.8)	$ 9.1

(1) Information from external sources includes information obtained from OTC brokers, industry price services or surveys and multiple-party on-line platforms.
(2) Model prices are used for determining the fair value of energy derivatives where price quotes are infrequent or the market is illiquid. Significant inputs to the models are derived from market observable data and actual historical experience.

For all unrealized energy derivative contracts, the valuation is an estimate based on the best available information. Actual cash flows could be materially different from the estimated value upon maturity.

Other Items Impacting Net Income

2003 Items

In 2003, our results from continuing operations included $223.1 million of charges related to valuation adjustments, project cancellation costs, turbine valuation adjustments, tax credit reversals and corporate restructuring at the various operating companies and $43.6 million related to the sale of HPP and its operating net income through the date of the sale. (See the **Earnings Summary** section.) In addition, we recognized $1.1 million in after-tax charges related a change in accounting principle for the implementation of FAS 143, *Accounting for Asset Retirement Obligations*, and a $3.2 million after-tax charge for the implementation FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.*

2002 Items

In 2002, our results included a $3.0 million after-tax charge at TECO Investments related to an aircraft leased to US Airways, which filed for bankruptcy. Results at TWG included a $5.8 million after-tax asset valuation charge for the sale of its interests in generating facilities in the Czech Republic. Results at TECO Energy included a $34.1 million pre-tax ($20.9 million after-tax) charge related to a debt refinancing.

2001 Items

In 2001, our results included charges to adjust asset valuations totaling $7.2 million after-tax. The adjustments included a $6.1 million after-tax charge related to the sale of a minority interest in EGI, which owns smaller power generation projects in Central America, and a $1.1 million after-tax charge related to the sale of leveraged leases at TECO Investments.

Discontinued Operations

Discontinued operations include the operational losses and charges for the Union and Gila River power stations and operations of Prior Energy and TECO Gas Services.

The 2003 loss from discontinued operations of $890.4 million reflects primarily the $762.0 million after-tax impairment charges for the Union and Gila River power stations and their $62.0 million operating losses, partially offset by net income of $5.5 million from Prior Energy and TECO Gas Services and a $23.5 million after-tax gain on the final installment of the TECO Coalbed Methane sale in January 2003.

In September 2002, as a component of its cash raising plans, TECO Energy initiated activities to sell the TECO Coalbed Methane gas assets. That sale was substantially completed in December 2002 to the Municipal Gas Authority of Georgia. Proceeds from the sale were $140 million, of which $42 million was paid in cash at

closing and $98 million was paid in January 2003. TECO Coalbed Methane's results are accounted for as discontinued operations for all periods reported.

TECO Coalbed Methane's 2002 net income was $31.4 million including a $7.7 million after-tax net gain on the $42 million portion of the sale proceeds. These results reflected production of 14.2 billion cubic feet (Bcf), compared to 15 Bcf in 2001 at an effective gas price, including the effects of hedging, of about $2.80 per thousand cubic feet (Mcf), an almost 20 percent lower realized price than in 2001.

Production from TECO Coalbed Methane's reserves was eligible for Section 29 non-conventional fuels tax credits through 2002. The credit was $1.09 per million Btu for 2002 and $1.08 per million Btu in 2001. This rate escalated with inflation and could have been limited by domestic oil prices. In 2002, domestic oil prices would have had to exceed $50 per barrel for this limitation to have been effective. In 2002, TECO Coalbed Methane's Section 29 tax credits were $15.9 million, compared to $16.1 million in 2001.

Other Income (Expense)

In 2003, Other Income (Expense) of $101.9 million reflects the income related to the gain on the sale of Hardee Power Partners and the sale of the 49.5% interest in the synthetic fuel production facilities at TECO Coal, partially offset by an arbitration reserve established for TMDP, the indirect owner of the Commonwealth Chesapeake Power Station, and lower AFUDC Equity at Tampa Electric. Results in 2002 included income from loans to Panda Energy for the TIE projects which converted to an equity ownership position in January 2003. (See the TWG section.)

In 2002, Other Income (Expense) of $15.2 million included $60.7 million from construction-related and loan agreements with Panda Energy and earnings on the equity investment in EEGSA at TWG, and income from the investment in TPV, partially offset by the $9.4 million pre-tax ($5.8 million after-tax) asset valuation charge for TWG's sale of its minority interest in generating facilities in the Czech Republic and a $34.1 million ($20.9 million after-tax) pre-tax charge related to a TECO Energy debt refinancing completed in 2002.

In 2001, Other Income (Expense) of $38.7 million included income from loan agreements with Panda Energy related to the TIE projects and earnings on the equity investment in EEGSA, and income from the investment in TPV, partially offset by a $9.9 million pre-tax ($6.1 million after-tax) charge for TWG's sale of its minority interest in EGI.

AFUDC equity at Tampa Electric, which is included in Other Income, was $19.8 million in 2003, $24.9 million in 2002 and $6.6 million in 2001. AFUDC is expected to drop to almost zero in 2004, with the completion of Tampa Electric's Bayside repowering.

Interest Charges

Interest expense was $288.4 million in 2003, compared with $142.3 million in 2002 and $164.1 million in 2001. Interest expense increased in 2003 reflecting higher debt balances at both Tampa Electric and TECO Energy associated with the completion of major construction programs. In addition, $45 million less interest was capitalized in 2003, because of the completion of the Union and Gila River construction and the suspension of construction of Dell and McAdams. The decline in 2002 was primarily because of lower short-term debt rates and balances and a favorable settlement with the Internal Revenue Service regarding disputed income tax amounts for which interest had been previously paid.

Income Taxes

Income taxes decreased in 2003 as the result of a loss from continuing operations, continuing non-taxable AFUDC equity, and substantial tax credits associated with the production of non-conventional fuels. Income tax expense decreased in 2002, reflecting greater AFUDC Equity and a substantial increase in tax credits associated with the production of non-conventional fuels. In 2001 income tax expense decreased, reflecting higher taxable income offset by an increase in tax credits associated with the production of non-conventional fuels. Income tax expense as a percentage of income from continuing operations before taxes was 90.2 percent in 2003, -22.9 percent in 2002, and -2.8 percent in 2001. During 2004, we expect the effective tax rate to be in the range of 35-40%.

The cash payment for income taxes, as required by the Alternative Minimum Tax Rules, was $58.8 million, $71.9 million, and $52.4 million in 2003, 2002, and 2001, respectively.

Total income tax expense was reduced by the Federal tax credits related to the production of non-conventional fuels, under Section 29 of the Internal Revenue Code. This tax credit totaled $66.0 million in 2003, $107.3 million in 2002, and $86.2 in 2001. These tax credits are generated annually on qualified production at TECO Coal through Dec. 31, 2007, subject to changes in law, regulation or administration that could impact the qualification of Sec. 29 tax credits. (See the TECO Coal section.)

The tax credit is determined annually and is estimated to be $1.11 per million Btu for 2003 and was $1.09 per million Btu in 2002 and $1.08 per million Btu in 2001. This rate escalates with inflation but could be limited by domestic oil prices. In 2003, domestic oil prices would have had to exceed $50 per barrel for this limitation to have been effective.

In 2003, 2002, and 2001, the decreased income tax expense also reflected the impact of increased overseas operations with deferred U.S. tax structures. The decrease related to these deferrals was $12.3 million, $8.1 million, and $7.2 million for 2003, 2002, and 2001, respectively.

The income tax effect of gains and losses from discontinued operations is shown as a component of results from discontinued operations.

Enron Related Matters

TWG filed a claim in the Enron bankruptcy proceeding associated with the NEPCO "swept cash" for the four projects in the amount of $214 million. TWG and others have filed adversary proceedings in the bankruptcy to try to establish a constructive trust with respect to the cash used by Enron that belonged to its subsidiary, NEPCO, the engineering, procurement and construction contractor of four TWG projects.

In 2003, TWG sold its bankruptcy claims for approximately 15.5 cents on the dollar which amounted to a recovery of about $42 million. There was a holdback of 20% to be released at the time of payment by Enron to the purchaser. The cash received in excess of the holdback was approximately $33.4 million. Under the arrangement, the pending adversary proceedings would still be prosecuted to the extent practicable with the excess recovery, if any, shared by us and the purchaser. This recovery would primarily offset increases in construction costs associated with the effect of Enron's bankruptcy on its subsidiary NEPCO.

Environmental Compliance

Consent Decree

Tampa Electric Company, in cooperation with the Environmental Protection Agency (EPA) and the U.S. Department of Justice, signed a Consent Decree which became effective Oct. 5, 2000, and a Consent Final Judgment with the Florida Department of Environmental Protection (FDEP), effective Dec. 7, 1999. Pursuant to these agreements, allegations of violations of New Source Review requirements of the Clean Air Act were resolved, provision was made for environmental controls and pollution reductions, and Tampa Electric began implementing a comprehensive program to dramatically decrease emissions from its power plants.

The emission reduction requirements included specific detail with respect to the availability of flue gas desulfurization systems (scrubbers) to help reduce sulfur dioxide (SO2), projects for nitro-

gen oxides (NOx) reduction efforts on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Station to natural gas. The commercial operation dates for the two repowered Bayside units were on April 24, 2003 and Jan. 15, 2004. The completed station has total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled electric generation. By May 1, 2005, Tampa Electric must decide whether to install NOx controls, repower, or shutdown Big Bend Unit 4, and it must implement the chosen methodology by June 1, 2007. By May 1, 2007, Tampa Electric will decide whether to install NOx controls, repower, or shutdown Big Bend Units 1, 2 and 3, and it must implement the chosen methodology beginning in 2008. Tampa Electric's capital investment forecast includes amounts in the 2006 through 2008 period for compliance with the NOx SO2 and particulate matter reduction requirements.

Emission Reductions

Since 1998, Tampa Electric has reduced annual SO2, NOx, and particulate matter (PM) emissions from its facilities by 129,430 tons, 27,630 tons, and 2,865 tons, respectively.

Reductions in SO2 emissions were accomplished through the installation of scrubber systems on Big Bend Units 1 and 2 in 1999. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3. Currently, the scrubbers at Big Bend Station remove more than 95 percent of the SO2 emissions from the flue gas streams.

In addition, Consent Decree and Consent Final Judgment related projects will result in significant reductions in emissions. Reductions have already resulted from the completion of the repowering of Gannon Station to Bayside Power Station in April 2003 (Bayside Unit 1) and January 2004 (Bayside Unit 2). Should Tampa Electric decide to continue to burn coal, the installation of additional NOx emissions controls on all Big Bend Units will result in the further reduction of emissions. By 2010, these projects will result in the additional phased reduction of SO2 by 156,501 tons per year, NOx by 61,549 tons per year, and PM by 3,626 tons per year from 1998 levels. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO2, NOx, and PM emissions by 90 percent, 89 percent, and 70 percent, respectively, below 1998 levels. With these improvements in place, Tampa Electric's facilities will meet the same standards required of new power generating facilities and help to significantly enhance the quality of the air in the community.

Due to pollution control co-benefits from the Consent Final Judgment and Consent Decree, reductions in mercury emissions have occurred due to the re-powering of Gannon Station to Bayside Station. At Bayside, where mercury levels have decreased 44 percent below 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions are also anticipated from the installation of NOx controls at Big Bend Station, which would lead to a mercury removal efficiency of approximately 70 percent. Depending on the NOx control technology selected for Big Bend, the mercury reductions may vary and lead to lower than anticipated mercury removal efficiencies.

The repowering of Gannon Station to Bayside Station will also lead to a significant reduction in carbon dioxide (CO2) emissions. It is expected, that by 2005, the repowering will bring an approximate 5.2 million ton decrease in CO2 emissions below 1998 levels. This reduction will result in the Tampa Electric system CO2 emissions being in line with its 1990 CO2 emission levels.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2003, Tampa Electric Company has estimated its ultimate financial liability to be approximately $20 million, and this amount has been reflected in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors, or Tampa Electric Company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other potentially responsible parties (PRPs) is based on each parties' relative ownership interest in or usage of a site. Accordingly, Tampa Electric Company's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Regulation

Tampa Electric Rate Strategy

In 1996, during the construction of Polk Unit one, Tampa Electric entered into a series of agreements with Florida's Office of Public Counsel (OPC) and the Florida Industrial Power Users Group (FIPUG), which were approved by the FPSC to stabilize prices while securing fair earnings opportunities through 1999.

Since the expiration of the agreements, Tampa Electric's rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue earning within its allowed ROE range even with the rate base additions associated with the repowering of the Bayside Power Station.

Tampa Electric has not sought a base rate increase to recover the investment in the Bayside Power Station which entered service in two phases, with the first in April 2003 and the second in January 2004.

Cost Recovery Clauses – Tampa Electric

In February 2003, Tampa Electric filed a request for an additional fuel cost adjustment of almost $61 million due to continued increase in the cost of natural gas and oil. The request also reflected Tampa Electric's operational plan to phase out Gannon Units 1 through 4 in 2003. In March 2003, the FPSC approved Tampa Electric's new fuel rates as well as new fuel rates for the other peninsular Florida investor-owned utilities.

In September 2003, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery clause rates for the period January through December 2004. In November, the FPSC approved Tampa Electric's requested changes. The resulting rates include the impacts of increased use of natural gas at the Bayside Power Station and the collection of $91 million for under recovery of fuel expense for 2002 and 2003. The filing also included estimated waterborne transportation rates for coal transportation services,

discussed below. The FPSC did not allow the recovery of $8.4 million it characterized as "savings" from shutting down the Gannon Station earlier than originally planned which the FPSC deemed generated operations and maintenance savings. Accordingly, Tampa Electric's residential customer rate per 1,000-kilowatt hours increased to $99.01. The rates include projected costs associated with environmental projects required under the EPA Consent Decree and the FDEP Consent Final Judgment.

Tampa Electric filed its objection to the disallowance of the recovery of the $8.4 million and a motion asking the FPSC to reconsider its decision because all facts and law were not taken into account. The motion was filed on Jan. 6, 2004, and a decision on this matter is expected in the first quarter of 2004.

Coal Transportation Contract

Tampa Electric's contract for coal transportation and storage services with TECO Transport expired on Dec. 31, 2003. TECO Transport had been providing river, cross-gulf transportation services and storage services under that contract since 1999 and under a series of contracts for more than 40 years. In June, Tampa Electric issued a Request For Proposal (RFP) to potential providers requesting services for the next five years. The result of the RFP process was the execution of a new contract between Tampa Electric and TECO Transport, effective Jan. 1, 2004, with market rates supported by the results of the RFP and an independent expert in maritime transportation matters. The prudence of the RFP process and final contract were originally scheduled to be reviewed by the FPSC in the course of the normal fuel cost recovery hearings in November 2003. That hearing was deferred due to protests from other parties seeking more time to evaluate the contract information. The matter is scheduled to be heard by the FPSC in May 2004 with a decision expected in July 2004.

In the meantime, Tampa Electric is recovering fuel transportation costs at the rates from the now expired contract, which are slightly higher than those in the contract effective Jan. 1, 2004.

Cost Recovery Clauses – Peoples Gas

In November 2003, the FPSC approved rates under Peoples' Gas Purchased Gas Adjustment (PGA) cap factor for the period January 2004 through December 2004. The PGA is a factor that can vary monthly due to changes in actual fuel costs but is not anticipated to exceed the annual cap. The approved cap includes an under-recovery of $7.5 million for 2002 and a projected over-recovery of $10.3 million in 2003.

Utility Competition – Electric

Tampa Electric's retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of self-generation available to larger users of electric energy. Such users may seek to expand their alternatives through various initiatives, including legislative and/or regulatory changes that would permit competition at the retail level. Tampa Electric intends to retain and expand its retail business by managing costs and providing high-quality service to retail customers.

There is presently competition in Florida's wholesale power markets, increasing largely as a result of the Energy Policy Act of 1992 and related federal initiatives. However, the state's Power Plant Siting Act, which sets the state's electric energy and environmental policy and governs the building of new generation involving steam capacity of 75 megawatts or more, requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits.

In 2003, the FPSC implemented rules that modified rules from 1994 that required investor-owned electric utilities (IOUs) to issue RFPs prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle greater than 75 megawatts. The modified rules provide a mechanism for expedited dispute resolution; allow bidders to submit new bids whenever the IOU revises its cost estimates for its self-build option; require IOUs to disclose the methodology and criteria to be used to evaluate the bids; and provide more stringent standards for the IOUs to recover cost overruns in the event the self-build option is deemed the most cost-effective. The new rules became effective for requests for proposal for applicable capacity additions, prospectively.

Transmission Rates

In October 2002, Tampa Electric submitted a FERC filing to increase its transmission and ancillary services rates under the company's open access transmission tariff. These rates apply to wholesale transmission users of Tampa Electric's transmission system and do not affect retail service rates. In December, the FERC accepted the filing and set the matter for settlement negotiations and a potential hearing should the settlement process fail. Settlement discussions that began in January 2003 resulted in a settlement agreement that approved increased rates and resolved all disputed issues and was certified by the FERC in June 2003. In compliance with the FERC order approving the settlement, Tampa Electric made timely refunds, plus interest, for amount collected in excess of the settlement rates.

Regional Transmission Organization (RTO)

In December 1999, the Federal Energy Regulatory Commission (FERC) issued Order No. 2000, dealing with FERC's continuing effort to affect open access to transmission facilities in large regional markets. In response, the peninsular Florida IOUs (Florida Power & Light, Progress Energy Florida and Tampa Electric) agreed to form an RTO to be known as GridFlorida LLC which would independently control the transmission assets of the filing utilities, as well as other utilities in the region that chose to join. In March 2001, the FERC conditionally approved GridFlorida.

In May 2001, the FPSC questioned the prudence of the three filing utilities joining GridFlorida. After an October 2001 hearing, the FPSC found that the companies were prudent in forming GridFlorida, but ordered the companies to modify their proposal to develop a non-transmission owning RTO model. An updated filing was submitted to the FPSC. In August 2002, the FPSC voted to approve many of the compliance changes submitted, but set an October 2002 hearing on the market design changes proposed in the updated filing.

In October 2002, the process was delayed when the OPC filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the IOUs and, by approving GridFlorida, they were doing just that. Oral arguments occurred in May 2003, and the Florida Supreme Court dismissed the OPC appeal citing that it was premature because certain portions of the FPSC GridFlorida order are not final.

In September 2003, a joint meeting of the FERC and FPSC took place to discuss wholesale market and RTO issues related to GridFlorida and in particular federal/state interactions. The FPSC has scheduled a series of collaborative meetings with all interested parties and, upon their conclusion, will set items for hearing and a hearing schedule. This is expected to occur throughout 2004.

Peoples Gas Rate Proceeding

On Jun. 27, 2002, PGS filed a petition with the FPSC to increase its service rates. The requested rates would have resulted in a $22.6 million annual base revenue increase, reflecting a ROE midpoint of 11.75 percent.

On the date of the FPSC hearing, PGS agreed to a settlement with all parties involved, and a final Commission order was granted on Dec. 17, 2002. PGS received authorization to increase annual base revenues by $12.05 million. The new rates allow for an allowed ROE range from 10.25 percent to 12.25 with an 11.25 percent midpoint and a capital structure with 57.43 percent equity and were effective after Jan. 16, 2003.

Utility Competition – Gas

Although PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity.

In Florida, gas service is unbundled for all non-residential customers. In November 2000, PGS implemented its "NaturalChoice" program offering unbundled transportation service to all eligible customers. This means that non-residential customers can purchase commodity gas from a third party but continue to pay PGS for the transportation of the gas.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by companies seeking to sell gas directly, by transporting gas through other facilities, thereby bypassing PGS facilities. In response to this competition, PGS has developed various programs, including the provision of transportation services at discounted rates.

In general, PGS faces competition from other energy source suppliers offering fuel oil, electricity and in some cases, propane. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high-quality service to customers.

TWG Federal and State Regulatory and Legislative Involvement

Along with TECO Energy's active involvement in restructuring initiatives, TWG has been proactively involved in regulatory and legislative forums in the markets in which it competes, including Arizona, Texas, Arkansas, Mississippi, and Louisiana. This has included repeal of retail deregulation rules and laws in Arkansas and restructured regulatory rules regarding the settlement agreement that governs retail and wholesale competition in Arizona.

TWG was an active intervener in Arizona Public Service Company's (APS) regulatory proceedings regarding a request to be exempt from its obligation, beginning on Jan. 1, 2003, to purchase at least 50 percent (about 3,000 MW) of its load requirements through a formal, arms-length, competitive procurement process and instead to purchase almost all of its load requirements from its unregulated affiliate, Pinnacle West Energy Corporation. Tucson Electric Power Company (TEP) filed a similar variance request with the Arizona Corporate Commission, although it only sought a postponement of the implementation date. As a result, in early 2003 APS and TEP were required to competitively procure their unmet needs through separate RFP processes, which were held during the spring. During those competitive solicitations, Gila River Power Station was selected to provide power to both of these entities for three years. Power deliveries began under the agreements last year.

During the 2003 regular legislative session, the Arkansas Legislature repealed its earlier legislation, which was to initiate retail electric deregulation in Arkansas sometime between October 2003 and October 2005. TWG and other independent power producers, embarked on a strategy that would displace the region's older, less efficient, more polluting generating units so that state-of-the-art, gas-fired, combined-cycle units, such as the Union Power Station, could serve the growing needs of the area. This is a strategy that TWG has advanced at the federal level and within other markets it serves. As a result, the Louisiana Public Service Commission ordered its Staff to conduct a unit displacement/retirement study to achieve the identified economic and environmental benefits. This study should be completed during the first half of 2004.

TWG is working on behalf of both the Frontera and TIE facilities to effectuate change at ERCOT, (Electric Reliability Council of Texas) the Public Utility Commission of Texas (PUCT) and Legislature on matters of common interest for the two facilities. Despite the advent of competition in Texas, the market design does not yet result in the dispatch of the region's most economical resources namely, newer, more-efficient, gas-fired capacity.

TWG has taken an active role on ERCOT committees, in proceedings at the PUCT and in the Legislature, whose next session begins in mid-January 2005. Transmission congestion remains a major concern in the ERCOT market, and has affected Frontera's ability to economically operate. Several initiatives within the ERCOT committees and at the PUCT are underway to address these ongoing congestion problems, and fundamental market redesign issues.

In the meantime until market changes are implemented, local congestion remains a significant issue for the load-serving entities and generation facilities within ERCOT. The new market design will directly assign congestion costs to those who cause the transmission system congestion. TWG is advocating interim market solutions that would eliminate Reliability-Must-Run (RMR) contracts and provide adequate compensation for Frontera when called upon by ERCOT to alleviate congestion in the Rio Grande Valley.

Corporate Governance

In the last several years, the Congress, the Securities and Exchange Commission (SEC), the New York Stock Exchange (NYSE), and other interested groups have focused extensively on improving corporate accountability and corporate governance in an effort to restore investor confidence. The rules passed by the SEC, as well as the listing standards adopted by the NYSE that become effective after the 2004 Annual Meeting of Shareholders, are already a part of our corporate culture and we have been voluntarily complying with them. These rules require, among other things, independence by the Board of Directors and various Board committees, a statement of governance guidelines and detailed committee charters, an internal audit function, a code of ethics for the CEO, senior financial officers and directors, adequate internal controls to detect fraud, increased oversight of financial disclosure by the Audit Committee, and certification by the CEO and CFO of the financial results.

For many years, the vast majority of our Board of Directors have been independent, and the required independent Board committees have been in place. In addition, we have had a rigorous internal audit and compliance function, including an anonymous reporting system which now has been expanded to cover matters required to be disclosed to the Audit Committee and the non-management directors, and a code of ethics for all employees and officers, the *Standards of Integrity*. The code was expanded in 2002 to include directors and is posted on the company's website. Our long-standing controls for full and complete financial reporting and disclosure have been formalized and are reviewed quarterly for effectiveness. The CEO and CFO have filed sworn statements with the SEC quarterly, as required by law, to certify without exception the accuracy of the financial results, and the CEO will be signing the required certification as to compliance with the NYSE's corporate governance listing standards following the next annual meeting.

The Board of Directors operates under a set of guidelines that clearly establish the Board's responsibilities, and each committee has a charter that defines its purpose, duties and responsibilities. The Corporate Governance Guidelines and the committee charters are reviewed regularly to ensure that they comply with all of the relevant regulations and meet the needs of the Board. More information about the members of the Board of Directors, as well as copies of the Corporate Governance Guidelines, the various committee charters, and the *Standards of Integrity*, can be found in the corporate governance section of the Investor Relations page on our website, www.tecoenergy.com.

Transactions with Related and Certain Other Parties

We and our subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests that are reported in our annual proxy statement and Tampa Electric's annual regulatory filings. These transactions, primarily for legal services, were not material for the periods ended Dec. 31, 2003, 2002 and 2001. There are no material transactions of this type where the payments are in excess of those that would be paid under an arms-length transaction. We have interests in unconsolidated affiliates, which are discussed in the **TECO Wholesale Generation, Other Unregulated Companies** and **Off-Balance Sheet Financing** sections.

In October 2003, Tampa Electric signed a five-year contract renewal with an affiliate company, TECO Transport Corporation, for integrated waterborne fuel transportation services effective Jan. 1, 2004. The contract calls for inland river and ocean transportation along with river terminal storage and blending services for up to 5.5 million tons of coal annually through 2008.

TWG Arkansas Operations Company and TWG Arizona Operations Company, both wholly-owned subsidiaries of TWG, had a combined receivable from Union and Gila River of $0.8 million as of Dec. 31, 2002.

TWG's position in the Odessa and Guadalupe power stations in Texas was in the form of a $137 million loan to a Panda Energy International subsidiary, which is a partner in TIE at Dec. 31, 2002. In September 2003, TWG completed the foreclosure on Panda's interest in TIE for a default on a $23 million note receivable which resulted in TWG becoming a 50-percent owner in the plants and a total investment in TIE of $160 million. In 2003, improved peak season power prices and a new power and gas manager retained to increase the energy sales from these plants resulted in improved financial performance, however; the plants still had a negative impact on earnings. The interest earned on the loans to TIE was reflected in 2002 and 2001 earnings.

In February 2002, the TWG and Panda affiliates that comprised the joint venture that owned the Union and Gila River projects entered into an arrangement obligating TWG to purchase and Panda to sell Panda's interest in the joint venture in 2007 for $60 million. In July 2003, TWG acquired Panda's interest in these plants through a modification of the Purchase Agreement and termination of the joint venture.

Investment Considerations

The following are certain factors that could affect TECO Energy's future results. They should be considered in connection with evaluating forward-looking statements contained in this report and otherwise made by or on behalf of TECO Energy because these factors could cause actual results and conditions to differ materially from those projected in those forward-looking statements.

Financing Risks

We have substantial indebtedness, which could adversely affect our financial condition and financial flexibility.

In recent years, we have significantly increased our indebtedness which has resulted in an increase in the amount of fixed charges we are obligated to pay. The level of our indebtedness and restrictive covenants contained in our debt obligations could limit our ability to obtain additional financing or refinance existing debt and could prevent the repayment of subordinated debt and the payment of dividends if those payments would cause a violation of the covenants.

In order for us to use our credit facilities, we must meet certain financial tests. Our credit facilities require that at the end of each quarter our debt-to-capital ratio, as defined in the applicable agreements, not exceed 65%. Tampa Electric Company's credit facility requires that at the end of each quarter Tampa Electric Company's debt-to-capital ratio, as defined in the agreement, not exceed 60% and its earnings before interest, taxes, depreciation and amortization (EBITDA) to interest coverage ratio, as defined in the applicable agreement, not be less than 2.5 times. At Dec. 31, 2003, our debt-to-capital ratio was 61.9% and Tampa Electric Company's debt-to-capital ratio was 49.2% and its interest coverage ratio was 5.8 times. Similarly, certain long-term debt at Tampa Electric Company's Peoples Gas System division contains a prohibition on the incurrence of funded debt if Tampa Electric Company's debt-to-capital ratio, as defined in the applicable agreement, exceeds 65%. The Tampa Electric Company debt related to Peoples Gas also carries a requirement that Tampa Electric Company's interest coverage ratio, as defined in the applicable agreement, be 2.0 times or greater for four consecutive quarters.

Our construction undertaking obligations associated with TWG's Gila River and Union Power Projects, in effect until twelve months after commercial operation, require our consolidated EBITDA to interest coverage ratio, as defined in the applicable agreement, to equal or exceed 3.0 times for the twelve-month period ended each quarter and a debt-to-capital ratio not to exceed 65% at the end of each fiscal quarter. Under the suspension agreement between TECO Energy, the project companies and the lenders, TECO Energy was not required to calculate the EBITDA to interest coverage ratio required in the undertaking for the quarters ended Sep. 30, 2003 and Dec. 31, 2003 until Feb. 1, 2004 which was orally extended until Feb. 5, 2005. On that date, the calculations were made resulting in 2.7 and 2.4 times for the two quarters, respectively. Non-compliance with this covenant could accelerate the $1.395 billion of non-recourse construction debt absent the sale of the projects to the lenders. (See **TECO Wholesale Generation – Letter of Intent** section.)

Our 10.5% Notes due 2007 issued in November 2002, contain covenants that limit our ability to incur additional liens and require us to achieve certain interest coverage levels in order to pay dividends, make distributions or certain investments, or issue additional indebtedness. The 7.5% Notes issued in June 2003 contain the same limitation on liens covenant. The covenants apply only if either the notes are rated non-investment grade by either S&P or Moody's or the notes are rated below the level required by the equity bridge loan and Union and Gila River Construction Undertaking while those obligations are outstanding. The covenants became applicable upon Moody's downgrade of TECO Energy's senior unsecured debt in April 2003. The limitation on restricted payments restricts us from paying dividends or making distributions or certain investments unless there is sufficient cumulative operating cash flow, as defined in the agreement applicable to the 10.5% Notes, in excess of 1.7 times interest coverage to make contemplated dividend payments, distributions or investments. Our operating cash flow, restricted payments and interest coverage are calculated on a cumulative basis from the issuance of the 10.5% Notes in November 2002. As of Dec. 31, 2003, $285 million was accumulated and available for future restricted payments, representing a four quarter accumulation. Further, we are not permitted, with certain exceptions as stated in that agreement, to create any lien upon any of our property in excess of 5% of consolidated net tangible assets as defined, without equally and ratably securing the 10.5% Notes. As of Dec. 31, 2003 this limitation would apply to the creation of covered liens exceeding $206 million. Finally, our operating cash flow to interest coverage ratio, as defined in that agreement, for the immediate preceding four quarters must exceed 2.0 times for us to be able to issue additional indebtedness, with certain exceptions as provided in that agreement. As of Dec. 31, 2003, our operating cash flow to interest coverage ratio for the immediate preceding four quarters, with pro forma adjustments as provided in the agreement, was 2.6 times.

Tampa Electric Company's 6.25% Senior Notes Due 2016 contain covenants that require Tampa Electric Company to maintain, as of the last day of each fiscal quarter, a debt-to-capital ratio, as

defined in the agreement, that does not exceed 60%, and prohibit the creation of any covered lien on any of its property in excess of $787 million, with certain exceptions as defined in the agreement, without equally and ratably securing the 6.25% Senior Notes.

Finally, in addition to our debt-to-capital ratio requirement discussed above, our credit facility with an affiliate of Merrill Lynch has covenants that, if the facility is drawn, could limit the payment of dividends exceeding $40 million in any quarter unless, prior to the payment of any dividends, we deliver to Merrill Lynch liquidity projections demonstrating that we will have sufficient cash or cash equivalents to pay both the dividends contemplated and each of the three quarterly dividends next scheduled to be paid on our common stock.

We cannot assure you that we will be in compliance with these financial covenants in the future. Our failure to comply with any of these covenants or to meet our payment obligations could result in an event of default which, if not cured or waived, could result in the acceleration of other outstanding debt obligations. We may not have sufficient working capital or liquidity to satisfy our debt obligations in the event of an acceleration of all or a portion of our outstanding obligations. In addition, if we had to defer interest payments on our subordinated notes that support the distributions on our outstanding trust preferred securities, we would be prohibited from paying cash dividends on our common stock until all unpaid distributions on those subordinated notes were made.

We also incur obligations in connection with the operations of our subsidiaries and affiliates, which do not appear on our balance sheet, including obligations related to the development of power projects by unconsolidated affiliates. These obligations take the form of guarantees, letters of credit and contractual commitments, as described in the sections titled **Off Balance Sheet Financing** and **Liquidity, Capital Resources** section. In addition, our unconsolidated affiliates from time to time incur non-recourse debt to finance their power projects. Although we are not obligated on that debt, our investments in those unconsolidated affiliates are at risk if the affiliates default on their debt.

Our financial condition and ability to access capital may be materially adversely affected by further ratings downgrades.

In February 2004, Moody's Investor Service, Inc. lowered the ratings on our senior unsecured debt to Ba2 with a negative outlook. This followed actions in April 2003, when Moody's and Fitch Ratings lowered their ratings on our senior unsecured debt to Ba1 and BB+, respectively, both with a negative outlook. In May 2003, Standard & Poor's Ratings Services lowered the ratings on our senior unsecured debt to BB+ with a negative outlook. These agencies also lowered the ratings on other of our securities, as well as those of TECO Finance and Tampa Electric. Tampa Electric Company's senior secured and unsecured debt ratings were lowered to Baa1 and Baa2, respectively, by Moody's, to A- and BBB+, respectively, by Fitch and to BBB- for both senior secured and unsecured debt by Standard & Poor's. Currently the outlook for Tampa Electric, TECO Energy and TECO Finance at all of the credit rating agencies is negative. The 2003 and 2004 downgrades and any future downgrades may affect our ability to borrow and may increase our financing costs, which may decrease our earnings. We are also likely to experience greater interest expense than we may have otherwise if, in future periods, we replace maturing debt with new debt bearing higher interest rates due to our lower credit ratings. In addition, such downgrades could adversely affect our relationships with customers and counterparties.

In addition, as a result of the 2003 ratings actions, TES, Prior Energy and TECO Gas Services were required to post collateral with counterparties in order to continue to transact in the forward markets for electricity and natural gas. Collateral or margin postings may fluctuate based on either the fair value of open forward positions or credit assurance assessments negotiated with counterparties. Based on the fair value of existing contractual obligations as of Dec. 31, 2003, the maximum collateral obligation, if all counterparties exercised their full rights, would be approximately $16 million. Counterparties with the right to call for collateral or margin postings are not obligated to do so. Based on our analysis of the rights of those counterparties that have the right to call for collateral or margin postings, we believe the maximum collateral obligation would be approximately $16.0 million (including actual collateral posted of $11.8 million).

In November 2003, S&P affirmed TECO Energy's current credit ratings and removed the ratings from Credit Watch with negative implications following the resolution of the Private Letter Ruling issues related to the production of synthetic fuel at TECO Coal, (see the TECO Coal section). At that time, S&P stated that future ratings stability was directly correlated with TECO Energy's exit from the merchant energy business and the use of future cash flows to reduce debt. S&P went on to state that a failure to exit the merchant energy business would likely result in addition credit rating reductions. Such reductions could result in Tampa Electric's credit rating falling below investment grade. In February 2004, S&P stated that the announcement to exit the Union and Gila River projects was favorable to credit quality but took no ratings action and maintained its negative outlook.

If we are unable to limit capital expenditure levels as forecasted or successfully complete planned facility sales to the extent anticipated, our financial condition and results could be adversely affected.

Part of our plans includes capital expenditures at the operating companies at maintenance levels for the next several years. We cannot be sure that we will be successful in limiting capital expenditures to the planned amount. Our plan also includes the sale of an additional 40% portion of our interest in facilities that produce synthetic fuel which qualifies for Section 29 tax credits at TECO Coal. We cannot be certain, however, that we will find purchasers or be able to sell these synthetic fuel production facilities at the prices we expect. If we are unable to limit capital expenditures to the forecasted levels or to sell the synthetic fuel production facilities at the prices we expect or at all, we may need to draw on credit facilities or access the capital markets on unfavorable terms or ultimately sell additional assets to improve our financial position. We cannot be sure that we will be able to obtain additional financings or sell such assets, in which case our financial position, earnings and credit ratings could be adversely affected.

Because we are a holding company, we are dependent on cash flow from our subsidiaries, which may not be available in the amounts and at the times we need it.

We are a holding company and dependent on cash flow from our subsidiaries to meet our cash requirements that are not satisfied from external funding sources. Some of our subsidiaries have indebtedness containing restrictive covenants which, if violated, would prevent them from making cash distributions to us. In particular, Tampa Electric Company's first mortgage bonds indenture contains restrictions on distributions on its common stock, and certain long-term debt at Tampa Electric Company's Peoples Gas System division prohibits payment of dividends to us if Tampa Electric Company's consolidated shareholders' equity is not at least $500 million. At Dec. 31, 2003, Tampa Electric Company's unrestricted retained earnings available for dividends on its common stock were approximately $5 million and its consolidated shareholders' equity was approximately $1.7 billion. Also, our wholly-owned subsidiary, TECO Diversified, the holding company for TECO Transport, TECO Coal and TECO Solutions, has a guarantee related to a coal supply agreement that could limit the payment of dividends by TECO Diversified to us.

Various factors could affect our ability to sustain our dividend.

Our ability to pay a dividend or sustain it at current levels could be affected by such factors as (i) the level of our earnings and therefore our dividend payout ratio, (ii) the level of our retained

earnings could be affected by payment of dividends in excess of earnings and further write-offs of our merchant generation investments or other assets, (iii) pressures on our liquidity needs, including unplanned debt repayments, unexpected capital needs and shortfalls in operating cash flow and (iv) a breach of our 65% debt-to-total capital financial covenant, which could occur in the event of further erosion of our retained earnings without infusion of additional capital. These are in addition to any restrictions on dividends from our subsidiaries to us discussed above.

We are vulnerable to interest rate changes and may not have access to capital at favorable rates, if at all.

Changes in interest rates and capital markets generally affect our cost of borrowing and access to these markets. We cannot be sure that we will be able to accurately predict the effect those changes will have on our cost of borrowing or access to capital markets.

Merchant Power Project Risks

We and the project companies have not yet reached a definitive agreement with the non-recourse project lending banks for the transfer of our ownership of the Union and Gila River projects through a purchase and sale or other agreement to the lending group.

Our decision to exit from the ownership of the projects is not conditioned on reaching a consensual agreement with the lenders for the sale of the projects. If a definitive agreement cannot be reached, however, there could be a delay in the ultimate forgiveness of the non-recourse debt and there could be a change in the accounting treatment from discontinued operations back to continuing operations in a future period.

Under the letter of intent, the parties have retained the right to assert certain claims they may have against one another until a definitive agreement is reached. Assertion of such claims and defense against them could be time consuming and costly and delay the ultimate disposition of our interest in the projects.

The failure of the project companies to make interest payment on the project debt, which they failed to do beginning December 31, 2003, could permit a claim of a cross default under two leases of TECO Transport. (See the **TECO Transport** section.)

TECO Wholesale Generation's (TWG) power plants are affected by market conditions, and they may not be able to sell power at prices that enable it to recover its investments in the plants.

The TWG power plants that are in operation currently sell most of their power based on market conditions at the time of sale, so TWG cannot predict with certainty:

- the amount or timing of revenue it may receive from power sales from operating plants;
- the differential between the cost of operations (in particular, natural gas prices) and power sales revenue;
- the effect of competition from other suppliers of power;
- regulatory actions that may affect market behavior, such as price limitations or bidding rules imposed by the Federal Energy Regulatory Commission (FERC) or state regulatory bodies or reimposition of regulation in power markets;
- the demand for power in a market served by TWG's plants relative to available supply;
- the availability of transmission to accommodate the sale of power; or
- whether TWG will recover its initial investment in these plants.

At present, several of the wholesale markets supplied by so-called "merchant" power plants are experiencing significant pricing declines due to excess supply and weak economies. The excess supply is partially due to the slowdown of electric deregulation in many states, or the outright repeal of electric competition legislation as occurred in Arkansas in 2003 (where the Dell and Union power stations are sited or located). This has allowed incumbent utilities to continue to operate older, less efficient generating facilities in lieu of purchasing power from newer, more efficient independent power plants. Consequently, only a small portion of the output of TWG's plants has been sold forward, or hedged, under short-term agreements. TWG's results could be adversely affected if it is unable to sufficiently sell the output of its plants under longer-term contracts or at a premium to forward curve prices for short-term sales or if we need to write off any of the capital already invested in the projects.

Our outlook assumes that TWG will manage these risks by:

- optimizing among a mix of forward on-peak energy sales, daily and hourly spot market sales of capacity, energy and ancillary services, and longer-term structured transactions;
- avoiding short positions; and
- retaining flexibility to continue to defer, where advisable, construction of output capacity in a market that has become oversupplied.

However, we cannot be sure how successfully TWG will be able to implement these risk management measures. For instance, in oversupplied markets, entering into long-term contracts could be difficult.

TWG may be unable to successfully complete current projects on schedule or within budget, and the book value of uncompleted projects could be impaired.

TWG currently has new power generating facilities where construction has been suspended. The construction and maintenance of these facilities involves risks of shortages and inconsistent qualities of equipment and material, labor shortages and disputes, engineering problems, work stoppages, unanticipated cost increases and environmental or geological problems. Any of these events could delay a project's construction schedule or increase its costs, which may impact TWG's ability to generate sufficient cash flow. In addition, if these projects remain suspended beyond the currently anticipated time frame, the book value of those projects would likely be impaired.

Asset valuation adjustments or sales of these facilities at prices below the book value would reduce our equity levels and could potentially result in a breach of our 65 percent debt-to-total capital covenant in our bank credit facility.

TWG's marketing and risk management policies may not work as planned, and it may suffer economic losses despite such policies.

TWG seeks to actively manage the market risk inherent in its energy and fuel positions. Nonetheless, adverse changes in energy and fuel prices may result in losses in our earnings or cash flows and adversely affect our balance sheet. TWG's marketing and risk management procedures may not always be followed or may not work as planned. As a result, we cannot predict with precision the impact that its marketing, energy management and risk management decisions may have on its business, operating results or financial position. In addition, to the extent it does not cover its positions to market price volatility, or the hedging procedures do not work as planned, fluctuating commodity prices would cause our sales and net income to be volatile.

TWG's and its affiliates' marketing and risk management activities also are exposed to the credit risk that counterparties to its transactions will not perform their obligations. Should counterparties to these arrangements fail to perform, it may be forced to enter into alternative hedging arrangements, honor underlying commitments at then-current market prices or otherwise satisfy its obligations on unfavorable terms. In that event, its financial results would likely be adversely affected.

General Business and Operational Risks

General economic conditions may adversely affect our businesses.

Our businesses are affected by general economic conditions. In particular, the projected growth in Tampa Electric's service area and in Florida is important to the realization of Tampa Electric's and Peoples Gas System's forecasts for annual energy sales growth. An unanticipated downturn in the local area's or Florida's economy could adversely affect Tampa Electric's or Peoples Gas System's expected performance.

Our unregulated businesses, particularly TWG, TECO Transport and TECO Coal, are also affected by general economic conditions in the industries and geographic areas they serve, both nationally and internationally.

Potential competitive changes may adversely affect our gas and electricity businesses.

The U.S. electric power industry has been undergoing restructuring. Competition in wholesale power sales has been introduced on a national level. Some states have mandated or encouraged competition at the retail level and, in some situations, required divestiture of generating assets. While there is active wholesale competition in Florida, the retail electric business has remained substantially free from direct competition. Changes in the competitive environment occasioned by legislation, regulation, market conditions or initiatives of other electric power providers, particularly with respect to retail competition, could adversely affect Tampa Electric's business and its performance.

The gas distribution industry has been subject to competitive forces for several years. Gas services provided by Peoples Gas System are now unbundled for all non-residential customers. Because Peoples Gas System earns margins on distribution of gas, but not on the commodity itself, unbundling has not negatively impacted Peoples Gas System's results. However, future structural changes that we cannot predict could adversely affect Peoples Gas System.

Our gas and electricity businesses are highly regulated, and any changes in regulatory structures could lower revenues or increase costs or competition.

Tampa Electric and Peoples Gas System operate in highly regulated industries. Their retail operations, including the prices charged, are regulated by the FPSC, and Tampa Electric's wholesale power sales and transmission services are subject to regulation by the FERC. Changes in regulatory requirements or adverse regulatory actions could have an adverse effect on Tampa Electric's or Peoples Gas System's performance by, for example, increasing competition or costs, threatening investment recovery or impacting rate structure.

Tampa Electric is seeking regulatory approval for the costs associated with a new contract for coal transportation services.

Tampa Electric has executed a new 5-year contract for coal transportation services with TECO Transport. These services have been provided by TECO Transport historically and represent about 40% of TECO Transport's revenues. The costs associated with the transportation services are subject to FPSC review and a number of parties, including alternative transportation providers have intervened in the proceedings, which are scheduled for hearings in April 2004. Failure to gain regulatory approval for the recovery of the costs associated with these services could adversely impact Tampa Electric's financial results.

Our businesses are sensitive to variations in weather and have seasonal variations.

Most of our businesses are affected by variations in general weather conditions and unusually severe weather. Tampa Electric's, Peoples Gas System's and TWG's energy sales are particularly sensitive to variations in weather conditions. Those companies forecast energy sales on the basis of normal weather, which represents a long-term historical average. Significant variations from normal weather could have a material impact on energy sales. Unusual weather, such as hurricanes, could adversely affect operating costs and sales.

Peoples Gas System, which has a single winter peak period, is more weather sensitive than Tampa Electric, which has both summer and winter peak periods. Mild winter weather in Florida can be expected to negatively impact results at Peoples Gas System.

Variations in weather conditions also affect the demand and prices for the commodities sold by TECO Coal, as well as electric power sales from TECO Wholesale Generation's merchant power plants. TECO Transport is also impacted by weather because of its effects on the supply of and demand for the products transported. Severe weather conditions could interrupt or slow service and increase operating costs of those businesses.

Electric power marketing may be seasonal. For example, in some parts of the country, demand for, and market prices of, electricity peak during the hot summer months, while in other parts of the country such peaks occur in the cold winter months. As a result, our power marketing results may fluctuate on a seasonal basis. The pattern of this fluctuation may change depending on the nature and location of the facilities we operate and the terms under which we sell electricity.

Commodity price changes may affect the operating costs and competitive positions of our businesses.

Most of our businesses are sensitive to changes in coal, gas, oil and other commodity prices. Any changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services.

In the case of Tampa Electric, fuel costs used for generation have been affected primarily by the cost of coal. Tampa Electric's fuel costs will be increasingly impacted by the cost of natural gas with the completion of the Bayside repowering. Tampa Electric is able to recover the cost of fuel through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

Regarding wholesale sales of electricity, the ability to make sales and margins on power sales is affected by the cost of fuel to Tampa Electric, particularly as it compares to the costs of other power producers.

In the case of TECO Wholesale Generation, results are impacted by changes in the cost of fuel and the market price for electricity. The profitability of merchant power plants is heavily dependent on the price for power in the markets they serve. Wholesale power prices are set by the market assuming a cost for the input energy and conversion efficiency, but the fixed costs may not be reflected in the price for spot, or excess, power.

In the case of Peoples Gas System, costs for purchased gas and pipeline capacity are recovered through retail customers' bills, but increases in gas costs affect total retail prices and therefore the competitive position of Peoples Gas System relative to electricity, other forms of energy and other gas suppliers.

We rely on some transmission and distribution assets that we do not own or control to deliver wholesale electricity, as well as natural gas. If transmission is disrupted, or if capacity is inadequate, our ability to sell and deliver power and natural gas may be hindered.

We depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity and natural gas we sell to the wholesale market, as well as the natural gas we sell and purchase for use in our electric generation facilities. If transmission is disrupted, or if capacity is inadequate, our ability to sell and deliver products and satisfy our contractual and service obligations may be hindered.

The FERC has issued regulations that require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, there is the potential that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electric power as we desire. We cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities in specific markets.

In addition, the independent system operators that oversee the transmission systems in certain wholesale power markets have from time to time been authorized to impose price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the profitability of our wholesale power marketing business.

The uncertain outcome regarding the creation of regional transmission organizations, or RTOs, may impact our operations, cash flows or financial condition.

Although Tampa Electric Company continues to make progress towards the development of its RTO, GridFlorida, which would independently control the transmission assets of participating utilities in peninsular Florida, progress has slowed considerably. Given the regulatory uncertainty of the ultimate timing, structure and operations of GridFlorida or an alternate combined transmission structure, we cannot predict what effect its creation will have on our future consolidated results of operations, cash flow or financial condition.

We may be unable to take advantage of our existing tax credits.

We derive a portion of our net income from Section 29 tax credits related to the production of non-conventional fuels. Although we sold a significant portion of our interest in the production facilities in April 2003 and plan to sell the majority of our remaining interest in the production capacity, until and unless we successfully do so, our use of these tax credits is dependent on our generating sufficient taxable income against which to use the credits. The future results of this business could be negatively impacted by administrative actions of the Internal Revenue Service or the U.S. Treasury or changes in law, regulation or administration.

Problems with operations could cause us to incur substantial costs.

Each of our subsidiaries is subject to various operational risks, including accidents or equipment breakdown or failure and operations below expected levels of performance or efficiency. As operators of power generation facilities, Tampa Electric and TECO Wholesale Generation could incur problems such as the breakdown or failure of power generation equipment, transmission lines, pipelines or other equipment or processes which would result in performance below assumed levels of output or efficiency. Our outlook assumes normal operations and normal maintenance periods for our subsidiaries' facilities.

The international projects and operations of TECO Transport are subject to risks that could result in losses or increased costs.

Our subsidiaries are involved in certain international projects. These projects involve numerous risks that are not present in domestic projects, including expropriation, political instability, currency exchange rate fluctuations, repatriation restrictions, and regulatory and legal uncertainties. The international subsidiaries attempt to manage these risks through a variety of risk mitigation measures, including specific contractual provisions, obtaining non-recourse financing and obtaining political risk insurance where appropriate.

TECO Transport is exposed to operational risks in international ports, primarily in the form of its need to obtain suitable labor and equipment to safely discharge its cargoes in a timely manner. TECO Transport attempts to manage these risks through a variety of risk mitigation measures, including retaining agents with local knowledge and experience in successfully discharging cargoes and vessels similar to those used.

Changes in the environmental laws and regulations to which our regulated businesses are subject could increase our costs or curtail our activities.

Our businesses are subject to regulation by various governmental authorities dealing with air, water and other environmental matters. Changes in compliance requirements or the interpretation by governmental authorities of existing requirements may impose additional costs on us or require us to curtail some of our businesses' activities.

Consolidated FINANCIAL STATEMENTS

Consolidated Balance Sheets

Assets *(millions, except share amounts) Dec. 31,*	*2003*	*2002*
Current assets		
Cash and cash equivalents	$ 108.2	$ 411.1
Restricted cash	51.4	1.6
Receivables, less allowance for uncollectibles of $4.5 and $6.6 at Dec. 31, 2003 and 2002, respectively	280.4	422.7
Current notes receivable	–	235.1
Current derivative assets	21.1	12.5
Inventories, at average cost		
Fuel	88.2	113.7
Materials and supplies	82.5	96.1
Prepayments and other current assets	68.6	30.4
Assets held for sale	169.4	–
Total current assets	869.8	1,323.2
Property, plant and equipment		
Utility plant in service		
Electric	5,245.6	5,054.4
Gas	778.1	746.7
Construction work in progress	1,193.3	1,556.8
Other property	823.2	857.4
Property, plant and equipment, at original cost	8,040.2	8,215.3
Accumulated depreciation	(2,361.2)	(2,310.7)
Total property, plant and equipment (net)	5,679.0	5,904.6
Other assets		
Deferred income taxes	1,051.5	340.2
Other investments	16.5	845.3
Regulatory assets	188.3	163.2
Investment in unconsolidated affiliates	343.5	149.2
Goodwill	71.2	193.7
Deferred charges and other assets	165.1	159.0
Assets held for sale	2,077.4	-
Total other assets	3,913.5	1,850.6
Total assets	$10,462.3	$9,078.4

Liabilities and capital *(millions, except share amounts) Dec. 31,*	*2003*	*2002*
Current liabilities		
Long-term debt due within one year		
Recourse	$ 6.1	$ 106.3
Non-recourse	25.5	20.8
Notes payable	37.5	360.5
Accounts payable	313.8	377.4
Customer deposits	101.4	94.6
Current derivative liabilities	12.0	3.9
Interest accrued	56.6	49.8
Taxes accrued	149.9	95.9
Liabilities associated with assets held for sale	1,544.4	–
Total current liabilities	2,247.2	1,109.2
Other liabilities		
Deferred income taxes	498.0	495.0
Investment tax credits	22.8	27.5
Regulatory liabilities	560.2	538.7
Deferred credits and other liabilities	364.1	321.7
Liabilities associated with assets held for sale	697.8	–
Long-term debt, less amount due within one year		
Recourse	3,660.3	3,112.7
Non-recourse	83.2	211.6
Preferred securities	649.1	–
Minority interest	1.9	1.2
Total other liabilities	6,537.4	4,708.4
Commitments and contingencies	–	–
Preferred securities	–	649.1
Capital		
Common equity (400 million shares authorized; par value $1; 187.8 million shares and 175.8 million shares outstanding at Dec. 31, 2003 and 2002, respectively)	187.8	175.8
Additional paid in capital	1,220.8	1,094.5
Retained earnings	339.5	1,413.7
Accumulated other comprehensive income	(55.8)	(41.2)
Common equity	1,692.3	2,642.8
Unearned compensation	(14.6)	(31.1)
Total capital	1,677.7	2,611.7
Total liabilities and capital	$10,462.3	$9,078.4

Consolidated Statements of Income

(millions, except per share amounts) *For the years ended Dec. 31,*		*2003*	*2002*	*2001*
Revenues	Regulated electric and gas (includes franchise fees and gross receipts taxes of $77.7 million in 2003, $73.8 million in 2002 and $71.1 million in 2001)	$ 1,991.1	$ 1,867.0	$ 1,733.0
	Unregulated	748.9	797.9	750.3
	Total revenues	2,740.0	2,664.9	2,483.3
Expenses	Regulated operations			
	Fuel	344.9	312.7	218.2
	Purchased power	184.8	202.3	144.7
	Cost of natural gas sold	224.0	149.0	186.4
	Other	258.4	257.2	250.0
	Other operations	761.8	705.7	688.8
	Maintenance	152.4	162.1	151.4
	Depreciation	326.0	303.2	284.6
	Asset impairment	145.1	–	–
	Goodwill and intangible asset impairment	122.7	–	–
	Restructuring charges	24.6	17.8	–
	Taxes, other than income	175.2	173.1	161.3
	Total expenses	2,719.9	2,283.1	2,085.4
Income (loss) from operations		20.1	381.8	397.9
Other income (expense)	Allowance for other funds used during construction	19.8	24.9	6.6
	Other income	114.5	19.0	23.1
	Loss on debt extinguishment	–	(34.1)	–
	Contingent arbitration reserve	(32.0)	–	–
	Earnings (loss) from equity investments	(0.4)	5.5	9.1
	Total other income (expense)	101.9	15.3	38.8
Interest charges	Interest expense	288.4	142.3	164.1
	Distribution on preferred securities	39.9	38.9	17.0
	Allowance for borrowed funds used during construction	(7.6)	(9.6)	(2.6)
	Total interest charges	320.7	171.6	178.5
(Loss) income from continuing operations before provision for income taxes		(198.7)	225.5	258.2
(Benefit) for income taxes		(135.2)	(51.7)	(7.3)
Net (loss) income from continuing operations before minority interests		(63.5)	277.2	265.5
Minority interest		48.8	–	–
Net (loss) income from continuing operations		(14.7)	277.2	265.5
Discontinued operations	Income (loss) from discontinued operations	(1,394.6)	60.3	35.4
	Income tax (benefit) provision	(504.2)	7.4	(2.8)
	Total discontinued operations	(890.4)	52.9	38.2
Cumulative effect of change in accounting principle, net of tax		(4.3)	–	–
Net (loss) income		$ (909.4)	$ 330.1	$ 303.7
Average common shares outstanding				
	Basic	179.9	153.2	134.5
	Diluted	179.9	153.3	135.4
Earnings per share from continuing operations				
	Basic	$ (0.08)	$ 1.81	$ 1.98
	Diluted	$ (0.08)	$ 1.81	$ 1.96
Earnings per share				
	Basic	$ (5.05)	$ 2.15	$ 2.26
	Diluted	$ (5.05)	$ 2.15	$ 2.24
Dividends paid per common share outstanding		$ 0.925	$ 1.41	$ 1.37

Consolidated Statements of Comprehensive Income

(millions) *For the years ended Dec. 31,*		*2003*	*2002*	*2001*
Net (loss) income		$ (909.4)	$ 330.1	$ 303.7
Other comprehensive loss, net of tax				
	Foreign currency translation adjustments	1.2	(1.2)	–
	Net unrealized gains (losses) on cash flow hedges	28.1	(13.2)	(19.2)
	Minimum pension liability adjustments	(43.9)	(4.4)	0.3
	Other comprehensive loss, net of tax	(14.6)	(18.8)	(18.9)
Comprehensive (loss) income		$ (924.0)	$ 311.3	$ 284.8

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statements of Cash Flows

(millions) For the years ended Dec. 31,	2003	2002	2001
Cash flows from operating activities			
Net (loss) income	$ (909.4)	$ 330.1	$ 303.7
Adjustments to reconcile net (loss) income to net cash from operating activities:			
Depreciation	382.0	303.2	284.6
Deferred income taxes	(709.4)	(96.5)	(102.9)
Investment tax credits, net	(4.7)	(4.8)	(4.9)
Allowance for funds used during construction	(27.4)	(34.5)	(9.2)
Amortization of unearned compensation	18.3	13.9	9.7
Cumulative effect of change in accounting principle, pre-tax	7.1	–	–
Gain on sales of business/assets, pre-tax	(147.5)	(15.1)	–
Equity in earnings of unconsolidated affiliates	13.8	15.3	(3.1)
Minority loss	(48.8)	–	–
Asset impairment, pre-tax	1,330.8	–	–
Goodwill and intangible asset impairment, pre-tax	122.7	–	–
Loss on joint venture termination, pre-tax	153.9	–	–
Contingent arbitration reserve	32.0	–	–
Deferred recovery clause	(27.3)	72.2	(19.0)
Refunded to customers	–	(6.4)	–
Receivables, less allowance for uncollectibles	96.4	(64.1)	57.1
Inventories	7.0	(39.4)	(22.8)
Prepayments and other deposits	(16.5)	6.3	(14.3)
Taxes accrued	34.5	24.1	16.4
Interest accrued	(60.7)	14.2	(6.3)
Accounts payable	(17.5)	98.3	(51.3)
Other	99.3	38.9	65.0
Cash flows from operating activities	328.6	655.7	502.7
Cash flows from investing activities			
Capital expenditures	(590.6)	(1,065.2)	(965.9)
Allowance for funds used during construction	27.4	34.5	9.2
Purchase of minority interest	–	(9.9)	–
Net proceeds from sales of business/assets	296.5	103.3	(272.6)
Restricted cash	(63.5)	–	–
Investment in unconsolidated affiliates	(30.6)	(7.6)	27.6
Other non-current investments	(32.4)	(715.6)	95.7
Cash flows from investing activities	(393.2)	(1,660.5)	(1,106.0)
Cash flows from financing activities			
Dividends	(165.2)	(215.8)	(184.2)
Common stock	136.6	572.6	348.4
Proceeds from long-term debt	655.1	1,758.4	1,255.9
Minority interest	44.4	–	–
Restricted cash	(5.9)	–	–
Repayment of long-term debt	(526.5)	(949.7)	(236.5)
Settlement of joint venture termination obligation	(33.5)	–	
Net decrease in short-term debt	(323.0)	(278.4)	(570.0)
Issuance of preferred securities	–	435.6	–
Equity contract adjustment payments	(20.3)	(15.3)	–
Cash flows from financing activities	(238.3)	1,307.4	613.6
Net (decrease) increase in cash and cash equivalents	(302.9)	302.6	10.3
Cash and cash equivalents at beginning of year	411.1	108.5	98.2
Cash and cash equivalents at end of year	$ 108.2	$ 411.1	$ 108.5
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest (net of amounts capitalized) [1]	$ 493.1	$ 160.2	$ 178.1
Income taxes	$ 58.8	$ 71.9	$ 52.4

(1) Included in interest paid during the year is interest paid on debt obligations for discontinued operations of $166.6 million for 2003. There was no interest paid on debt obligations for discontinued operations in 2002 or 2001.

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statements of Common Equity

(millions)	*Shares* [1]	*Common Stock*	*Additional Paid-in Capital*	*Treasury Stock*	*Retained Earnings*	*Accumulated Other Comprehensive Income (Loss)*	*Unearned Compensation*	*Total Common Equity*
Balance, Dec. 31, 2000	126.3	$133.3	$ 397.3	$(144.7)	$ 1,177.1	$ (3.5)	$ (52.6)	$ 1,506.9
Net income for 2001					303.7			303.7
Other comprehensive loss, after tax						(18.9)		(18.9)
Common stock issued	13.3	6.3	203.2	144.7			(5.8)	348.4
Cash dividends declared					(184.2)			(184.2)
Amortization of unearned compensation							9.7	9.7
Tax benefits - ESOP dividends and stock options			0.2		1.4			1.6
Performance shares							4.4	4.4
Balance, Dec. 31, 2001	139.6	$139.6	$ 600.7	$ –	$ 1,298.0	$(22.4)	$ (44.3)	$ 1,971.6
Net income for 2002					330.1			330.1
Other comprehensive loss, after tax						(18.8)		(18.8)
Common stock issued	36.2	36.2	544.4				(8.0)	572.6
Cash dividends declared					(215.8)			(215.8)
Amortization of unearned compensation							13.9	13.9
Convertible preferred stock – present value of contract adjustment payments			(53.1)					(53.1)
Tax benefits - ESOP dividends and stock options			2.5		1.4			3.9
Performance shares							7.3	7.3
Balance, Dec. 31, 2002	175.8	$175.8	$ 1,094.5	$ –	$ 1,413.7	$(41.2)	$ (31.1)	$ 2,611.7
Net (loss) for 2003					(909.4)			(909.4)
Other comprehensive loss, after tax						(14.6)		(14.6)
Common stock issued	12.0	12.0	125.0				(0.4)	136.6
Cash dividends declared					(165.2)			(165.2)
Amortization of unearned compensation							18.3	18.3
Tax benefits - ESOP dividends and stock options			1.3		0.4			1.7
Performance shares							(1.4)	(1.4)
Balance, Dec. 31, 2003	**187.8**	**$187.8**	**$ 1,220.8**	**$ –**	**$ 339.5**	**$(55.8)**	**$ (14.6)**	**$ 1,677.7**

(1) TECO Energy had 400 million shares of $1 par value common stock authorized in 2003, 2002 and 2001.
The accompanying notes are an integral part of the consolidated financial statements.

1. Significant Accounting Policies

The significant accounting policies for both utility and diversified operations are as follows:

Principles of Consolidation

The consolidated financial statements include the accounts of TECO Energy, Inc. and its majority-owned subsidiaries (TECO Energy or the company). All significant intercompany balances and intercompany transactions have been eliminated in consolidation. The equity method of accounting is used to account for investments in partnership or other arrangements in which TECO Energy or its subsidiary companies do not have majority ownership or exercise control.

Results of operations for the proportional share of expenses, revenues and assets reflecting TECO Coalbed Methane's undivided interest in joint venture property are included in the consolidated financial statements through Dec. 31, 2002.

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles (GAAP). Actual results could differ from these estimates.

Revised Segment Reporting

As more fully described in **Note 14**, the Union and Gila River projects' results have been reflected in discontinued operations. This reclassification, as well as other changes described below, significantly revised operating segments used for decision-making purposes.

In 2003, the company, as part of its renewed focus on core utility operations, revised internal reporting information used for decision making purposes. With this change, management focused on the results and performance of TECO Wholesale Generation, Inc. (formerly TECO Power Services Corporation), or TWG, as a segment comprised of all merchant operations, from which the Union and Gila River projects' operations have been reclassified to discontinued operations. TWG includes the results of operations for the Frontera, Commonwealth Chesapeake, Dell and McAdams power plants, as well as the equity investment in the Odessa and Guadalupe power plants, held through PLC Development Holdings, LLC (PLC), and TECO EnergySource (TES), the energy marketing operation for the merchant plants.

The non-merchant operations, formerly included in the TECO Power Services operating segment, are comprised of the results from Hardee Power Partners, Ltd. (HPP), up to the date of the sale (see **Note 21** for details), the Hamakua power plant in Hawaii, the Guatemalan operations which include the San José and Alborada power plants and an equity investment in the Guatemalan distribution company, EEGSA, and other non-merchant activities. These non-merchant operations are reported in the Other Unregulated segment (see **Note 19**).

Cash Equivalents

Cash equivalents are highly liquid, high-quality investments purchased with an original maturity of three months or less. The carrying amount of cash equivalents approximated fair market value because of the short maturity of these instruments.

Restricted Cash

Restricted cash at Dec. 31, 2003 is comprised of $15.4 million of cash accumulated in escrow under the sale agreement of the 49.5-percent interest of TECO Coal's synthetic fuel production facilities to provide credit support for the company's obligation under the sale agreement due to the company's current credit rating, and $36.0 million held in escrow from the sale HPP (see **Note 21**). Over time, up to $50 million of cash from the synthetic fuel facility sale will accumulate in escrow to support the company's obligation under the sale agreement due to the company's current credit rating.

Cost Capitalization

Development costs – TECO Energy capitalizes the external costs of construction-related development activities after achieving certain project-related milestones that indicate that completion of a project is probable. Such costs include direct incremental amounts incurred for professional services (primarily legal, engineering and consulting services), permits, options and deposits on land and equipment purchase commitments, capitalized interest and other related costs. Capitalized costs are transferred to construction in progress when financing has been obtained and construction activity has commenced. In accordance with Statement of Position (SOP) 98-5, *Reporting on the Costs of Start-up Activities*, start-up costs and organization costs are expensed as incurred.

Debt issuance costs – The company capitalizes the external costs of obtaining debt financing and amortizes such costs over the life of the related debt.

Capitalized interest expense – Interest costs for the construction of non-utility facilities are capitalized and depreciated over the service lives of the related property. TECO Energy capitalized $17.3 million, $63.2 million, and $23.0 million of interest costs in 2003, 2002 and 2001, respectively.

Planned Major Maintenance

TECO Energy accounts for planned maintenance projects by expensing the costs as incurred. Planned major maintenance projects that do not increase the overall life or value of the related assets are expensed. When the major maintenance materially increases the life or value of the underlying asset, the cost is capitalized. While normal maintenance outages covering various components of the plants generally occur on at least a yearly basis, major overhauls occur less frequently.

Tampa Electric, Peoples Gas System (PGS) and TWG expense major maintenance costs as incurred. For Tampa Electric and PGS, concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with Florida Public Service Commission (FPSC) and Federal Energy Regulatory Commission (FERC) regulations.

The San José and Alborada plants in Guatemala each have a long-term power purchase agreement (PPA) with EEGSA. A major maintenance revenue recovery component is implicit in the capacity payment portion of the PPA for each plant. Accordingly, a portion of each monthly fixed capacity payment is deferred to recognize the portion that reflects recovery of future planned major maintenance expenses. Actual maintenance costs are expensed when incurred with a like amount of deferred recovery revenue recognized at the same time.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2003, 2002 and 2001. Total AFUDC for 2003, 2002 and 2001 was $27.4 million, $34.5 million, and $9.2 million, respectively. The base on which AFUDC is calculated excludes construction work-in-progress which has been included in rate base.

Other Investments

Other investments, which include longer-term passive investments, at Dec. 31, 2003 and 2002 were as follows:

Other Investments

(millions) Dec. 31,	*Rate*	*Due Date*	*2003*	*2002*
Notes receivable from:				
Panda Energy [1]	14.00%	1/3/03	$ –	$ 137.0
EEGSA	6.14% [2]	9/11/07	8.1	11.1
TECO-Panda Generating Company, L.P. (TPGC) [4]	7.79% [3]	11/30/04	–	369.5
TECO-Panda Generating Company, L.P. [5]	6.58% [3]	11/30/04	–	426.3
Municipal Gas Authority of Georgia [5]	1.38%	3/31/03	–	98.1
Continuing investments in leveraged leases	–	–	8.4	9.4
Other investments	–	–	–	29.0
			16.5	1,080.4
Current notes receivable			–	235.1
Other non-current investments			$ 16.5	$ 845.3

(1) On Jan. 3, 2003, this note receivable was converted to an ownership interest (see **Note 21**).
(2) Current rate at Dec. 31, 2003.
(3) Current rate at Dec. 31, 2002.
(4) As of Apr. 1, 2003, TPGC was consolidated as part of the TWG consolidated group. See **Note 12** for additional details regarding the consolidation.
(5) Received payment of this note receivable, relating to the sale of TECO Coalbed Methane, on Jan. 30, 2003 (see **Note 21**).

These financial investments have no quoted market prices and, accordingly, a reasonable estimate of fair market value could not be made without incurring excessive costs. However, the company believes by reference to stated interest rates and security description, the fair value of these assets would not differ significantly from the carrying value.

Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates are accounted for using the equity method of accounting. The percentage ownership interest for each investment at Dec. 31, 2003 and 2002 is presented in the following table:

TECO Energy and Subsidiaries' Percent Ownership in Unconsolidated Affiliates

Dec. 31,	*2003*	*2002*
TECO Wholesale Generation (TWG)		
TPGC [1]	100%	50%
Texas Independent Energy, L.P. (TIE) [2]	50	–
Other unregulated		
Empresa Eléctrica de Guatemala, S.A. (EEGSA)	24%	24%
Hamakua Energy Partners, L.P.	50	50
Hamakua Land Partnership, LLP	50	50
US Propane, LLC [3]	38	38
TECO AGC, Ltd.	50	50
Litestream Technologies, LLC	36	65
Hernando Oaks, LLC	50	50
Brandon Properties Partners, Ltd.	50	50
Walden Woods Business Center, Ltd.	50	50
B-T One, LLC [4]	80	50

(1) TWG consolidated TPGC effective Apr. 1, 2003 and received Panda's 50-percent interest in June 2003. See **Note 12** for a detailed discussion.
(2) The TIE investment is held by PLC Development Holdings, LLC (PLC). TWG indirectly obtained 50-percent of PLC in January 2003 and the remaining ownership interests outstanding in September 2003. See **Notes 12, 17** and **21** for a complete description of these transactions.
(3) See **Note 23** for information regarding the recent sale of interests held by US Propane.
(4) During April 2003, the company renegotiated the terms of the partnership agreement of B-T One, LLC, to reflect the economic interests of the partners. Effective Apr. 1, 2003, the company indirectly owns an 80-percent interest in the partnership.

Deferred Income Taxes

TECO Energy utilizes the liability method in the measurement of deferred income taxes. Under the liability method, the temporary differences between the financial statement and tax bases of assets and liabilities are reported as deferred taxes measured at current tax rates. Tampa Electric and PGS are regulated, and their books and records reflect approved regulatory treatment, including certain adjustments to accumulated deferred income taxes and the establishment of a corresponding regulatory tax liability reflecting the amount payable to customers through future rates.

Investment Tax Credits

Investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property.

Revenue Recognition

TECO Energy recognizes revenues consistent with the Securities and Exchange Commission's Staff Accounting Bulletin (SAB) 104, *Revenue Recognition in Financial Statements*. The interpretive criteria outlined in SAB 104 are that 1) there is persuasive evidence that an arrangement exists; 2) delivery has occurred or services have been rendered; 3) the fee is fixed and determinable; and 4) collectibility is reasonably assured. Except as discussed below, TECO Energy and its subsidiaries recognize revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The regulated utilities' (Tampa Electric and PGS) retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by FERC. See **Note 4** for a discussion of significant regulatory matters and the applicability of Financial Accounting Standard No. (FAS) 71, *Accounting for the Effects of Certain Types of Regulation*, to the company.

Revenues for certain transportation services at TECO Transport are recognized using the percentage of completion method, which includes estimates of the distance traveled and/or the time elapsed, compared to the total estimated contract. Revenues for long-term engineering or construction-type contracts at BCH Mechanical (formerly part of TECO Energy Services) are recognized under the same method, which includes estimates of the total costs for the project compared to the estimated progress of the work required to complete the contract.

Revenues and Fuel Costs

Revenues include amounts resulting from cost recovery clauses which provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs for Tampa Electric and purchased gas, interstate pipeline capacity and conservation costs for PGS. These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over-recovery or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. Over-recoveries of costs are recorded as deferred credits, and under-recoveries of costs are recorded as deferred charges.

Certain other costs incurred by the regulated utilities are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed. The regulated utilities accrue base revenues for services rendered but unbilled to provide a closer matching of revenues and expenses. See **Note 4**.

As of Dec. 31, 2003 and 2002, unbilled revenues of $45.7 million and $41.3 million, respectively, are included in the "Receivables" line item on the balance sheet.

Purchased Power

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. As a result of the sale of HPP in 2003 (see **Notes 14** and **21**), power purchases from HPP, subsequent to the sale, are reflected as non-affiliate purchases by Tampa Electric. Tampa Electric's long-term power purchase agreement from HPP was not affected by the sale of HPP. Under the existing agreement, which has been approved by the FPSC, Tampa Electric has the right to purchase, on average, approximately 52% of the total output of the Hardee power station. Tampa Electric purchased power from non-TECO Energy affiliates, including purchases from HPP, at a cost of $234.9 million, $253.7 million, and $209.7 million, respectively, for the years ended Dec. 31, 2003, 2002 and 2001. The associated revenue at HPP from power sold to Tampa Electric of $50.1 million, $51.4 million and $65.0 million for 2003, 2002 and 2001, respectively, is offset against "Regulated operations – Purchased power" in the income statement. The purchased power costs at Tampa Electric are recoverable through an FPSC-approved cost recovery clause.

In order to meet firm commitments or maintain acceptable operating conditions, TWG's power plants may also purchase power in the ordinary course of business. Total unregulated purchases of power at TWG for continuing operations, for the years ended Dec. 31, 2003, 2002 and 2001, were $26.6 million, $20.2 million, and $4.2 million, respectively. Unregulated power purchases are reported in "Other operations" in the income statement.

Depreciation

TECO Energy provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage value, of depreciable property over its estimated service life. Unregulated electric generating, pipeline and transmission facilities are depreciated over the expected useful lives of the related equipment, a period of up to 40 years. The provision for total regulated and unregulated plant in service, expressed as a percentage of the original cost of depreciable property, was 4.5% for 2003 and 4.2% for 2002 and 2001. For the year ended Dec. 31, 2003, Tampa Electric recognized depreciation expense of $36.6 million related to accelerated depreciation of certain Gannon power station coal-fired assets, in accordance with a regulatory order issued by the FPSC. Construction work-in-progress is not depreciated until the asset is completed or placed in service.

The implementation of FAS 143, *Accounting for Asset Retirement Obligations*, in 2003 resulted in an increase in the carrying amount of long-lived assets and the reclassification of the accumulated reserve for cost of removal from accumulated depreciation to "Regulatory liabilities" for all periods presented. The adjusted capitalized amount is depreciated over the remaining useful life of the asset. See **Note 5**.

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

TECO Coal and TECO Transport incur most of TECO Energy's total excise taxes, which are accrued as an expense and reconciled to the actual cash payment of excise taxes. As general expenses, they are not specifically recovered through revenues. Excise taxes paid by the regulated utilities are not material and are expensed when incurred.

The regulated utilities are allowed to recover certain costs incurred from customers through prices approved by the FPSC. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. These amounts totaled $77.7 million, $73.8 million and $71.1 million for the years ended Dec. 31, 2003, 2002 and 2001, respectively. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statements of Income in "Taxes, other than income." For the years ended Dec. 31, 2003, 2002 and 2001, these totaled $77.5 million, $73.7 million and $71.0 million, respectively.

Asset Impairments

Effective Jan. 1, 2002, TECO Energy and its subsidiaries adopted FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which superseded FAS 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*. FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a component of a business.

In accordance with FAS 144, the company assesses whether there has been an impairment of its long-lived assets and certain intangibles held and used by the company when such impairment indicators exist. During 2003, certain events, including market conditions, third-party actions, operating results and changes in the company's long-term strategic plan have occurred, requiring management to assess the likelihood of an impairment for certain long-lived assets and certain intangibles held and used by the company. Indicators of impairment existed for certain asset groups, including long-term turbine purchase contracts, finite-lived intangible assets and merchant power plants, triggering a requirement to ascertain the recoverability of these assets using undiscounted cash flows before interest expense. See **Note 10** for specific details regarding the results of these assessments.

Deferred Credits and Other Liabilities

Other deferred credits primarily include the accrued post-retirement benefit liability, the pension liability, deferred gains and the liability for future contract adjustment payments related to the mandatorily convertible equity securities.

Stock-Based Compensation

TECO Energy has adopted the disclosure-only provisions of FAS 123, *Accounting for Stock-Based Compensation*, but applies Accounting Principles Board Opinion No. (APB) 25, *Accounting for Stock Issued to Employees*, and related interpretations in accounting for its stock-based compensation plans. See **Note 9** for the pro forma impact that the application of the recognition provisions of FAS 123 would have on reported net income and earnings per share.

Effective Jan. 1, 2003, the company adopted FAS 148, *Accounting for Stock-Based Compensation–Transition and Disclosure, an amendment of FASB Statement No. 123.* This standard amends FAS 123 to provide alternative methods of transition for companies that voluntarily change to the fair value-based method of accounting for stock-based employee compensation. It also requires prominent disclosure about the effects on reported net income of the company's accounting policy decisions with respect to stock-based employee compensation in both annual and interim financial statements. The adoption of the disclosure provisions of this standard did not have a material impact on the company's financial position.

Restrictions on Dividend Payments and Transfer of Assets

Dividends on TECO Energy's common stock are declared and paid at the discretion of its Board of Directors. The primary sources of funds to pay dividends on TECO Energy's common stock are dividends and other distributions from its operating companies. TECO Energy's $380 million note indenture contains a covenant that requires the company to achieve certain interest coverage levels in order to pay dividends. TECO Energy's Merrill Lynch credit facility contains a covenant that could limit the payment of dividends exceeding $40 million in any quarter under certain circumstances if the facility is drawn. Tampa Electric's first mortgage bond indenture and certain long-term debt at PGS contain restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric. Tampa Electric's first mortgage bond indenture does not limit loans or advances. As of Dec. 31, 2003 and 2002, the balances restricted as to transfers from Tampa Electric to TECO Energy under the first mortgage bonds were 3% and 20%, respectively, of consolidated common equity. Tampa Electric's new credit facilities include a covenant limiting cumulative distributions and outstanding affiliate loans.

In addition, TECO Diversified, Inc., a wholly-owned subsidiary of TECO Energy and the holding company for TECO Transport, TECO Coal and TECO Solutions, has a guarantee related to a coal supply agreement that limits the payment of dividends to its common shareholder, TECO Energy, but does not limit loans or advances.

See Notes 6, 7 and 20 for a more detailed description of significant financial covenants.

TECO Energy holds the right to defer payments on its subordinated notes issued in connection with the issuance of trust preferred securities by TECO Capital Trust I or TECO Capital Trust II. Should the company exercise this right, it would be prohibited from paying cash dividends on its common stock until the unpaid distributions on the subordinated notes are made. TECO Energy has not exercised that right.

Foreign Operations

The functional currency of the company's foreign investments is primarily the U.S. dollar. Transactions in the local currency are remeasured to the U.S. dollar for financial reporting purposes. The aggregate remeasurement gains or losses included in net income in 2003, 2002 and 2001 were not significant. The foreign investments are generally protected from any significant currency gains or losses by the terms of the power sales agreements and other related contracts, in which payments are defined in U.S. dollars.

Reclassifications

Certain prior year amounts were reclassified to conform with the current year presentation. Results for all prior periods have been reclassified from continuing operations to discontinued operations as appropriate for each of the entities as discussed in Note 14.

2. Derivatives and Hedging

From time to time, TECO Energy and its affiliates enter into futures, forwards, swaps and option contracts for the following purposes:

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric and PGS;
- To limit the exposure to interest rate fluctuations on debt issuances at TECO Energy and its other affiliates;
- To limit the exposure to electricity, natural gas and fuel oil price fluctuations related to the operations of natural gas-fired and fuel oil-fired power plants at TWG; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport.

TECO Energy and its affiliates use derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers. For unregulated operations, the company uses derivative instruments primarily to optimize the value of physical assets, including generation capacity, natural gas production, and natural gas delivery.

The risk management policies adopted by TECO Energy provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operating companies.

The company applies the provisions of FAS 133, *Accounting for Derivative Instruments and Hedging Activities.* The standard requires companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of other comprehensive income (OCI) or in net income, depending on the designation of those instruments. The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or the loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of its reclassification. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the amount paid or received on the underlying physical transaction. Additionally, amounts deferred in OCI related to an effective designated cash flow hedge must be reclassified to current earnings if the anticipated hedged transaction is no longer probable of occurring. At adoption on Jan. 1, 2001, the company had derivatives in place at TECO Coalbed Methane that qualified for cash flow hedge accounting treatment under FAS 133, and recorded an opening swap liability of $19.0 million and an after-tax reduction to OCI of $12.6 million. TECO Coalbed Methane was subsequently reclassified to discontinued operations, reflecting the December 2002 sale of the company's investment in the entity, as discussed in Notes 14 and 21.

At Dec. 31, 2003 and 2002, respectively, TECO Energy and its affiliates had derivative assets (current and non-current) totaling $21.1 million and $12.6 million, and liabilities (current and non-current) totaling $12.0 million and $4.1 million. At Dec. 31, 2003 and 2002, accumulated other comprehensive income (OCI) included $4.3 million and $32.4 million, respectively, of unrealized after-tax losses, representing the fair value of cash flow hedges whose transactions will occur in the future. Included in OCI at Dec. 31, 2003 is an unrealized after-tax loss of $14.6 million on

interest rate swaps designated as cash flow hedges, reflecting the remaining amount included in OCI related to cash flow hedges for the period preceding the expected disposition of TPGC (see Note 14). At Dec. 31, 2002 the unrealized after-tax loss of $37.3 million, included in OCI, represented the company's proportionate share of OCI at TPGC, in accordance with the equity method of accounting. Amounts recorded in OCI reflect the estimated fair value of derivative instruments designated as hedges, based on market prices as of the balance sheet date. These amounts are expected to fluctuate with movements in market prices and may or may not be realized as a loss upon future reclassification from OCI.

For the years ended Dec. 31, 2003, 2002 and 2001, TECO Energy and its affiliates reclassified amounts from OCI (excluding certain reclassifications for interest rate swaps described below) and recognized net pre-tax losses of $12.6 million, $29.0 million and $19.7 million, respectively. Amounts reclassified from OCI were primarily related to cash flow hedges of physical purchases of natural gas and physical sales of electricity. For these types of hedge relationships, the loss on the derivative, reclassified from OCI to earnings, is offset by the reduced expense arising from lower prices paid or received for spot purchases of natural gas or decreased revenue from sales of electricity. Conversely, reclassification of a gain from OCI to earnings is offset by the increased cost of spot purchases of natural gas or sales of electricity.

As a result of 1) the suspension of construction on the Dell and McAdams power plants at TWG in 2003 and 2) the maintenance activity on the Frontera Power Station at TWG in early 2003, the company discontinued hedge accounting for purchases of natural gas and sales of electricity which were no longer anticipated to take place within two months of the originally designated time period for delivery. The discontinuation of hedge accounting resulted in a reclassification of a pre-tax gain of $0.2 million from OCI to earnings, reflecting the fair value of the related derivatives as of the discontinuation date. This gain is included in the net pre-tax loss reported above for 2002. In addition, as a result of the designation of TPGC as an asset held for sale, the company concluded that the hedged interest expense for periods beyond the expected disposition date are no longer probable. As a result, the company reclassified a pre-tax loss of $63.8 million ($41.5 million after tax) from OCI to income from discontinued operations (see Note 14). Gains and losses on these derivative instruments, subsequent to the discontinuation of hedge accounting treatment, were recorded in earnings.

Based on the fair value of cash flow hedges at Dec. 31, 2003, pre-tax losses of $9.0 million are expected to be reversed from OCI to the Consolidated Statements of Income within the next twelve months. However, these losses and other future reclassifications from OCI will fluctuate with movements in the underlying market price of the derivative instruments. The company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2006.

At Dec. 31, 2003, Prior Energy, a subsidiary of TECO Energy, had transactions in place to hedge gas storage inventory that qualify for fair value hedge accounting treatment under FAS 133. During the years ended Dec. 31, 2003, 2002 and 2001, respectively, the company recognized pre-tax gains (losses) of $(1.3) million, $0.7 million and $0.1 million, respectively. These gains and losses are included in discontinued operations as a result of the expected sale of Prior Energy (see Notes 14 and 21). See Note 23 for details regarding the subsequent sale of Prior Energy. For the years ended Dec. 31, 2003, 2002 and 2001, respectively, the company also recognized pre-tax losses of $6.5 million, $2.4 million and $1.5 million, relating to derivatives that were not designated as either a cash flow or fair value hedge.

3. Goodwill and Other Intangible Assets

Effective Jan. 1, 2002, TECO Energy and its subsidiaries adopted FAS 141, *Business Combinations*, and FAS 142, *Goodwill and Other Intangible Assets*. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting. With the adoption of FAS 142, goodwill is no longer subject to amortization. Rather, goodwill and intangible assets, with an indefinite life, are subject to an annual assessment for impairment by applying a fair-value-based test. Intangible assets with a measurable useful life are required to be amortized.

As required under FAS 142, *Goodwill and Other Intangible Assets*, TECO Energy reviews recorded goodwill and intangible assets at least annually for each reporting unit. Reporting units are generally determined as one level below the operating segment level; reporting units with similar characteristics are grouped for the purpose of determining the impairment, if any, of goodwill and other intangible assets. The fair value for the reporting units evaluated is generally determined using discounted cash flows appropriate for the business model of each significant group of assets within each reporting unit. The models incorporate assumptions relating to future results of operations that are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. Management periodically reviews and adjusts the assumptions, as necessary, to reflect current market conditions and observable activity. If a sale is expected in the near term or a similar transaction can be readily observed in the marketplace, then this information is used by management to estimate the fair value of the reporting unit.

As a result of the consolidation of TPGC, effective Apr. 1, 2003 (see Note 12), the completion and commercial operation of the Union Power Partners (UPP) plant in June 2003, and the termination of the partnership with Panda Energy in June 2003, management initiated an interim review for the possible impairment of goodwill associated with TWG's reporting units. This evaluation indicated that an impairment of goodwill existed. Accordingly, the fair value of the reporting unit was determined, in accordance with the policy described above, to calculate the goodwill impairment. Consequently, the company recorded a pre-tax impairment charge in June 2003 of $95.2 million to write off all of the goodwill previously recorded at these reporting units based on the implied fair value of the goodwill for each respective reporting unit. This goodwill arose from the previous acquisitions of the Commonwealth Chesapeake power station in Virginia and the Frontera power station in Texas. TWG has no remaining goodwill.

In connection with the annual goodwill assessment, the company determined that the goodwill recognized and associated with TECO Energy Services, relating to BCH Mechanical and BGA, was impaired. The company recognized a goodwill impairment pre-tax loss of $19.4 million. Additionally, goodwill of $9.6 million related to Prior Energy has been reclassified to "Assets held for sale" (see Notes 14 and 23).

The amount of intangible assets recorded in "Other assets" at Dec. 31, 2003 and 2002 was $4.9 million and $12.6 million, respectively (net of accumulated amortization in 2002 of $13.3 million). For the years ended Dec. 31, 2003 and 2002, the company recognized amortization expense of $4.7 million and $23.1 million, respectively. TECO Energy expects to recognize amortization expense of $0.2 million each year for 2004-2009.

Intangible assets at Dec. 31, 2002 included $8.1 million relating to an indefinite-lived intangible asset arising from gasification technology licenses held by TWG and a long-term customer arrangement at BGA. However, in 2003, due to changes in management's long-term strategic plan and the expected disposal of BGA, a pre-tax impairment charge of $8.1 million was recognized to write off the value of these intangible assets.

The pro forma reconciliation of reported net income and earnings per share to adjusted net income excluding goodwill amortization expense for the years ended Dec. 31, 2003, 2002 and 2001 follows:

Pro Forma Effect of FAS 142 Adoption

(millions, except per share amounts)	*2003*	*2002*	*2001*
Net (loss) income:			
As reported	**$(909.4)**	$330.1	$303.7
Add: Goodwill amortized, net of tax	–	–	3.7
Adjusted net (loss) income	**$(909.4)**	$330.1	$307.4
Earnings per share – basic:			
As reported	**$ (5.05)**	$ 2.15	$ 2.26
Add: Goodwill amortized, net of tax	–	–	0.03
Adjusted basic earnings per share	**$ (5.05)**	$ 2.15	$ 2.29
Earnings per share – diluted:			
As reported	**$ (5.05)**	$ 2.15	$ 2.24
Add: Goodwill amortized, net of tax	–	–	0.03
Adjusted diluted earnings per share	**$ (5.05)**	$ 2.15	$ 2.27

4. Regulatory

As discussed in **Note 1**, Tampa Electric's and PGS' retail businesses are regulated by the FPSC.

Base Rate – Tampa Electric

Since the expiration, in 1999, of agreements entered into in 1996 with Florida's Office of Public Counsel (OPC) and the Florida Industrial Power Users Group (FIPUG), which were approved by the FPSC, Tampa Electric is not under a new stipulation to stabilize prices while securing fair earnings opportunities. Tampa Electric's rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue earning within its allowed ROE range.

Tampa Electric has not sought a base rate increase to recover the investment in the Bayside Power Station, of which phase one entered service in April 2003.

Cost Recovery – Tampa Electric

2003 Proceedings

In February 2003, Tampa Electric filed a request for an additional fuel cost adjustment of almost $61 million due to continued increases in the cost of natural gas and oil and the plan to phase out Gannon Units 1 through 4 in 2003. In March 2003, the FPSC approved Tampa Electric's new fuel rates as well as new fuel rates for the other peninsular Florida investor-owned utilities.

In September 2003, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery clause rates for the period January through December 2004. In November 2003, the FPSC approved Tampa Electric's requested changes. The resulting rates included the impact of increased use of natural gas at the Bayside Power Station, the collection of approximately $91 million for underrecovery of fuel expense for 2002 and 2003, and estimated waterborne transportation rates for coal transportation services (see Note 17). The FPSC did not allow recovery of $8.4 million it characterized as savings from shutting down the Gannon Station earlier than originally planned, which the FPSC asserted generated operations and maintenance savings. The rates include projected costs associated with environmental projects required under the Environmental Protection Agency (EPA) Consent Decree and the Florida Department of Environmental Protection (FDEP) Consent Final Judgment (see **Note 20** for additional details regarding these environmental matters). The costs associated with this disallowance were recognized in 2003.

Tampa Electric filed its objection to the disallowance of the recovery of the $8.4 million and a motion asking the FPSC to reconsider its decision because all facts and law were not taken into account. The motion was filed on Jan. 6, 2004, and a decision on this matter is expected in the first quarter of 2004.

As part of the regulatory process, it is reasonably likely that third parties may intervene on this or similar matters in the future. The company is unable to predict the timing, nature or impact of such future actions.

Base Rate – Peoples Gas

On June 27, 2002, PGS filed a petition with the FPSC to increase its service rates. The requested rates would have resulted in a $22.6 million annual base revenue increase, reflecting a ROE midpoint of 11.75 percent.

On the date of the FPSC hearing, PGS agreed to a settlement with all parties involved, and a final FPSC order was granted on Dec. 17, 2002. PGS received authorization to increase annual base revenues by $12.05 million. The new rates allow for an ROE range of 10.25 to 12.25 percent with an 11.25 percent midpoint ROE and a capital structure with 57.43 percent equity. The increase went into effect on Jan. 16, 2003.

Cost Recovery – Peoples Gas

In November 2003, the FPSC approved rates under Peoples' Gas Purchased Gas Adjustment (PGA) cap factor for the period January 2004 through December 2004. The PGA is a factor that can vary monthly due to changes in actual fuel costs but is not anticipated to exceed the annual cap.

Other Items

Coal Transportation Contract

Tampa Electric's contract for coal transportation and storage services with TECO Transport expired on Dec. 31, 2003. In June 2003, Tampa Electric issued a Request For Proposal (RFP) to potential providers requesting services for the next five years. The result of the RFP process was the execution of a new contract between Tampa Electric and TECO Transport with market rates supported by the results of the RFP and an independent consultant in maritime transportation matters. The prudence of the RFP process and final contract is expected to be reviewed by the FPSC in May 2004, with a decision expected in July 2004.

Regional Transmission Organization (RTO)

In October 2002, the RTO process involving the proposed formation of GridFlorida LLC, as initiated in response to the Federal Regulatory Commission's (FERC's) continuing effort to affect open access to transmission facilities in large regional markets, was delayed when the OPC filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the IOUs and the approval of GridFlorida would result in such a relinquishment. Oral arguments occurred in May 2003, and the Florida Supreme Court dismissed the OPC appeal citing that it was premature because certain portions of the FPSC GridFlorida order are not final.

In September 2003, a joint meeting of the FERC and FPSC took place to discuss wholesale market and RTO issues related to GridFlorida and in particular federal/state interactions. The FPSC has scheduled a series of collaborative meetings with all interested parties and upon their conclusion, will set items for hearing and a hearing schedule. This is expected to occur throughout 2004.

Regulatory Assets and Liabilities

Tampa Electric and PGS maintain their accounts in accordance with recognized policies of the FPSC. In addition, Tampa Electric maintains its accounts in accordance with recognized policies prescribed or permitted by the FERC. These policies conform with generally accepted accounting principles in all material respects.

Tampa Electric and PGS apply the accounting treatment permitted by FAS 71, *Accounting for the Effects of Certain Types of Regulation*. Areas of applicability include deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel; purchased power, conservation and environmental costs; and deferral of costs as regulatory assets, when cost recovery is ordered over a period longer than a fiscal year, to the period that the regulatory agency recognizes them. Details of the regulatory assets and liabilities as of Dec. 31, 2003 and 2002 are presented in the following table:

Regulatory Assets and Liabilities *(millions)*

Dec. 31,	*2003*	*2002*
Regulatory assets:		
Regulatory tax asset (1)	$ 63.3	$ 54.9
Other:		
Cost recovery clauses	59.7	34.7
Coal contract buy-out (2)	2.7	5.4
Deferred bond refinancing costs (3)	32.2	35.9
Environmental remediation	20.7	20.3
Competitive rate adjustment	5.3	7.4
Other	4.4	4.6
	125.0	108.3
Total regulatory assets	$ 188.3	$ 163.2
Regulatory liabilities:		
Regulatory tax liability (1)	$ 29.9	$ 36.6
Other:		
Deferred allowance auction credits	1.9	2.1
Recovery clause related	–	2.2
Environmental remediation	20.7	20.3
Transmission and distribution storm reserve	40.0	36.0
Deferred gain on property sales (4)	1.9	0.9
Accumulated reserve – cost of removal	462.2	440.6
Other	3.6	–
	530.3	502.1
Total regulatory liabilities	$ 560.2	$ 538.7

(1) Related primarily to plant life. Includes $17.0 million and $20.9 million of excess deferred taxes as of Dec. 31, 2003 and 2002, respectively.
(2) Amortized over a 10-year period ending December 2004.
(3) Unamortized refinancing costs:

Related to debt transactions as follows (millions):	Amortized until:
$ 50.0	2004
$ 51.6	2005
$ 22.1	2007
$ 25.0	2011
$ 50.0	2011
$ 150.0	2012
$ 150.0	2012
$ 85.9	2014
$ 25.0	2021
$ 100.0	2022

(4) Amortized over a 5-year period with various ending dates.

5. Asset Retirement Obligations

On Jan. 1, 2003, TECO Energy adopted FAS 143, *Accounting for Asset Retirement Obligations*. The company recognized liabilities for retirement obligations associated with certain long-lived assets, in accordance with the relevant accounting guidance. An asset retirement obligation for a long-lived asset is recognized at fair value at inception of the obligation if there is a legal obligation under an existing or enacted law or statute, a written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are recognized only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its future value. The corresponding amount capitalized at inception is depreciated over the remaining useful life of the asset. The liability must be revalued each period based on current market prices.

TECO Energy has recognized asset retirement obligations for reclamation and site restoration obligations principally associated with coal mining, storage and transfer facilities. The majority of obligations arise from environmental remediation and restoration activities for coal-related operations. Prior to the adoption of FAS 143, TECO Coal accrued reclamation costs for such activities. For TECO Coal, the adoption of FAS 143 modifies the valuation and accrual methods used to estimate the fair value of asset retirement obligations.

As a result of the adoption of FAS 143, TECO Energy recorded an increase to net property, plant and equipment of $7.8 million (net of accumulated depreciation of $6.6 million) and an increase to asset retirement obligations of $22.1 million, partially offset by previously recognized accrued reclamation obligations associated with coal mining activities of $12.3 million. A pre-tax charge of $1.8 million, net of a $0.2 million offset due to a regulatory asset at Tampa Electric, ($1.1 million after tax) was recognized as a change in accounting principle.

For the year ended Dec. 31, 2003, TECO Energy recognized $1.2 million of accretion expense associated with asset retirement obligations. During this period, no new retirement obligations were incurred and no significant revisions to estimated cash flows used in determining the recognized asset retirement obligations were necessary. FAS 143 was not effective for the years ended Dec. 31, 2002 and 2001.

As regulated utilities, Tampa Electric and PGS must file depreciation and dismantlement studies periodically and receive approval from the FPSC before implementing new depreciation rates. Included in approved depreciation rates is either an implicit net salvage factor or a cost of removal factor, expressed as a percentage. The net salvage factor is principally comprised of two components—a salvage factor and a cost of removal or dismantlement factor. The company uses current cost of removal or dismantlement factors as part of the estimation method to approximate the amount of cost of removal in accumulated depreciation.

Upon adoption of FAS 143 at Jan. 1, 2003, the estimated accumulated cost of removal and dismantlement included in net accumulated depreciation as of Dec. 31, 2003 and 2002 of $462.2 million and $440.6 million, respectively, was reclassified to a regulatory liability for all periods presented (see also **Note 4**). For Tampa Electric and PGS, the original cost of utility plant retired or otherwise disposed of and the cost of removal, or dismantlement, less salvage value is charged to accumulated depreciation and the accumulated cost of removal reserve reported as a regulatory liability, respectively.

6. Short-Term Debt

At Dec. 31, 2003 and 2002, the following credit facilities and related borrowings existed:

Credit Facilities

	Dec. 31, 2003			Dec. 31, 2002		
(millions)	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*
Recourse:						
Tampa Electric:						
1-year facility	$ 125.0	$ –	$ –	$ 300.0	$ –	$ –
3-year facility	125.0	–	–	–	–	–
TECO Energy:						
1-year term loan	–	–	–	350.0	350.0	–
18-month facility[1]	100.0	–	–	–	–	
1-year facility	37.5	37.5	–	–	–	–
3-year facility	350.0	–	109.9	350.0	–	179.8
Total	$ 737.5	$ 37.5	$ 109.9	$ 1,000.0	$ 350.0	$ 179.8

(1) See **Note 23** for details regarding the subsequent reduction of this credit facility.

These credit facilities require commitment fees ranging from 20 to 50 basis points. The weighted average interest rate on outstanding notes payable at Dec. 31, 2003 and 2002 was 6.63% and 1.88%, respectively. At Dec. 31, 2003 and 2002, notes payable consisted of the following:

Notes Payable

(millions) Dec. 31,	*2003*	*2002*
Credit facilities outstanding	$ 37.5	$ 350.0
Commercial paper	–	10.5
Total notes payable	$ 37.5	$ 360.5

Tampa Electric 1-year and 3-year facilities

On Nov. 7, 2003, Tampa Electric Company replaced its maturing $300 million credit facility with a $125 million one-year credit facility and a $125 million three-year credit facility, maturing in November 2004 and November 2006, respectively. In addition to the financial covenants described below and in **Notes 1** and **20**, the two new facilities include a covenant limiting cumulative distributions after Oct. 31, 2003 and outstanding affiliate loans to an amount representing an accumulation of net income after May 31, 2003 and capital contributions from the parent after Oct. 31, 2003, plus $450 million.

TECO Energy 1-year term loan

On Nov. 13, 2003, TECO Energy repaid the $350 million one-year credit facility maturing on that date.

TECO Energy 18-month facility

On Apr. 9, 2003, TECO Energy entered into a $350 million unsecured credit facility with Merrill Lynch for a term of up to eighteen months. The Merrill Lynch credit facility requires TECO Energy's debt-to-capital ratio, as defined in the credit agreement, not to exceed 65%. This facility also has covenants that, if the facility is drawn, could limit the payment of dividends exceeding $40 million in any quarter unless, prior to the payment of any dividends, the company delivers to Merrill Lynch liquidity projections satisfactory to Merrill Lynch demonstrating that the company will have sufficient cash or cash equivalents to pay both the dividends contemplated and each of the three quarterly dividends next scheduled to be paid on its common stock. Current quarterly dividends are $34.8 million.

On Nov. 12, 2003, TECO Energy and Merrill Lynch amended the existing $350 million credit facility to allow $100 million of credit capacity to remain in place subsequent to the repayment of the $350 million bank term maturity on Nov. 13, 2003. Under the terms of the original agreement, the facility would have been extinguished upon that repayment. The amendment made the $100 million commitment of undrawn line capacity available through Apr. 8, 2004, at which time the facility can be drawn up to $100 million and remain outstanding to Oct. 8, 2004. The $100 million facility is required to be reduced for certain asset sales and financings. See **Note 23** for details regarding the subsequent reduction of this facility due to subsequent asset sales.

On Dec. 19, 2003, TECO Energy and Merrill Lynch further amended the existing Merrill Lynch credit facility to put in place with Merrill and JP Morgan a contingent credit facility of $200 million. The contingent facility becomes effective only if the existing $350 million bank credit facility becomes unavailable because of non-compliance with the 65% debt-to-total-capital covenant or transfer of assets covenant as a result of write-offs or the disposition of TWG assets. Upon the occurrence of these particular events, TECO Energy would pledge the common stock of TECO Transport Corporation as security under the amended credit facility and the commitment available under the facility would be increased to $200 million, all of which would be available for letters of credit or cash draws. If the terms of the facility change as a result of these particular events, the amended facility would mature in December 2004. The contingent facility, if activated, would replace the existing $100 million Merrill Lynch facility. See **Note 20** for a summary of performance against significant financial covenant requirements.

TECO Energy 1-year facility

On June 24, 2003, TECO Energy entered into a one-year $37.5 million credit facility with four banks, collateralized by 50% of the Union and Gila River assets. The proceeds from the credit facility were used in the termination of the partnership with Panda. This credit facility has a debt-to-capital covenant similar to those of the other TECO Energy credit facilities, but also includes an earnings before interest, taxes, depreciation and amortization (EBITDA) to interest coverage requirement of 2.5 times, a limitation on liens of not more than 60% of the fair value of assets, and a restriction on the sale of any of the company's interest in the Union and Gila River projects. This loan can be repaid without penalty at any time with three business days' notice. See **Note 20** for a summary of performance against significant financial covenant requirements. Subsequent to Dec. 31, 2003, this obligation was repaid (see **Note 23**).

7. Long-Term Debt

At Dec. 31, 2003, total long-term debt had a carrying amount of $4,392.6 million and an estimated fair market value of $4,503.6 million. The estimated fair market value of long-term debt was based on quoted market prices for the same or similar issues, on the current rates offered for debt of the same remaining maturities, or for long-term debt issues with variable rates that approximate market rates, at carrying amounts. The carrying amount of long-term debt due within one year approximated fair market value because of the short maturity of these instruments.

A substantial part of the tangible assets of Tampa Electric is pledged as collateral to secure its first mortgage bonds, and certain pollution control equipment is pledged to secure certain installment contracts payable.

TECO Energy's maturities and annual sinking fund requirements of long-term debt for 2004 through 2008 are as follows:

Long-Term Debt Maturities For Continuing Operations

Dec. 31, 2003				*Total*
(millions)	*2004*	*2005*	*2006 – 2008*	*2004 – 2008*
TECO Energy				
Debt securities	$ –	$ –	$ 680.0	$ 680.0
Preferred securities[1]	–	–	449.1	449.1
Tampa Electric	0.8	–	125.0	125.8
Peoples Gas	5.3	5.5	42.7	53.5
TWG	–	–	–	–
TECO Transport	–	–	110.6	110.6
TECO Coal	–	–	–	–
Other[2]	25.5	20.7	51.6	97.8
	31.6	26.2	1,459.0	1,516.8
Liabilities associated with assets held for sale	2,087.3	–	–	2,087.3
Total long-term debt maturities	$ 2,118.9	$ 26.2	$ 1,459.0	$ 3,604.1

(1) FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*, which was adopted on July 1, 2003, requires the classification of the preferred securities as debt.
(2) Includes debt maturities for the Guatemalan operations of $17.8 million, $20.7 million, and $51.6 million for 2004, 2005 and 2006-2008, respectively.

Debt

TECO Energy – $300 million 7.5% Senior Unsecured Notes

On June 13, 2003, TECO Energy issued $300 million of 7.5% Senior Unsecured Notes due in 2010. These notes contain a covenant that limits the ability of the company to create any lien upon any of its property in excess of 5% of consolidated tangible net assets, as defined in the agreement, without equally and ratably securing the 7.5% Notes. Net proceeds of $293 million were used to repay short-term debt and for general corporate purposes. See Note 20 for a summary of performance against significant financial covenant requirements.

TECO Energy – $380 million 10.5% Senior Unsecured Notes

In November 2002, the proceeds from the issuance of TECO Energy notes were used for general corporate purposes and to pay the $34.1 million option premium associated with the refinancing of $200 million of notes. The $34.1 million option premium ($20.9 million after tax) was recognized as a charge in 2002.

Tampa Electric – $250 million 6.25% Senior Notes

In April 2003, Tampa Electric issued $250 million of 6.25% Senior Notes due in 2016, in a private placement. Net proceeds of approximately $250 million were used to repay short-term indebtedness and for general corporate purposes at Tampa Electric. The 6.25% Senior Notes contain covenants that (1) require Tampa Electric Company to maintain, as of the last day of each fiscal quarter, a debt-to-capital ratio, as defined in the agreement, that does not exceed 60%, and (2) prohibit the creation of any liens on any of its property in excess of $787 million in the aggregate, with certain exceptions, as defined, without equally and ratably securing the 6.25% Senior Notes.

Preferred Securities

As a result of the adoption of FAS 150, on July 1, 2003, the preferred securities issued by the company were reclassified and presented as long-term debt for external financial reporting purposes only. The cumulative effect of the adoption of FAS 150 was an after-tax loss of $3.2 million ($5.3 million pre-tax), reflecting an adjustment to recognize interest expense ratably over the life of the instruments in accordance with the new guidance. See **Note 22** for a discussion of the estimated impact of new accounting guidance in 2004.

Capital Trust I

In December 2000, TECO Capital Trust I, a trust established for the sole purpose of issuing Trust Preferred Securities (TRuPS) and purchasing company preferred securities, issued 8 million shares of $25 par, 8.5% TRuPS, due 2041, with an aggregate liquidation value of $200 million. Each TRuPS represents an undivided beneficial interest in the assets of the Trust. The TRuPS represent an indirect interest in a corresponding amount of TECO Energy 8.5% junior subordinated notes due 2041. TECO Energy's proceeds from the sale of the junior subordinated notes were used to reduce the commercial paper outstanding and for general corporate purposes. Distributions are payable quarterly in arrears on January 31, Apr. 30, July 31, and October 31 of each year. Distributions were $17.0 million in 2003 and 2002 and $14.6 million in 2001.

The junior subordinated notes may be redeemed at the option of TECO Energy at any time on or after Dec. 20, 2005 at 100% of their principal amount plus accrued interest through the redemption date. Upon any liquidation of the company preferred securities, holders of the TRuPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends through the date of redemption.

Capital Trust II

In January 2002, TECO Energy sold 17.965 million mandatorily convertible equity security units in the form of 9.5% equity units at $25 per unit resulting in $436 million of net proceeds. Each equity unit consisted of $25 in principal amount of a trust preferred security of TECO Capital Trust II, a Delaware business trust formed for the purpose of issuing these securities, with a stated liquidation amount of $25 and a contract to purchase shares of common stock of TECO Energy in January 2005 at a price per share of between $26.29 and $30.10 based on the market price at that time. If the equity units had been converted as of Dec. 31, 2003, the company would have been required to issue 17.1 million shares of common stock to satisfy the mandatory conversion obligation. This is also the maximum number of shares issuable under the conversion feature. The equity units represent an indirect interest in a corresponding amount of TECO Energy 5.11% subordinated debt. The holders of these contracts are entitled to quarterly contract adjustment payments at the annualized rate of 4.39% of the stated amount of $25 per year through and including Jan. 15, 2005. The net proceeds from the offering were used to repay short-term debt and for general corporate purposes.

At Dec. 31, 2003 and 2002, TECO Energy had the following long-term debt outstanding:

Long-Term Debt *(millions) Dec. 31,*		*Due*	*2003*	*2002*
TECO Energy	Notes: 7.2% (effective rate of 7.38%) [1]	2011	$ 600.0	$ 600.0
	6.125% (effective rate of 6.31%) [1]	2007	300.0	300.0
	7% (effective rate of 7.08%) [1]	2012	400.0	400.0
	10.5% (effective rate of 12.37%) [1] [4]	2007	380.0	380.0
	7.5% (effective rate of 7.85%) [1] [2]	2010	300.0	–
	Preferred securities: 8.50% [3]	2041	200.0	–
	9.50% [4]	2007	449.1	–
			2,629.1	1,680.0
Tampa Electric	First mortgage bonds (issuable in series):			
	7.75% (effective rate of 7.96%)	2022	75.0	75.0
	6.125% (effective rate of 6.61%)	2003	–	75.0
	Installment contracts payable: [5]			
	6.25% Refunding bonds (effective rate of 6.81%) [6]	2034	86.0	86.0
	5.85% Refunding bonds (effective rate of 5.88%)	2030	75.0	75.0
	5.1% Refunding bonds (effective rate of 5.77%) [7]	2013	60.7	60.7
	5.5% Refunding bonds (effective rate of 6.34%) [7]	2023	86.4	86.4
	4% (effective rate of 4.22%) [8]	2025	51.6	51.6
	4% (effective rate of 4.17%) [8]	2018	54.2	54.2
	4.25% (effective rate of 4.44%) [8]	2020	20.0	20.0
	Notes: 6.875% (effective rate of 6.98%) [1]	2012	210.0	210.0
	6.375% (effective rate of 7.35%) [1]	2012	330.0	330.0
	5.375% (effective rate of 5.59%) [1]	2007	125.0	125.0
	6.25% (effective rate of 6.31%) [1]	2016	250.0	–
			1,423.9	1,248.9
Peoples Gas System	Senior Notes: [2] 10.35%	2007	3.4	4.2
	10.33%	2008	4.8	5.6
	10.3%	2009	6.4	7.2
	9.93%	2010	6.6	7.4
	8%	2012	23.3	25.4
	Notes: 6.875% (effective rate of 6.98%) [1]	2012	40.0	40.0
	6.375% (effective rate of 7.35%) [1]	2012	70.0	70.0
	5.375% (effective rate of 5.59%) [1]	2007	25.0	25.0
			179.5	184.8
TECO Wholesale Generation	Non-recourse secured facility notes, Series A: 7.8%	2003	–	111.0
	Non-recourse secured facility notes, variable rate:			
	4.38% for 2003 and 4.36% for 2002 [9]	2004-2007	36.7	50.1
	6.63% for 2003 and 6.88% for 2002 [9]	2004-2009	16.0	16.0
	4.75% for 2003 and 5.00% for 2002 [9]	2004-2009	14.0	14.0
	Non-recourse secured facility notes: 10.1%	2004-2009	15.3	16.4
	9.629%	2004-2009	19.1	24.8
	Non-recourse secured facility note, variable rate: 3.00% weighted average [9] [10]	2004-2006	1,395.0	–
	Non-recourse financing facility - Union County: 7.5% [5] [10]	2004-2021	692.3	–
			2,188.4	232.3
Diversified companies	Dock and wharf bonds, 5% [5]	2007	110.6	110.6
	Non-recourse mortgage notes: 4.45% (effective rate of 4.62%) [11]	2004	4.6	–
	3.95% (effective rate of 4.16%) [11]	2004	3.0	–
	Capital lease: implicit rate of 8.5%	2003	–	25.3
			118.2	135.9
Unamortized debt premium (discount), net			(27.6)	(30.5)
			6,511.5	3,451.4
Less amount due within one year [12]			31.6	127.1
Less long-term liabilities held for sale [10]			2,087.3	–
Total long-term debt			$4,392.6	$3,324.3

(1) These notes are subject to redemption in whole or in part, at any time, at the option of the company.
(2) These long-term debt agreements contain various restrictive covenants, such as limitations on restricted payments, liens and indebtedness (see **Note 20**).
(3) These securities may be redeemed in whole or in part, by action of the company on or after Dec. 20, 2005.
(4) These securities are comprised of two components–an equity contract which pays a coupon of 4.39%, adjusted quarterly, and a note obligation which pays a coupon of 5.11% (effective rate of 5.85%). The note obligation is subject to a potential rate reset on Oct. 15, 2004.
(5) Tax-exempt securities.
(6) Proceeds of these bonds were used to refund bonds with an interest rate of 9.9% in February 1995. For accounting purposes, interest expense has been recorded using a blended rate of 6.52% on the original and refunding bonds, consistent with regulatory treatment.
(7) Proceeds of these bonds were used to refund bonds with interest rates of 5.75%-8%.
(8) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002.
(9) Composite year-end interest rate.
(10) This obligation is expected to be transferred in the disposition of the Union and Gila River power plants. As a result, the liability has been reclassified to "Liabilities associated with assets held for sale". See **Note 14** for additional details.
(11) These notes represent 100% of the debt for BT-One, LLC, an 80-percent owned unconsolidated affiliate. In total, the company has a $1.0 million guarantee on these notes.
(12) Of the amount due in 2004, $0.8 million may be satisfied by the substitution of property in lieu of cash payments.

8. Preferred Stock

Preferred stock of TECO Energy – $1 par 10 million shares authorized, none outstanding.

Preference stock of Tampa Electric – no par 2.5 million shares authorized, none outstanding.

Preferred stock of Tampa Electric – no par 2.5 million shares authorized, none outstanding.

Preferred stock of Tampa Electric – $100 par value 1.5 million shares authorized, none outstanding.

9. Common Stock

Stock-Based Compensation

In April 1996, the shareholders approved the 1996 Equity Incentive Plan (1996 Plan). The 1996 Plan superseded the 1990 Equity Incentive Plan (1990 Plan), and no additional grants will be made under the 1990 Plan. The rights of the holders of outstanding options under the 1990 Plan were not affected. The purpose of the 1996 Plan is to attract and retain key employees of the company, to provide an incentive for them to achieve long-range performance goals and to enable them to participate in the long-term growth of the company. The 1996 Plan amended the 1990 Plan to increase the number of shares of common stock subject to grants by 3,750,000 shares, expand the types of awards available to be granted and specify a limit on the maximum number of shares with respect to which stock options and stock appreciation rights may be made to any participant under the plan. Under the 1996 Plan, the Compensation Committee of the Board of Directors may award stock grants, stock options and/or stock equivalents to officers and key employees of TECO Energy and its subsidiaries.

The Compensation Committee has discretion to determine the terms and conditions of each award, which may be subject to conditions relating to continued employment, restrictions on transfer or performance criteria.

In 2003, under the 1996 Plan, 2,828,806 stock options were granted, with a weighted average option price of $11.10 and a maximum term of 10 years. In addition, 561,050 shares of restricted stock were awarded, each with a weighted average fair value of $11.14. Compensation expense recognized for stock grants awarded under the 1996 Plan was $1.6 million, $1.7 million and $2.8 million in 2003, 2002 and 2001, respectively. Approximately half of the stock grants awarded in 2003 and 2002 and all of the stock grants awarded in 2001 are performance shares, restricted subject to meeting specified total shareholder return goals, vesting in three years with final payout ranging from zero to 200% of the original grant. Adjustments are made to reflect contingent shares which could be issuable based on current period results. The consolidated balance sheets at Dec. 31, 2003 and 2002 reflected a $(4.7) million and a $(6.3) million liability, respectively, classified as other deferred credits, for these contingent shares. The remaining stock grants are restricted subject to continued employment generally, with the 2003 and 2002 stock grants vesting in three years, and the 1997 and 1996 stock grants vesting at normal retirement age.

In April 2001, the shareholders approved an amendment to the 1996 Plan to increase the number of shares of common stock subject to grants by 6.3 million.

Stock option transactions during the last three years under the 1996 Plan and the 1990 Plan (collectively referred to as the "Equity Plans") are summarized as follows:

Stock Options - Equity Plans

	Option Shares (thousands)	*Weighted Avg. Option Price*
Balance at Dec. 31, 2000	4,559	$22.54
Granted	1,268	$31.39
Exercised	(605)	$21.53
Cancelled	(32)	$26.88
Balance at Dec. 31, 2001	5,190	$24.79
Granted	1,770	$27.97
Exercised	(487)	$20.93
Cancelled	(57)	$27.03
Balance at Dec. 31, 2002	6,416	$25.94
Granted	2,829	$11.10
Exercised	(14)	$11.09
Cancelled	(306)	$23.35
Balance at Dec. 31, 2003	8,925	$21.35
Exercisable at Dec. 31, 2003	–	–
Available for future grant at Dec. 31, 2003	1,447	

As of Dec. 31, 2003, the 8.9 million options outstanding under the Equity Plans are summarized below.

Stock Options Outstanding at Dec. 31, 2003

Option Shares (thousands)	*Range of Option Prices*	*Weighted Avg. Option Price*	*Weighted Avg. Remaining Contractual Life*
2,783	$11.09 - $11.78	$11.10	9 Years
2,070	$19.44 - $22.48	$21.16	5 Years
535	$23.55 - $25.97	$24.22	4 Years
3,537	$27.56 - $31.58	$29.08	7 Years

In April 1997, the Shareholders approved the 1997 Director Equity Plan (1997 Plan), as an amendment and restatement of the 1991 Director Stock Option Plan (1991 Plan). The 1997 Plan superseded the 1991 Plan, and no additional grants will be made under the 1991 Plan. The rights of the holders of outstanding options under the 1991 Plan will not be affected. The purpose of the 1997 Plan is to attract and retain highly qualified non-employee directors of the company and to encourage them to own shares of TECO Energy common stock. The 1997 Plan is administered by the Board of Directors. The 1997 Plan amended the 1991 Plan to increase the number of shares of common stock subject to grants by 250,000 shares, expanded the types of awards available to be granted and replaced the fixed formula grant by giving the Board discretionary authority to determine the amount and timing of awards under the plan.

In 2003, 40,000 options were granted, with a weighted average option price of $11.73. Transactions during the last three years under the 1997 Plan are summarized as follows:

Stock Options - Director Equity Plans

	Option Shares (thousands)	*Weighted Avg. Option Price*
Balance at Dec. 31, 2000	258	$21.68
Granted	35	$31.26
Exercised	(91)	$19.12
Cancelled	–	–
Balance at Dec. 31, 2001	202	$24.49
Granted	28	$27.97
Exercised	(22)	$20.95
Cancelled	(2)	$27.56
Balance at Dec. 31, 2002	206	$25.31
Granted	40	$11.73
Exercised	–	–
Cancelled	(10)	$23.41
Balance at Dec. 31, 2003	236	$23.08
Exercisable at Dec. 31, 2003	40	$11.72
Available for future grant at Dec. 31, 2003	230	

As of Dec. 31, 2003, the 236,000 options outstanding under the 1997 Plan with option prices of $11.09 – $31.58, had a weighted average option price of $23.08 and a weighted average remaining contractual life of six years.

TECO Energy has adopted the disclosure-only provisions of FAS 123, *Accounting for Stock-Based Compensation*, as amended by FAS 148, but applies Accounting Principles Board Opinion No. 25 and related interpretations in accounting for its plans. Therefore, since stock options are granted with an option price greater than or equal to the fair value on the grant date, no compensation expense has been recognized for stock options granted under the 1996 Plan and the 1997 Plan. If the company had elected to recognize compensation expense for stock options based on the fair value at grant date, consistent with the method prescribed by FAS 123, net income and earnings per share would have been reduced to the pro forma amounts as follows. These pro forma amounts were determined using the Black-Scholes valuation model with weighted average assumptions as set forth below:

Pro Forma Stock-Based Compensation Expense

(millions, except per share amounts)		*2003*	*2002*	*2001*
Net (loss) income from continuing operations	As reported	$ (14.7)	$ 277.2	$ 265.5
	Pro forma expense[1]	2.7	5.1	4.3
	Pro forma	$ (17.4)	$ 272.1	$ 261.2
Net (loss) income	As reported	$(909.4)	$ 330.1	$ 303.7
	Pro forma expense[1]	2.7	5.1	4.3
	Pro forma	$(912.1)	$ 325.0	$ 299.4
Net (loss) income from continuing operations - EPS, basic	As reported	$ (0.08)	$ 1.81	$ 1.98
	Pro forma	$ (0.10)	$ 1.78	$ 1.95
Net (loss) income from continuing operations - EPS, diluted	As reported	$ (0.08)	$ 1.81	$ 1.96
	Pro forma	$ (0.10)	$ 1.78	$ 1.93
Net income (loss) - EPS, basic	As reported	$ (5.05)	$ 2.15	$ 2.26
	Pro forma	$ (5.07)	$ 2.12	$ 2.23
Net income (loss) - EPS, diluted	As reported	$ (5.05)	$ 2.15	$ 2.24
	Pro forma	$ (5.07)	$ 2.12	$ 2.21
Assumptions				
Risk-free interest rate		3.52%	5.09%	4.89%
Expected lives (in years)		7	6	6
Expected stock volatility		32.68%	25.92%	27.45%
Dividend yield		6.87%	5.47%	5.46%

(1) Compensation expense for stock options determined using the fair-value based method, after tax.

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy raised $8.0 million, $11.2 million and $8.6 million of common equity from this plan in 2003, 2002 and 2001, respectively.

Common Stock and Treasury Stock

On Mar. 12, 2001, the company completed a public offering of 8.625 million common shares at $27.75 per share, 7.0 million shares of which were reissued from treasury shares.

On Oct. 4, 2001, S&P announced the inclusion of TECO Energy shares in the S&P 500 Index effective as of the market close on Oct. 9, 2001. On Oct. 12, 2001, TECO Energy issued 3.5 million additional common shares at $26.72 per share. The sales of the common shares resulted in total net proceeds to TECO Energy of $325.5 million in 2001, which were used to fund capital expenditures, for working capital requirements, general corporate purposes and to repay short-term debt.

In June 2002, the company completed a public offering of 15.525 million common shares at a price to the public of $23.00 per share. The sale of these shares resulted in net proceeds to the company of approximately $346.4 million, which were used to repay short-term debt and for general corporate purposes. In October 2002, the company issued 19.385 million common shares at a price to the public of $11.00 per share. The sale of these shares resulted in net proceeds to the company of approximately $206.8 million, which were used to repay short-term debt.

On Sep. 10, 2003, TECO Energy sold 11 million shares of common stock to funds managed by Franklin Advisers, Inc. of San Mateo, California at a price of $11.76 per share. Net proceeds of approximately $129 million were used to repay short-term indebtedness and for general corporate purposes.

Shareholder Rights Plan

In accordance with the company's Shareholder Rights Plan, a Right to purchase one additional share of the company's common stock at a price of $90 per share is attached to each outstanding share of the company's common stock. The Rights expire in May 2009, subject to extension. The Rights will become exercisable 10 business days after a person acquires 10 percent or more of the company's outstanding common stock or commences a tender offer that would result in such person owning 10 percent or more of such stock. If any person acquires 10 percent or more of the outstanding common stock, the rights of holders, other than the acquiring person, become rights to buy shares of common stock of the company (or of the acquiring company if the company is involved in a merger or other business combination and is not the surviving corporation) having a market value of twice the exercise price of each Right.

The company may redeem the Rights at a nominal price per Right until 10 business days after a person acquires 10 percent or more of the outstanding common stock.

Employee Stock Ownership Plan

Effective Jan. 1, 1990, TECO Energy amended the TECO Energy Group Retirement Savings Plan, a tax-qualified benefit plan available to substantially all employees, to include an employee stock ownership plan (ESOP). During 1990, the ESOP purchased 7 million shares of TECO Energy common stock on the open market for $100 million. The share purchase was financed through a loan from TECO Energy to the ESOP. This loan is at a fixed interest rate of 9.3% and will be repaid from dividends on ESOP shares and from TECO Energy's contributions to the ESOP.

TECO Energy's contributions to the ESOP were $21.1 million, $13.6 million and $5.6 million in 2003, 2002 and 2001, respectively.

TECO Energy's annual contribution equals the interest accrued on the loan during the year plus additional principal payments needed to meet the matching allocation requirements under the plan, less dividends received on the ESOP shares. The components of net ESOP expense recognized for the past three years are as follows:

ESOP Expense

(millions)	*2003*	*2002*	*2001*
Interest expense	$ 2.6	$ 4.3	$ 5.2
Compensation expense	16.0	12.2	7.4
Dividends	(5.3)	(8.5)	(8.5)
Net ESOP expense	$ 13.3	$ 8.0	$ 4.1

Compensation expense was determined by the shares allocated method.

At Dec. 31, 2003, the ESOP had 4.8 million allocated shares, 0.3 million committed-to-be-released shares, and 0.6 million unallocated shares. Shares are released to provide employees with the company match in accordance with the terms of the TECO Energy Group Retirement Savings Plan and in lieu of dividends on allocated ESOP shares. The dividends received by the ESOP are used to pay debt service on the loan between TECO Energy and the ESOP.

For financial statement purposes, the unallocated shares of TECO Energy stock are reflected as a reduction of common equity, classified as unearned compensation. Dividends on all ESOP shares are recorded as a reduction of retained earnings, as are dividends on all TECO Energy common stock. The tax benefit related to the dividends paid to the ESOP in 2003 for allocated shares ($1.6 million) is a reduction of income tax expense and for unallocated shares ($0.4 million) is an increase in retained earnings. All ESOP shares are considered outstanding for earnings per share computations.

10. Asset Impairments

In September 2003, as a result of the market conditions for merchant assets, management tested the merchant plants for impairment. This test was performed using undiscounted cash flows based on assumptions which included long-term gross margin projections, long-term forecasts of supply and demand growth rates, and reasonably available information to develop long term expectations. As of Sep. 30, 2003, based on the then-current assumptions and expectations of management, no impairment was indicated based on the undiscounted cash flows of the merchant assets tested, in accordance with FAS 144.

As of Dec. 31, 2003, based on the negotiations with potential buyers, including the project lenders, a change in management's expectations regarding an exit strategy in the near term, and management's designation of the Union and Gila River project companies as held for sale, a pre-tax asset impairment charge of $1,099.3 million was recognized and reflected in discontinued operations, in accordance with FAS 144 (see Note 14 for additional details). The impairment charge was calculated as the difference between the carrying value of the net assets and liabilities held for sale and the respective estimated fair value of those net assets and liabilities. The fair value was estimated using available market information, corroborated by discounted cash flow analyses. The discounted cash flow analyses included significant assumptions relating to long-term price and economic forecasts, refinancing of the non-recourse debt and an appropriate discount rate.

In December 2003, additional pre-tax asset impairment charges of $41.0 million ($25.6 million after tax) were recognized primarily related to certain steam turbines and licenses, originally planned for use in a cogeneration project, and an estimated pre-tax loss on the disposal of BGA (see Notes 14 and 23 for additional details of the disposition).

In 2003, TECO Energy recognized a pre-tax asset impairment charge of $104.1 million ($64.2 million after tax) relating to installment payments made and capitalized under turbine purchase commitments in prior periods. As reported previously and in Note 17, certain turbine rights had been transferred from Other Unregulated operations to Tampa Electric in 2002 for use in Tampa Electric's generation expansion activities. These cancellations, made in April 2003, fully terminate all turbine purchase obligations for these entities.

11. Restructuring Costs

In September and October of 2003, TECO Energy announced a corporate reorganization to restructure the company along functional lines, consistent with its objectives to grow the core utility operations, maintain liquidity, generate cash and maximize the value in the existing assets. As a result of these actions, the company is now aligned to provide for centralized oversight along functional lines for power plant operations, energy delivery, energy management, terminal operations, human resources and technology/support services. The 2003 actions included the involuntary termination or retirement of 337 employees, including officers and other personnel from operations and support services.

In 2002, TECO Energy initiated a restructuring program that impacted approximately 250 employees across multiple operations and services within, primarily, Tampa Electric. This program included retirements, the elimination of positions and other cost control measures. The total costs associated with this program, included severance, salary continuation and other termination and retirement benefits.

The company recognized a pre-tax expense of $24.6 million and $17.8 million for accrued benefits and other termination and retirement benefits for the years ended Dec. 31, 2003 and 2002, respectively. The company completed these restructuring activities as of Dec. 31, 2003. As of Dec. 31, 2003 and 2002, respectively, no adjustments were made to the benefits initially accrued for and $14.0 million and $17.8 million, respectively, of the accrued benefits were paid or otherwise settled. The table below details the pre-tax expense recognized by the operating segments:

Restructuring Charges

For the year ended Dec. 31, (millions)	*2003*	*2002*
Tampa Electric	$ 9.9	$16.6
Peoples Gas	4.1	–
TWG	0.4	–
TECO Transport	1.7	–
TECO Coal	–	–
Other Unregulated	5.9	1.2
Eliminations and other [1]	2.6	–
Total TECO Energy	$24.6	$17.8

(1) This amount relates to charges at TECO Energy parent.

12. TPGC Joint Venture Termination

In January 2002, TWG (formerly TECO Power Services Corporation) subsidiaries agreed to purchase the interests of Panda Energy in the TPGC projects in 2007 for $60 million, and TECO Energy guaranteed payment of this obligation. Panda Energy obtained bank financing using the purchase obligation and assigned TECO Energy's guarantee as collateral. Under certain circumstances, the purchase obligation could have been accelerated for a reduced price based on the timing of the acceleration. In connection with this purchase obligation, Panda Energy retained a cancellation right, exercisable in 2007 for $20 million by the holder, with early exercise permitted for a reduced price of $8 million.

On Apr. 9, 2003, the TWG subsidiaries and Panda Energy amended the agreements related to the purchase obligation. The modified terms accelerated the purchase obligation to occur on or before July 1, 2003, and reduced the overall purchase obligation to $58 million. Under the guarantee, TWG became obligated to make interest and certain principal payments to or on behalf of Panda related to the collateralized loan obligation of Panda. The purchase obligation of $58 million included $35 million for Panda Energy's interest in TPGC, and a short-term receivable from Panda, collateralized by Panda's remaining interests in PLC (see **Notes 1** and **17** for additional details on TECO Energy's indirect ownership interest in PLC). Both modifications to the purchase obligation were subject to the condition, which TECO Energy could waive, that bank financing be obtained by TECO Energy. Panda Energy's cancellation right was accelerated to expire on June 16, 2003. TECO Energy's guarantee of the TWG subsidiaries' obligation was modified to reflect the amendments to the purchase obligation. In April 2003, TECO Energy recognized the fair value of the guarantee as a pre-tax loss of $35.0 million ($21.4 million after tax), included in discontinued operations, as a result of the expected disposition of the project companies (see **Note 14**). From April 2003 through June 2003, TECO Energy made and accrued certain principal payments under the guarantee commitment.

As a result of the amendments to these agreements in early April 2003, management believed the exercise of the modified guarantee and the related purchase obligation became highly probable. The likelihood of the exercise of the purchase obligation created a presumption of effective control. When combined with TECO Energy's exposure to the majority of risk of loss under the previously disclosed letters of credit and contractor undertakings, management believed that consolidation of TPGC was appropriate as of the date of the modifications to the agreements. For convenience of reporting periods and accounting cycles, management selected Apr. 1, 2003 as the initial date of consolidation. Prior to Apr. 1, 2003, TWG recognized assets of $839.1 million, liabilities of $48.9 million and an unrealized loss in OCI of $69.0 million, to reflect the equity method of accounting for its investment in TPGC. As a result of the consolidation on Apr. 1, 2003, the company recognized additional assets of $2,446.9 million, primarily relating to utility plant and construction work in progress, additional liabilities of $1,976.8 million (including non-recourse debt), and an additional unrealized loss in OCI of $69.0 million for interest rate swaps designated as hedges. See **Note 14** for a discussion of the subsequent designation of the TPGC projects as assets and liabilities held for sale.

In June 2003, TECO Energy satisfied the bank financing condition resulting in the acceleration of TECO Energy's guarantee obligation and executed a final agreement with Panda to effect the termination of Panda's involvement in the partnership. Proceeds from the bank financing obtained in June 2003, which is more fully discussed in **Note 6**, were used to fund the net termination payment to Panda. Upon acceleration of the guarantee obligation and the resulting partnership termination, TWG indirectly received the 50-percent outstanding partnership interests in TPGC. As previously discussed, under the amended agreements, $35.0 million, pre-tax, had been recognized in April 2003 as the fair value of the guarantee obligation. The remaining amount was recorded as due from Panda and collateralized by Panda's remaining interests in PLC. Foreclosure proceedings were consummated on Panda's remaining interests in PLC in September 2003 (see **Notes 1, 17** and **21** for additional details). As of Dec. 31, 2003 substantially all of the assets and liabilities associated with the TPGC projects (Union and Gila River) were classified as held for sale. All results of operations for these two projects have been reclassified to discontinued operations for all periods presented.

For the year ended Dec. 31, 2003, TWG recorded total pre-tax charges of $249.1 million ($155.9 million after tax) as a direct result of the consolidation of TPGC. Of the total charges recorded, $95.2 million pre-tax ($61.2 million after tax), was recorded in continuing operations to reflect a goodwill impairment discussed in **Note 3**. See **Note 14** for a discussion of the remaining amount recorded in discontinued operations.

13. Income Tax Expense

Income tax expense consists of the following components:

Income Tax Expense

(millions)	*Federal*	*Foreign*	*State*	*Total*
2003				
Continuing operations				
Current payable	$ 49.7	$ 2.2	$ 6.3	$ 58.2
Deferred	(175.4)	5.3	(18.6)	(188.7)
Amortization of investment tax credits	(4.7)	–	–	(4.7)
Income tax benefit from continuing operations	(130.4)	7.5	(12.3)	(135.2)
Discontinued operations				
Current payable	8.4	–	8.0	16.4
Deferred	(487.3)	–	(33.3)	(520.6)
Income tax benefit from discontinued operations	(478.9)	–	(25.3)	(504.2)
Total income tax expense (benefit)	$ (609.3)	$ 7.5	$ (37.6)	$ (639.4)
2002				
Continuing operations				
Current payable	$ 17.8	$ 1.0	$ 10.4	$ 29.2
Deferred	(70.9)	–	(5.2)	(76.1)
Amortization of investment tax credits	(4.8)	–	–	(4.8)
Income tax benefit from continuing operations	(57.9)	1.0	5.2	(51.7)
Discontinued operations				
Current payable	22.2	–	5.6	27.8
Deferred	(18.2)	–	(2.2)	(20.4)
Income tax benefit from discontinued operations	4.0	–	3.4	7.4
Total income tax expense (benefit)	$ (53.9)	$ 1.0	$ 8.6	$ (44.3)
2001				
Continuing operations				
Current payable	$ 81.3	$ –	$ 17.5	$ 98.8
Deferred	(94.1)	–	(7.1)	(101.2)
Amortization of investment tax credits	(4.9)	–	–	(4.9)
Income tax benefit from continuing operations	(17.7)	–	10.4	(7.3)
Discontinued operations				
Current payable	(3.5)	–	2.4	(1.1)
Deferred	(1.4)	–	(0.3)	(1.7)
Income tax benefit from discontinued operations	(4.9)	–	2.1	(2.8)
Total income tax expense (benefit)	$ (22.6)	$ –	$ 12.5	$ (10.1)

TECO Energy uses the liability method to determine deferred income taxes. Under the liability method, the company estimates its current tax exposure and assesses the temporary differences resulting from differences in the treatment of items, such as depreciation, for financial statement and tax purposes. These differences are reported as deferred taxes, measured at current rates, in the consolidated financial statements. Management reviews all reasonably available current and historical information, including forward-looking information, to determine if it is more likely than not, that some or all of the deferred tax asset will not be realized. If management determines that it is likely that some or all of a deferred tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized. In accordance with the policy, at Dec. 31, 2003 a valuation reserve of $64.2 million was established and charged to income to reflect the estimated amount of state deferred tax assets which may not be realized due to the lack of future taxable income.

Based primarily on the reversal of deferred income tax liabilities and future earnings of the company's core utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2003 will be realized in future periods.

The principal components of the company's deferred tax assets and liabilities recognized in the balance sheet are as follows:

Deferred Income Tax Assets and Liabilities

(millions) Dec. 31,	*2003*	*2002*
Deferred income tax assets[1]		
Property related	$ 578.8	$ 86.8
Alternative minimum tax credit forward	224.6	201.3
Goodwill writedown	107.5	–
Other	204.8	52.1
Valuation allowance	(64.2)	–
Total deferred income tax assets	$ 1,051.5	$ 340.2
Deferred income tax liabilities [1]		
Property related	$ (521.8)	$ (565.3)
Basis difference in oil and gas properties	4.4	(13.9)
Other	19.4	84.2
Total deferred income tax liabilities	$ (498.0)	$ (495.0)
Net deferred tax assets	$ 553.5	$ (154.8)

(1) Certain property related assets and liabilities have been netted.

Included in the "Property related" component of the deferred tax asset, as of Dec. 31, 2003, is the impact of the asset impairments and the related effect on hedge accounting discussed in Notes 2, 10 and 14.

Effective Income Tax Rate

(millions) For the years ended Dec. 31,	*2003*	*2002*	*2001*
Net (loss) income from continuing operations before minority interest	$ (63.5)	$ 277.2	$ 265.5
Plus: minority interest	48.8	–	–
Net (loss) income from continuing operations	(14.7)	277.2	265.5
Total income tax provision (benefit)	(135.2)	(51.7)	(7.3)
(Loss) income from continuing operations before income taxes	(149.9)	225.5	258.2
Income taxes on above at federal statutory rate of 35%	(52.4)	78.9	90.4
Increase (decrease) due to			
State income tax, net of federal income tax	(8.0)	3.4	6.8
Foreign income taxes	7.5	1.0	–
Amortization of investment tax credits	(4.7)	(4.8)	(4.9)
Permanent reinvestment – foreign income	(12.3)	(8.1)	(7.2)
Non-conventional fuels tax credit	(66.0)	(107.3)	(86.2)
AFUDC Equity	(6.9)	(8.7)	(2.3)
Other	7.6	(6.1)	(3.9)
Total income tax provision from continuing operations	$(135.2)	$ (51.7)	$ (7.3)
Provision for income taxes as a percent of income from continuing operations, before income taxes	90.2% [1]	-22.9%	-2.8%

(1) This calculation is not necessarily meaningful as a result of the interaction between tax losses and tax credits for the period.

During 2003, pre-tax losses from continuing operations, Sec. 29 credits and the reclassification of results of operations to discontinued operations as described in Note 14, caused variations in the overall effective income tax rate throughout the year and at year-end.

The provision for income taxes as a percent of income from discontinued operations was 36.2%, 12.3% and -8.0%, respectively, in 2003, 2002 and 2001. The total effective income tax rate differs from the federal statutory rate due to state income tax, net of federal income tax, the non-conventional fuels tax credit and other miscellaneous items. The actual cash paid for income taxes as required by the alternative minimum tax rules in 2003, 2002, and 2001 was $58.8 million, $71.9 million and $52.4 million, respectively.

14. Discontinued Operations and Assets Held for Sale

Union and Gila River Project Companies (TPGC)

In October 2003, the company, the bank financing group and the Union and Gila River project companies entered into a suspension agreement (see Note 20) in order to continue discussions regarding the operating budgets and performance of the two power plants. In late December 2003, a stand-still agreement was entered into by the same parties to continue to facilitate the discussions (see Note 20). See Note 23 for a discussion of subsequent events which impact both the suspension and the stand-still agreements. As of Dec. 31, 2003, management was committed to a plan to sell TECO Energy's ownership of the equity or net assets of the project companies. The company expects to complete the transfer of TPGC in 2004. The Union and Gila River project companies comprised part of the TWG operating segment until designated as assets held for sale in December 2003.

See Note 23 regarding subsequent events relating to the Union and Gila River project companies.

As an asset held for sale, the assets and liabilities that are expected to be transferred as part of the sale, as of Dec. 31, 2003, have been reclassified, respectively, in the balance sheet. Furthermore, the company has determined that TPGC meets the criteria of a discontinued operation. Results from operations for the Union and Gila River project companies have been reclassified to "Discontinued operations" for all periods presented. For the years ended Dec. 31, 2002 and 2001, TPGC was a development stage company. The following table provides selected components of discontinued operations for TPGC.

Components of income from discontinued operations – Union and Gila River Project Companies

(millions) For the years ended Dec. 31,	*2003*	*2002*	*2001*
Revenues	$ 319.4	$ –	$ –
Asset impairment [1]	(1,185.7)	–	–
(Loss) income from operations	(1,239.8)	–	–
(Loss) on joint venture termination	(153.9)	–	–
(Loss) income before provision for income taxes	(1,441.4)	27.4	13.1
(Benefit) provision for income taxes	(522.7)	10.6	5.0
Net (loss) income from discontinued operations	$ (918.7)	$ 16.8	$ 8.1

(1) Includes charges recognized in accordance with FAS 133.

Asset impairment charge

The pre-tax asset impairment charge of $1,185.7 million ($762.0 million after tax) is comprised of an impairment in long-lived assets and a related charge to reflect the impacts of hedge accounting. The pre-tax asset impairment charge of $1,099.3 million was recognized in accordance with FAS 144. The recognition of the asset impairment effectively accelerated the recognition of previously capitalized interest. As a result, in accordance with cash flow hedge accounting under FAS 133, a reversal from OCI of $22.6 million of pre-tax losses on the interest rate swaps was required to give effect in the income statement to the previously hedged interest which was capitalized during construction.

In addition, the change in future expectations regarding the probability of the company retaining the long-term, non-recourse debt resulted in the reversal of an additional $63.8 million pre-tax losses which were previously deferred in OCI and related to the future recognition of capitalized interest amortization and future interest expense on the non-recourse debt, anticipated to be recognized in periods subsequent to 2004. See Note 10 for a full description of the asset impairment component and Note 2 for additional details on the hedge accounting (OCI reversal) components.

Loss on joint venture termination

As discussed in greater detail in Note 12, the consolidation of TPGC on Apr. 1, 2003 resulted in the recognition of a pre-tax charge of $153.9 million ($94.7 million after tax) which was record-

ed in discontinued operations. This pre-tax charge included: $35.0 million ($21.4 million after tax) related to the partnership termination under the guarantee; and $118.9 million ($73.3 million after tax) related to the consolidation of TPGC to reflect the impact of Panda's portion of TPGC's partnership deficit and the elimination of certain related-party liabilities (see Note 17).

The following table provides a summary of the carrying amounts of the significant assets and liabilities reported in the combined current and non-current "Assets held for sale" and "Liabilities associated with assets held for sale" line items:

Assets held for sale – Union and Gila River Project Companies

(millions)	*Dec. 31, 2003*
Current assets	$ 72.9
Net property, plant and equipment	1,367.9
Other investments	676.1
Other non-current assets	23.7
Total assets held for sale	$2,140.6

Liabilities associated with assets held for sale – Union and Gila River Project Companies

(millions)	*Dec. 31, 2003*
Current liabilities	$ 94.0
Long-term debt, non-recourse:	
Secured facility note [1]	1,395.0
Financing facility note	676.1
Other non-current liabilities	21.7
Total liabilities associated with assets held for sale	$2,186.8

(1) As defined in the legal documents.

Current and non-current assets

Current assets include $18.8 million of restricted cash which, under the terms of the lending agreements for the projects, is primarily related to cash to be used for construction-related purposes only. Also included in current assets is $16.2 million, representing the current portion of the investment in Union County bonds, described in Other investments below.

Net property, plant and equipment

Net property, plant and equipment has been reduced by accumulated depreciation of $49.4 million and an asset impairment charge of $1,099.3 million. This impairment charge arose as a result of changes in management's expectations, including its long-term strategic outlook, and is more fully described in Note 10. The decline of the fair value of the disposal group (comprised of the assets and liabilities expected to be transferred upon disposition) below the carrying value is directly attributable to the decline in future wholesale power price expectations as a result of the repercussions of the failure of deregulation in California and the Enron bankruptcy; less than economic dispatch in some areas of the country; the U.S. economic slowdown; uncertainty with respect to long-term price recovery; and the significant excess generating capacity in the many areas of the country. The primary triggering event for the recognition of the charge by the company was the significant change in management's expectations regarding the company's long-term future involvement in the Union and Gila River project companies and the decision, during the fourth quarter of 2003, to sell the project companies.

Other investments

Other investments includes industrial revenue bonds from Union County, Arkansas, which were acquired by Union Power Partners, L.P. (UPP), a subsidiary of TPGC, with financing obtained by borrowings from Union County (the County). As of Dec. 31, 2003, UPP's investment in the bonds from the County totaled $692.3 million, which equals the non-recourse financing facility from Union County. Union County's debt service payments on the bonds equal UPP's debt service obligations to the County. This agreement provides an incentive to and a means through which the company can invest in the County. For periods prior to Dec. 31, 2003, TECO Energy did not include TPGC in the Consolidated Balance Sheet (see Note 12).

Interest income on the investment and interest expense on the related long-term, non-recourse financing have no net impact on the company's results of discontinued operations. The obligation to pay cash under the long-term debt is fully offset by the right to receive cash from the bond issuer. The interest rate and maturity date on both the bonds and the related long-term debt is 7.5% per year and June 2021.

Current and non-current liabilities

Included in current liabilities is the current portion of the financing facility due to Union County, described in Other investments above, of $16.2 million and $58.6 million ($26.4 million current and $32.2 million non-current) for interest rate swaps entered into by the Union and Gila River projects in connection with the non-recourse collateralized borrowings.

The purpose of the interest rate swap agreement is to effectively convert a portion of the floating-rate debt to a fixed rate. At Dec. 31, 2003 and 2002, the notional amount of the interest rate swap agreements was $697.5 million and $1,035.0 million, respectively. The interest rate swap agreements have terms ranging from 2 to 5 years with the majority maturing in June 2006. As more fully described in Note 2, the designation of the secured facility note as a liability associated with assets held for sale resulted in the prospective loss of hedge accounting for the periods beyond the expected effective date of the sale.

Non-recourse, secured facility note

In 2001, the Union and Gila River project companies obtained construction financing of $1,395.0 million in the form of floating rate, non-recourse senior secured credit facilities from a bank group. The construction loans will convert to term loans upon the completion and full commercial operation of the Union and Gila River projects, however, conversion will not occur during the Suspension Period, as agreed under the Suspension Agreement described in Note 20. The Union and Gila River project companies each jointly and severally guarantee and cross-collateralize the loans and debts of the other. The loans are non-recourse to TECO Energy, TWG and its subsidiaries that own the project entities.

Credit Facilities

The Union and Gila River project companies have credit facilities for commercial letters of credit and debt service as part of the non-recourse project financing. These facilities are recourse only to the project companies, and not to TECO Energy or its other subsidiaries. Each project company's commercial letter of credit facility of $100 million is to facilitate gas purchases and power sales. Total aggregate letters of credit outstanding under the two commercial facilities at Dec. 31, 2003 was $144.2 million. Each project company also has a $40 million debt service reserve facility, neither of which has been drawn upon at Dec. 31, 2003. The Union and Gila River project companies' non-recourse project facilities have maturity dates of June 2006.

See Note 23 regarding subsequent events relating to the Union and Gila River projects companies.

Other transactions

In 2003 and 2002, the company completed several sales transactions and achieved significant milestones towards additional transactions anticipated to be completed, as of Dec. 31, 2003, in 2004. The completed transactions include: the sale of Hardee Power Partners, Ltd. (HPP) in 2003; and the sale of TECO Coalbed Methane in 2002 (see Note 21). As a result of the accounting treatment of the sale of HPP, the results from operations of HPP through the date of the sale and for all prior periods presented are included in continuing operations. For all periods presented, the results from operations of TECO Coalbed Methane are presented as discontinued operations on the income statement. As of Dec. 31, 2003, no significant assets or liabilities remained relating to

these two entities, with the exception of certain cash proceeds held by TECO Energy which are subject to restriction, as described in Note 1.

As of Dec. 31, 2003, management was committed to a plan to sell Prior Energy and BGA (formerly a component of TECO Energy Services). The company expects to complete these sales in early 2004 (see Note 23 for details of these subsequent transactions). As of the same date, a subsidiary of TECO Energy completed the sale of substantially all of the net assets of TECO Gas Services. These entities comprised part of TECO Energy's Other unregulated businesses segment. In accordance with FAS 144, the assets and liabilities that have yet to be transferred as part of these transactions, as of Dec. 31, 2003, have been reclassified, respectively, in the balance sheet. Results from operations for Prior Energy and TECO Gas Services have been reclassified to "Discontinued operations".

Below is a table which provides selected components of discontinued operations for transactions other than the Union and Gila River projects (TPGC) transaction:

Components of income from discontinued operations – Other

(millions)			
For the years ended Dec. 31,	*2003*	*2002*	*2001*
Revenues	$ 21.6	$ 51.5	$ 60.1
Income from operations	9.1	22.1	24.6
Gain on sale	39.7	12.7	–
Income before provision for income taxes[1]	46.8	32.9	22.3
Provision for income taxes	18.5	(3.2)	(7.8)
Net income from discontinued operations[1]	$ 28.3	$ 36.1	$ 30.1

(1) Includes internal financing costs, allocated prior to discontinued operations designation. Internally allocated costs for 2003, 2002 and 2001 were at pre-tax rates of 8%, 7% and 7%, respectively, based on the average investment in each subsidiary.

Revenues

Revenues for energy marketing operations at Prior Energy and TECO Gas Services are presented on a net basis in accordance with Emerging Issues Task Force No. (EITF) 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*, and EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, to reflect the nature of the contractual relationships with customers and suppliers. As a result, costs netted against revenues for the years ended Dec. 31, 2003, 2002 and 2001 were $853.4 million, $568.3 million and $105.5 million, respectively.

Gain on sale

As a result of the sale of TECO Coalbed Methane in December 2002, the company recognized pre-tax gains of $39.7 million ($24.1 million after tax) and $12.7 million ($7.7 million after tax) for the years ended Dec. 31, 2003 and 2002, respectively.

The following table provides a summary of the carrying amounts of the significant assets and liabilities reported in the combined current and non-current "Assets held for sale" and "Liabilities associated with assets held for sale" line items for all other transactions described above:

Assets held for sale – Other

(millions)	*Dec. 31, 2003*
Current assets	$ 96.5
Net property, plant and equipment	1.5
Other non-current assets	8.2
Total assets held for sale	$106.2

Liabilities associated with assets held for sale – Other

(millions)	*Dec. 31, 2003*
Current liabilities	$ 55.4
Other non-current liabilities	–
Total liabilities associated with assets held for sale	$ 55.4

15. Other Comprehensive Income

TECO Energy reported the following other comprehensive income (loss) for the years ended Dec. 31, 2003, 2002 and 2001, related to changes in the fair value of cash flow hedges, foreign currency adjustments and adjustments to the minimum pension liability associated with the company's supplemental executive retirement plan:

Comprehensive Income (Loss) (millions)	*Gross*	*Tax*	*Net*
2003			
Unrealized (loss) gain on cash flow hedges[1]	$ (31.8)	$ (10.6)	$ (21.2)
Less: Loss (gain) reclassified to net income	76.4	27.1	49.3
Gain (loss) on cash flow hedges	$ 44.6	$ 16.5	$ 28.1
Foreign currency adjustments	1.2	—	1.2
Pension adjustments[2]	(69.3)	(25.4)	(43.9)
Total other comprehensive (loss) income	$ (23.5)	$ (8.9)	$ (14.6)
2002			
Unrealized (loss) gain on cash flow hedges[1]	$ (51.2)	$ (20.4)	$ (30.8)
Less: Loss (gain) reclassified to net income	29.0	11.4	17.6
Gain (loss) on cash flow hedges	$ (22.2)	$ (9.0)	$ (13.2)
Foreign currency adjustments	(1.2)	–	(1.2)
Pension adjustments[2]	(7.2)	(2.8)	(4.4)
Total other comprehensive (loss) income	$ (30.6)	$ (11.8)	$ (18.8)
2001			
Initial adoption of FAS 133	$ (19.0)	$ (7.3)	$ (11.7)
Unrealized (loss) gain on cash flow hedges[1]	(32.1)	(12.5)	(19.6)
Less: Loss (gain) reclassified to net income	19.7	7.6	12.1
Gain (loss) on cash flow hedges	$ (31.4)	$ (12.2)	$ (19.2)
Pension adjustments[2]	0.5	0.2	0.3
Total other comprehensive (loss) income	$ (30.9)	$ (12.0)	$ (18.9)

(1) Amounts include interest rate swaps designated as cash flow hedges at TPGC, which was consolidated effective Apr. 1, 2003 as a result of the termination of the partnership. Prior to Apr. 1, 2003, only the company's proportionate share of its equity investee's comprehensive loss was included. See Notes 12 and 14 for additional details regarding the OCI balances for cash flow hedges.

(2) See Note 16 for additional details regarding pension adjustments.

16. Employee Postretirement Benefits

Pension Benefits

TECO Energy has a non-contributory defined benefit retirement plan which covers substantially all employees. Benefits are based on employees' age, years of service and final average earnings. On Apr. 1, 2000, the plan was amended to provide for benefits to be earned and payable substantially on a lump sum basis through an age and service credit schedule for eligible participants leaving the company on or after July 1, 2001. Other significant provisions of the plan, such as eligibility, definitions of credited service, final average earnings, etc., were largely unchanged. This amendment resulted in decreased pension expense of approximately $0.8 million in 2001 and a reduction of benefit obligation of $6.2 million at Sep. 30, 2001.

The company's policy is to fund the plan within the guidelines set by ERISA for the minimum annual contribution and the maximum allowable as a tax deduction by the IRS. In 2004, the company expects to make a contribution of about $14.2 million.

Amounts disclosed for pension benefits also include the unfunded obligations for the supplemental executive retirement plans, non-qualified, non-contributory defined benefit retirement plans available to certain senior management. In 2004, the company expects to make a contribution of about $1.7 million to these plans. TECO Energy reported other comprehensive losses of $43.9 million and $4.4 million in 2003 and 2002, respectively, and other comprehensive income of $0.3 million in 2001, related to adjustments to the minimum pension liability associated with the pension plan and supplemental executive retirement plans.

The asset allocation for the company's pension plan as of Sep. 30, 2003 and 2002, and the target allocation for 2004, by asset category, follows:

Asset Allocation

	Target Allocation for	*Percentage of Plan Assets at Sep. 30,*	
Asset category	*2004*	*2003*	*2002*
Equities	55% – 60%	57%	53%
Fixed income	40% – 45%	43%	47%
Real Estate	–	–	–
Other	–	–	–
Total		100%	100%

The company's investment objective is to obtain above average returns while minimizing volatility of expected returns over the long term. The target equities/fixed income mix is designed to meet investment objectives. The company's strategy is to hire proven managers and allocate assets to reflect a mix of investment styles, emphasize preservation of principal to minimize the impact of declining markets, and stay fully invested except for cash to meet benefit payment obligations and plan expenses.

The assumptions for the expected return on plan assets were developed based on an analysis of historical market returns, the plan's past experience and current market conditions. Estimates of future market returns are lower than actual long-term historical returns of the plan but were factored into the expected return on asset assumptions to generate a conservative forecast.

In 2001, TECO Energy elected to change the measurement date for pension obligations and plan assets from Dec. 31 to Sep. 30. The effect of this accounting change was not material.

Other Postretirement Benefits

TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. The company contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and June 30, 2001, is limited to a defined dollar benefit based on years of service. On Apr. 1, 2000, the company adopted changes to this program for participants retiring from the company on or after July 1, 2001. The company contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after July 1, 2001, is limited to a defined dollar benefit based on an age and service schedule. The impact of this amendment, including a change in the company's commitment for future retirees combined with a grandfathering provision for current retired participants, resulted in a reduction in the benefit obligation of $1.4 million in 2001. In 2004, the company expects to make a contribution of about $9.5 million to this program. Postretirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify the plans in whole or in part at any time.

On Dec. 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). Beginning in 2006, the new law adds prescription drug coverage to Medicare, with a 28% tax-free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. TECO Energy's current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs. The company is continuing to analyze the potential impact the Act may have on the company's FAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions,* expense and what, if any, plan design changes should be made with respect to the company's retiree medical program in response to the Act.

In 2001, TECO Energy elected to change the measurement date for benefit obligations from Dec. 31 to Sep. 30. The effect of this accounting change was not material.

The following charts summarize the income statement and balance sheet impact, as well as the benefit obligations, assets, funded status and rate assumptions associated with the pension and other postretirement benefits.

Benefit Expense

	Pension Benefits			*Other Postretirement Benefits*		
(millions)	*2003*	*2002*	*2001*	*2003*	*2002*	*2001*
Components of net periodic benefit expense						
Service cost (benefits earned during the period)	$ 14.3	$ 11.8	$ 11.2	$ 4.2	$ 3.5	$ 3.4
Interest cost on projected benefit obligations	30.8	28.7	27.9	12.5	11.2	10.9
Expected return on assets	(42.1)	(42.9)	(42.0)	–	–	–
Amortization of:						
Transition obligation (asset)	(1.1)	(1.1)	(1.1)	2.7	2.7	2.7
Prior service cost (benefit)	(0.5)	(0.5)	(0.5)	1.8	1.9	2.0
Actuarial (gain) loss	1.4	(3.7)	(4.4)	1.5	0.1	0.4
Pension expense (benefit)	2.8	(7.7)	(8.9)	22.7	19.4	19.4
Special termination benefit charge	–	2.7	–	–	0.6	–
Additional amounts recognized	–	–	–	0.1	–	–
Net pension expense (benefit)recognized in the Consolidated Statements of Income	$ 2.8	$ (5.0)	$ (8.9)	$ 22.8	$ 20.0	$ 19.4
Assumptions used to determine net cost						
Discount rate	6.75%	7.50%	7.50%	6.75%	7.50%	7.50%
Rate of compensation increase	4.82%	4.66%	4.69%	4.82%	4.66%	4.69%
Expected return on plan assets	9.00%	9.00%	9.00%	N/A	N/A	N/A

The following table shows the funded status of the qualified and non-qualified pension plans for which the projected obligation exceeds the fair value of the plan assets:

Pension Plans – Projected Obligation Exceeds Plan Assets

(millions) Dec. 31,	*2003*	*2002*
Projected benefit obligation	$ 554.5	$ 455.1
Fair value of plan assets	391.8	371.9
Projected obligation in excess of plan assets	$ 162.7	$ 83.2
Accumulated benefit obligation	$ 480.0	$ 400.8

As of Dec. 31, 2003, for the qualified and non-qualified pension plans, the accumulated obligation exceeded the fair value of the plan assets. As of Dec. 31, 2002 the accumulated obligation exceeded the fair value of the plan assets for only the non-qualified pension plan. The table below shows the funded status at the end of 2003 and 2002 for the respective plans:

Pension Plans – Accumulated Obligation Exceeds Plan Assets

(millions) Dec. 31,	*2003*	*2002* [1]
Accumulated benefit obligation	$ 480.0	$ 32.8
Fair value of plan assets	391.8	–
Accumulated obligation in excess of plan assets	$ 88.2	$ 32.8
Projected benefit obligation	$ 554.5	$ 41.3

(1) In 2002 only the non-qualified plan is presented due to the fact that the fair value of plan assets exceeded the accumulated obligation for the qualified plan.

The accumulated postretirement benefit obligation exceeds plan assets for the postretirement health and welfare benefits plan.

Employee Postretirement Benefits

	Pension Benefits		*Other Postretirement Benefits*	
(millions)	*2003*	*2002*	*2003*	*2002*
Change in benefit obligation				
Net benefit obligation at prior measurement date	$ 455.1	$ 382.3	$ 184.6	$ 150.2
Service cost	14.3	11.8	4.2	3.5
Interest cost	30.8	28.7	12.5	11.2
Plan participants' contributions	–	–	1.4	1.0
Actuarial loss	89.7	58.3	6.5	25.6
Plan amendments	–	1.1	–	–
Special termination benefits	–	2.7	–	0.6
Curtailment	(1.9)	–	–	–
Gross benefits paid	(33.5)	(29.8)	(10.5)	(7.5)
Net benefit obligation at measurement date	$ 554.5	$ 455.1	$ 198.7	$ 184.6
Change in plan assets				
Fair value of plan assets at prior measurement date	$ 371.9	$ 428.0	$ –	$ –
Actual return on plan assets	51.7	(24.9)	–	–
Employer contributions	1.7	1.7	9.1	6.5
Plan participants' contributions	–	–	1.4	1.0
Gross benefits paid (including expenses)	(33.5)	(32.9)	(10.5)	(7.5)
Fair value of plan assets at measurement date	$ 391.8	$ 371.9	$ –	$ –
Funded status				
Fair value of plan assets	$ 391.8	$ 371.9	$ –	$ –
Benefit obligation	554.5	455.1	198.7	184.6
Funded status at measurement date	(162.7)	(83.2)	(198.7)	(184.6)
Net contributions after measurement date	6.7	0.4	2.4	1.9
Unrecognized net actuarial loss	165.6	88.9	47.4	42.4
Unrecognized prior service cost (benefit)	(6.9)	(7.4)	20.5	22.4
Unrecognized net transition obligation (asset)	(1.4)	(2.5)	24.7	27.4
Accrued liability at end of year	$ 1.3	$ (3.8)	$(103.7)	$ (90.5)
Amounts recognized in the statement of financial position				
Prepaid benefit cost	$ 16.9	$ 14.8	$ –	$ –
Accrued benefit cost	(15.7)	(18.5)	(103.7)	(90.5)
Additional minimum liability	(82.7)	(13.8)	–	–
Intangible asset	1.3	1.5	–	–
Accumulated other comprehensive income	81.5	12.2	–	–
Net amount recognized at end of year	$ 1.3	$ (3.8)	$(103.7)	$ (90.5)
Assumptions used in determining benefit obligations, end of year				
Discount rate to determine projected benefit obligation	6.00%	6.75%	6.00%	6.75%
Rate of increase in compensation levels	4.25%	4.82%		

Employer contributions and benefits paid in the above table include both those amounts contributed directly to, and paid directly from both plan assets and directly to plan participants. The assumed health care cost trend rate for medical costs was 11.5% in 2003 and decreases to 5.0% in 2013 and thereafter.

A 100 basis point increase in the medical trend rates would produce a 4 percent ($0.6 million) increase in the aggregate service and interest cost for 2003 and a 4 percent ($7.5 million) increase in the accumulated postretirement benefit obligation as of Sep. 30, 2003.

A 100 basis point decrease in the medical trend rates would produce a 3 percent ($0.4 million) decrease in the aggregate service and interest cost for 2003 and a 3 percent ($5.3 million) decrease in the accumulated postretirement benefit obligation as of Sep. 30, 2003.

17. Related Parties

In February 2002, Tampa Electric and TECO-PANDA Generating Company II (TPGC II) entered into an assignment and assumption agreement under which Tampa Electric obtained TPGC II's rights and interests to four combustion turbines being purchased from General Electric, and assumed the corresponding liabilities and obligations for such equipment. In accordance with the terms of the assignment and assumption agreement, Tampa Electric paid $62.5 million to TPGC II as reimbursement for amounts already paid to General Electric by TPGC II for such equipment. No gain or loss was incurred on the transfer. In the first quarter of 2003, Tampa Electric recorded a $48.9 million after-tax charge related to the cancellation of these turbine purchase commitments (see **Note 10**).

In the second and third quarters of 2003, Tampa Electric returned approximately $158 million of capital to TECO Energy. TECO Energy had previously contributed capital to Tampa Electric in support of Tampa Electric's construction program in the wholesale business, which was subsequently scaled back.

In October 2003, Tampa Electric signed a five-year contract renewal with an affiliate company, TECO Transport Corporation, for integrated waterborne fuel transportation services effective Jan. 1, 2004. The contract calls for inland river and ocean transportation along with river terminal storage and blending services for up to 5.5 million tons of coal annually through 2008. See **Note 4** for additional details.

At Dec. 31, 2002, notes receivable from unconsolidated affiliates included the following: $795.8 million due from TPGC; $137.0 million due from PLC; $1.4 million due from Energeticke Centrum Kladno (ECKG); $13.7 million due from Mosbacher Power Partners L.P.; and $11.1 million due from EEGSA.

As of Dec. 31, 2003, a note receivable of $8.1 million due from EEGSA, an unconsolidated affiliate, bearing a current effective interest rate of 6.14%, was recorded on the balance sheet.

On Jan. 3, 2003, the $137.0 million loan receivable from PLC, a wholly-owned subsidiary of Panda Energy, converted to a 50-percent ownership interest in PLC, leading to a joint venture with Panda Energy. This joint venture holds a 50-percent ownership interest in Texas Independent Energy, L.P. (TIE). The TIE partnership owns and operates the Odessa and Guadalupe power stations in Texas. In September 2003, TWG completed foreclosure proceedings against Panda Energy for their ownership interest in PLC as a result of Panda's default under a $23.0 million note receivable. Consequently, as of Sep. 30, 2003, PLC is fully consolidated and the $23.0 million note receivable was converted to an equity interest. See also **Notes 1, 12** and **21** for additional information regarding PLC.

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests. These transactions were not material for the years ended Dec. 31, 2003, 2002 and 2001. No material balances were payable as of Dec. 31, 2003 or 2002.

18. Earnings Per Share

For the years ended Dec. 31, 2003, 2002 and 2001, stock options for 9.2 million shares, 4.5 million shares and 1.2 million shares, respectively, were excluded from the computation of diluted earnings per share due to their antidilutive effect. Additionally, 17.1 million common shares issuable under the purchase contract associated with the mandatorily convertible equity units issued in January 2002 were also excluded from the computation of diluted earnings per share for each of the years ended Dec. 31, 2003 and 2002, due to their antidilutive effect.

Earnings Per Share

(millions, except per share amounts)			*2003*	*2002*	*2001*
Numerator	Net (loss) income from continuing operations, basic and diluted		$ (14.7)	$277.2	$ 265.5
	Discontinued operations, net of tax		(890.4)	52.9	38.2
	Cumulative effect of a change in accounting principle, net		(4.3)	–	–
	Net (loss) income, basic and diluted		$(909.4)	$330.1	$ 303.7
Denominator	Average number of shares outstanding - basic		179.9	153.2	134.5
	Plus: Incremental shares for assumed conversions:				
	Stock options at end of period and contingent performance shares		–	2.1	4.2
	Less: Treasury shares which could be purchased		–	(2.0)	(3.3)
	Average number of shares outstanding - diluted		179.9	153.3	135.4
Earnings per share from continuing operations		Basic	$ (0.08)	$ 1.81	$ 1.98
		Diluted	$ (0.08)	$ 1.81	$ 1.96
Earnings per share from discontinued operations, net		Basic	$ (4.95)	$ 0.34	$ 0.28
		Diluted	$ (4.95)	$ 0.34	$ 0.28
Earnings per share from cumulative effect of change in accounting principle, net		Basic	$ (0.02)	$ –	$ –
		Diluted	$ (0.02)	$ –	$ –
Earnings per share		Basic	$ (5.05)	$ 2.15	$ 2.26
		Diluted	$ (5.05)	$ 2.15	$ 2.24

19. Segment Information

TECO Energy is an electric and gas utility holding company with significant diversified activities. Segments are determined based on how management evaluates, measures and makes decisions with respect to the operations of the entity. The management of TECO Energy reports segments based on each subsidiary's contribution of revenues, net income and total assets, as required by FAS 131, *Disclosures about Segments of an Enterprise and Related Information*. All significant intercompany transactions are eliminated in the consolidated financial statements of TECO Energy, but are included in determining reportable segments.

As more fully described in **Note 1**, in 2004, the company revised internal reporting information for the purpose of evaluating, measuring and making decisions with respect to the components which previously comprised the TECO Power Services operating segment. The revised operating segment, TECO Wholesale Generation, is comprised of all merchant operations. The non-merchant components are now included in Other Unregulated operations.

The information presented in the following table excludes all discontinued operations. See **Note 14** for additional details of the components of discontinued operations.

Segment Information [1]

(millions)		Tampa Electric	Peoples Gas	TWG Merchant	TECO Transport	TECO Coal	Other Unregulated	Eliminations & Other	Total TECO Energy
2003	Revenues - outsiders	$ 1,582.7	$ 408.4	$ 95.9	$ 162.2	$ 296.3	$ 194.0	$ 0.5	$ 2,740.0
	Sales to affiliates	3.4	–	–	98.4	–	69.5	(171.3)	–
	Total revenues	$ 1,586.1	$ 408.4	$ 95.9	$ 260.6	$ 296.3	$ 263.5	$ (170.8)	$ 2,740.0
	Depreciation	210.3	32.7	12.3	20.6	34.2	15.9	–	326.0
	Restructuring costs [2]	9.9	4.1	0.4	1.7	–	5.9	2.6	24.6
	Interest charges [3]	85.0	15.6	50.6	4.9	11.0	34.7	118.9	320.7
	(Benefit) provision for taxes	48.1	15.2	(27.0) [4]	9.7	(64.4)	(85.6)	(31.2)	(135.2)
	Net (loss) income from continuing operations [5] [6] [7]	$ 98.9 [5]	$ 24.5	$ (147.6) [6]	$ 15.3	$ 77.1	$ (5.4) [7]	$ (77.5)	$ (14.7)
	Goodwill, net	–	–	–	–	–	71.2	–	71.2
	Investment in unconsolidated affiliates	–	–	158.9	–	–	184.6	–	343.5
	Other non-current investments	–	–	–	–	–	16.5	–	16.5
	Total assets	4,178.6	651.5	3,398.7	315.8	340.8	958.7	618.2	10,462.3
	Capital expenditures	289.1	42.6	194.3	19.6	20.6	24.3	0.1	590.6
2002	Revenues - outsiders	$ 1,548.9	$ 318.1	$ 111.1	$ 143.9	$ 316.4	$ 226.5	$ –	$ 2,664.9
	Sales to affiliates	34.3	–	–	110.7	0.7	71.2	(216.9)	–
	Total revenues	$ 1,583.2	$ 318.1	$ 111.1	$ 254.6	$ 317.1	$ 297.7	$ (216.9)	$ 2,664.9
	Depreciation	189.8	30.5	12.0	22.3	31.4	17.2	–	303.2
	Restructuring costs [2]	16.6	–	–	–	–	1.2	–	17.8
	Interest charges [3]	51.5	14.8	24.3	6.3	8.2	37.1	29.4	171.6
	(Benefit) provision for taxes	85.7	14.7	5.8 [4]	10.8	(22.9)	(9.7)	(136.1)	(51.7)
	Net income (loss) from continuing operations [3]	$ 171.8	$ 24.2	$ (7.9)	$ 21.0	$ 76.4	$ 27.8	$ (36.1)	$ 277.2
	Goodwill, net	–	–	95.1	–	–	98.6	–	193.7
	Investment in unconsolidated affiliates	–	–	(38.2)	–	–	187.4	–	149.2
	Other non-current investments	–	–	795.8	–	–	49.2	0.3	845.3
	Total assets	4,119.4	629.9	2,020.1	355.1	283.5	1,167.3	503.1	9,078.4
	Capital expenditures	632.2	53.4	223.1	25.2	48.2	79.9	3.2	1,065.2
2001	Revenues - outsiders	$ 1,380.1	$ 352.9	$ 81.8	$ 151.7	$ 298.4	$ 218.4	$ –	$ 2,483.3
	Sales to affiliates	32.6	–	–	123.2	5.1	80.4	(241.3)	–
	Total revenues	$ 1,412.7	$ 352.9	$ 81.8	$ 274.9	$ 303.5	$ 298.8	$ (241.3)	$ 2,483.3
	Depreciation	173.4	27.9	9.8	24.1	28.3	21.1	–	284.6
	Restructuring costs	–	–	–	–	–	–	–	–
	Interest charges [3]	60.8	14.3	17.3	8.9	7.6	39.1	30.5	178.5
	(Benefit) provision for taxes	83.5	14.2	4.6 [4]	14.2	(19.0)	(6.1)	(98.7)	(7.3)
	Net income (loss) from continuing operations [3]	$ 154.0	$ 23.1	$ 0.5	$ 27.6	$ 59.0	$ 22.1	$ (20.8)	$ 265.5
	Goodwill, net	–	–	70.0	–	–	95.8	–	165.8
	Investment in unconsolidated affiliates	–	–	(14.1)	–	–	187.0	–	172.9
	Other non-current investments	–	–	124.1	–	–	85.7	0.6	210.4
	Total assets	3,674.5	582.6	1,129.7	333.1	258.5	1,101.3	96.5	7,176.2
	Capital expenditures	426.3	73.0	368.4	38.8	25.8	29.0	4.6	965.9

(1) From continuing operations. All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for the Union and Gila River projects (formerly part of TWG); and TECO Coalbed Methane. Prior Energy and substantially all of TECO Gas Services (formerly part of Other Unregulated).

(2) See **Note 11** for a discussion of restructuring charges in 2003 and 2002.

(3) Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated costs for 2003, 2002 and 2001 were at pre-tax rates of 8%, 7% and 7%, respectively, based on the average investment in each subsidiary.

(4) Taxes have been allocated, for segment reporting purposes, to TWG based on the weighted-average tax rates of the TWG components.

(5) Net income for 2003 includes a $48.9 million after-tax ($79.6 million pre-tax) asset impairment charge related to the turbine purchase cancellations (see **Note 10**).

(6) Net income for 2003 includes a $25.9 million after-tax charge ($40.7 million pre-tax) related to a contingent arbitration proceeding (see the **Legal Contingencies** section of **Note 20**), a $61.2 million after-tax charge ($95.2 million pre-tax) for goodwill impairment (see **Note 3**), and a $15.3 million after-tax asset impairment charge ($24.5 million pre-tax) related to the turbine purchase cancellations (see **Note 10**).

(7) Net income for 2003 includes a $40.9 million after-tax asset impairment charge ($65.5 million pre-tax).

Tampa Electric Company provides retail electric utility services to more than 612,000 customers in West Central Florida. Its Peoples Gas System division is engaged in the purchase, distribution and marketing of natural gas for more than 299,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

TECO Transport, through its wholly-owned subsidiaries, transports, stores and transfers coal and other dry bulk commodities for third parties and Tampa Electric. TECO Transport's subsidiaries operate on the Mississippi, Ohio and Illinois rivers, in the Gulf of Mexico and worldwide.

TECO Coal, through its wholly-owned subsidiaries, owns mineral rights and owns or operates surface and underground mines and coal processing and loading facilities in Kentucky, Tennessee and Virginia. In 2000, these subsidiaries began operating two synthetic fuel processing facilities, whose production qualifies for the non-conventional fuels tax credit. TECO Coal transferred the synthetic fuel operations into a newly formed LLC for the purpose of continuing growth in the production and sale of synthetic fuel. In April 2003, TECO Coal sold a 49.5 percent interest in this entity.

TWG has subsidiaries that have interests in independent power projects in Virginia, Texas, Arkansas, Mississippi and Arizona.

TECO Energy's other unregulated businesses are primarily engaged in energy services, engineering and owning and operating independent power projects with long-term contracts, in Hawaii, Guatemala, and, until the date of the sale of HPP, Florida (see Note 21).

Foreign Operations

Other Unregulated includes independent power operations and investments in Guatemala. TECO Energy, through its subsidiaries, has a 96 percent ownership interest and operates a 78-megawatt power station that supplies energy to EEGSA, an electric utility in Guatemala, under a U.S. dollar-denominated power sales agreement.

At Dec. 31, 2003, TECO Energy, through a wholly-owned subsidiary, had a 100 percent ownership interest in a 120-megawatt power station and in transmission facilities in Guatemala. The plant provides capacity under a U.S. dollar-denominated power sales agreement to EEGSA.

TECO Energy, through a subsidiary, owns a 30 percent interest in a consortium that includes Iberdrola, an electric utility in Spain, and Electricidad de Portugal, an electric utility in Portugal. The consortium owns an 80.9 percent interest in EEGSA.

Total assets at Dec. 31, 2003, 2002 and 2001 included $445.8 million, $415.9 million and $454.2 million, respectively, related to these Guatemalan operations and investments. Revenues included $91.5 million, $88.5 million and $79.9 million for the years ended Dec. 31, 2003, 2002 and 2001, respectively, and operating income included $53.1 million, $33.0 million and $38.0 million for the same periods from these Guatemalan operations and investments.

20. Commitments and Contingencies

Capital Investments

TECO Energy has made certain commitments in connection with its continuing capital expenditure program. At Dec. 31, 2003, these estimated capital investments total approximately $1.7 billion for the years 2004 through 2008 and are summarized as follows:

Forecasted Capital Investments

As of Dec. 31, 2003				*Total*
			2006 –	*2004 –*
(millions)	*2004*	*2005*	*2008*	*2008*
Tampa Electric	$182.9	$213.5	$ 792.9	$1,189.3
Peoples Gas	40.0	40.0	120.0	200.0
TWG	14.9	25.0	75.0	114.9
TECO Transport	19.9	20.0	60.0	99.9
TECO Coal	20.7	19.4	53.3	93.4
Other	1.2	1.0	2.4	4.6
Total capital investments	$279.6	$318.9	$1,103.6	$1,702.1

For 2004, Tampa Electric expects to spend $182.9 million, consisting of $9.4 million (committed as of Dec. 31, 2003) for the completion of the repowering project at the Gannon Station, $18.2 million for environmental expenditures and $155.3 million to support system growth and generation reliability. Tampa Electric's estimated capital expenditures over the 2005-2008 period are projected to be $1,006.4 million, including $323.8 million for environmental expenditures.

Capital expenditures for PGS are expected to be about $40 million in 2004 and $160 million during the 2005-2008 period. Included in these amounts are approximately $25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing maintenance and system safety.

TWG expects to invest $14.9 million in 2004, $6.2 million of ongoing maintenance and warranty related items on the TECO Undertaking for Union and Gila River power stations plus $8.7 million of net contributions to projects of unconsolidated affiliates. Capital expenditures at TWG for 2005 through 2008 are expected to be about $100 million for the completion of the Dell and McAdams power stations. TWG had outstanding commitments of approximately $13.3 million primarily for contributions to projects of unconsolidated affiliates and maintenance projects.

The other unregulated companies expect to invest $41.8 million in 2004 and $156.1 million during 2005 through 2008, mainly for normal renewal and replacement capital.

Legal Contingencies

TM Delmarva Power Arbitration Proceeding

A dispute resulting in an arbitration proceeding was brought against a TWG subsidiary, TM Delmarva Power, L.L.C. (TMDP), by the non-equity member, NCP of Virginia, L.L.C. (NCP), in the Commonwealth Chesapeake Project (CCC). The arbitration panel, in a 2-to-1 decision, found in favor of NCP and issued an interim award on Dec. 17, 2002 and, after several briefing cycles and a reopened hearing, issued its final award in September 2003.

Under the award TMDP is obligated to acquire NCP's voting and other rights, pay NCP interest on the deemed acquisition price from a pre-determined date, and pay NCP's legal fees as prescribed under the final award. The forced acquisition created a pre-tax loss of $32.0 million, representing the excess of the purchase price over the fair value of the interests acquired. TMDP is seeking to vacate the arbitration award in the U.S. District Court for the District of Columbia and has not yet paid the amount of the award. As of Dec. 31, 2003, the company has reserved for the full $46.9 million, representing the maximum payment obligation for the award plus accrued interest. The vacatur proceeding is still pending, and is expected to be completed in the third or fourth quarter of 2004.

Other Actions

In March 2001, TWG (under its former name of TECO Power Services) was served with a lawsuit filed in the Circuit Court for Hillsborough County by a Tampa-based firm called Grupo Interamerica, LLC. ("Grupo") in connection with a potential investment in a power project in Columbia in 1996. Grupo alleges, among other things, that TWG breached an oral contract with Grupo that would have allowed Grupo to acquire up to a 20-percent interest in the Columbian wholesale generation project when TWG declined to invest in such project. Grupo is seeking damages equal to the net present value of the value of 20-percent of the project over its life. TWG disputes the allegations and denies liability since any understanding made regarding the investment in the project was subject to TECO Energy Board approval which was not obtained. A trial date has not been set.

Three lawsuits have been filed in the Circuit Court in Hillsborough County against Tampa Electric, in connection with the location of transmission structures in certain residential areas, by residents in the areas surrounding the structures. The high-voltage power lines are needed by Tampa Electric to move electricity to the northwest part of its service territory where population growth has been experienced. The residents are seeking to remove the poles or to receive monetary damages. Tampa Electric is working with the community to determine the feasibility of alternate routes or structures or some combination.

From time to time TECO Energy and its subsidiaries are involved in various other legal, tax, and regulatory proceedings before various courts, regulatory commissions, and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with FAS 5, *Accounting for Contingencies*, to provide for matters that are reasonably likely to result in an estimable, material loss. While the outcome of such proceedings is uncertain, management does not believe that the ultimate resolution of pending matters will have a material adverse effect on the company's results of operations or financial condition.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2003, Tampa Electric Company has estimated its ultimate financial liability to be approximately $20 million, and this amount has been accrued in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors, or Tampa Electric Company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other potentially responsible parties (PRPs) is based on each party's relative ownership interest in or usage of a site. Accordingly, Tampa Electric Company's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Long Term Commitments

TECO Energy has commitments under long-term operating leases, primarily for building space, office equipment and heavy equipment, and marine assets at TECO Transport. On Dec. 30, 2002, TECO Transport completed a sale-leaseback transaction to be accounted for as an operating lease covering one ocean-going tug and barge, five river towboats and 49 river barges. On Dec. 21, 2001, TECO Transport sold three ocean-going barges and one ocean-going tug boat in a sale-leaseback transaction to be accounted for as an operating lease. Both lease terms are 12 years with early buyout options after 5 years.

Total rental expense for these operating leases, included in the Consolidated Statements of Income for the years ended Dec. 31, 2003, 2002 and 2001 was $29.5 million, $26.0 million and $20.4 million, respectively. The following is a schedule of future minimum lease payments at Dec. 31, 2003 for all operating leases with noncancelable lease terms in excess of one year:

Future Minimum Lease Payments For Operating Leases

Year ended Dec. 31:	*Amount (millions)*
2004	$ 24.1
2005	21.3
2006	17.6
2007	14.9
2008	12.4
Later Years	79.2
Total minimum lease payments	$ 169.5

In 1994, Tampa Electric bought out a long-term coal supply contract which would have expired in 2004 for a lump sum payment of $25.5 million. In February 1995, the FPSC authorized the recovery of this buy-out amount plus carrying costs through the Fuel and Purchased Power Cost Recovery Clause over the 10-year period beginning Apr. 1, 1995. In each of the years 2003, 2002 and 2001, $2.7 million of buy-out costs were amortized to expense.

Guarantees and Letters of Credit

On Jan. 1, 2003, TECO Energy adopted the prospective initial measurement provisions for certain types of guarantees, in accordance with FASB Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (an interpretation of FASB Statements No. 5, 57, and 107 and rescission of FASB Interpretation No. 34)*. Upon issuance or modification of a guarantee after Jan. 1, 2003, the company must determine if the obligation is subject to either or both of the following:

- Initial recognition and initial measurement of a liability; and/or
- Disclosure of specific details of the guarantee.

Generally, guarantees of the performance of a third party or guarantees that are based on an underlying (where such a guarantee is not a derivative subject to FAS 133) are likely to be subject to the recognition and measurement, as well as the disclosure provisions, of FIN 45. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation.

Alternatively, guarantees between and on behalf of entities under common control or that are similar to product warranties are subject only to the disclosure provisions of the interpretation. The company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

A summary of the face amount or maximum theoretical obligation under TECO Energy's letters of credit and guarantees as of Dec. 31, 2003 are as follows:

Letters of Credit and Guarantees

($ millions) *Letters of Credit and Guarantees for the Benefit of:*	*2004*	*2005*	*2006-2008*	*After 2008*	*Total*	*Liabilities Recognized at Dec. 31, 2003*
Tampa Electric						
Letters of credit	$ –	$ –	$ –	$ 0.9	$ 0.9	$ –
Guarantees:						
Fuel purchase/energy management [1]	–	–	–	15.0	15.0	–
	–	–	–	15.9	15.9	–
TECO Wholesale Generation						
Letters of credit [2]	67.2	–	–	–	67.2	–
Guarantees:						
Debt related	–	–	–	–	–	–
Tax related	–	–	–	1.3	1.3	–
Fuel purchase/energy management [1]	10.0	–	–	149.5	159.5	14.6
Construction/Investment related	5.0	–	–	–	5.0	–
	82.2	–	–	150.8	233.0	14.6
TECO Transport						
Letters of credit	–	–	–	1.5	1.5	–
TECO Coal						
Letters of credit	–	–	–	20.0	20.0	–
Guarantees: Fuel purchase related	–	–	–	1.5	1.5	1.5
	–	–	–	21.5	21.5	1.5
Other unregulated subsidiaries						
Letters of credit	11.5	–	4.7	4.3	20.5	–
Guarantees:						
Debt related	–	–	–	24.5	24.5	–
Tax related	–	–	–	2.5	2.5	–
Fuel purchase/energy management [1]	173.2 [3]	–	–	14.7	187.9	33.4
	184.7	–	4.7	46.0	235.4	33.4
Total	$266.9	$ –	$ 4.7	$235.7	$ 507.3	$49.5

(1) These guarantees renew annually and are shown on the basis that they will continue to renew beyond 2008. The amounts shown are the maximum theoretical amount guaranteed under current agreements. Liabilities recognized represent the associated obligation of TECO Energy under these agreements at Dec. 31, 2003. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.
(2) Primarily includes letters of credit for construction support for the Gila River and Union power stations.
(3) These guarantees will be eliminated as a result of the sale of Prior Energy subsequent to Dec. 31, 2003. See Note 23.

TECO Energy and its subsidiaries also enter into commercial agreements in the normal course of business that typically contain standard indemnification clauses. TECO Energy may sometimes agree to make payments to compensate or indemnify the counterparty for legal fees, environmental remediation costs and other similar costs arising from possible future events or changes in laws or regulations. These agreements cover a variety of goods and services, and have varying triggering events dependent on actions by third parties.

TECO Energy is unable to estimate the maximum potential future exposure under these clauses because the events that would obligate TECO Energy have not occurred, or if such event has occurred, TECO Energy has not been notified of any occurrence. As claims are made or changes in laws or regulations indicate, an amount related to the indemnification is reflected in the financial statements.

Financial Covenants

A summary of TECO Energy's significant financial covenants as of Dec. 31, 2003 is as follows:

TECO Energy Significant Financial Covenants

(millions, unless otherwise indicated) *Instrument*	*Financial Covenant* [1]	*Requirement/Restriction*	*Calculation at Dec. 31, 2003*
Tampa Electric			
Mortgage bond indenture	Dividend restriction	Cumulative distributions cannot exceed cumulative net income plus $4	$5 unrestricted [2]
PGS senior notes	EBIT/interest [3]	Minimum of 2.0 times	3.5 times
	Restricted payments	Shareholder equity at least $500	$1,652
	Funded debt/capital	Cannot exceed 65%	50.5%
	Sale of assets	Less than 20% of total assets	~%
Credit facility	Debt/capital	Cannot exceed 60%	49.2%
	EBITDA/interest [3]	Minimum of 2.5 times	5.8 times
	Restriction on distributions	Limit on cumulative distributions and outstanding affiliate loans [4]	$483 unrestricted
6.25% senior notes	Debt/capital	Cannot exceed 60%	49.2%
	Limit on liens	Cannot exceed $787	$362
TECO Energy			
Credit facilities [5]	Debt/capital	Cannot exceed 65%	61.9%
$37.5 credit facility [6]	EBITDA/interest [3]	Minimum of 2.5 times	2.4 times [6]
	Limit on liens	Cannot exceed 60% of fair value of assets	24.9% [7]
	Debt/capital	Cannot exceed 65%	61.9%
$380 million note indenture	Limit on restricted payments [8]	Cumulative operating cash flow in excess of 1.7 times interest	$284 unrestricted
	Limit on liens	Cannot exceed 5% of tangible assets	$206 unrestricted [9]
	Limit on indebtedness	Interest coverage at least 2.0 times	2.6 times
$300 million note indenture	Limit on liens	Cannot exceed 5% of tangible assets	$206 unrestricted [9]
TPGC guarantees [10]	Debt/capital	Cannot exceed 65%	61.9%
	EBITDA/interest [3]	Minimum of 3.0 times	– [11]
TECO Diversified			
Energy management services agreement guarantee	Consolidated tangible net worth	Minimum of $200 net worth	$548
	Consolidated funded debt	Cannot exceed 60%	17.8%
Coal supply agreement guarantee	Dividend restriction	Tangible net worth not less than $200 or $424 (40% of tangible net assets)	$548

(1) As defined in each applicable instrument.
(2) Reflects the determination as of Dec. 31, 2003, after giving effect to $158 million distributed to TECO Energy as a return of capital during 2003. There were $75 million of callable bonds outstanding under the indenture at Dec. 31, 2003.
(3) EBIT generally represents earnings before interest and taxes. EBITDA generally represents EBIT before depreciation and amortization. However, in each circumstance, the term is subject to the definition prescribed under the relevant legal agreements.
(4) Limits cumulative distributions after Oct. 31, 2003 and outstanding affiliate loans to an amount representing an accumulation of net income after May 31, 2003 and capital contributions from the parent after Oct. 31, 2003, plus $450 million.
(5) One of TECO Energy's credit facilities, if drawn upon, can limit payment of dividends each quarter to $40 million, unless the company provides the lender with satisfactory liquidity projections demonstrating the company's ability to pay both the dividends contemplated and each of the three quarterly dividends next scheduled to be paid. See Note 6 for the details regarding this credit facility.
(6) This facility was repaid in full in February 2004 prior to a declaration of default under the agreements. See Note 23.
(7) The fair market value of the assets has not been calculated. This calculation represents total collateralized debt, including TWG non-recourse debt, divided by the book value of total assets.
(8) The limitation on restricted payments restricts the company from paying dividends or making distributions or certain investments unless there is sufficient cumulative operating cash flow, as defined, in excess of 1.7 times interest to make such distribution or investment. The operating cash flow and restricted payments are calculated on a cumulative basis since the issuance of the 10.5% Notes in the fourth quarter of 2002. This calculation, at Dec. 31, 2003, reflects the amount accumulated and available for future restricted payments, representing the accumulation of four quarters' activities.
(9) The repayment of the collateralized $37.5 million credit facility in early 2004 increases this unrestricted amount to $244 million. See Note 23.
(10) Includes the Construction Undertaking Guarantees related to the TPGC projects.
(11) This calculation was not required for Sep. 30 or Dec. 31, 2003, as provided by the terms of the Suspension Agreement entered into between the lenders, the project companies and TECO Energy, as discussed below. The related long-term obligation is a component of the disposal group reported as a current liability on the balance sheet in the "Liabilities associated with assets held for sale" line item (see Note 14). Also, see Note 23 for subsequent events relating to this covenant.

In April 2003, Moody's lowered TECO Energy's senior unsecured debt rating to Ba1 with a negative outlook. This debt rating change triggered the payment of the $250 million equity bridge loan balance associated with the construction of the Union and Gila River power projects. In addition, this ratings change required the company to post letters of credit, in an amount satisfactory to the majority of lenders, to secure the projects and project lenders for the remaining potential cost to complete the projects.

Suspension / Standstill Agreement

On Oct. 28, 2003, TECO Energy and the Union and Gila River project companies entered into a Suspension Agreement with the lending group for the Union and Gila River projects to suspend until Feb. 1, 2004 (see Note 23 – subsequently, orally extended to Feb. 5, 2004) the quarterly calculation of the 3.0 times EBITDA-to-interest coverage ratio covenant included in the "TPGC guarantees" line in the table above. The Suspension Agreement contemplated discussions among TECO Energy, the Union and Gila River project companies and the lending group to reach an understanding regarding the projects' operating budgets and performance before expiration of the suspension period on Jan. 31, 2004. At the end of the suspension period, the Sep. 30 and Dec. 31, 2003 quarterly calculations would be performed.

In December 2003, the Union and Gila River project companies were unable to make interest payments on the non-recourse debt and payments under interest rate swap agreements due Dec. 31, 2003 when the project lenders declined to fund the debt service reserve. On Dec. 31, 2003, TECO Energy and the Union and Gila River project companies entered into a Standstill Agreement with the lending group for the Union and Gila River projects under which the lending group agreed to not exercise its rights or pursue remedies until after Jan. 31, 2004, while preserving such rights and remedies, relating to this payment default.

Subsequent to Dec. 31, 2003, the bank group for the Union and Gila River projects approved a non-binding letter of intent containing a binding Settlement Agreement which impacted these two agreements. See Note 23 for additional details of these subsequent events and their impact.

21. Mergers, Acquisitions and Dispositions

Hardee Power Partners

In 2003, Hardee Power Partners, Ltd. (HPP), which holds a 370-MW gas-fired generation facility located in central Florida, was sold to an affiliate of Invenergy LLC and GTCR Golden Rauner LLC. Under the terms of the sale, subsidiaries of the company will continue to provide service to HPP under the existing operation and maintenance agreement. The new owner may, at any time, choose to cancel this agreement. Additionally, Tampa Electric's long-term power purchase obligation to receive electricity from HPP remains in effect with no changes as a result of the transaction (see Note 1). The sale proceeds of approximately $107 million exceeded the net book value of $51.5 million (including assets of $149.1 million and liabilities of $97.6 million) resulting in a pre-tax gain of $56.3 million.

Due to the anticipated power purchases by Tampa Electric from HPP under the pre-existing long-term power purchase agreement (see the Purchased Power section of Note 1) resulting in cash outflows, the results from operations are precluded from being presented as discontinued operations.

PLC Development/TIE

At Dec. 31, 2002, TWG had a loan receivable of $137 million from PLC, a subsidiary of Panda Energy International. On Jan. 3, 2003, this loan was converted to a partnership interest in PLC. See Notes 1 and 17 for additional details regarding the conversion of this loan to an equity interest in PLC. Furthermore, in September 2003, the company consummated the foreclosure on Panda Energy's interest in PLC for a default under a $23 million note receivable leading to TWG's 100-percent ownership in PLC which owns 50 percent of TIE (see Notes 1, 12 and 17). As of Sep. 30, 2003, TWG consolidated PLC, resulting in a net increase in investment in unconsolidated affiliates of approximately $18 million. For additional details related to this transaction see Note 12.

Synthetic Fuel Facilities

Effective Apr. 1, 2003, TECO Coal sold a 49.5-percent interest in its synthetic fuel production facilities located at its operations in eastern Kentucky. No significant gain or loss was recognized at the time of the sale. The company, through its various affiliates, will provide feedstock supply, and operating, sales and management services to the buyer through 2007, the current expiry date for the related Section 29 credit for which the production qualifies. Because the transaction was structured on a "pay-as-you-go" basis typical of similar transactions in the industry, TECO Coal received no significant cash at the time of sale. The sale required receipt of a positive response to a Private Letter Ruling (PLR) request, and the proceeds from this transaction were held in escrow pending resolution of this contingency. On Oct. 31, 2003, TECO Coal received a PLR from the IRS that resolved any uncertainty related to the previous sale of the 49.5-percent interest in its synthetic fuel facilities; triggered the release of certain cash escrows related to this sale; and confirmed that synthetic fuel produced by TECO Coal is eligible for Section 29 credits and that its testing procedures are in compliance with the requirements of the IRS. On Nov. 5, 2003, $58.9 million of restricted cash that had been held in escrow was released following receipt of the PLR.

TECO Coalbed Methane

TECO Coalbed Methane, a subsidiary of TECO Energy, produced natural gas from coal seams in Alabama's Black Warrior Basin. In September 2002, the company announced its intent to sell the TECO Coalbed Methane gas assets. On Dec. 20, 2002, substantially all of TECO Coalbed Methane's assets in Alabama were sold to the Municipal Gas Authority of Georgia. Proceeds from the sale were $140 million, $42 million paid in cash at closing, and a $98 million note receivable which was paid in January 2003. Net income for the year ended Dec. 31, 2003 included a $23.5 million after-tax gain for the final cash installment from the sale of these assets. TECO Coalbed Methane's results are included in discontinued operations for all periods presented (see Note 14).

Commonwealth Chesapeake

In May 2002, TWG purchased Mosbacher Power Partners' interest in TM Power Ventures (TMPV) for $29.3 million. The majority of the purchase price was allocated to TMPV's investment in the 312-megawatt Commonwealth Chesapeake Power Station located on the Delmarva Peninsula in Virginia, and was initially recorded as an increase in goodwill. The acquisition increased the company's ownership interest in TMPV to 100 percent. In 2003, the goodwill initially recorded was written off. See Note 3 for additional details.

Prior Energy

In November 2001, TECO Solutions acquired Prior Energy Corporation, a natural gas management company serving customers in Alabama, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee and Texas. Prior Energy handles all facets of natural gas energy management services, including natural gas purchasing and marketing. The company has an established market base in the Southeast and one of the top customer service reputations in the region. The acquisition was accounted for by the purchase method of accounting with Nov. 1, 2001 as the acquisition date. The final working capital adjustment and purchase price allocation was completed in 2002. The total cost of the acquisition was $23.0 million plus a net working capital payment of $6.4 million. Goodwill of $9.6 million was initially recorded. Net intangible assets of $39.8 million were recorded, representing the value of customer backlog and supply agreements as well as the open cash flow hedges as of Nov. 1, 2001.

At Dec. 31, 2003, the assets and liabilities expected to be transferred in the disposition of Prior Energy have been presented as held for sale on the balance sheet. The results of operations have been included in discontinued operations for all periods presented (see **Note 14**). See **Note 23** for details regarding the recent sale of Prior Energy.

Frontera Power Station

In March 2001, TWG acquired the Frontera Power Station located near McAllen, Texas, accounting for the transaction using the purchase method of accounting. This 477-megawatt, natural gas-fired combined-cycle plant, originally developed by CSW Energy (CSW), began commercial operation in May 2000. As a condition of the merger of Central & South West Corporation, CSW's parent company, with American Electric Power Company, Inc., the FERC required CSW to divest its ownership in this facility. The total cost of the acquisition was $265.3 million. Goodwill of $70.4 million, representing the excess of purchase price over the fair market value of assets acquired, was recorded, and was amortized on a straight-line basis over 40 years until the requirements of FAS 142 became effective on Jan. 1, 2002 (see **Note 3**). The results of operations of Frontera Power Station are included as part of TWG's results beginning Mar. 16, 2001.

The following pro forma disclosure includes the Frontera Power Station as if it had been included in TECO Energy's financial statements for the year ended Dec. 31, 2001.

Pro Forma Disclosure

(millions, except per share data)	
Year ended Dec. 31,	*Pro Forma 2001*
Revenues	$2,506.5
Net income from continuing operations	262.2
Earnings per share from continuing operations – basic	$ 1.95

This pro forma information is not necessarily indicative of the operating results that would have occurred had the acquisitions been completed as of the dates indicated, nor are they indicative of future operating results.

22. New Accounting Pronouncements

Gains and Losses on Energy Trading Contracts

On Oct. 25, 2002, the Emerging Issues Task Force released EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, which 1) precludes mark-to-market accounting for energy trading contracts that are not derivatives pursuant to FAS 133, 2) requires that gains and losses on all derivative instruments within the scope of FAS 133 be presented on a net basis in the income statement if held for trading purposes, and 3) limits the circumstances in which a reporting entity may recognize a "day one" gain or loss on a derivative contract. The measurement provisions of the issue are effective for all fiscal periods beginning after Dec. 15, 2002. The net presentation provisions are effective for all financial statements issued after Dec. 15, 2002. The adoption of the measurement provisions on Jan. 1, 2003 did not have a material impact. See **Note 14** for additional details of amounts presented on a net basis.

Consolidation of Variable Interest Entities

The equity method of accounting is generally used to account for significant investments in partnership arrangements in which TECO Energy or its subsidiary companies do not have a majority ownership interest or exercise control. On Jan. 17, 2003, the FASB issued FIN 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*, which imposes a new approach in determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as variable interest entities or VIEs. On Dec. 24, 2003, the FASB published a revision to FIN 46 (FIN 46R), to clarify some of the provisions of FIN 46 and exempt certain entities from its requirements.

Under FIN 46R, a legal entity is considered a VIE, with some exemptions if specific criteria are met, if it does not have sufficient equity at risk to finance its own activities without relying on financial support from other parties. Additional criteria must be applied to determine if this condition is met or if the equity holders, as a group, lack any one of three stipulated characteristics of a controlling financial interest. If the legal entity is a VIE, then the reporting entity determined to be the primary beneficiary of the VIE must consolidate it. Even if a reporting entity is not obligated to consolidate a VIE, then certain disclosures must be made about the VIE if the reporting entity has a significant variable interest. Certain transition disclosures are required for all financial statements issued after Jan. 31, 2003. The effective date of the interpretation was modified under FIN 46R. A reporting entity is required to apply the provisions of FIN 46R to all VIEs that previously were subject to certain previously issued special purpose entity, or SPE, accounting pronouncements for all reporting periods ending after Dec. 15, 2003. For all other VIEs, a reporting entity is required to adopt the provisions of FIN 46R for all reporting periods after Mar. 15, 2004.

Based on its review under the existing approved guidance, TECO Energy believes that FIN 46R will impact the accounting for certain unconsolidated affiliates. Below is a discussion of the legal entities as of Dec. 31, 2003 that TECO Energy believes will be subject to either additional disclosure requirements or consolidation by the company, in accordance with FIN 46R.

In November 2000 and January 2002, respectively, TECO Energy established TECO Funding I, LLC and TECO Funding II, LLC. Each of these limited-liability companies are wholly-owned subsidiaries of TECO Energy. These companies sold preferred securities to Capital Trust I and Capital Trust II, respectively. The funding companies used the proceeds to purchase subordinated notes from TECO Energy. The subordinated notes are not secured by specific assets of the company. The terms of these notes are similar to the terms of the preferred securities (see **Note 7** for additional details, including the impact of FAS 150 on the preferred securities). The funding companies are expected to be considered VIEs in accordance with FIN 46R. As of Dec. 31, 2003, management expects the potential impact of the adoption of FIN 46R to not be material for the funding companies.

Pike Letcher Synfuel, LLC was established as part of the Apr. 1, 2003 sale of TECO Coal's synthetic fuel production facilities. See **Note 21** for additional details regarding the terms of the sale and purpose of the entity. TECO Energy's maximum loss exposure in this entity is its equity investment of approximately $10.9 million and potential losses related to the production costs for the future production of synthetic fuel, in the event that such production creates Section 29 non-conventional fuel tax credits in excess of TECO Energy's capacity to generate sufficient taxable income to use such credits.

TECO Transport entered into two separate sale-leaseback transactions for certain vessels which were recognized as sales in December 2001 and December 2002, and are currently recognized as operating leases for the assets. The sale-leaseback transactions were entered into with separate third parties that the company believes meet the definition of a VIE. TECO Transport currently leases two ocean-going tugboats, four ocean-going barges, five river towboats and 49 river barges through these two trusts. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable equipment to meet the company's contractual shipping obligations. The company does not expect to consolidate upon the effective date of FIN 46R.

TECO Properties formed a limited liability company with a project developer which meets the definition of a VIE. Hernando Oaks, LLC was formed by TECO Properties with the Pensacola Group to buy and develop 627 acres of land in Hernando County, Florida into a residential golf community comprised of an 18-hole golf course and 975 single-family lots for sale to homebuilders. The company has provided subordinated financial support in the form of a guarantee on behalf of the limited liability company. Hernando Oaks, LLC had total assets at Dec. 31, 2003 of $21.6 million. TECO Properties' estimated maximum loss exposure in this project is approximately $10.6 million, representing the sum of its guarantee and equity investment. The company expects to consolidate Hernando Oaks, LLC for all financial reporting periods ending after Mar. 15, 2004.

TECO Energy Services (formerly TECO BGA) formed a partnership to construct, own and operate a water cooling plant to produce and distribute chilled water to customers via a local distribution loop primarily for use in air conditioning systems. The partnership, TECO AGC, Ltd., meets the definition of a VIE. The company is the primary beneficiary, in accordance with FIN 46R, due to subordinated financing and other funding of $3.3 million provided to the partnership as of Dec. 31, 2003, in addition to the company's equity investment. This note receivable from the partnership is collateralized by the assets in the partnership. The estimated maximum loss exposure associated with this partnership is approximately $3.8 million as of Dec. 31, 2003, representing substantially all of the assets of the partnership. The company expects to consolidate TECO AGC, Ltd. for all financial reporting periods ending after Mar. 15, 2004.

Amendment to Derivatives Accounting

In April 2003, the FASB issued FAS 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, which clarifies the definition of a derivative and modifies, as necessary, FAS 133 to reflect certain decisions made by the FASB as part of the Derivatives Implementation Group (DIG) process. The majority of the guidance was already effective and previously applied by the company in the course of the adoption of FAS 133.

In particular, FAS 149 incorporates the conclusions previously reached in 2001 under DIG Issue C10, *"Can Option Contracts and Forward Contracts with Optionality Features Qualify for the Normal Purchases and Normal Sales Exception"*, and DIG Issue C15, *"Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity"*. In limited circumstances when the criteria are met and documented, TECO Energy designates option-type and forward contracts in electricity as a normal purchase or normal sale (NPNS) exception to FAS 133. A contract designated and documented as qualifying for the NPNS exception is not subject to the measurement and recognition requirements of FAS 133. The incorporation of the conclusions reached under DIG Issues C10 and C15 into the standard will not have a material impact on the consolidated financial statements of TECO Energy.

FAS 149 establishes multiple effective dates based on the source of the guidance. For all DIG Issues previously cleared by the FASB and not modified under FAS 149, the effective date of the issue remains the same. For all other aspects of the standard, the guidance is effective for all contracts entered into or modified after June 30, 2003. The company does not anticipate that the adoption of the additional guidance in FAS 149 will have a material impact on the consolidated financial statements.

Financial Instruments with Characteristics of both Liabilities and Equity

In May 2003, the FASB issued FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*, which requires that an issuer classify certain financial instruments as a liability or an asset. Previously, many financial instruments with characteristics of both liabilities and equity were classified as equity. Financial instruments subject to FAS 150 include financial instruments with any of the following features:

- An unconditional redemption obligation at a specified or determinable date, or upon an event that is certain to occur;
- An obligation to repurchase shares, or indexed to such an obligation, and may require physical share or net cash settlement;
- An unconditional, or for new issuances conditional, obligation that may be settled by issuing a variable number of equity shares if either (a) a fixed monetary amount is known at inception, (b) the variability is indexed to something other than the fair value of the issuer's equity shares, or (c) the variability moves inversely to changes in the fair value of the issuer's shares.

The standard requires that all such instruments be classified as a liability, or an asset in certain circumstances, and initially measured at fair value. Forward contracts that require a fixed physical share settlement and mandatorily redeemable financial instruments must be subsequently re-measured at fair value on each reporting date.

This standard is effective for all financial instruments entered into or modified after May 31, 2003, and for all other financial instruments, at the beginning of the first interim period beginning after June 15, 2003. See **Note 7** for a discussion of the impact of the adoption of this standard on July 1, 2003.

23. Subsequent Events

Sale of TECO BGA, Inc. (formerly a component of TECO Energy Services)

Effective Jan. 1, 2004, the company completed the sale of TECO BGA, Inc. (formerly a component of TECO Energy Services) to an entity owned by an employee group for a pre-tax loss on disposal of $12.2 million ($7.5 million after tax). This loss was recorded as part of the asset impairment charge reported in the income statement for the year ended Dec. 31, 2003, in accordance with FAS 144 (see **Note 10** and the **Other transactions** section of **Note 14** for additional details relating to this disposition).

Repayment of $37.5 million one-year TECO Energy credit facility

On Jan. 5, 2004, TECO Energy repaid $20 million of the $37.5 million one-year credit facility collateralized by the Union and Gila River assets. On Feb. 4, 2004, TECO Energy repaid the remaining $17.5 million of the one-year credit facility.

Sale of TECO Propane Ventures' Indirect Interest in Heritage Propane Partners, L.P.

On Jan. 20, 2004, US Propane LP, in which TECO Propane Ventures holds a 38% equity interest, completed the sale of its direct and indirect equity investments in Heritage Propane Partners, L.P. (Heritage). The sale, part of a larger transaction that involved the merging of privately held Energy Transfer Company with Heritage, was announced Nov. 7, 2003. TECO Propane Ventures received $49.4 million in cash on Jan. 20, 2004 related to the sale and will record a $17.2 million pre-tax gain.

Recent Agreements Related to the Union and Gila River Project Exit Activities

Letter of Intent

On Feb. 5, 2004, the bank group for the Union and Gila River projects approved a non-binding letter of intent containing a binding Settlement Agreement. Under the agreement, TECO Energy and the project companies will work toward a definitive agreement with the lending banks for a purchase and sale or other agreement to transfer the ownership of the projects to the lending banks in exchange for a release of all obligations under the project loan agreements. The letter of intent specifies target dates for a definitive agreement by Jun. 30, 2004 and for closing by Sep. 30, 2004. The Settlement Agreement provides for the treatment of the $66 million of letters of credit posted by TECO Energy under the Construction Undertaking, with $35 million for the benefit of the project companies (drawn in February 2004) and the remaining $31 million of letters of credit to be cancelled and returned to TECO Energy. Under the letter of intent, all parties have specified a target completion of due diligence for final acceptance under the construction and undertaking contracts for both projects within 45 days; however, TECO Energy and the project companies will remain responsible to address certain permit issues at the Gila River project. No new investment in the projects will be made by TECO Energy. Since the projects have achieved commercial operation on all facilities at Union and Gila River, TECO Energy believes that it has met all but limited warranty and final acceptance responsibilities to the project companies. TECO Energy and various of its subsidiaries plan to continue to provide services and continue to provide expertise and operating support to help the project companies operate the facilities consistent with past practices at least through the completion of the transfer of ownership. The lending banks and TECO Energy and its affiliates have reserved their rights to assert certain claims they may have against one another until a definitive agreement is reached.

Expiration of Suspension / Standstill Agreement

The letter of intent permits the parties to reserve their rights against each other, including with respect to TECO Energy's failure to comply with the 3.0 times EBITDA-to-interest ratio coverage requirement in its Construction Undertakings for the quarters ending Sep. 30 and Dec. 31, 2003 (a cross default to the non-recourse credit agreements) that were covered by the Suspension Agreement, which has expired, and the failure of the project companies to make interest payments on the non-recourse project debt and payments under interest rate swap agreements due Dec. 31, 2003 when the project lenders declined to fund the debt service reserve.

The Construction Undertakings permit TECO Energy to terminate its obligations thereunder, including the requirement to comply with the covenants, by providing a Substitute Guarantor reasonably satisfactory to the lending group. On Sept. 22, 2003, TECO Energy tendered a Substitute Guarantor, which it believes satisfied the requirements of the Construction Undertakings. The lending group declined to accept this tender as being satisfactory. Under the letter of intent, TECO Energy has retained its right to assert that the Construction Undertakings were terminated in the event that the lending group seeks to exercise its rights thereunder based on a violation of the EBITDA-to-interest coverage ratio covenant.

As a result, the lending bank group could seek to exercise remedies against the project companies as a result of defaults in connection with the non-recourse project debt, including accelerating the non-recourse debt, foreclosing on the project collateral and suspending further funding; subject to the defenses that TECO Energy and its affiliates may have.

Under the Suspension Agreement between TECO Energy, the project companies and the lending bank group, TECO Energy was not required to calculate the EBITDA to interest coverage ratio required in the undertaking for the quarters ended Sep. 30, 2003 and Dec. 31, 2003 until Feb. 1, 2004 (orally extended until Feb. 5, 2004). On that date, the calculations were made resulting in a 2.7 and 2.4 times interest coverage ratio for the two quarters, respectively. Due to non-compliance with this covenant, the lenders could accelerate the $1.395 billion of non-recourse construction debt, absent the sale of the projects to the bank group.

Sale of Prior Energy

Effective Feb. 1, 2004, a subsidiary of TECO Energy completed the sale of Prior Energy for net proceeds of approximately $30 million. This sale did not result in a material gain or loss to the company. Outstanding guarantees related to the operations of Prior Energy are expected to be eliminated as a result of this transaction (see **Note 20**). See the **Other transactions** section of **Note 14** for additional details relating to this disposition.

TECO Energy 18-Month Credit Facility

As a result of receipt of cash proceeds from certain asset sales in early 2004, the existing $100 million unsecured credit facility with Merrill Lynch has been reduced to $20.6 million per the terms of the amended facility. The $200 million contingent credit facility with Merrill Lynch and JP Morgan, if activated would replace the existing Merrill Lynch facility. See Note 6.

24. Quarterly Data (unaudited)

The results for the three months ended Sep. 30, 2003 have been restated from amounts previously reported in the Form 10-Q for the quarter then ended due to a re-evaluation of the accounting for the HPP sale transaction subsequent to the filing date. The "Restated" column for Sep. 30, 2003 below:

(1) Reflects the results of operations for HPP as a component of continuing operations, rather than discontinued operations, due to a pre-existing long-term power purchase agreement from HPP to Tampa Electric, in accordance with FAS 144 (see the Purchased Power section of Note 1); and

(2) Reflects in the fourth quarter, rather than the third quarter, the gain on the sale of HPP to a third party, in accordance with SAB 104 (see Note 21).

The reclassification of HPP's operating results for the three months ended Sep. 30, 2003, after intercompany eliminations, increased a) revenues by $7.3 million, b) income from operations by $7.1 million and c) net income from continuing operations by $2.8 million. The recognition of the gain on the sale of HPP in the fourth quarter, rather than the third quarter, reduced net income in the third quarter by $34.6 million ($0.19 per share). The $34.6 million after-tax ($56.3 million pre-tax) gain on the sale of HPP was recognized in the fourth quarter. These revisions had no impact on TECO Energy's net loss for the year ended Dec. 31, 2003.

(millions, except per share amounts)		*Restated*			
Quarter ended	*Dec. 31*	*Sep. 30*	*Sep. 30*[1]	*June 30*[2]	*Mar. 31*[2]
2003					
Revenues	$ 633.8	$759.1	$751.8	$ 695.3	$651.8
Income from operations	$ (63.8)	$ 92.2	$ 85.1	$ 0.5	$ (8.8)
Net income					
Net income from continuing operations	$ (4.0)	$ 4.6	$ 1.8	$ 5.0	$ (20.3)
Net income	$(790.7)	$ (19.5)	$ 15.0	$(101.9)	$ 2.7
Earnings per share (EPS) - basic					
EPS from continuing operations	$ (0.02)	$ 0.03	$ 0.01	$ 0.03	$ (0.12)
EPS	$ (4.21)	$ (0.11)	$ 0.08	$ (0.58)	$ 0.02
Earnings per share (EPS) - diluted					
EPS from continuing operations	$ (0.02)	$ 0.03	$ 0.01	$ 0.03	$ (0.12)
EPS	$ (4.21)	$ (0.11)	$ 0.08	$ (0.58)	$ 0.01
Dividends paid per common share[3]	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.355
Stock price per common share[4]					
High	$ 14.85	$ 14.20	$ 14.20	$ 13.69	$ 17.00
Low	$ 11.80	$ 11.50	$ 11.50	$ 10.05	$ 9.47
Close	$ 14.41	$ 13.82	$ 13.82	$ 11.99	$ 10.63

Quarter ended	*Dec. 31*	*Sep. 30*	*June 30*	*Mar. 31*
2002[5]				
Revenues	$ 665.2	$727.2	$ 672.7	$599.8
Income from operations	$ 58.0	$141.5	$ 95.7	$ 86.6
Net income				
Net income from continuing operations	$ 28.5	$106.6	$ 76.0	$ 66.1
Net income	$ 50.1	$118.9	$ 85.7	$ 75.4
Earnings per share (EPS) - basic				
EPS from continuing operations	$ 0.17	$ 0.68	$ 0.53	$ 0.47
EPS	$ 0.29	$ 0.76	$ 0.59	$ 0.54
Earnings per share (EPS) - diluted				
EPS from continuing operations	$ 0.17	$ 0.68	$ 0.53	$ 0.47
EPS	$ 0.29	$ 0.76	$ 0.59	$ 0.54
Dividends paid per common share[3]	$ 0.355	$ 0.355	$ 0.355	$ 0.345
Stock price per common share[4]				
High	$ 16.48	$ 24.71	$ 29.05	$ 28.94
Low	$ 10.02	$ 14.20	$ 22.70	$ 23.40
Close	$ 15.47	$ 15.88	$ 24.75	$ 28.63

(1) The amounts which were reported in the Form 10-Q for the quarter ended Sep. 30, 2003 (which amounts were subsequently changed to reflect both the revisions for the HPP sale and the reclassifications for the discontinued operations occurring in the fourth quarter as further discussed in Note 14) were as follows: revenues of $940.7 million; income from operations of $74.4 million; net income (loss) from continuing operations of $(19.2) million; net income of $15.0 million; EPS from continuing operations – basic and diluted of $(0.11); and EPS – basic and diluted of $0.08.

(2) Amounts shown reflect reclassifications to reflect discontinued operations as discussed in Note 14.

(3) Dividend paid on TECO Energy common stock.

(4) Trading prices for common shares.

(5) Amounts shown for 2002 reflect reclassifications to conform with the current year presentation. In particular, reclassifications have been made from continuing operations to discontinued operations as discussed in Note 14.

REPORT *of Independent Certified Public Accountants*

To Board of Directors and Shareholders of TECO Energy, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common equity and cash flows present fairly, in all material respects, the financial position of TECO Energy, Inc. and its subsidiaries at Dec. 31, 2003 and Dec. 31, 2002, and the results of their operations and their cash flows for each of the three years in the period ended Dec. 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 7 to the consolidated financial statements, the Company changed the manner in which it accounts for mandatorily redeemable securities as of July 1, 2003. As discussed in Note 5 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement costs as of Jan. 1, 2003. As discussed in Note 3 to the consolidated financial statements, the Company changed the manner in which it accounts for goodwill and other intangible assets as of Jan. 1, 2002. As discussed in Note 2 to the consolidated financial statements, the Company changed the manner in which it accounts for derivative instruments as of Jan. 1, 2001.

PricewaterhouseCoopers LLP

Tampa, Florida
March 2, 2004

Selected Financial Data

(millions, except per share amounts) *Year ended Dec. 31,*	*2003*	*2002*	*2001*	*2000*	*1999*
Revenues	$ 2,740.0	$ 2,664.9	$ 2,483.3	$ 2,223.2	$ 1,932.6
Net (loss) income from continuing operations	$ (14.7)	$ 277.2	$ 265.5	$ 225.6	$ 179.2
Net (loss) income from discontinued operations	(890.4)	52.9	38.2	25.3	6.9
Cumulative effect of change in accounting principle, net	(4.3)	–	–	–	–
Net (loss) income	$ (909.4)	$ 330.1	$ 303.7	$ 250.9	$ 186.1
Total assets	$ 10,462.3	$ 9,078.4	$ 7,176.2	$ 6,167.8	$ 5,103.2
Long-term debt	$ 4,392.6	$ 3,324.3	$ 1,842.5	$ 1,374.6	$ 1,207.8
Earnings per share (EPS) – basic					
From continuing operations	$ (0.08)	$ 1.81	$ 1.98	$ 1.79	$ 1.37
From discontinued operations	(4.95)	0.34	0.28	0.20	0.05
From cumulative effect of change in accounting principle	(0.02)	–	–	–	–
EPS basic	$ (5.05)	$ 2.15	$ 2.26	$ 1.99	$ 1.42
Dividends paid per common share	$ 0.925	$ 1.41	$ 1.37	$ 1.33	$ 1.285

INFORMATION *for Investors*

Internet
Current information about TECO Energy is on the Internet at **www.tecoenergy.com**

TECO Energy is listed on the New York Stock Exchange symbol: TE

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702 N. Franklin Street
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813-228-1111
Fax 813-228-1670

Auditors
PricewaterhouseCoopers LLP
Tampa, FL

Annual Meeting
The Annual Meeting of Shareholders will be held on April 28, 2004, 11:30 a.m. at:
Hilton Tampa Airport Westshore
2225 N. Lois Avenue
Tampa, FL 33607

Shareholder Inquiries
Communication concerning transfer requirements, lost certificates, dividends and change of address should be directed to the Transfer Agent.

Transfer Agent & Registrar
The Bank of New York
Receive and Deliver Department
P.O. Box 11002
Church Street Station
New York, NY 10286
www.stockbny.com

Dividend Reinvestment
The company offers a Dividend Reinvestment and Common Stock Purchase Plan which allows common shareholders of record to purchase additional shares of common stock at the current market price. All correspondence concerning this Plan should be directed to the Plan Agent:
The Bank of New York
Investment Services Department
P.O. Box 1958
Newark, NJ 07101-9774

Form 10-K Available
TECO Energy's Annual Report on Form 10-K, which is filed with the Securities and Exchange Commission, is available to shareholders at no charge on the Internet at **www.sec.gov** or through the Investor Relations page at **www.tecoenergy.com**. Requests should be addressed to:
TECO Energy, Inc.
Investor Relations
P.O. Box 111
Tampa, FL 33601
813-228-1326
800-810-2032

Analyst Contacts
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

X Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2003

OR

___ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from _____ to _____

Commission File No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-8180	**TECO ENERGY, INC.** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-4111	**59-2052286**
1-5007	**TAMPA ELECTRIC COMPANY** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-4111	**59-0475140**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
TECO Energy, Inc.	
Common Stock, $1.00 par value	New York Stock Exchange
Common Stock Purchase Rights	New York Stock Exchange
Equity Security Units	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

YES [X] NO [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K. [ ]

Indicate by check mark whether TECO Energy, Inc. is an accelerated filer (as defined in Exchange Act Rule 12b-2).

YES [X] NO [ ]

Indicate by check mark whether Tampa Electric Company is an accelerated filer (as defined in Exchange Act Rule 12b-2). YES [ ] NO [X]

The aggregate market value of TECO Energy, Inc.'s common stock held by nonaffiliates of the registrant as of June 30, 2003 was $2,117,879,345.

(continued)

The aggregate market value of Tampa Electric Company's common stock held by nonaffiliates of the registrant as of June 30, 2003 was zero.

The number of shares of TECO Energy, Inc.'s common stock outstanding as of February 29, 2004 was 188,175,926. As of February 29, 2004, there were 10 shares of Tampa Electric Company's common stock issued and outstanding, all of which were held, beneficially and of record, by TECO Energy, Inc.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of TECO Energy, Inc.'s 2003 Annual Report are incorporated by reference into Parts II and IV.

Portions of the Definitive Proxy Statement relating to the 2004 Annual Meeting of Shareholders of TECO Energy, Inc. are incorporated by reference into Part III.

Tampa Electric Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format.

This combined Form 10-K represents separate filings by TECO Energy, Inc. and Tampa Electric Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Tampa Electric Company makes no representations as to the information relating to TECO Energy, Inc.'s other operations.

PART I

Item 1. BUSINESS.

TECO ENERGY

TECO Energy, Inc. (TECO Energy) was incorporated in Florida in 1981 as part of a restructuring in which it became the parent corporation of Tampa Electric Company. TECO Energy and its subsidiaries had 5,753 employees as of Dec. 31, 2003.

TECO Energy's Corporate Governance Guidelines, the charter of each committee of the Board of Directors, and the code of ethics applicable to all directors, officers and employees, *the Standards of Integrity*, are available on the Investor Relations page of TECO Energy's website, www.tecoenergy.com, or in print free of charge to any shareholder who requests the information. TECO Energy also makes its Securities and Exchange Commission (SEC) (www.sec.gov) filings available free of charge on the Investor Relations page of TECO Energy's web site.

TECO Energy currently owns no operating assets but holds all of the common stock of Tampa Electric Company and directly, or through its subsidiary TECO Diversified, Inc., the other subsidiaries listed below. Unless otherwise indicated by the context, "TECO Energy" means the holding company, TECO Energy, Inc., and its subsidiaries, and references to individual subsidiaries of TECO Energy, Inc. refer to that company and its respective subsidiaries. TECO Energy is a public utility holding company exempt from registration under the Public Utility Holding Company Act of 1935.

TECO Energy is a holding company for regulated utilities and other unregulated businesses. TECO Energy's significant business segments are identified below.

Tampa Electric Company, a Florida corporation and TECO Energy's largest subsidiary, through its Tampa Electric division (Tampa Electric) provides retail electric service to more than 612,000 customers in West Central Florida with a net system generating capability of 3,256 megawatts (MW). On Jan. 15, 2004, Tampa Electric commissioned Bayside 2 (rated at 1,022 MW) for a combined capacity of 4,278 MW. Peoples Gas System (PGS), a division of Tampa Electric Company, is engaged in the purchase, distribution and marketing of natural gas for residential, commercial, industrial and electric power generation customers in Florida. With more than 299,000 customers, PGS has operations in Florida's major metropolitan areas. Annual natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) in 2003 was 1.2 billion therms.

TECO Transport Corporation, a Florida corporation, owns no operating assets but owns all of the common stock of four subsidiaries which provide waterborne transportation, storage and transfer services of coal and other dry-bulk commodities.

TECO Coal Corporation, a Kentucky corporation, owns no operating assets but owns all of the common stock of nine subsidiaries which own mineral rights, and own or operate surface and underground mines, synthetic fuel production facilities, and coal processing and loading facilities in eastern Kentucky, Tennessee and southwestern Virginia.

TECO Wholesale Generation, Inc. (TWG) (formerly TECO Power Services Corporation), a Florida corporation, has subsidiaries that have interests in independent power projects in Florida, Virginia, Hawaii, Arkansas, Mississippi, Texas, Arizona and Guatemala, and has investments in unconsolidated affiliates that participate in independent power projects and electric distribution in other parts of the United States (U.S.) and Guatemala. As part of its renewed focus on core utility operations, TECO Energy revised its internal reporting information used for evaluating, measuring and making decisions with respect to the components which previously comprised the TECO Power Services (TPS) operating segment. The revised operating segment, TWG Merchant, is comprised of all merchant operations which include the results of operations for the Frontera, Commonwealth Chesapeake, Dell and McAdams power plants, as well as the equity investment in other U.S. plants, and TECO EnergySource, Inc. (TES), the energy marketing operation for the merchant plants. The non-merchant assets that were formerly reported with TPS include the company's interests in Florida, Hawaii and Guatemala and are now reported with Other Unregulated Companies.

TECO Energy's other unregulated companies with continuing operations include the non-merchant operations of TECO Wholesale Generation as described above, TECO Solutions, Inc. (TECO Solutions), TECO Properties, Inc. (TECO Properties), and TECO Investments, Inc. The TECO Solutions' subsidiaries provide mechanical contracting, air conditioning, electrical and plumbing systems and repair and maintenance services in Florida.

Revenues for TECO Energy's significant business segments for the years indicated follow. For additional financial information regarding TECO Energy's significant business segments, see **Note 19** to the TECO Energy **Consolidated Financial Statements**.

Revenues from Continuing Operations

(millions)	*2003*	*2002*	*2001*
Tampa Electric	$ 1,586.1	$ 1,583.2	$ 1,412.7
Peoples Gas System	408.4	318.1	352.9
Total regulated businesses	1,994.5	1,901.3	1,765.6
TECO Wholesale Generation	95.9	111.1	81.8
TECO Transport	260.6	254.6	274.9
TECO Coal	296.3	317.1	303.5
Other unregulated businesses	263.5	297.7	298.8
	2,910.8	2,881.8	2,724.6
Other and eliminations	(170.8)	(216.9)	(241.3)
	$ 2,740.0	$ 2,664.9	$ 2,483.3

TWG's interest in the Union and Gila River Project Companies, which own merchant generation plants in Arkansas and Arizona, respectively, is held by an indirect wholly owned subsidiary of TWG, TECO-Panda Generating Company, L.P. (TPGC). TPGC was part of the TWG Merchant operating segment until designated as assets held for sale in December 2003. As of Dec. 31, 2003, TECO Energy management was committed to a plan to sell TECO Energy's indirect ownership of the equity or net assets of TPGC through a purchase and sale or other agreement, and expects to complete the transaction in 2004. TPGC's results are accounted for as discontinued operations for all periods reported. Revenues from the discontinued operations of TPGC in 2003 were $319.4 million.

TECO Energy's other unregulated companies completed several dispositions in 2003 and 2002, including the sale of Hardee Power Partners, Ltd. (HPP) in 2003 (part of the non-merchant operations of TWG) and the sale of TECO Coalbed Methane in 2002. Additionally in 2003, TECO Energy was committed to a plan to sell Prior Energy and TECO BGA (formerly a component of TECO Energy Services) as of Dec. 31, 2003. These sales were completed in early 2004. (See **Note 23** to the TECO Energy **Consolidated Financial Statements.**) The company also completed the sale of substantially all of the net assets of TECO Gas Services in 2003. Results for TECO Coalbed Methane, Prior Energy and TECO Gas Services have been accounted for as discontinued operations for all periods reported. HPP is accounted for in continuing operations because of the continuing involvement of Tampa Electric through a pre-existing agreement to purchase power from HPP. In January 2004, TECO Energy completed the sale of its general and limited partnership interests in Heritage Propane Partners, L.P. as a part of a larger transaction that involved the merging of privately held Energy Transfer Company with Heritage Propane Partners. Revenues from the discontinued operations of other unregulated companies were $21.6 million, $51.5 million and $60.1 million for the years ended Dec. 31, 2003, 2002 and 2001, respectively.

TAMPA ELECTRIC--Electric Operations

Tampa Electric Company was incorporated in Florida in 1899 and was reincorporated in 1949. Tampa Electric Company is a public utility operating within the state of Florida. Through its Tampa Electric division, it is engaged in the generation, purchase, transmission, distribution and sale of electric energy. The retail territory served comprises an area of about 2,000 square miles in West Central Florida, including Hillsborough County and parts of Polk, Pasco and Pinellas Counties, and has an estimated population of over one million. The principal communities served are Tampa, Winter Haven, Plant City and Dade City. In addition, Tampa Electric engages in wholesale sales to utilities and other resellers of electricity. It has two electric generating stations in or near Tampa, one electric generating station in southwestern Polk County, Florida and two electric generating stations (one of which is on long-term standby) located near Sebring, a city located in Highlands County in South Central Florida.

Tampa Electric had 2,434 employees as of Dec. 31, 2003, of which 905 were represented by the International Brotherhood of Electrical Workers and 250 were represented by the Office and Professional Employees International Union.

In 2003, approximately 48 percent of Tampa Electric's total operating revenue was derived from residential sales, 29 percent from commercial sales, 10 percent from industrial sales and 13 percent from other sales, including bulk power sales for resale. The sources of operating revenue and megawatt-hour sales for the years indicated were as follows:

Operating Revenue

(millions)	*2003*	*2002*	*2001*
Residential	$ 767.4	$ 753.9	$ 659.8
Commercial	460.1	459.6	409.7
Industrial – Phosphate	65.3	74.3	57.0
Industrial – Other	88.5	83.8	71.8
Other retail sales of electricity	124.9	117.4	103.0
Total retail	1,506.2	1,489.0	1,301.3
Sales for resale	41.6	67.7	82.4
Other	38.3	26.5	29.0
	$ 1,586.1	$ 1,583.2	$ 1,412.7

Megawatt-hour Sales

(millions)	*2003*	*2002*	*2001*
Residential	8,265	8,046	7,594
Commercial	5,860	5,832	5,685
Industrial	2,579	2,612	2,329
Other retail sales of electricity	1,538	1,435	1,368
Total retail	18,242	17,925	16,976
Sales for resale	691	1,084	1,499
Total energy sold	18,933	19,009	18,475

No significant part of Tampa Electric's business is dependent upon a single customer or a few customers, the loss of any one or more of whom would have a significant adverse effect on Tampa Electric. IMC-Agrico, a large phosphate producer, is Tampa Electric's largest customer and represents less than 3 percent of Tampa Electric's 2003 base revenues.

Tampa Electric's business is not highly seasonal, but winter peak loads are experienced due to electric heating, fewer daylight hours and colder temperatures, and summer peak loads are experienced due to the use of air conditioning and other cooling equipment.

Regulation

The retail operations of Tampa Electric are regulated by the Florida Public Service Commission (FPSC), which has jurisdiction over retail rates, quality of service and reliability, issuances of securities, planning, siting and construction of facilities, accounting and depreciation practices, and other matters.

In general, the FPSC's pricing objective is to set rates at a level that allows the utility to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The costs of owning, operating and maintaining the utility system, other than fuel, purchased power, conservation and certain environmental costs, are recovered through base rates. These costs include operation and maintenance expenses, depreciation and taxes, as well as a return on Tampa Electric's investment in assets used and useful in providing electric service (rate base). The rate of return on rate base, which is intended to approximate Tampa Electric's weighted cost of capital, primarily includes its costs for debt, deferred income taxes at a zero cost rate and an allowed return on common equity. Base rates are determined in FPSC rate setting hearings which occur at irregular intervals at the initiative of Tampa Electric, the FPSC or other parties. See the discussion of the FPSC-approved agreements covering 1995 through 1999 in the **Regulation – Tampa Electric Rate Strategy** section of **Management's Discussion & Analysis of Financial Condition & Results of Operations (MD&A)**.

Tampa Electric's rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue earning within its allowed ROE range without a base rate increase, even with the rate base additions associated with the repowering of the Bayside Power Station.

Fuel, purchased power, conservation and certain environmental costs are recovered through levelized monthly charges established pursuant to the FPSC's cost recovery clauses. These charges, which are reset annually in an FPSC proceeding, are based on estimated costs of fuel, environmental compliance, conservation programs and purchased power and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs from the projected charges. The FPSC may disallow recovery of any costs that it considers imprudently incurred.

In September 2003, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery rates for the period January through December 2004. In November, the FPSC approved Tampa Electric's requested changes except for the lower coal transportation rate driven by a new contract with TECO Transport described below. The resulting rates include the impacts of the increased use of natural gas at the Bayside Power Station and the collection of $91 million for under-recovery of fuel expense for 2002 and 2003. The filing also included estimated waterborne transportation rates for coal transportation services. The FPSC did not allow the recovery of $8.4 million it characterized as savings from shutting down the Gannon Station earlier than originally planned which the FPSC deemed generated operations and maintenance savings. Tampa Electric filed its objection to the disallowance of the recovery of the $8.4 million and a motion asking FPSC to reconsider its decision because all facts and law were not taken into account. The motion was filed on Jan. 6, 2004, and a decision on this matter is expected in the first quarter of 2004. See **Regulation – Cost Recovery Clauses** section of **MD&A**.

Tampa Electric is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in various respects, including wholesale power sales, certain wholesale power purchases, transmission services, and accounting and depreciation practices. See the **Regulation – Transmission Rates** and **Regional Transmission Organization (RTO)** sections of **MD&A**.

Federal, state and local environmental laws and regulations cover air quality, water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters. See **Environmental Matters** on pages 7 and 8.

The transactions between Tampa Electric and its affiliates and the prices paid by Tampa Electric are subject to regulation by the FPSC and FERC, and any charges deemed to be imprudently incurred may be disallowed for recovery from Tampa Electric's customers. TECO Transport sells transportation services to Tampa Electric and other third parties. Tampa Electric's contract for coal transportation and storage services with TECO Transport expired on Dec. 31, 2003. In June 2003, Tampa Electric issued a Request For Proposal (RFP) to potential providers requesting services for the next five years. The results of the RFP process was the execution of a new contract between Tampa Electric and TECO Transport, effective Jan. 1, 2004, with market rates supported by the results of the RFP and an independent expert in maritime transportation matters. The prudence of the RFP process and final contract scheduled to be reviewed by the FPSC in the course of the normal fuel cost recovery hearings in November was deferred due to protests from other parties seeking more time to evaluate the contract information. The matter is scheduled to be heard by the FPSC in May with a decision expected in July. In the meantime, Tampa Electric is recovering fuel transportation costs at the rates from the

now expired contract, which are slightly higher than those in the contract effective Jan. 1, 2004. See the **Regulation – Coal Transportation Contract** section of **MD&A**. Except for transportation services performed by TECO Transport under the U.S. bulk cargo preference program, the prices charged by TECO Transport to third-party customers are not subject to regulatory oversight.

Competition

Tampa Electric's retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of self-generation available to larger users of electric energy. Such users may seek to expand their alternatives through various initiatives, including legislative and/or regulatory changes that would permit competition at the retail level. Tampa Electric intends to retain and expand its retail business by managing costs and providing high-quality service to retail customers.

In 1999, the FERC approved a market-based sales tariff for Tampa Electric, which allows Tampa Electric to sell excess power at market prices within Florida. The FERC had already approved market-based prices for interstate sales for Tampa Electric and the other investor-owned utilities (IOUs) operating in the state; however, Tampa Electric is the only IOU in the state with intrastate market-based sales authority.

There is presently competition in Florida's wholesale power markets, increasing largely as a result of the Energy Policy Act of 1992 and related federal initiatives. However, the state's Power Plant Siting Act, which sets the state's electric energy and environmental policy and governs the building of new generation involving steam capacity of 75 megawatts or more, requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits. In 2003, the FPSC implemented rules that modified rules from 1994 that required investor-owned electric utilities (IOUs) to issue RFP's prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle greater than 75 megawatts. The new rules became effective for requests for proposal for applicable capacity additions, prospectively. See **Regulation – Utility Competition-Electric** section of **MD&A**.

FERC requires transmission system owners to operate an Open Access Non-discriminatory Transmission, Standard Costs, Same-time Information System (OASIS) providing, via the Internet, access to transmission service information (including price and availability) and to rely exclusively on their own OASIS system for such information for purposes of their own wholesale power transactions. This rule works to open access for wholesale power flows on transmission systems and requires utilities such as Tampa Electric, which own transmission facilities, to provide services to wholesale transmission customers comparable to those they provide to themselves on comparable terms and conditions, including price. Among other things, the rules require transmission services to be unbundled from power sales and owners of transmission systems to take transmission service under their own transmission tariffs. To facilitate compliance, owners must maintain Standards of Conduct to ensure that personnel involved in marketing wholesale power are functionally separated from personnel involved in transmission services and reliability functions. Tampa Electric, together with other utilities, has an OASIS system and believes it is in compliance with the Standards of Conduct. See **Regulation – Transmission Rates** section of **MD&A**.

In December 1999, the FERC issued Order No. 2000, dealing with FERC's continuing effort to affect open access to transmission facilities in large regional markets. In response, the peninsular Florida IOUs agreed to form an RTO to be known as GridFlorida LLC which would independently control the transmission assets of the filing utilities, as well as other utilities in the region that chose to join. In March 2001, the FERC conditionally approved GridFlorida. In May 2001, the FPSC questioned the prudence of the three filing utilities joining GridFlorida. After an October 2001 hearing, the FPSC found that the companies were prudent in forming GridFlorida, but ordered the companies to modify their proposal to develop a non-transmission owning RTO model. In August 2002, the FPSC voted to approve many of the compliance changes submitted, but set an October 2002 hearing on the market design changes proposed in the updated filing.

In October 2002, the process was delayed when the OPC filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the IOUs and, by approving GridFlorida, they were doing just that. Oral arguments occurred in May 2003, and the Florida Supreme Court dismissed the OPC appeal citing that it was premature because certain portions of the FPSC GridFlorida order are not final. In September 2003, a joint meeting of the FERC and FPSC took place to discuss wholesale market and RTO issues related to GridFlorida and in particular, federal/state interactions. The FPSC has scheduled a series of collaborative meetings with all interested parties and, upon their conclusion, will set items for hearing and a hearing schedule. This is expected to occur throughout 2004.

Fuel

Approximately 78 percent of Tampa Electric's generation of electricity for 2003 was coal-fired, with natural gas representing approximately 21 percent and oil representing approximately 1 percent. Tampa Electric used its generating units to meet approximately 81 percent of the system load requirements, with the remaining 19 percent coming from purchased power. A lower level of coal generation as a percentage of total generation is anticipated for 2004 as a result of Gannon's repowering to the natural gas fueled Bayside Power Station.

Tampa Electric's average delivered fuel cost per million Btu and average delivered cost per ton of coal burned have been as follows:

Average cost per million Btu:	*2003*	*2002*	*2001*	*2000*	*1999*
Coal	$ 2.02	$ 1.93	$ 2.06	$ 1.92	$ 2.00
Oil	$ 6.42	$ 5.33	$ 5.79	$ 5.33	$ 3.09
Gas (Natural)	$ 6.45	$ 5.86	$ 4.84	$ 5.49	—
Composite	$ 2.83	$ 2.11	$ 2.19	$ 2.07	$ 2.03
Average cost per ton of coal burned	$ 48.32	$ 45.04	$ 47.53	$ 44.36	$ 44.63

Tampa Electric's generating stations burn fuels as follows: Bayside 1, which went into commercial operation in April of 2003, and Bayside 2, which went into commercial operation in January of 2004, burn natural gas; Big Bend Station, which has sulfur dioxide scrubber capabilities, burns a combination of high-sulfur coal, petroleum coke and No. 2 fuel oil; Polk Power Station burns a blend of low-sulfur coal, high-sulfur coal, and petroleum coke which is gasified and subject to sulfur and particulate matter removal prior to combustion, natural gas and oil; and Phillips Station burns residual fuel oil.

Coal. Tampa Electric used approximately 5.7 million tons of coal during 2003 and estimates that its fuel consumption will be about 5.0 million tons for 2004. During 2003, Tampa Electric purchased approximately 76 percent of its coal under long-term contracts with seven suppliers, and approximately 24 percent of its coal and petroleum coke in the spot market. Tampa Electric expects to obtain approximately 70 percent of its coal requirements in 2004 under long-term contracts with six suppliers and the remaining 30 percent in the spot market. The temporary change in the balance of long-term versus spot contracts is due to declining coal needs at Gannon Station in connection with the repowering to the Bayside Power Station. Tampa Electric's remaining long-term contracts provide for revisions in the base price to reflect changes in a wide range of cost factors and for suspension or reduction of deliveries if environmental regulations should prevent Tampa Electric from burning the coal supplied, provided that a good faith effort has been made to continue burning such coal. For information concerning transportation services by affiliated companies to Tampa Electric, see the **TECO Transport** section of **Business**.

In 2003, approximately 56 percent of Tampa Electric's coal supply was deep-mined, approximately 37 percent was surface-mined and the remainder was a processed oil by-product known as petroleum coke. Federal surface-mining laws and regulations have not had any material adverse impact on Tampa Electric's coal supply or results of its operations. Tampa Electric, however, cannot predict the effect of any future mining laws and regulations.

Natural Gas. In 2003, Tampa Electric contracted for 80 percent of winter 2003-2004 expected gas needs and 40 percent for the 2004 summer period. In the spring of 2004, Tampa Electric expects to contract for an additional 20-40 percent of the 2004 summer and 40 percent of the winter 2004-2005 requirements. Additional volumes are expected to be procured on the short-term spot market.

Oil. Tampa Electric is in the process of finalizing supply agreements for No. 2 fuel oil for its Polk and Big Bend Stations at prices based on Gulf Coast Cargo spot indices. No. 6 fuel oil is purchased on the spot market for its Phillips Station.

Franchises and Other Rights

Tampa Electric holds franchises and other rights that, together with its charter powers, give it the right to carry on its retail business in the localities it serves. The franchises give Tampa Electric rights to the use of rights of way and other public property to place its facilities, and are irrevocable and not subject to amendment without the consent of Tampa Electric, although, in certain events, they are subject to forfeiture.

Florida municipalities are prohibited from granting any franchise for a term exceeding 30 years. All of the municipalities, except for the cities of Tampa and Winter Haven, have reserved the right to purchase Tampa Electric's property used in the exercise of its franchise if the franchise is not renewed; otherwise, based on judicial precedent, Tampa Electric is able to keep its facilities in place subject to reasonable rules and regulations imposed by the municipalities.

Tampa Electric has franchise agreements with 13 incorporated municipalities within its retail service area. These agreements have various expiration dates ranging from November 2005 to March 2021.

Franchise fees payable by Tampa Electric, which totaled $27.6 million in 2003, are calculated using a formula based primarily on electric revenues and are collected on customers' bills.

Utility operations in Hillsborough, Pasco, Pinellas and Polk Counties outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the county commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates for the Hillsborough County and Pinellas County agreements. The agreements covering electric operations in Polk and Pasco counties expire in 2004 and 2023, respectively. Tampa Electric expects to reach a renewal agreement for the Polk agreement.

Environmental Matters

Consent Decree

Tampa Electric Company, in cooperation with the Environmental Protection Agency (EPA) and the U.S. Department of Justice, signed a Consent Decree which became effective October 5, 2000, and a Consent Final Judgment with the Florida Department of Environmental Protection (FDEP), effective December 7, 1999. Pursuant to these agreements, allegations of violations of New Source Review requirements of the Clean Air Act were resolved, provision was made for environmental controls and pollution reductions, and Tampa Electric began implementing a comprehensive program that will dramatically decrease emissions from the company's power plants.

The emission reduction requirements included specific detail with respect to the availability of flue gas desulfurization systems (scrubbers) to help reduce sulfur dioxide (SO2), projects for nitrogen oxide (NOx) reduction efforts on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Station to natural gas. The commercial operation dates for the two repowered Bayside units were on Apr. 24, 2003 and Jan. 15, 2004. The completed station has total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled electric generation. By May 1, 2005, Tampa Electric must decide whether to install NOx controls, repower, or shutdown Big Bend Unit 4, and it must implement the chosen solution by June 1, 2007. By May 1, 2007, Tampa Electric will decide whether to install NOx controls, repower, or shutdown Big Bend Units 1, 2 and 3 and it must implement the chosen methodology beginning in 2008. Tampa Electric's capital investment forecast includes amounts in the 2006 through 2008 period for compliance with the NOx, SO2 and particulate matter reduction requirements.

Emission Reductions

Since 1998, Tampa Electric has reduced annual SO2, NOx, and particulate matter (PM) emissions from its facilities by 129,430 tons, 27,630 tons, and 2,865 tons, respectively. Reductions in SO2 emissions were accomplished through the installation of scrubber systems on Big Bend Units 1 and 2 in 1999. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3. Currently, the scrubbers at Big Bend Station remove more than 95 percent of the SO2 emissions from the flue gas streams.

In addition, the Consent Decree and Consent Final Judgment related projects will result in significant reductions in emissions. Reductions have already resulted from the completion of the repowering of Gannon Station to Bayside Power Station in April 2003 (Bayside Unit 1) and January 2004 (Bayside Unit 2). Should Tampa Electric decide to continue to burn coal, the installation of additional NOx emissions controls on all Big Bend Units will result in the further reduction of emissions. By 2010, these projects are expected to result in the additional phased reduction of SO2 by 156,501 tons per year, NOx by 61,549 tons per year, and PM by 3,626 tons per year from 1998 levels. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO2, NOx and PM emissions by 90 percent, 89 percent, and 70 percent, respectively, below 1998 levels. With these improvements in place, Tampa Electric's facilities will meet the same standards required of new power generating facilities and help to significantly enhance the quality of the air in the community.

Due to pollution control co-benefits from the Consent Decree and Consent Final Judgment, reductions in mercury emissions have occurred due to the re-powering of Gannon Station to Bayside Station. At Bayside, where mercury levels have decreased 44 percent below 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions are also anticipated from the installation of NOx controls at Big Bend Station, which would lead to a mercury removal efficiency of approximately 70 percent. Depending on the NOx control technology selected for Big Bend, the mercury reductions may vary and lead to lower than anticipated mercury removal efficiencies.

The repowering of Gannon Station to Bayside Station will also lead to a significant reduction in carbon dioxide (CO2) emissions. It is expected that by 2005, the repowering will bring an approximate 5.2 million ton decrease in CO2 emissions below 1998 levels. This reduction will result in the Tampa Electric system CO2 emissions being in line with its 1990 CO2 emission levels.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2003, Tampa Electric Company has estimated its ultimate financial liability to be approximately $20 million, and this amount has been reflected in the consolidated financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors or Tampa Electric Company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other potentially responsible parties (PRPs) is based on each parties' relative ownership interest in or usage of a site. Accordingly, Tampa Electric Company's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Capital Expenditures

During the five years ended Dec. 31, 2003, Tampa Electric spent $116.4 million, excluding the Gannon repowering, on capital additions to meet environmental requirements. A significant portion of the $83 million project for the Big Bend Units 1and 2 scrubbers is included in the five-year total. A new scrubber system was installed at Big Bend Units 1 and 2 to meet Phase 2 S02 emission reduction requirements under the Clean Air Act Amendments of 1990.

In total, Tampa Electric spent an estimated $11.7 million in 2003 on environmental projects. Environmental expenditures are estimated at $18.2 million for 2004 and an additional $324 million in total for 2005 through 2008. These totals include the expenditures required to comply with the EPA Consent Decree, which are discussed below.

In 2003, Tampa Electric spent approximately $3.6 million for compliance with the EPA consent decree requirements at Big Bend station for reduction of NOx and PM emissions and to improve the scrubber systems to reduce S02 emissions. Should Tampa Electric choose to continue to burn coal at Big Bend station, further NOx emission reductions would require expenditures in 2004 estimated at $3.7 million and as much as $221 million being spent during 2005 through 2008. Estimated expenditures for the continued improvement of electrostatic precipitators for PM emissions reductions will be $1.5 million in 2004 and an additional $6.5 million during 2005 through 2008. Tampa Electric has also spent $658 million, excluding allowance for funds used during construction (AFUDC) and dismantlement, on Bayside Power Station, the repowering of the company's coal-fired Gannon Station to use natural gas, to meet the EPA Consent Decree condition of eliminating coal-firing at Gannon Station.

PEOPLES GAS SYSTEM – Gas Operations

Peoples Gas System (PGS) operates as the Peoples Gas System division of Tampa Electric Company. PGS is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in the State of Florida.

PGS uses three interstate pipelines to receive gas for sale or other delivery to customers connected to its distribution system. PGS does not engage in the exploration for or production of natural gas. PGS operates a natural gas distribution system that serves over 299,000 customers. The system includes approximately 9,500 miles of mains and over 5,500 miles of service lines. (See PGS' **Franchise** section of **Business**.)

In 2003, the total throughput for PGS was 1.2 billion therms. Of this total throughput, 13 percent was gas purchased and resold to retail customers by PGS, 72 percent was third party supplied gas delivered for retail transportation only customers, and 15 percent was gas sold off-system. Industrial and power generation customers consumed approximately 65 percent of PGS' annual therm volume, commercial customers used approximately 30 percent and the balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations generally comprise 25 percent of total revenues. New residential construction including natural gas and conversions of existing residences to gas have steadily increased since the late 1980's.

Natural gas has historically been used in many traditional industrial and commercial operations throughout Florida, including production of products such as steel, glass, ceramic tile and food products. Within the PGS operating territory, large cogeneration facilities utilize gas-fired technology in the production of electric power and steam.

Revenues and therms for PGS for the years ended Dec. 31, are as follows:

	Revenues			*Therms*		
(millions)	*2003*	*2002*	*2001*	*2003*	*2002*	*2001*
Residential	$ 105.6	$ 76.6	$ 88.2	64.2	60.2	58.8
Commercial	143.6	122.3	163.6	354.8	327.6	308.9
Industrial	114.8	80.3	50.7	406.2	423.8	346.5
Power Generation	10.1	11.4	11.3	363.7	492.6	403.5
Other revenues	34.0	27.5	39.1	—	—	—
Total	$ 408.4	$ 318.1	$ 352.9	1,188.9	1,304.2	1,117.7

PGS had 565 employees as of Dec. 31, 2003. A total of 94 employees in six of PGS' 15 operating divisions are represented by various union organizations.

Regulation

The operations of PGS are regulated by the FPSC separate from the regulation of Tampa Electric's electric operations. The FPSC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the FPSC sets rates at a level that allows a utility such as PGS to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The basic costs of providing natural gas service, other than the costs of purchased gas and interstate pipeline capacity, are recovered through base rates. Base rates are designed to recover the costs of owning, operating and maintaining the utility system. The rate of return on rate base, which is intended to approximate PGS' weighted cost of capital, primarily includes its cost for debt, deferred income taxes at a zero cost rate, and an allowed return on common equity. Base rates are determined in FPSC proceedings which occur at irregular intervals at the initiative of PGS, the FPSC or other parties. For a description of recent proceeding activity, see the **Regulation – Peoples Gas Rate Proceeding** section of **MD&A**.

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the Purchased Gas Adjustment (PGA) clause. This charge is designed to recover the costs incurred by PGS for purchased gas, and for holding and using interstate pipeline capacity for the transportation of gas it sells to its customers. These charges are adjusted monthly based on a cap approved annually in an FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs and usage from the projected charges for prior periods. For a description of the most recent adjustment, see the **Regulation – Cost Recovery Clauses – Peoples Gas** section of **MD&A**.

In addition to its base rates and purchased gas adjustment clause charges for system supply customers, PGS customers (except interruptible customers) also pay a per-therm charge for all gas consumed to recover the costs incurred by PGS in developing and implementing energy conservation programs, which are mandated by Florida law and approved and supervised by the FPSC. PGS is permitted to recover, on a dollar-for-dollar basis, expenditures made in connection with these programs if it demonstrates that the programs are cost effective for its ratepayers.

In February 2000, the FPSC approved a rule that required natural gas utilities to offer transportation-only service to all non-residential customers. The net result of the unbundling is a shift from commodity sales to transportation sales. PGS continues to receive its base rate for distribution regardless of whether a customer decided to opt for transportation-only service or continue bundled service. PGS had over 10,500 transportation customers as of Dec. 31, 2003.

In addition to economic regulation, PGS is subject to the FPSC's safety jurisdiction, pursuant to which the FPSC regulates the construction, operation and maintenance of PGS' distribution system. In general, the FPSC has implemented this by adopting the Minimum Federal Safety Standards and reporting requirements for pipeline facilities and transportation of gas prescribed by the U.S. Department of Transportation in Parts 191, 192 and 199, Title 49, Code of Federal Regulations.

PGS is also subject to federal, state and local environmental laws and regulations pertaining to air and water quality, land use, noise and aesthetics, solid waste and other environmental matters.

Competition

PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity. In general, PGS faces competition from other energy source suppliers offering fuel oil, electricity and in some cases, propane. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high quality service to customers.

In Florida, gas service is unbundled for all non-residential customers. In 2000, PGS implemented its "NaturalChoice" program offering unbundled transportation service to all eligible customers. This means that non-residential customers can purchase commodity gas from a third party but continue to pay PGS for the transportation of the gas.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by competing companies seeking to sell alternate fuels or transport gas through other facilities, thereby bypassing PGS facilities. In response to this competition, PGS has developed various programs, including the provision of transportation services at discounted rates. See the **Regulation – Utility Competition – Gas** section of **MD&A**.

Gas Supplies

PGS purchases gas from various suppliers depending on the needs of its customers. The gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has reserved firm transportation capacity for delivery by PGS to its customers.

Gas is delivered by Florida Gas Transmission Company (FGT) through more than 55 interconnections (gate stations) serving PGS' operating divisions. In addition, PGS' Jacksonville Division receives gas delivered by the South Georgia Natural Gas Company (South Georgia) pipeline through two gate stations located northwest of Jacksonville.

In 2003, Gulfstream Natural Gas Pipeline initiated gas delivery through four new gate stations. PGS entered into a service agreement for capacity in 2002, which increases in 2003 and 2004. The addition of the Gulfstream pipeline enhances reliability of service and helps meet the capacity needs for PGS' growing customer base.

Companies with firm pipeline capacity receive priority in scheduling deliveries during times when the pipeline is operating at its maximum capacity. PGS presently holds sufficient firm capacity to permit it to meet the gas requirements of its system commodity customers, except during localized emergencies affecting the PGS distribution system and on abnormally cold days.

Firm transportation rights on an interstate pipeline represent a right to use the amount of the capacity reserved for transportation of gas on any given day. PGS pays reservation charges on the full amount of the reserved capacity whether or not it actually uses such capacity on any given day. When the capacity is actually used, PGS pays a volumetrically-based usage charge for the amount of the capacity actually used. The levels of the reservation and usage charges are regulated by FERC. PGS actively markets any excess capacity available on a day-to-day basis to partially offset costs recovered through the Purchased Gas Adjustment Clause.

PGS procures natural gas supplies using base load and swing supply contracts with various suppliers along with spot market purchases. Pricing generally takes the form of either a variable price based on published indices, or a fixed price for the contract term.

Neither PGS nor any of the interconnected interstate pipelines have storage facilities in Florida. PGS occasionally faces situations when the demands of all of its customers for the delivery of gas cannot be met. In these instances, it is necessary that PGS interrupt or curtail deliveries to its interruptible customers. In general, the largest of PGS' industrial customers are in the categories that are first curtailed in such situations. PGS' tariff and transportation agreements with these customers give PGS the right to divert these customers' gas to other higher priority users during the period of curtailment or interruption. PGS pays these customers for such gas at the price they paid their suppliers, or at a published index price, and in either case pays the customer for charges incurred for interstate pipeline transportation to the PGS system.

Franchises

PGS holds franchise and other rights with approximately 100 municipalities throughout Florida. These include the cities of Lakeland, Jacksonville, Daytona Beach, Eustis, Fort Myers, Ocala, Brooksville, Orlando, Tampa, St. Petersburg, Sarasota, Avon Park, Frostproof, Palm Beach Gardens, Pompano Beach, Fort Lauderdale, Hollywood, North Miami, Miami Beach, Miami, and Panama City. These franchises give PGS a right to occupy municipal rights-of-way within the franchise area. The franchises are irrevocable and are not subject to amendment without the consent of PGS, although in certain events, they are subject to forfeiture.

Municipalities are prohibited from granting any franchise for a term exceeding 30 years. Several franchises contain purchase options with respect to the purchase of PGS' property located in the franchise area, if the franchise is not renewed; otherwise, based on judicial precedent, PGS is able to keep its facilities in place subject to reasonable rules and regulations imposed by the municipalities.

PGS' franchise agreements with the incorporated municipalities within its service area have various expiration dates ranging from the present through July 2031. PGS has two franchises in negotiations for 2004. One is a renewal and the second is a new franchise. Franchise fees payable by PGS, which totaled $8.0 million in 2003, are calculated using various formulas which are based principally on natural gas revenues. Franchise fees are collected from only those customers within each franchise area.

Utility operations in areas outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the county commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates and these rights are, therefore, considered perpetual.

Environmental Matters

PGS' operations are subject to federal, state and local statutes, rules and regulations relating to the discharge of materials into the environment and the protection of the environment generally that require monitoring, permitting and ongoing expenditures.

Tampa Electric Company is one of several potentially responsible parties for certain superfund sites and, through PGS, for certain superfund and former manufactured gas plant sites. See the previous discussion in the **Environmental Matters** section of **Tampa Electric – Electric Operations** on pages 6 and 7.

Expenditures. During the five years ended Dec. 31, 2003, PGS has not incurred any material capital expenditures to meet environmental requirements, nor are any anticipated for 2004 through 2008.

TECO WHOLESALE GENERATION (FORMERLY TECO POWER SERVICES)

TECO Wholesale Generation, Inc. (TWG) has subsidiaries that have interests in independent power projects in Florida, Virginia, Hawaii, Mississippi, Arkansas, Texas, Arizona and Guatemala. TWG had 352 employees as of Dec. 31, 2003.

As discussed under the **TECO Energy** section of **Business**, the TWG operating segment is comprised of all continuing merchant operations, including the direct and indirect results from continuing operations of the independent power projects in

Virginia, Mississippi, Arkansas and Texas, as well as the energy marketing operation for these plants, TECO EnergySource, Inc. (TES). Prior to Dec. 31, 2003, the results of operations of Union and Gila River's independent power projects in Arkansas and Arizona, respectively, (TPGC) were included in TWG; however, these are now reported in discontinued operations. Included in the Other Unregulated companies operating segment are the results of operations of the non-merchant independent power projects in Florida, Hawaii and Guatemala (i.e., those with long-term power projects).

Like Tampa Electric, the U.S. operations of TWG are subject to federal, state and local environmental laws and regulations covering air quality, water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters.

See **Note 19** to the TECO Energy **Consolidated Financial Statements** for specific details of the results of operations for the TWG Merchant operating segment and the non-merchant power component of the Other Unregulated Companies segment described below.

TWG Merchant Operating Segment

In 1998, TM Power Ventures LLC (TMPV) was created by TWG and Mosbacher Power Partners, Ltd. (Mosbacher Power), an independent power company headquartered in Houston, to jointly develop, own and operate domestic and international independent power projects. Under this arrangement, TWG provided capital and technical expertise to TMPV. In 1998, TWG, through TMPV, made certain loans to Mosbacher Power. Also in 1998, TWG, through TMPV, acquired approximately a 13 percent interest in a re-powered independent power project in the Czech Republic (the ECKG project). The facility completed its expansion to a total of 344 megawatts in the first quarter of 2000. In 2002, TWG purchased Mosbacher Power's minority ownership interest in TMPV, thereby giving TWG a 100-percent ownership interest in TMPV. As part of the purchase, TWG received principal and interest due on its loans to Mosbacher Power. Also in 2002, TWG recorded a $5.8 million after-tax charge to adjust the valuation of the investment in the ECKG project in connection with the proposed sale of that investment. In 2003, TMPV sold its interest in the ECKG project. As a result of the sale, TMPV received for $33 million in cash.

TWG, through TMPV, has a 100-percent economic interest in Commonwealth Chesapeake Power Station (CCC), a 315-megawatt power plant on the Delmarva Peninsula of Virginia. The first phase of 134 megawatts went into service in the third quarter of 2000, and the second phase went into service in August 2001. In 2003, an after-tax charge of $26.7 million was recognized to establish a reserve against an arbitration award against TMDP, the indirect owner of CCC.

In the first quarter of 2001, TWG sold its minority interest in EGI, a Bermuda-based energy development firm. As part of the sale, TWG took an after-tax charge of $6.1 million ($9.3 million pre-tax) to adjust the asset valuation of the investment.

In September 2000, TWG provided a $93 million investment in the form of a loan related to Panda Energy International's (Panda) Texas Independent Energy projects (TIE). In February 2002, TWG provided an additional investment in the form of a loan in the amount of $44 million. These loans converted in accordance with their terms into an ownership interest on Jan. 3, 2003. Subsequently, in 2003, as part of the TPGC joint venture termination, described below, TWG foreclosed on an additional loan to a subsidiary of Panda Energy for $23 million. This foreclosure resulted in TWG obtaining an indirect effective economic interest of 50 percent in the aggregate of 2,000-megawatts in TIE. The two TIE projects, known as Guadalupe and Odessa, are located in Texas and operate as gas-fired, combined-cycle units. The projects were brought on line in phases beginning in December 2000, with all the capacity in service in August 2001.

In October 2000, TWG acquired from Genpower LLC full ownership of two independent power projects being developed in Arkansas and Mississippi with combined capacity of the two plants to be nearly 1,200 megawatts. The two 599-megawatt facilities, known as the Dell and McAdams projects, were designed to be natural gas-fired combined-cycle plants. Construction on these plants was suspended at the end of 2002 due to low energy prices in the markets that these plants were expected to serve. Market conditions will be monitored to determine when these plans will be completed. As of Dec. 31, 2003, approximately $690 million had been invested in these plants and TWG estimates that the construction cost to complete these projects would be approximately $100 million. (See the **TECO Wholesale Generation, Inc. – Merchant Generation Facilities** section of **MD&A**.)

In November 2000, TWG announced a joint venture with Panda to build, own and operate two natural gas power plants located in Arkansas and Arizona, known as the Union and Gila River projects. The first phase of the Union power plant began commercial operations in January 2003, and the entire facility was commercially operational in the second quarter of 2003. Union sells power primarily to utilities and industrial customers in Arkansas, Louisiana, eastern Texas and Mississippi. The first phase of the other project, in Gila Bend, Arizona, began commercial operations in the second quarter of 2003 and the entire facility was commercially operational in the third quarter of 2003. Electricity from Gila River is primarily sold in Arizona, Nevada and New Mexico. In February 2002, subsidiaries of TWG entered into an agreement requiring those subsidiaries to purchase 100 percent of Panda's interest in the joint venture for $60 million in 2007, unless Panda chose to remain a partner by canceling the agreement and paying a cancellation fee. In April 2003, subsidiaries of TWG and Panda agreed to amendments to this agreement which resulted in TWG indirectly consolidating the joint venture (TPGC) at that time. (See the **Transactions with Related and Certain Other Parties** section of **MD&A**.) In June 2003, subsidiaries of TWG terminated Panda's continued involvement in the partnership, resulting in the recognition of after-tax charges in the second quarter of 2003 of $155.9 million, as a direct result of the consolidation of TPGC.

In June 2001, the project entities owned by TWG and Panda closed on a bank financing for the Union and Gila River power stations. This $2.175 billion bank financing included $1.675 billion in five-year non-recourse debt and $500 million in equity

bridge loans guaranteed by TECO Energy. The equity bridge loans were repaid in 2002 and 2003. As a result of events in October 2003 and December 2003 (see the **TECO Wholesale Generation, Inc.** section of **MD&A**), and other economic factors impacting the general market conditions for independent power projects, TWG recognized a pre-tax asset impairment charge of $1,185.7 million in 2003. Subsequent to Dec. 31, 2003, discussions with the bank financing group have resulted in a non-binding letter of intent that would allow for an exit from the ownership of these project companies. (See also **Notes 10, 12, 20** and **23** to the TECO Energy **Consolidated Financial Statements** for additional details of the results of operations for these project companies.)

In March 2001, subsidiaries of TWG acquired American Electric Power's (AEP) Frontera Power Station, located near McAllen, Texas. Frontera is a 477-megawatt natural gas-fired combined-cycle plant. Frontera is capable of selling power domestically, as well as into the Mexican power market, through a direct interconnection with the Comisión Federal de Electricidad, the Mexican power authority.

Other Unregulated Companies Operating Segment

Hardee Power Partners, Ltd. (HPP) is a Florida limited partnership which wholly owns the Hardee Power Station, a 370-megawatt combined cycle electric generating facility located in Hardee County, Florida, which began commercial operation in 1993. Until recently, HPP was an indirect wholly-owned subsidiary of TWG. In 1993, HPP began to fulfill 20-year power supply agreements for all the capacity and energy of the Hardee Power Station, with Tampa Electric and Seminole Electric Cooperative (Seminole Electric), a Florida electric cooperative that provides wholesale power to ten electric distribution cooperatives. Under the Seminole Electric agreements, HPP agreed to supply Seminole Electric with an additional 145 megawatts of capacity during the first ten years of the contract, which ended on Dec. 31, 2002. This additional capacity was purchased from Tampa Electric's coal-fired Big Bend Unit Four for resale to Seminole Electric. The 75-megawatt capacity expansion completed at Hardee Power Station in May 2000 is expected to serve Tampa Electric through 2012. The expansion consists of a General Electric combustion turbine operating in simple-cycle mode. In 2003, the company sold the partnership interests of HPP to a third party. (See **Note 21** to the TECO Energy **Consolidated Financial Statements** for a description of the sale and its impact on the results of continuing operations.) The sale did not impact the long-term power supply agreements with Tampa Electric or Seminole Electric.

As part of its non-merchant operations, TWG is a 50-percent indirect owner in the Hamakua Energy Project, a 60-megawatt combined cycle cogeneration facility in Hamakua, Hawaii. The facility was constructed and placed into service during 2000. A subsidiary of TWG jointly owns and operates the project under a 30-year power purchase agreement with Hawaii Electric Light Company. The interests of the previous joint owner, J.A. Jones Ventures, were auctioned to a third party in early 2004.

As part of its non-merchant operations, TWG indirectly owns 100 percent of Central Generadora Eléctrica San Jose, Limitada (CGESJ), the owner of a project located in Guatemala, which consists of a single-unit pulverized-coal baseload facility (the San Jose Power Station). This facility was the first coal-fueled plant in Central America and meets environmental standards set by the World Bank. In 1996, CGESJ signed a U.S. dollar-denominated power sales agreement (PPA) with Empresa Eléctrica de Guatemala, S.A. (EEGSA), a private distribution and generation company, to provide 120 megawatts of capacity for 15 years beginning in 2000. In 2001, CGESJ signed an option with EEGSA to extend that PPA for five years for approximately $2.5 million. In 2002, CGESJ began to transfer the port assets to Tecnología Marítima, S.A. (TEMSA), a new indirect wholly-owned subsidiary. This transaction was completed in the first quarter of 2003. TEMSA, in addition to receiving the coal shipments for CGESJ, provides unloading services to third parties. Political risk insurance has been obtained for currency inconvertibility, expropriation and political violence covering up to 100 percent of TWG's indirect equity investment and economic returns.

Tampa Centro Americana de Electricidad, Limitada (TCAE), an entity 96.06-percent owned by TPS Guatemala One, Inc., a subsidiary of TWG and the owners of the Alborada Power Station, have a U.S. dollar-denominated PPA with EEGSA to provide 78 megawatts of capacity for a 15-year period ending in 2010. In 2001, TCAE signed an option with EEGSA to extend that PPA for five years at the end of its current term for approximately $2.9 million. EEGSA is responsible for providing the fuel for the plant, with a subsidiary of TWG providing assistance in fuel administration. Affiliates of TWG had originally obtained $29 million of limited recourse financing from the Overseas Private Investment Corporation (OPIC) for the Alborada Power Station. In 2002, TCAE paid off its loan with OPIC with a portion of the proceeds from a non-recourse $25 million loan from Banco Industrial, a local bank in Guatemala. Political risk insurance has been obtained for currency inconvertibility, expropriation and political violence covering up to 100 percent of TWG's indirect equity investment and economic returns.

EEGSA serves more than 717,000 customers. EEGSA's service territory includes the capital of Guatemala, Guatemala City. In 1998, a consortium that includes affiliates of the company, Iberdrola, an electric utility in Spain, and Electricidade de Portugal, an electric utility in Portugal, completed the purchase of an 80-percent ownership interest in EEGSA for $520 million. The company indirectly owns a 24 percent interest in this consortium and contributed $100 million in equity. The consortium obtained limited-recourse debt financing for a portion of the purchase price. A subsidiary of TWG has obtained political risk insurance for currency inconvertibility, expropriation and political violence covering up to 100 percent of TWG's indirect equity investment and economic returns.

Competition and Markets

The U.S. power plants that TWG indirectly owns and operates and those for which construction has been suspended are located in markets with a history of high load growth. However, the general U.S. economic slowdown over the past several years has

slowed the growth in demand for power in some of these markets. In addition, the slowdown of electricity deregulation initiatives across the United States, including the markets that these facilities serve, caused in part by the failure of deregulation in California and other events, has allowed the traditional, incumbent utilities to continue to operate older, less efficient generating facilities in lieu of purchasing power from newer, more efficient independent power plants. These factors have combined with aggressive plans by the independent power industry to add merchant power facilities to cause excess generating capacity that is either being built or has come on line in many markets. This excess supply has depressed both spot and forward prices. Accordingly, TWG has ceased work on any new power plant developments, and is active in its efforts to reduce its merchant exposure.

TECO Energy's renewed focus is on core utility operations. In April 2003, TECO Energy announced that the company would seek to increase its flexibility to be able to mitigate the risk from the merchant portfolio through a number of steps, including the termination of joint ventures with Panda Energy in the TPGC plants and in the TIE plants. These terminations were accomplished in 2003. In October 2003, the company announced that little, if any, additional cash would be invested into the merchant generation portfolio. Significant steps have been achieved in 2003 with respect to TWG's ownership exit plan for the Union and Gila River project companies. See the **TWG – Energy Markets** section of **MD&A** for additional discussion of competition and the merchant energy markets.

See the discussion of the risks applicable to TWG in the **Investment Considerations** section of **MD&A**. For financial information about geographic areas, see **Note 19** to the TECO Energy **Consolidated Financial Statements**.

TECO TRANSPORT

TECO Transport owns all of the common stock of four subsidiaries which transport, store and transfer coal and other dry-bulk commodities. These subsidiaries include TECO Ocean Shipping, Inc. (Ocean Shipping), TECO Barge Line, Inc. (TECO Barge), TECO Bulk Terminal, LLC (Bulk Terminal) and TECO Towing Company. TECO Transport currently owns no operating assets. TECO Transport and its subsidiaries had 914 employees as of Dec. 31, 2003.

TECO Transport's subsidiaries perform substantial services for Tampa Electric. In 2003, approximately 62 percent of TECO Transport's revenues were from third-party customers and approximately 38 percent were from Tampa Electric. The pricing for services performed by TECO Transport's operating companies for Tampa Electric is based on a market-based fixed-price per ton, generally adjusted quarterly for changes in certain fuel and price indices. Most of the third-party utilization of the ocean-going barges is for domestic and international movements of other dry-bulk commodities and domestic phosphate movements. Both the terminal and river transport operations handle a variety of dry-bulk commodities for third party customers.

A substantial portion of TECO Transport's business is dependent upon Tampa Electric, phosphate customers, steel industry customers, grain customers, coal and petroleum coke customers, and participation in the U.S. Government's cargo preference programs.

Ocean Shipping transports products in the Gulf of Mexico and worldwide, and TECO Barge operates on the Mississippi, Ohio and Illinois rivers and their tributaries. Their primary competitors are other barge and shipping lines and railroads, as well as a number of other companies offering transportation services on the waterways used by TECO Transport's subsidiaries. Ocean Shipping is the largest US flag coastwise dry bulk operator based on capacity, while TECO Barge is in the top ten, based on number of barges, of companies in its business. To date, physical and technological improvements have allowed ship and barge operators to maintain competitive rate structures with alternate methods of transporting bulk commodities when the origin and destination of such shipments are contiguous to navigable waterways.

Bulk Terminal operates the largest transfer and storage terminal on the Gulf coast. Demand for the use of such terminals is dependent upon customers' use of water transportation versus alternate means of moving bulk commodities and the demand for these commodities. Competition consists primarily of mid-stream operators and other land-based terminals.

Competition within TECO Transport's markets is based primarily on geographic markets served, pricing, and service level. The majority of the ocean and all of the river business is subject to the Jones Act, which prohibits the use of non-US flag vessels for movement between US ports.

The business of TECO Transport's subsidiaries, taken as a whole, is not subject to significant seasonal fluctuation, but is sensitive to economic conditions.

The Interstate Commerce Act exempts from regulation water transportation of certain dry-bulk commodities. In 2003, all transportation services provided by TECO Transport's subsidiaries were within this exemption.

TECO Transport's subsidiaries are subject to the provisions of the Clean Water Act of 1977 which authorizes the Coast Guard and the EPA to assess penalties for oil and hazardous substance discharges. Under this Act, these agencies are also empowered to assess clean-up costs for such discharges. In 2003, TECO Transport spent $0.3 million for environmental compliance. Environmental expenditures are estimated at $0.2 million in 2004, primarily for work on solid waste disposal and storm water drainage at the Bulk Terminal facility in Louisiana and for expenses related to oil and bilge water disposal at its river-barge repair facility in Illinois.

TECO COAL

TECO Coal owns no operating assets but holds all of the common stock of Gatliff Coal Company, Rich Mountain Coal Company, Clintwood Elkhorn Mining Company, Pike-Letcher Land Company, Premier Elkhorn Coal Company, Bear Branch Coal Company, Perry County Coal Corporation, and TECO Synfuel Operations, LLC. The TECO Coal subsidiaries own or control mineral rights, and own or operate surface and underground mines, synthetic fuel production facilities and coal processing and loading facilities in eastern Kentucky, Virginia and Tennessee. TECO Coal and its subsidiaries had 713 employees as of Dec. 31, 2003.

In 2003, TECO Coal subsidiaries sold 9.2 million tons of coal, with 100 percent sold to parties other than Tampa Electric. Of the total sold, 5.8 million tons were produced and sold as synthetic fuel.

In 2000, TECO Coal acquired Perry County Coal Corporation (Perry County), which owns or controls in excess of 21 million tons of low sulfur reserves and operates both deep and surface contract mines along with a preparation plant and two loadouts. Perry County produced and sold 2.6 million tons of coal in 2003.

In April 2003, TECO Coal sold a 49.5-percent interest in its synthetic fuel production facilities located at its operations in eastern Kentucky. (See the **TECO Coal** section of **MD&A**) The 5.8 million tons of synfuel produced in 2003 replaced some of TECO Coal's conventional coal production in 2003. Sales of the fuel processed through these types of facilities are eligible for non-conventional fuels tax credits under Section 29 of the Internal Revenue Code, which are available through 2007. TECO Coal received Private Letter Rulings from the Internal Revenue Service confirming that the facilities produce a qualified fuel eligible for Section 29 tax credits available for the production of such non-conventional fuels and resolved any uncertainty related to the sale of its interest in the production facilities.

The Section 29 tax credit is determined annually and is estimated to be $1.11 per million Btu in 2003, $1.09 per million Btu in 2002 and $1.08 per million Btu in 2001. This rate escalates with inflation but could be limited by domestic oil prices. In 2003, domestic oil prices would have had to exceed $50 per barrel for the limitation to have been effective. In 2003, TECO Coal's Section 29 tax credits were $66.0 million, compared to $107.3 million in 2002 and $86.2 million in 2001.

Primary competitors of TECO Coal's subsidiaries are other coal suppliers, many of which are located in Central Appalachia. To date, TECO Coal has been able to compete for coal sales by mining high-quality steam and specialty coals and by effectively managing production and processing costs.

The operations of underground mines, including all related surface facilities, are subject to the Federal Coal Mine Safety and Health Act of 1977. TECO Coal's subsidiaries are also subject to various Kentucky, Tennessee and Virginia mining laws which require approval of roof control, ventilation, dust control and other facets of the coal mining business. Federal and state inspectors inspect the mines to ensure compliance with these laws. TECO Coal believes it is in substantial compliance with the standards of the various enforcement agencies. It is unaware of any mining laws or regulations that would materially affect the market price of coal sold by its subsidiaries.

TECO Coal's subsidiaries are subject to various federal, state and local air and water pollution standards in their mining operations. In 2003, TECO Coal spent approximately $1.5 million on environmental protection and reclamation programs. TECO Coal expects to spend a similar amount in 2004 on these programs.

Coal mining operations are also subject to the Surface Mining Control and Reclamation Act of 1977 which places a charge of $0.15 and $0.35 on every net ton of underground and surface coal mined, respectively, to create a fund for reclaiming land and water adversely affected by past coal mining. Other provisions establish standards for the control of environmental effects and reclamation of surface coal mining and the surface effects of underground coal mining and requirements for federal and state inspections.

TECO SOLUTIONS

TECO Solutions was formed during the early stages of Florida's proposed electric industry restructuring, as a vehicle through which to support TECO Energy's strategy of offering customers (primarily in Florida) a comprehensive and competitive package of energy services and products, including energy-efficient engineering and construction and gas management services. The subsequent rollback of the proposed deregulation and TECO Energy's refocus on the core utility operations has caused the company to reexamine its participation in these lines of business. The result was the sale of several of the entities that previously were part of TECO Solutions. Operating companies under TECO Solutions include TECO BCH Mechanical, TECO Gas Services Inc., TECO Propane Ventures LLC (TPV) and TECO Partners, Inc., with total employees of 655 as of Dec. 31, 2003.

TECO BCH Mechanical and its affiliated companies (BCH), one of Florida's leading mechanical contracting firms, is headquartered in Largo, Florida and has offices in Cocoa Beach and Ft. Lauderdale. It provides air-conditioning, electrical and plumbing systems, and repair and maintenance services to more than 750 institutional and commercial customers throughout Florida.

TECO Gas Services provides gas management services to cogeneration facilities in Florida. On July 21, 2003, TECO Solutions sold TECO Gas Services' commercial and industrial book of business. TECO Gas Services will continue to provide services to their cogeneration customers. TECO Gas Services owns no operating assets.

TECO BGA, Inc. (formerly a component of TECO Energy Services) (BGA) is an engineering energy services company headquartered in Tampa, providing engineering, construction management and energy services to more than 300 customers.

Effective Jan. 1, 2004, the company completed the sale of BGA to an entity owned by an employee group. BGA's results are accounted for as continuing operations for all periods reported.

Prior Energy, a leading natural gas management company headquartered in Mobile, Alabama, serves customers throughout the Southeast. Prior Energy owns no operating assets. In December 2003, TECO Solutions entered into an agreement to sell this end use gas marketing company; effective Feb. 1, 2004, the sale of Prior Energy was completed. Prior Energy's results are accounted for as discontinued operations for all periods reported.

TPV held TECO Energy's propane business investment. In 2000, TECO Energy combined its propane operations with three other southeastern propane companies to form U.S. Propane. In a series of transactions, U.S. Propane combined with Heritage Holdings, Inc. In January 2004, U.S. Propane completed the sale of its direct and indirect equity investments in Heritage Propane Partner, L.P. (Heritage). The sale, part of a larger transaction that involved the merging of privately held Energy Transfer Company with Heritage, was announced in November 2003. TPV owns no operating assets.

TECO COALBED METHANE

TECO Coalbed Methane, Inc. had developed jointly with another entity the natural gas production from coal seams in Alabama's Black Warrior Basin. In September 2002, TECO Energy initiated activities to sell the TECO Coalbed Methane gas assets. That sale was substantially completed in December 2002 to the Municipal Gas Authority of Georgia. Proceeds for the sale were $140 million, of which $42 million was paid in cash at closing and $98 million was paid in January 2003. TECO Coalbed Methane's results are accounted for as discontinued operations for all periods reported. Following the sale of substantially all of its assets, TECO Coalbed Methane, Inc. was merged with and into TECO Coalbed Methane Florida, Inc.

Production from TECO Coalbed Methane's reserves was eligible for Section 29 non-conventional fuels tax credits through 2002. The credit was $1.09 per million Btu for 2002 and $1.08 per million Btu in 2001. This rate escalated with inflation but could be limited by domestic oil prices. In 2002, domestic oil prices would have had to exceed $49 per barrel for this limitation to have been effective. In 2002, TECO Coalbed Methane's Section 29 tax credits were $15.9 million, compared to $16.1 million in 2001. TECO Coalbed Methane's operations are subject to federal, state and local regulations for air emissions and water and waste disposal.

Item 2. PROPERTIES.

TECO Energy believes that the physical properties of its operating companies are adequate to carry on their businesses as currently conducted. The properties of Tampa Electric and most of the subsidiaries of TECO Wholesale Generation are generally subject to liens securing long-term debt.

TAMPA ELECTRIC

At Dec. 31, 2003, Tampa Electric had five electric generating plants and four combustion turbine units in service with a total net winter generating capability of 3,256 megawatts, including Big Bend (1,759-MW capability from four coal units), Bayside (752-MW capability from one natural gas unit), Phillips (34-MW capability from two diesel units), Polk (260-MW capability from one integrated gasification combined cycle (IGCC) unit), two combustion turbine units (CTs) located at Big Bend (85-MW each) and two CTs at Polk (360-MW). Additionally, Tampa Electric has 6-MW of generating capability from generation units located at the Howard Curren Advanced Waste Water Treatment Plant in the City of Tampa. The capability indicated represents the demonstrable dependable load carrying abilities of the generating units during winter peak periods as proven under actual operating conditions. Units at Big Bend went into service from 1970-1985. The Polk IGCC unit began commercial operation in September 1996. In 1991, Tampa Electric purchased two power plants (Dinner Lake and Phillips) from the Sebring Utilities Commission (Sebring). Dinner Lake (11-MW capability from one natural gas unit) and Phillips were placed in service by Sebring in 1966 and 1983, respectively. In March 1994, Dinner Lake Station was placed on long-term reserve standby and was retired from service in January 2003. Hookers Point Station's Unit 5 (67-MW) was placed on long-term standby in January 2001. All units at Hookers Point were retired from service in January 2003.

The repowering of Gannon station to Bayside station was completed with the conversion of Gannon Unit 5 to Bayside Unit 1 in April 2003 and Gannon Unit 6 to Bayside Unit 2 in January 2004 (see the **Environmental Compliance** section of **MD&A**). Total capacity at Bayside has increased to 1,774 megawatts as a result of the operation of Bayside Unit 2. Gannon Units 1 and 2 were placed on long term reserve standby (LTRS) in April 2003 and retired in January 2004. Gannon Units 3 and 4 were placed on LTRS in September 2003 and retired from coal operation in January 2004, after which the assets may be utilized for future gas operations. The agreement between Tampa Electric and the U.S. Environmental Protection Agency (EPA), and the Florida Department of Environmental Protection (DEP) required all coal burning to cease by the end of 2004, but allows the units to be repowered on natural gas.

Tampa Electric owns 187 substations having an aggregate transformer capacity of 19,825 MVA. The transmission system consists of approximately 1,308 pole miles of high voltage transmission lines, and the distribution system consists of 7,038 pole miles of overhead lines and 3,252 trench miles of underground lines. As of Dec. 31, 2003, there were 612,465 meters in service. All of this property is located in Florida.

All plants and important fixed assets are held in fee except that title to some of the properties is subject to easements, leases, contracts, covenants and similar encumbrances and minor defects of a nature common to properties of the size and character of those of Tampa Electric.

Tampa Electric has easements for rights-of-way adequate for the maintenance and operation of its electrical transmission and distribution lines that are not constructed upon public highways, roads and streets. It has the power of eminent domain under Florida law for the acquisition of any such rights-of-way for the operation of transmission and distribution lines. Transmission and distribution lines located in public ways are maintained under franchises or permits.

Tampa Electric has a long-term lease for the office building in downtown Tampa which serves as headquarters for TECO Energy, Tampa Electric and numerous other TECO Energy subsidiaries.

PEOPLES GAS SYSTEM

PGS' distribution system extends throughout the areas it serves in Florida and consists of approximately 15,000 miles of pipe, including approximately 9,500 miles of mains and over 5,500 miles of service lines. Mains and service lines are maintained under rights-of-way, franchises or permits.

PGS' operating divisions are located in fourteen markets throughout Florida. While most of the operations and administrative facilities are owned, a small number are leased.

TECO WHOLESALE GENERATION (FORMERLY TECO POWER SERVICES)

TWG Merchant Operating Segment

TWG indirectly holds a 100-percent ownership interest in TECO-Panda Generating Company, LP, which owns Union Power Partners, LP, Panda Gila River, LP, and Trans-Union Interstate Pipeline, LP. Union Power Partners owns 330 acres of land in Union County, Arkansas, on which the 2,200 MW gas-fired combined-cycle Union electric generation plant is located. The first 550-megawatt power block of Union began operating in January 2003 with all power blocks in operation by June 2003. Panda Gila River, LP owns approximately 1,099 acres of land in Maricopa County, Arizona, on which the 2,145-megawatt gas-fired combined-cycle Gila River electric generation plant is located. Trans-Union owns an interstate pipeline associated with the Union facility. See the **TECO Wholesale Generation, Inc.** section of **MD&A** for a discussion of the expected transfer of the ownership of these projects.

Frontera Generation, LP owns 40 acres of land in Hidalgo County, Texas on which the 477-megawatt gas-fired combined cycle Frontera electric generation plant is located.

TM Delmarva Power, LLC has a 100-percent economic interest in Commonwealth Chesapeake Company, LLC, which owns approximately 105 acres of land outside of New Church, in Accomack County, Virginia on which the 315-megawatt oil-fired single cycle Commonwealth Chesapeake Power Station is located.

TPS Dell, LLC, owns approximately 100 acres in the City of Dell in Mississippi County, Arkansas, on which the 599-megawatt gas-fired combined-cycle Dell electric generation plant has been under construction. TPS McAdams, LLC, owns approximately 210 acres of land in McAdams and Sallis in Attala County, Mississippi, on which the 599-megawatt gas-fired combined cycle McAdams electric generation plant has been under construction. Construction on these projects was suspended at the end of 2002 due to projected low energy prices in the markets these plants were expected to serve. Markets will be monitored to determine when these plants will be completed.

Other Unregulated Companies Operating Segment

The company, through its indirect subsidiary TPS Hamakua Land, Inc., has a 50-percent indirect interest in Hamakua Land Partnership, LLP, which owns 140 acres in Hawaii on which the Hamakua Energy Project is located.

TPS Guatemala One, Inc. has a 96.06-percent interest in TCAE, which owns 7 acres in Guatemala on which the Alborada Power Station is located. TPS San Jose, LDC has a 100-percent ownership in a project entity, CGESJ, which owns 190 acres in Guatemala on which the San Jose Power Station is located.

In 2003, Hardee Power Partners, Ltd. (HPP), which owned a 370-MW gas-fired generation facility located in central Florida, was sold to an affiliate of Invenergy LLC and GTCR Golden Rauner LLC. Under the terms of the sale, subsidiaries of the company will continue to provide service to HPP under the existing operation and maintenance agreement. The new owner may, at any time, choose to cancel this agreement.

TECO TRANSPORT

TECO Bulk Terminal's storage and transfer terminal is on a 1,070-acre site fronting on the Mississippi River, approximately 40 miles south of New Orleans. Bulk Terminal owns 342 of these acres in fee, with the remainder held under long-term leases.

TECO Barge operates a fleet of 18 towboats and 726 river barges, approximately 87 percent of which it owns, on the Mississippi, Ohio and Illinois rivers. TECO Barge owns 15 acres of land fronting on the Ohio River at Metropolis, Illinois on which its operating offices, warehouse and repair facilities are located. Fleeting and repair services for its barges and those of other barge lines are performed at this location. Additionally, TECO Barge performs fleeting and supply activities at leased facilities in Cairo, Illinois.

As of Dec. 31, 2003, TECO Ocean Shipping owned and operated a fleet of 8 ocean-going tug/barge units, a 33,500 short ton ocean-going ship, a 40,900 short ton ocean-going ship, and a 41,400 short ton ocean-going ship, with a combined cargo capacity of over 335,000 tons.

TECO COAL

TECO Coal, through its subsidiaries, controls approximately 179,000 acres of coal reserves and mining property in Kentucky, Virginia and Tennessee.

Property

Gatliff Coal Company controls approximately 11,000 acres of coal and mining properties and has operations in Campbell County, Tennessee, as well as in Bell, Knox and Whitley Counties, Kentucky. Additionally, in east central Kentucky, Bear Branch Coal Company and Perry County Coal Corporation control 50,000 acres of coal reserves and operate in Perry, Leslie and Knott Counties. In eastern Kentucky, Premier Elkhorn Coal Company and Pike-Letcher Land Company are located in Letcher and Pike Counties where they control 50,000 acres of properties. Clintwood Elkhorn Mining also operates in Pike County, Kentucky, as well as in Buchanan County Virginia. Clintwood Elkhorn controls 68,000 acres of property.

In situations where property is controlled by lease, the lease terms are generally sufficient to insure that the reserves for the associated operation can be mined within the initial lease term. If, however, extensions are necessary, provisions have generally been made within the original lease, whereby extensions may be granted upon payment of minimum royalties.

Facilities

Coal mined by the operating companies of TECO Coal is processed and shipped from state-of-the art facilities located at each of the operating companies, with Clintwood Elkhorn having two facilities – one at Biggs, Kentucky and one at Hurley, Virginia. The equipment at each facility is in good condition and regularly maintained by qualified personnel. Major renovations are currently on-going at the Perry County Coal facility that will enable the plant to meet the additional production requirements brought about by the opening of the Bear Branch Elkhorn 4 seam underground mine. The following is a summary of the TECO Coal processing facilities:

Company	*Facility*	*Location*	*Railroad Service*	*Utility Service*
Gatliff Coal	Ada Tipple	Himyar, KY	CSX Railroad	RECC
Clintwood Elkhorn	Clintwood #2 Plant	Biggs, KY	Norfolk Southern	American Electric Power
Clintwood Elkhorn	Clintwood #3 Plant	Hurley, VA	Norfolk Southern	American Electric Power
Premier Elkhorn	Burk Branch Plant	Myra, KY	CSX Railroad	American Electric Power
Perry County Coal	Perry County Plant	Hazard, KY	CSX Railroad	American Electric Power

Significant projects completed in 2003 included completion of preparation plant upgrades at Perry County.

Coal Reserves

As of Dec. 31, 2003, the TECO Coal Corporation operating companies have a combined estimated 219.4 million tons of recoverable reserves, all of which are assigned. The reserves are proven and probable. All of the reserves consist of High Vol A Bituminous coal. Reserves are generally considered to be tonnages that are proven and probable and meet the generally accepted mining criteria including, but not limited to, mining height, preparation plant recovery, and strip ratio. These reserves are generally projected to be mined and sold at a profit, based on year-end price and cost levels. When calculating reserves, TECO Coal has assumed the following recovery rates for the various mining methods:

	Mining Recovery Rates
Underground	52%
Contour, Surface	85%
Point Removal/Mt. Top	90%
Auger	30%
Highwall Miner	50%

The following is a summary of the coal quality associated with each of the operations.

	Average Quality			Assigned Reserves		Surface	Underground	Total
Company	BTU/lb.	% Ash	% Sulfur	% Owned	% Leased	Reserves (000s)	Reserves (000s)	Reserves (000s)
Gatliff Coal	14,586	3.84	0.96	0	100	1,800	9,492	11,292
Perry County Coal	13,091	7.20	0.90	0	100	5,609	15,795	21,404
Bear Branch	13,227	6.23	0.92	0	100	—	69,899	69,899
Premier Elkhorn Coal/ Pike Letcher Land (1)	13,976	6.78	1.16	90	10	19,655	53,700	73,355
Clintwood Elkhorn Mining	14,198	7.35	1.05	10	90	12,141	31,345	43,486
Total Reserves	13,726	6.61	1.03			39,205	180,231	219,436

(1) The Premier Elkhorn/Pike Letcher Land reserves were reduced from the 2001 amounts due to unfavorable economic conditions.

The following table shows a further breakdown of product by geographic region with projected market type.

Region/Company	Product	BTU/lb.	% Ash	% Sulfur	Reserves (000s)	% by Region
East Central Kentucky						
Gatliff Coal	Steam coal	14,586	3.84	0.96	11,292	5.15
Perry County Coal	Steam coal	14,076	7.74	0.97	21,404	9.75
Bear Branch Coal	Steam coal	14,223	6.70	0.99	69,899	31.85
					102,595	46.75
Eastern Kentucky						
Premier/Pike Letcher Land	Steam coal	13,976	6.78	1.16	73,355	33.43
Clintwood	Steam coal	12,713	13.40	1.08	1,309	0.60
Clintwood	Metallurgical coal	14,429	6.51	1.08	20,521	9.35
					95,185	43.38
Southwestern Virginia						
Clintwood	Steam coal	12,713	13.40	1.08	6,650	3.03
Clintwood	Metallurgical coal	14,621	5.37	1.01	15,006	6.84
					21,656	9.87
Total					219,436	100.00

TECO Coal Corporation's reserves are based on over 1700 data points, including drill holes, prospect measurements, and mine measurements. Reserve classification is determined by evaluation of engineering and geologic information along with economic analysis. These reserves are adjusted periodically to reflect fluctuations in the economics in the market and/or changes in engineering parameters and/or geologic conditions. The information is assembled by qualified geologists and engineers located throughout the company. The information is constantly being updated to reflect new data for existing property as well as new acquisitions and depleted reserves. Information is entered into sophisticated computer modeling programs from which preliminary reserves estimations are generated. Final determinations of reserves are made after in-house geologists have reviewed the computer models and manipulated the grids to better reflect regional trends.

TECO COALBED METHANE

The sale of TECO Coalbed Methane's gas assets was substantially completed in December 2002, and the final proceeds were paid in January 2003. (See **Business – TECO Coalbed Methane** section.) TECO Coalbed Methane's gas production for 2002 was 14.2 billion cubic feet (Bcf), at an effective gas price, including the effect of hedging, of about $2.80 per million cubic feet (Mcf) compared to production of 15 Bcf in 2001 at an effective gas price, including the effects of hedging, of about $3.66 Mcf.

Item 3. LEGAL PROCEEDINGS.

TM Delmarva Power Arbitration Proceeding

A dispute resulting in an arbitration proceeding was brought against a TWG subsidiary, TM Delmarva Power, L.L.C. (TMDP), by the non-equity member, NCP of Virginia, L.L.C. (NCP), in the Commonwealth Chesapeake Project (CCC). The arbitration panel, in a 2-to-1 decision, found in favor of NCP and issued an interim award on Dec. 17, 2002 and, after several briefing cycles and a reopened hearing, issued its final award in September 2003.

Under the award TMDP is obligated to acquire NCP's voting and other rights, pay NCP interest on the deemed acquisition price from a pre-determined date, and pay NCP's legal fees as prescribed under the final award. The forced acquisition created a pre-tax loss of $32.0 million, representing the excess of the purchase price over the fair value of the interests acquired. TMDP is seeking to vacate the arbitration award in the U.S. District Court for the District of Columbia and has not yet paid the amount of the award. As of Dec. 31, 2003, the company has reserved for the full $46.9 million, representing the maximum payment obligation for the award plus accrued interest. The vacatur proceeding is still pending, and is expected to be completed in the third or fourth quarter of 2004.

Other Actions

In March 2001, TWG (under its former name of TECO Power Services) was served with a lawsuit filed in the Circuit Court for Hillsborough County by a Tampa-based firm called Grupo Interamerica, L.L.C. ("Grupo") in connection with a potential investment in a power project in Columbia in 1996. Grupo alleges, among other things, that TWG breached an oral contract with Grupo that would have allowed Grupo to acquire up to a 20-percent interest in the Columbian wholesale generation project when TWG declined to invest in such project. Grupo is seeking damages equal to the net present value of 20-percent of the project over its life. TWG disputes the allegations and denies liability since any understanding made regarding the investment in the project was subject to TECO Energy Board approval which was not obtained. A trial date has not been set.

Three lawsuits have been filed in the Circuit Court in Hillsborough County against Tampa Electric, in connection with the location of transmission structures in certain residential areas, by residents in the areas surrounding the structures. The high-voltage power lines are needed by Tampa Electric to move electricity to the northwest part of its service territory where population growth has been experienced. The residents are seeking to remove the poles or to receive monetary damages. Tampa Electric is working with the community to determine the feasibility of alternate routes or structures or some combination.

See also the **Enron Related Matters** and **Superfund and Former Manufactured Gas Plant Sites** sections of **MD&A** and the discussion of environmental matters in **Note 20** to the TECO Energy **Consolidated Financial Statements** and **Note 14** to the Tampa Electric Company **Consolidated Financial Statements**.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

No matter was submitted during the fourth quarter of 2003 to a vote of TECO Energy's security holders, through the solicitation of proxies or otherwise.

EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages, current positions and principal occupations during the last five years of the current executive officers of TECO Energy are described below.

Name	Age	Current Positions and Principal Occupations During Last Five Years
Robert D. Fagan	59	Chairman of the Board, President and Chief Executive Officer, December 1999 to date; President and Chief Executive Officer, May 1999 to December 1999; and prior thereto, President of PP&L Global, Inc. (diversified energy company), Fairfax, Virginia.
Charles R. Black	53	Senior Vice President-Generation, September 2003 to date; Vice President-Energy Supply, Energy and Construction, Tampa Electric Company, February 2000 to September 2003; Vice President-Energy Supply, Tampa Electric Company, November 1996 to February 2000.
William N. Cantrell	51	President, Tampa Electric Company, September 2003 to date, President, Peoples Gas System, April 2000 to date and President, TECO Solutions, Inc., September 2000 to date; President, Peoples Gas Companies, June 1997 to April 2000, and President, Bosek, Gibson and Associates, Inc., January 1998 to September 2000.
Clinton E. Childress	55	Senior Vice President-Human Resources and Services, September 2003 to date; Chief Human Resources Officer, July 2000 to September 2003; and prior thereto, Director of Compensation and Benefits.
Gordon L. Gillette	44	Senior Vice President-Finance and Chief Financial Officer, April 2001 to date; Vice President-Finance and Chief Financial Officer, April 1998 to April 2001.
Richard Lehfeldt	52	Senior Vice President-External Affairs, November 1999 to date; and prior thereto, Vice President and Assistant General Counsel of Edison Mission Energy (independent power company), Irvine, California.
Sheila M. McDevitt	57	Senior Vice President-General Counsel, April 2001 to date; Vice President-General Counsel, January 1999 to April 2001; and prior thereto, Vice President-Assistant General Counsel.
John B. Ramil	48	Executive Vice President and Chief Operating Officer, September 2003 to date; Executive Vice President, December 2002 to September 2003; President, Tampa Electric Company, April 1998 to September 2003.
D. Jeffrey Rankin	57	President of TECO Transport Corporation, since prior to 1999.
J. J. Shackleford	57	President of TECO Coal Corporation, since prior to 1999.

There is no family relationship between any of the persons named above. The term of office of each officer extends to the meeting of the Board of Directors following the next annual meeting of shareholders, scheduled to be held on April 28, 2004, and until such officer's successor is elected and qualified.

PART II

Item 5. MARKET PRICE OF AND DIVIDENDS ON THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

The following table shows the high and low sale prices for shares of TECO Energy common stock, which is listed on the New York Stock Exchange, and dividends paid per share, per quarter.

	1st Quarter	*2nd Quarter*	*3rd Quarter*	*4th Quarter*
2003				
High	$ 17.00	$ 13.69	$ 14.20	$ 14.85
Low	$ 9.47	$ 10.05	$ 11.50	$ 11.80
Close	$ 10.63	$ 11.99	$ 13.82	$ 14.41
Dividend	$ 0.355	$ 0.19	$ 0.19	$ 0.19
2002				
High	$ 28.94	$ 29.05	$ 24.71	$ 16.48
Low	$ 23.40	$ 22.70	$ 14.20	$ 10.02
Close	$ 28.63	$ 24.75	$ 15.88	$ 15.47
Dividend	$ 0.345	$ 0.355	$ 0.355	$ 0.355

The approximate number of shareholders of record of common stock of TECO Energy as of Feb. 29, 2004 was 22,097.

Dividends on TECO Energy's common stock are declared and paid at the discretion of its Board of Directors. The primary sources of funds to pay dividends to its common stockholders is dividends and other distributions from its operating companies. Tampa Electric's first mortgage bond indenture and certain long-term debt at PGS contain restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric Company. Tampa Electric's first mortgage bond indenture does not limit loans or advances. As of Dec. 31, 2003 and 2002, balances restricted as to transfers from Tampa Electric to TECO Energy under the first mortgage bonds were 3% and 20%, respectively, of consolidated common equity. Tampa Electric's new credit facilities include a covenant limiting cumulative distributions and outstanding affiliate loans. (See the **Restrictions on Dividend Payments and Transfer of Assets** section in **Note 1** to the TECO Energy **Consolidated Financial Statements**.)

TECO Energy's $380 million note indenture contains a covenant that requires the company to achieve certain interest coverage levels in order to pay dividends. TECO Energy's Merrill Lynch credit facility contains a covenant that could limit the payment of dividends exceeding $40 million in any quarter under certain circumstances if the facility is drawn. (See **Covenants in Financing Agreements** section of **MD&A**, and **Notes 6, 7** and **20** to the TECO Energy **Consolidated Financial Statements** for a more detailed description of significant financial covenants.

In addition, TECO Diversified, Inc., a wholly-owned subsidiary of TECO Energy and the holding company for TECO Transport, TECO Coal and TECO Solutions, has a guarantee related to a coal supply agreement that limits the payment of dividends to its common shareholder, TECO Energy, but does not limit loans or advances.

TECO Energy has the right to defer payments on its subordinated notes issued in connection with the issuances of trust preferred securities by TECO Capital Trust I or TECO Capital Trust II. Should the company exercise this right, it would be prohibited from paying cash dividends on its common stock until the unpaid distributions on the subordinated notes are made. TECO Energy has not exercised that right.

All of Tampa Electric Company's common stock is owned by TECO Energy, Inc. and, therefore, there is no market for the stock. Tampa Electric Company pays dividends substantially equal to its net income applicable to common stock to TECO Energy. Such dividends totaled $151.4 million in 2003, $197.4 million in 2002 and $171.8 million for 2001. See the **Restrictions on Dividend Payments and Transfer of Assets** section in **Note 1** to the TECO Energy **Consolidated Financial Statements** for Tampa Electric Company for a description of restrictions on dividends on its common stock.

Item 6. SELECTED FINANCIAL DATA.

A summary of selected financial information for TECO Energy, Inc. for each of the last five fiscal years, is set forth under the heading **Selected Financial Data** in the **2003 Annual Report**, which information is hereby incorporated by reference and filed as part of **Exhibit 13** to this report.

Item 7. MANAGEMENT'S DISCUSSION & ANALYSIS OF FINANCIAL CONDITION & RESULTS OF OPERATIONS.

A discussion of TECO Energy, Inc.'s consolidated results of operations and financial condition is set forth on under the heading **Management's Discussion & Analysis of Financial Condition & Results of Operations** in the **2003 Annual Report**, which discussion is hereby incorporated by reference and filed as part of **Exhibit 13** to this report.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Information responding to Item 7A appears in the **2003 Annual Report** under the heading **Management's Discussion & Analysis of Financial Condition & Results of Operations — Disclosures About Market Risk**, which information is hereby incorporated by reference and filed as part of **Exhibit 13** to this report.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

TECO ENERGY, INC.

Information responding to Item 8 for TECO Energy, Inc., appears in the **2003 Annual Report** under the following headings: **Consolidated Financial Statements — Consolidated Balance Sheets**, **Consolidated Financial Statements — Consolidated Statements Of Income**, **Consolidated Financial Statements — Consolidated Statements of Comprehensive Income**, **Consolidated Financial Statements — Consolidated Statements of Cash Flows**, **Consolidated Financial Statement — Consolidated Statements of Common Equity**, **Notes to the Consolidated Financial Statements**, and **Report of Independent Certified Public Accountants**, which information is hereby incorporated by reference and filed as part of **Exhibit 13** to this report.

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All other financial statement schedules have been omitted since they are not required, are inapplicable or the required information is presented in the financial statements or notes thereto.

Report of Independent Certified Public Accountants on Financial Statement Schedules

To the Board of Directors of TECO Energy, Inc.:

Our audits of the consolidated financial statements referred to in our report dated March 2, 2004 appearing in the 2003 Annual Report to Shareholders of TECO Energy, Inc. (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedules listed in Item 15(a)(2) of this Form 10-K. In our opinion, these financial statement schedules present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PricewaterhouseCoopers LLP

Tampa, Florida
March 2, 2004

TAMPA ELECTRIC COMPANY
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All other financial statement schedules have been omitted since they are not required, are inapplicable or the required information is presented in the financial statements or notes thereto.

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

To the Board of Directors and Shareholders of Tampa Electric Company:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Tampa Electric Company and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) (2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Tampa, Florida
March 2, 2003

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TAMPA ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

Assets *(millions) Dec. 31,*	*2003*	*2002*
Property, plant and equipment		
Utility plant in service		
Electric	$ 4,693.5	$ 4,310.8
Gas	778.2	746.7
Construction work in progress	470.0	768.5
Property, plant and equipment, at original costs	5,941.7	5,826.0
Accumulated depreciation	(1,808.2)	(1,720.4)
	4,133.5	4,105.6
Other property	3.7	7.9
Total property, plant and equipment	4,137.2	4,113.5
Current assets		
Cash and cash equivalents	33.6	6.9
Receivables, less allowance for uncollectibles of $1.1 million and $1.1 million at Dec. 31, 2003 and 2002, respectively	186.0	186.5
Inventories		
Fuel, at average cost	71.2	79.1
Materials and supplies	43.8	48.1
Prepayments and other	22.8	18.4
Total current assets	357.4	339.0
Deferred debits		
Deferred income taxes	133.5	133.3
Unamortized debt expense	23.2	23.7
Regulatory assets	188.3	163.2
Other	0.1	5.6
Total deferred debits	345.1	325.8
Total assets	$ 4,839.7	$ 4,778.3

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS (continued)

Liabilities and capital (millions) Dec. 31.	2003	2002
Capital		
Common stock	$ 1,376.8	$ 1,535.1
Retained earnings	274.9	302.9
Total capital	1,651.7	1,838.0
Long-term debt, less amount due within one year	1,590.9	1,345.6
Total capitalization	3,242.6	3,183.6
Current liabilities		
Long-term debt due within one year	6.1	81.0
Notes payable	—	10.5
Accounts payable	167.9	178.8
Customer deposits	101.4	94.6
Interest accrued	26.7	18.3
Taxes accrued	82.9	46.9
Total current liabilities	385.0	430.1
Deferred credits		
Deferred income taxes	474.5	483.1
Investment tax credits	22.6	27.1
Regulatory liabilities	560.2	538.7
Other	154.8	115.7
Total deferred credits	1,212.1	1,164.6
Total liabilities and capital	$ 4,839.7	$ 4,778.3

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME

(millions) *For the years ended Dec. 31.*	*2003*	*2002*	*2001*
Revenues			
Electric (includes franchise fees and gross receipts taxes of $64.4 million in 2003, $63.5 million in 2002, and $56.0 million in 2001)	$ 1,585.4	$ 1,582.5	$ 1,411.8
Gas (includes franchise fees and gross receipts taxes of $13.3 million in 2003, $10.3 million in 2002, and $15.1 million in 2001)	408.4	318.1	352.9
Total revenues	$ 1,993.8	1,900.6	1,764.7
Expenses			
Operations			
Fuel	443.3	424.1	346.5
Purchased power	234.9	253.7	209.7
Cost of natural gas sold	224.0	148.9	186.4
Other	257.7	256.4	249.1
Maintenance	94.3	112.0	103.2
Depreciation	243.0	220.1	201.3
Restructuring charges	14.0	16.6	—
Taxes, federal and state income	94.0	100.3	97.7
Taxes, other than income	136.7	132.6	129.3
Total expenses	1,741.9	1,664.7	1,523.2
Income from operations	251.9	235.9	241.5
Other (expense) income			
Allowance for other funds used during construction	19.8	24.9	6.6
Other income, net	1.2	1.5	4.1
Asset impairment (net of income tax benefit of $30.7 million)	(48.9)	—	—
Total other (expense) income	(27.9)	26.4	10.7
Interest charges			
Interest on long-term debt	102.7	77.5	62.5
Other interest	5.5	(1.6)	15.2
Allowance for borrowed funds used during construction	(7.6)	(9.6)	(2.6)
Total interest charges	100.6	66.3	75.1
Net income	$ 123.4	$ 196.0	$ 177.1

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions) *For the years ended Dec. 31.*	*2003*	*2002*	*2001*
Net income	$ 123.4	$ 196.0	$ 177.1
Other comprehensive (loss) income, net of tax			
Net unrealized gain (loss) on cash flow hedges	—	0.1	(0.1)
Other comprehensive income (loss), net of tax	—	0.1	(0.1)
Comprehensive income	$ 123.4	$ 196.1	$ 177.0

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions) *For the years ended Dec. 31,*	*2003*	*2002*	*2001*
Cash flows from operating activities			
Net income	$ 123.4	$ 196.0	$ 177.1
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation	243.0	220.1	201.3
Deferred income taxes	(23.9)	23.6	(2.0)
Investment tax credits, net	(4.6)	(4.4)	(4.5)
Allowance for funds used during construction	(27.4)	(34.5)	(9.2)
Loss on sales of assets, pre-tax	0.8	—	—
Asset impairment, pre-tax	79.6	—	—
Deferred recovery clause	(27.3)	72.2	(19.0)
Refunded to customers	—	(6.4)	—
Receivables, less allowance for uncollectibles	0.5	(19.8)	19.1
Inventories	12.2	(7.2)	(10.8)
Prepayments and other deposits	(3.1)	(2.4)	(9.2)
Taxes accrued	36.0	(10.4)	(14.3)
Interest accrued	8.4	2.3	(18.1)
Accounts payable	(10.8)	43.1	(52.4)
Other	70.4	2.5	35.2
Cash flows from operating activities	477.2	474.7	293.2
Cash flows from investing activities			
Capital expenditures	(331.7)	(685.7)	(499.3)
Allowance for funds used during construction	27.4	34.5	9.2
Net proceeds from sales of assets	4.3	—	—
Cash flows from investing activities	(300.0)	(651.2)	(490.1)
Cash flows from financing activities			
Proceeds from contributed capital from parent	—	217.0	170.0
Return of contributed capital to parent	(158.3)	—	—
Proceeds from long-term debt	250.0	689.3	250.0
Repayment of long-term debt	(80.3)	(302.4)	(54.4)
Net (decrease) increase in short-term debt	(10.5)	(238.5)	17.8
Payment of dividends	(151.4)	(197.4)	(171.8)
Cash flows from financing activities	(150.5)	168.0	211.6
Net (decrease) increase in cash and cash equivalents	26.7	(8.5)	14.7
Cash and cash equivalents at beginning of year	6.9	15.4	0.7
Cash and cash equivalents at end of year	$ 33.6	$ 6.9	$ 15.4
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest	$ 109.4	$ 74.0	$ 85.3
Income taxes	$ 61.9	$ 143.9	$ 119.9

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(millions) *For the years ended Dec. 31,*	*2003*	*2002*	*2001*
Balance, beginning of year	$ 302.9	$ 304.3	$ 299.0
Add: Net income	123.4	196.0	177.1
	426.3	500.3	476.1
Deduct: Cash dividends on capital stock			
Common	151.4	197.4	171.8
	151.4	197.4	171.8
Balance, end of year	$ 274.9	$ 302.9	$ 304.3

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(millions, except share amounts)	*Current Redemption Price*	*Capital Stock Outstanding Dec. 31,* *Shares*	*Amount*	*Cash dividends paid (1)* *Per Share*	*Amount*
Common stock — without par value					
25 million shares authorized					
2003	N/A	10	$ 1,376.8	N/A	$ 151.4
2002	N/A	10	$ 1,535.1	N/A	$ 197.4
Preferred stock — $100 par value					
1.5 million shares authorized, none outstanding.					
Preferred stock – no par					
2.5 million shares authorized, none outstanding.					
Preference stock – no par					
2.5 million shares authorized, none outstanding.					

(1) Quarterly dividends paid on Feb. 15, May 15, Aug. 15 and Nov. 15.

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)

Long-Term Debt (millions) Dec. 31.	*Due*	*2003*	*2002*
Tampa Electric			
First mortgage bonds (issuable in series):			
7.75% (effective rate of 7.96%)	2022	$ 75.0	$ 75.0
6.125% (effective rate of 6.61%)	2003	—	75.0
Installment contracts payable (1):			
6.25% Refunding bonds (effective rate of 6.81%) (2)	2034	86.0	86.0
5.85% Refunding bonds (effective rate of 5.88%)	2030	75.0	75.0
5.1% Refunding bonds (effective rate of 5.77%) (3)	2013	60.7	60.7
5.5% Refunding bonds (effective rate of 6.34%) (3)	2023	86.4	86.4
4% (effective rate of 4.22%) (4)	2025	51.6	51.6
4% (effective rate of 4.17%) (4)	2018	54.2	54.2
4.25% (effective rate of 4.44%) (4)	2020	20.0	20.0
Notes: 6.875% (effective rate of 6.98%) (5)	2012	210.0	210.0
6.375% (effective rate of 7.35%) (5)	2012	330.0	330.0
5.375% (effective rate of 5.59%) (5)	2007	125.0	125.0
6.25% (effective rate of 6.31%) (5)	2016	250.0	—
		1,423.9	1,248.9
Peoples Gas System			
Senior Notes: (6) 10.35%	2007	3.4	4.2
10.33%	2008	4.8	5.6
10.3%	2009	6.4	7.2
9.93%	2010	6.6	7.4
8.0%	2012	23.3	25.4
Notes: 6.875% (effective rate of 6.98%) (5)	2012	40.0	40.0
6.375% (effective rate of 7.34%) (5)	2012	70.0	70.0
5.375% (effective rate of 5.58%) (5)	2007	25.0	25.0
		179.5	184.8
		1,603.4	1,433.7
Unamortized debt premium (discount), net		(6.4)	(7.1)
		1,597.0	1,426.6
Less amount due within one year (7)		6.1	81.0
Total long-term debt		$ 1,590.9	$ 1,345.6

(1) Tax exempt securities.

(2) Proceeds of these bonds were used to refund bonds with an interest rate of 9.9% in February 1995. For accounting purposes, interest expense has been recorded using a blended rate of 6.52% on the original and refunding bonds, consistent with regulatory treatment.

(3) Proceeds on these bonds were used to refund bonds with interest rates of 5.75% to 8%.

(4) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002.

(5) These notes are subject to redemption in whole or in part, at any time, at the option of the company.

(6) These long-term debt agreements contain various restrictive covenants, including provisions related to interest coverage, maximum levels of debt-to-total capitalization and limitations on dividends.

(7) Of the amount due in 2004, $0.8 million may be satisfied by the substitution of property in lieu of cash payments.

A substantial part of the tangible assets of Tampa Electric is pledged as collateral to secure its first mortgage bonds, and certain pollution control equipment is pledged to secure installment contracts payable. Maturities and annual sinking fund requirements of long-term debt for the years 2005, 2006, 2007 and 2008 are $5.5 million, $5.9 million, $156.1 million and $5.7 million, respectively.

At Dec. 31, 2003, total long-term debt had a carrying amount of $1,590.9 million and an estimated fair market value of $1,697.4 million. The estimated fair market value of long-term debt was based on quoted market prices for the same or similar issues, on the current rates offered for debt of the same remaining maturities, or for long-term debt issues with variable rates that approximate market rates, at carrying amounts. The carrying amount of long-term debt due within one year approximated fair market value because of the short maturity of these instruments.

In April 2003, Tampa Electric issued $250 million of 6.25% Senior Notes due in 2016, in a private placement. Net proceeds of approximately $250 million were used to repay short-term indebtedness and for general corporate purposes. The 6.25% Senior Notes contain covenants that (1) require Tampa Electric Company to maintain, as of the last day of each fiscal quarter, a debt-to-capital ratio, as defined in the agreement, that does not exceed 60%, and (2) prohibit the creation of any liens on any of its property in excess of $787 million in the aggregate, with certain exceptions, as defined, without equally and ratably securing the 6.25% Senior Notes.

The accompanying notes are an integral part of the consolidated financial statements.

1. Significant Accounting Policies

The significant accounting policies are as follows:

Principles of Consolidation

Tampa Electric Company is a wholly-owned subsidiary of TECO Energy, Inc. and is comprised of the Electric division, generally referred to as Tampa Electric, and the Natural Gas division, generally referred to as Peoples Gas System (PGS).

All significant intercompany balances and intercompany transactions have been eliminated in consolidation.

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles (GAAP). Actual results could differ from these estimates.

Planned Major Maintenance

Tampa Electric and PGS expense major maintenance costs as incurred. Concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with Florida Public Service Commission (FPSC) and Federal Energy Regulatory Commission (FERC) regulations.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2003, 2002 and 2001. Total AFUDC for 2003, 2002 and 2001 was $27.4 million, $34.5 million, and $9.2 million, respectively. The base on which AFUDC is calculated excludes construction work-in-progress which has been included in rate base.

Deferred Income Taxes

TECO Energy utilizes the liability method in the measurement of deferred income taxes. Under the liability method, the temporary differences between the financial statement and tax bases of assets and liabilities are reported as deferred taxes measured at current tax rates. Tampa Electric and PGS are regulated, and their books and records reflect approved regulatory treatment, including certain adjustments to accumulated deferred income taxes and the establishment of a corresponding regulatory tax liability reflecting the amount payable to customers through future rates.

Investment Tax Credits

Investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property.

Revenue Recognition

Tampa Electric Company recognizes revenues consistent with the Securities and Exchange Commission's Staff Accounting Bulleting (SAB) 104, *Revenue Recognition in Financial Statements*. The interpretive criteria outlined in SAB 104 are that 1) there is persuasive evidence that an arrangement exists; 2) delivery has occurred or services have been rendered; 3) the fee is fixed and determinable; and 4) collectibility is reasonably assured. Except as discussed below, Tampa Electric Company recognizes revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer.

The regulated utilities' (Tampa Electric and Peoples Gas System) retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by FERC. See **Note 3** for a discussion of significant regulatory matters and the applicability of Financial Accounting Standard No. (FAS) 71, *Accounting for the Effects of Certain Types of Regulation*, to the company.

Revenues and Fuel Costs

Revenues include amounts resulting from cost recovery clauses which provide for monthly billing charges to reflect increase or decreases in fuel, purchase power, conservation and environmental costs for Tampa Electric and purchase gas, interstate pipeline capacity and conservation costs for PGS. These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over-recovery or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. Over-recoveries of costs are recorded as deferred credits, and under-recoveries of costs are recorded as deferred charges.

Certain other costs incurred by the regulated utilities are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed. The regulated utilities accrue base revenues for services rendered but unbilled to provide a closer matching of revenues and expenses. See **Note 3**.

As of Dec. 31, 2003 and 2002, unbilled revenues of $45.7 million and $41.3 million, respectively, are included in the "receivables" line item on the balance sheet.

Purchased Power

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. As a result of the sale of Hardee Power Partners, Ltd. (HPP) in October 2003 (see **Notes 14** and **21** to the **TECO Energy Consolidated Financial Statements** in the **2003 Annual Report**), subsequent power purchases from HPP are reflected as non-affiliate purchases by Tampa Electric. Tampa Electric's long-term power purchase agreement from HPP was not affected by TPS' sale of HPP. Under the existing agreement, which has been approved by the FERC and FPSC, Tampa Electric has the right to purchase, on average, approximately 52% of the total output of the Hardee power station. Tampa Electric purchased power from non-TECO Energy affiliates, including HPP, at a cost of $234.9 million, $253.7 million, and $209.7 million, respectively, for the years ended Dec. 31, 2003, 2002 and 2001. These purchased power costs are recoverable through an FPSC-approved cost recovery clause.

Depreciation

Tampa Electric provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage value, of depreciable property over its estimated service life. The provision for utility plant in service, expressed as a percentage of the original cost of depreciable property was 4.6% for 2003 and 4.2% for 2002 and 2001. For the year ended Dec. 31, 2003, Tampa Electric recognized depreciation expense of $36.6 million related to accelerated depreciation of certain Gannon power station coal-fired assets, in accordance with a regulatory order issued by the FPSC. Construction work-in-progress is not depreciated until the asset is completed or placed in service.

The implementation of FAS 143, *Accounting for Asset Retirement Obligations* in 2003 resulted in an increase in the carrying amount of long-lived assets and the reclassification of the accumulated reserve for cost of removal from accumulated depreciation to "Regulatory liabilities," for all periods presented. The adjusted capitalized amount is depreciated over the remaining useful life of the asset (see **Note 4**).

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

Tampa Electric Company is allowed to recover certain costs incurred from customers through prices approved by the regulatory process. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. These amounts totaled $77.7 million, $73.8 million and $71.7 million, for the years ended Dec. 31, 2003, 2002 and 2001, respectively. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statements of Income in "Taxes, other than income". For the years ended Dec. 31, 2003, 2002 and 2001, these totaled $77.5 million, $73.7 million and $71.0 million, respectively.

Excise taxes paid by the regulated utilities are not material and are expenses when incurred.

Asset Impairments

Effective Jan. 1, 2002, Tampa Electric Company adopted FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which supersedes FAS 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*. FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a segment of a business.

In accordance with FAS 144, the company assesses whether there has been impairment of its long-lived assets and certain intangibles held and used by the company when such impairment indicators exist. Indicators of impairment existed for certain long-term turbine purchase contracts, triggering a requirement to ascertain the recoverability of these assets using undiscounted cash flows before interest expense. See **Note 7** for specific details regarding the results of these assessments.

Restrictions on Dividend Payments and Transfer of Assets

Tampa Electric's first mortgage bond indenture and certain long-term debt at PGS contain restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric Company. Tampa Electric's first mortgage bond indenture does not limit loans or advances. As of Dec. 31, 2003 and 2002, the balances restricted as to transfers from Tampa Electric to TECO Energy under the first mortgage bonds were 3% and 20%, respectively, of consolidated common equity. Tampa Electric's new credit facilities include a covenant limiting cumulative distributions and outstanding affiliate loans.

See **Notes 5** and **14** for a more detailed description of significant financial covenants.

2. Derivatives and Hedging

From time to time, Tampa Electric Company enters into futures, forwards, swaps and option contracts to limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations.

The company uses derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective is to reduce the impact of market price volatility on ratepayers, and uses derivative instruments primarily to optimize the value of physical assets, including generation capacity, natural gas production and natural gas delivery.

The risk management policies adopted by the company provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operating companies.

Effective Jan. 1, 2001, the company adopted FAS 133, *Accounting for Derivative Instruments and Hedging Activities*. The new standard requires companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of other comprehensive income (OCI) or in net income, depending on the designation of those instruments. The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or the loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of its reclassification. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the amount paid or received on the underlying physical transaction. Additionally, amounts deferred in OCI related to an effective designated cash flow hedge must be reclassified to current earnings if the anticipated hedged transaction is no longer probable of occurring.

At Dec. 31, 2003 and 2002, respectively, the company had derivatives assets of $4.8 million and $3.5 million. The amounts recorded in accumulated other comprehensive income (OCI), as of Dec. 31, 2003 and 2002, are fully offset by regulatory assets or liabilities to reflect the impact of the fuel recovery clause on the results of hedging activities.

For the years ended Dec. 31, 2003, 2002 and 2001, Tampa Electric Company reclassified from OCI to earnings, pre-tax gains (losses) of $3.2 million, $0.2 million and $(0.7) million, respectively. Amounts reclassified were primarily related to cash flow hedges of physical purchases of natural gas. For these types of hedge relationships, the gain or loss on the derivative, reclassified from OCI to earnings, is offset by a regulatory asset or liability, reflecting the fact that all fuel hedging activity is subject to the fuel recovery clause (see **Note 3**).

Based on the fair values of derivatives at Dec. 31, 2003, pre-tax gains of $4.8 million are expected to be reversed from OCI to the Consolidated Statements of Income within the next twelve months. However, these gains and other future reclassifications from OCI will fluctuate with movements in the underlying market price of the derivative instruments. The company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2004.

3. Regulatory

As discussed in **Note 1**, Tampa Electric's and PGS' retail business are regulated by the FPSC.

Base Rate – Tampa Electric

Since the expiration, in 1999, of agreements entered into in 1996 with Florida's Office of Public Counsel (OPC) and the Florida Industrial Power Users Group (FIPUG), which were approved by the FPSC, Tampa Electric is not under a new stipulation to stabilize prices while securing fair earnings opportunities. Tampa Electric's rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other PFSC actions as a result of rate other proceedings initiated by Tampa Electric, FPSC staff or other interest parties. Tampa Electric expects to continue earnings within its allowed ROE range.

Tampa Electric has not sought a base rate increase to recover the investment in the Bayside Power Station, of which phase one entered service in April 2003.

Cost Recovery – Tampa Electric

2003 Proceedings

In February 2003, Tampa Electric filed a request for an additional fuel cost adjustment of almost $61 million due to continued increases in the cost of natural gas and oil and the plan to phase out Gannon Units 1 through 4 in 2003. In March 2003, the FPSC approved Tampa Electric's new fuel rates as well as new fuel rates for the other peninsular Florida investor-owned utilities.

In September 2003, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery rates for the period January through December 2004. In November, the FPSC approved Tampa Electric's requested changes except for the lower coal transportation rate as a results of a new contract with TECO Transport described below. The resulting rates include the impacts of increased use of natural gas at the Bayside Power Station and the collection of $91 million for under recovery of fuel expense for 2002 and 2003. The filing also included estimated waterborne transportation rates for coal transportation services (see **Note 12**). The FPSC did not allow the recovery of $8.4 million it characterized as savings from shutting down the Gannon Station earlier than originally planned which the FPSC deemed generated operations and maintenance savings. The rates include projected costs associated with environmental projects required under the Florida Department of Environmental Protection (FDEP) Consent Final Judgment (see **Note 14** for additional details regarding these environmental matters). The costs associated with this disallowance were recognized in 2003.

Tampa Electric filed its objection to the disallowance of the recovery of the $8.4 million and a motion asking FPSC to reconsider its decision because all facts and law were not taken into account. The motion was filed on Jan. 6, 2004, and a decision on this matter is expected in the first quarter of 2004. See **Regulation – Cost Recovery Clauses** section of **MD&A**.

As part of the regulatory process, it is reasonably likely that third parties may intervene on this or similar matters in the future. The company is unable to predict the timing, nature or impact of such future actions.

Base Rate – Peoples Gas

On June 27, 2002, PGS filed a petition with the FPSC to increase its service rates. The requested rates would have resulted in a $22.6 million annual base revenue increase, reflecting a ROE mid-point of 11.75 percent.

On the date of the FPSC hearing, PGS agreed to a settlement with all parties involved, and a final FPSC order was granted on Dec. 17, 2002. PGS received authorization to increase annual base revenues by $12.05 million. The new rates allow for an ROE range of 10.25 to 12.25 percent with an 11.25 percent midpoint ROE and a capital structure with 57.43 percent equity. The increase went into effect on Jan. 16, 2003.

Cost Recovery – Peoples Gas

In November 2003, the FPSC approved rates under Peoples' Gas Purchased Gas Adjustment (PGA) cap factor for the period January 2004 through December 2004. The PGA is a factor that can vary monthly due to changes in actual fuel costs but is not anticipated to exceed the annual cap.

Other Items

Coal Transportation Contract

Tampa Electric's contract for coal transportation and storage services with TECO Transport expired on Dec. 31, 2003. In June 2003, Tampa Electric issued a Request For Proposal (RFP) to potential providers requesting services for the next five years. The result of the RFP process was the execution of a new contract between Tampa Electric and TECO Transport with market rates supported by the results of the RFP and an independent expert in maritime transportation matters. The prudence of the RFP process and final contract is expected to be reviewed by the FPSC in May 2004, with a decision expected in July 2004.

Regional Transmission Organization (RTO)

In October 2002, the RTO process involving the proposed formation of GridFlorida, LLC, as initiated in response to the Federal Regulatory Commission's (FERC's) continuing effort to affect open access to transmission facilities in large regional markets, was delayed when the OPC filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the IOUs and the approval of GridFlorida would result in such a relinquishment. Oral arguments occurred in May 2003, and the Florida Supreme Court dismissed the OPC appeal citing that it was premature because certain portions of the FPSC GridFlorida order are not final.

In September 2003, a joint meeting of the FERC and FPSC took place to discuss wholesale market and RTO issues related to GridFlorida and in particular federal/state interactions. The FPSC has scheduled a series of collaborative meetings with all interested parties upon their conclusion, will set items for hearing and a hearing schedule. This is expected to occur throughout 2004.

Regulatory Assets and Liabilities

Tampa Electric and PGS maintain their accounts in accordance with recognized policies of the FPSC. In addition, Tampa Electric maintains its accounts in accordance with recognized policies prescribed or permitted by the FERC. These policies conform with generally accepted accounting principles in all material respects.

Tampa Electric and PGS apply the accounting treatment permitted by FAS 71, *Accounting for the Effects of Certain Types of Regulation*. Areas of applicability include deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel; purchased power, conservation and environmental costs; and deferral of costs as regulatory assets when cost recovery is ordered over a period longer than a fiscal year, to the period that the regulatory agency recognizes them. Details of the regulatory assets and liabilities as of Dec. 31, 2003 and 2002 are presented in the following table:

Regulatory Assets and Liabilities *(millions)*

Dec. 31,	*2003*	*2002*
Regulatory assets:		
Regulatory tax asset (1)	$ 63.3	$ 54.9
Other:		
Cost recovery clauses	59.7	34.7
Coal contract buy-out (2)	2.7	5.4
Deferred bond refinancing costs (3)	32.2	35.9
Environmental remediation	20.7	20.3
Competitive rate adjustment	5.3	7.4
Other	4.4	4.6
	125.0	108.3
Total regulatory assets	$ 188.3	$ 163.2
Regulatory liabilities:		
Regulatory tax liability (1)	$ 29.9	$ 36.6
Other:		
Deferred allowance auction credits	1.9	2.1
Recovery clause related	—	2.2
Environmental remediation	20.7	20.3
Transmission and distribution storm reserve	40.0	36.0
Deferred gain on property sales (4)	1.9	0.9
Accumulated reserve – cost of removal	462.2	440.6
Other	3.6	—
	530.3	502.1
Total regulatory liabilities	$ 560.2	$ 538.7

(1) Related primarily to plant life. Includes excess deferred taxes of $17.0 million and $20.9 million as of Dec. 31, 2003 and 2002, respectively.

(2) Amortized over a 10-year period ending December 2004.

(3) Unamortized refinancing costs:

Related to debt transactions as follows (millions):	Amortized until:
$ 50.0	2004
$ 51.6	2005
$ 22.1	2007
$ 25.0	2011
$ 50.0	2011
$ 150.0	2012
$ 150.0	2012
$ 85.9	2014
$ 25.0	2021
$ 100.0	2022

(4) Amortized over a 5-year period with various ending dates.

4. Asset Retirement Obligations

On Jan. 1, 2003, Tampa Electric Company adopted FAS 143, *Accounting for Asset Retirement Obligations*. The company recognized liabilities for retirement obligations associated with certain long-lived assets, in accordance with the relevant accounting guidance. An asset retirement obligation for a long-lived asset is recognized at fair value at inception of the obligation if there is a legal obligation under an existing or enacted law or statute, a written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are recognized only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its future value. The corresponding amount capitalized at inception is depreciated over the remaining useful life of the asset. The liability must be revalued each period based on current market prices.

As a result of the adoption of FAS 143, Tampa Electric Company recorded an increase to net property, plant and equipment of $0.1 million (net of accumulated depreciation), an increase in regulatory assets of $0.2 million, and an increase to asset retirement obligations of $0.3 million. The after-tax charge recorded as a change in accounting principle was not material.

For year ended Dec. 31, 2003, accretion expense associated with asset retirement obligations for Tampa Electric Company was not material. During this period, no new retirement obligations were incurred and no significant revisions to estimated cash flows used in determining the recognized asset retirement obligations were necessary. FAS 143 was not effective for years ended Dec. 31, 2002 and 2001.

As regulated utilities, Tampa Electric and PGS must file depreciation and dismantlement studies periodically and receive approval from the FPSC before implementing new depreciation rates. Included in approved depreciation rates is either an implicit net salvage factor or a cost of removal factor, expressed as a percentage. The net salvage factor is principally comprised of two components – a salvage factor and a cost of removal or dismantlement factor. The company uses current cost of removal or dismantlement factors as part of the estimation method to approximate the amount of cost of removal in accumulated depreciation.

Upon adoption of FAS 143 at Jan. 1, 2003, the estimated accumulated cost of removal and dismantlement included in net accumulated depreciation at Dec. 31, 2003 and 2002 of $462.2 million and $440.6 million, respectively, was reclassified to a regulatory liability for all period presented (see also **Note 3**). For Tampa Electric and PGS, the original cost of utility plant retired or otherwise disposed of and the cost of removal, or dismantlement, less salvage value are charged to accumulated depreciation and the accumulated cost of removal reserve reported as a regulatory liability, respectively.

5. Short-Term Debt

At Dec. 31, 2003 and 2002, the following credit facilities and related borrowings existed:

Credit Facilities	*Dec. 31, 2003*			*Dec. 31, 2002*		
(millions)	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*
Recourse:						
Tampa Electric:						
1-year facility	$ 125.0	$ —	$ —	$ 300.0	$ —	$ —
3-year facility	125.0	—	—	—	—	—
Total	$ 250.0	$ —	$ —	$ 300.0	$ —	$ —

The credit facility requirements commitment fees of 20 basis points, and drawn amounts are charged interest at LIBOR 105-117.5 basis points, depending upon the amount of the draw, at current ratings. Notes payable at Dec. 31, 2002 consisted of $10.5 million of commercial paper with a weighted average interest rate of 1.86%. There were no notes payables at Dec. 31, 2003.

On Nov. 7, 2003, Tampa Electric replaced its maturing $300 million credit facility with a $125 million one-year credit facility and a $125 million three-year credit facility, maturing in November 2004 and November 2006, respectively. In addition to the financial covenants described below and in **Notes 1** and **14**, the two new facilities include a covenant limiting cumulative distributions after Oct. 31, 2003 and outstanding loans to its parent to an amount representing an accumulation of net income after May 31, 2003 and capital contributions from the parent after Oct. 31, 2003, plus $450 million.

6. Common Stock

Tampa Electric Company is a wholly owned subsidiary of TECO Energy, Inc.

	Common Stock		*Issue*	
(millions, except per share amounts)	*Shares*	*Amount*	*Expense*	*Total*
Balance Dec. 31, 2000	10	$ 1,148.8	$ (0.7)	$ 1,148.1
Contributed capital from parent	—	170.0	—	170.0
Balance Dec. 31, 2001	10	1,318.8	(0.7)	1,318.1
Contributed capital from parent	—	217.0	—	217.0
Balance Dec. 31, 2002	10	1,535.8	(0.7)	1,535.1
Contributed capital returned to parent	—	(158.3)	—	(158.3)
Balance Dec. 31, 2003	10	$ 1,377.5	$ (0.7)	$ 1,376.8

7. Asset Impairments

In 2003, Tampa Electric Company recorded a $48.9 million after-tax charge ($79.6 million pre-tax) to reflect the impact of the cancellation of turbine purchase commitments. As reported previously and in **Note 12**, certain turbine rights had been transferred from Other Unregulated operations of TECO Energy to Tampa Electric in 2002 for use in Tampa Electric's generation expansion activities. These cancellations, made in April 2003, fully terminate all turbine purchase obligations.

8. Restructuring Costs

In September and October of 2003, TECO Energy announced a corporate reorganization to restructure the company along functional lines, consistent with its objectives to grow the core utility operation, maintain liquidity, generate cash and maximize the value in the existing assets. As a result of these actions, TECO Energy is now aligned to provide for centralized oversight along functional lines for power plant operations, energy delivery, energy management, and human resources and technology/support services. The 2003 actions included the involuntary termination or retirement of 232 employees at Tampa Electric Company, including officers and other personnel from operations and support services.

In 2002, TECO Energy initiated a restructuring program that impacted approximately 182 employees at Tampa Electric. This program included retirements, the elimination of positions and other cost control measures. The total costs associated with this program included severance, salary continuation and other termination and retirement benefits.

Tampa Electric recognized a pre-tax expense of $14.0 million and $16.6 million for accrued benefits and other termination and retirement benefits for the years ended Dec. 31, 2003 and 2002, respectively. Tampa Electric Company completed these restructuring activities as of Dec. 31, 2003. As of Dec. 31, 2003 and 2002, respectively, no adjustments were made to the benefits initially accrued for and $8.4 million and $16.6 million, respectively, of the accrued benefits were paid or otherwise settled.

9. Income Tax Expense

Tampa Electric Company is included in the filing of a consolidated federal income tax return with TECO Energy and its affiliates. Tampa Electric Company's income tax expense is based upon a separate return computation. Income tax expense consists of the following components:

Income Tax Expense

(millions)	*Federal*	*State*	*Total*
2003			
Currently payable	$ 74.9	$ 17.6	$ 92.5
Deferred	(16.0)	(7.9)	(23.9)
Amortization of investment tax credits	(4.6)	—	(4.6)
Total income tax expense	$ 54.3	$ 9.7	64.0
Included in other income, net			(30.0)
Included in operating expenses			$ 94.0
2002			
Currently payable	$ 66.7	$ 14.9	$ 81.6
Deferred	23.2	0.4	23.6
Amortization of investment tax credits	(4.4)	—	(4.4)
Total income tax expense	$ 85.5	$ 15.3	100.8
Included in other income, net			0.5
Included in operating expenses			$ 100.3
2001			
Currently payable	$ 88.6	$ 15.7	$ 104.3
Deferred	(1.3)	(0.7)	(2.0)
Amortization of investment tax credits	(4.4)	—	(4.4)
Total income tax expense	$ 82.8	$ 15.0	97.9
Included in other income, net			0.2
Included in operating expenses			$ 97.7

Deferred taxes result from temporary differences in the recognition of certain liabilities or assets for tax and financial reporting purposes. The principal components of the company's deferred tax assets and liabilities recognized in the balance sheet are as follows:

Deferred Income Tax Assets and Liabilities

(millions) Dec. 31,	*2003*	*2002*
Deferred tax assets (1)		
Property related	$ 93.6	$ 90.3
Leases	3.1	3.5
Insurance reserves	20.5	17.7
Early capacity payments	3.5	6.0
Other	12.8	15.8
Total deferred income tax assets	133.5	133.3
Deferred income tax liabilities (1)		
Property related	(500.0)	(502.8)
Other	25.5	19.7
Total deferred income tax liabilities	(474.5)	(483.1)
Accumulated deferred income taxes	$ (341.0)	$ (349.8)

(1) Certain property related assets and liabilities have been netted.

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes for the following reasons:

Effective Income Tax Rate

(millions)	*2003*	*2002*	*2001*
Net income (1)	$ 123.4	$ 196.0	$ 177.1
Total income tax provision (1)	64.0	100.8	97.9
Income before income taxes (1)	$ 187.4	$ 296.8	$ 275.0
Income taxes on above at federal statutory rate of 35%	$ 65.6	$ 103.8	$ 96.2
Increase (decrease) due to			
State income tax, net of federal income tax	6.3	10.0	9.8
Amortization of investment tax credits	(4.6)	(4.4)	(4.5)
Equity portion of AFUDC	(7.0)	(8.7)	(2.3)
Other	3.7	0.1	(1.3)
Total income tax provision	$ 64.0	$ 100.8	$ 97.9
Provision for income taxes as a percent of income before income taxes	34.2%	34.0%	35.6%

(1) Includes $48.9 million after-tax ($79.6 million pre-tax) charges associated with cancellation of turbine purchase commitments noted above.

10. Other Comprehensive Income

Tampa Electric Company reported the following comprehensive income (loss) for the years ended Dec. 31, 2003, 2002 and 2001 related to changes in the fair value of cash flow hedges:

Comprehensive income (loss) (millions)	*Gross*	*Tax*	*Net*
2003			
Unrealized gain on cash flow hedges	$ 3.2	$ 1.2	$ 2.0
Less: Gain reclassified to net income	(3.2)	(1.2)	(2.0)
Total other comprehensive income (loss)	$ —	$ —	$ —
2002			
Unrealized gain on cash flow hedges	$ 0.3	$ 0.1	$ 0.2
Less: Gain reclassified to net income	(0.2)	(0.1)	(0.1)
Total other comprehensive income (loss)	$ 0.1	$ —	$ 0.1
2001			
Unrealized (loss) on cash flow hedges	$ (0.8)	$ (0.3)	$ (0.5)
Less: Loss reclassified to net income	0.7	0.3	0.4
Total other comprehensive income (loss)	$ (0.1)	$ —	$ (0.1)

11. Employee Postretirement Benefits

Pension Benefits

Tampa Electric Company is a participant in the comprehensive retirement plans of TECO Energy (multi-employer plans), including a non-contributory defined benefit retirement plan which covers substantially all employees. Where appropriate and reasonably determinable, the portion of expenses, income, gains or losses allocable to Tampa Electric Company are presented. Otherwise, such amounts presented reflect the amount allocable to all participants of the TECO Energy retirement plans. Benefits are based on employees' age, years of service and final average earnings. On Apr. 1, 2000, the plan was amended to provide for benefits to be earned and payable substantially on a lump sum basis through an age and service credit schedule for eligible participants leaving the company on or after July 1, 2001. Other significant provisions of the plan, such as eligibility, definitions of credited service, final average earnings, etc., were largely unchanged. This amendment resulted in decreased pension expense at TECO Energy of approximately $0.8 million in 2001 and a reduction of benefit obligation of $6.2 million at Sept. 30, 2001.

TECO Energy's policy is to fund the plan within the guidelines set by ERISA for the minimum annual contribution and the maximum allowable as a tax deduction by the IRS. In 2004, TECO Energy expects to make a contribution of about $14.2 million, of which Tampa Electric Company's portion is expected to be about $9.1 million.

Amounts disclosed for pension benefits also include the unfunded obligations for the supplemental executive retirement plan, non-qualified, non-contributory defined benefit retirement plans available to certain senior management. In 2004, TECO Energy expects to make a contribution of about $1.7 million to these plans. TECO Energy reported other comprehensive loss of $43.9 million and $4.4 million in 2003 and 2002, respectively and other comprehensive income of $0.3 million in 2001 related to adjustments to the minimum pension liability associated with the supplemental executive retirement plan.

The asset allocation for the company's pension plan as of Sept. 30, 2003 and 2002, and the target allocation for 2004, by asset category, follows:

Asset Allocation

Asset category	Target Allocation of 2004	Percentage of Plan Assets at Sept. 30, 2003	2002
Equities	55% – 60%	57%	53%
Fixed income	40% – 45%	43%	47%
Real Estate	—	—	—
Other	—	—	—
Total	—	100%	100%

TECO Energy's investment objective is to obtain above average returns while minimizing volatility of expected returns over the long term. The target equities/fixed income mix is designed to meet investment objectives. TECO Energy's strategy is to hire proven managers and allocate assets to reflect a mix of investment styles, emphasize preservation of principal to minimize the impact of declining markets, and stay fully invested except for cash to meet benefit payment obligations and plan expense.

The assumptions for the expected return on plan assets were developed based on an analysis of historical market returns, the plan's past experience and current market conditions. Estimates of future market returns are lower than actual long-term historical returns of the plan but were factored into the expected return on asset assumptions to generate a conservative forecast.

In 2001, TECO Energy elected to change the measurement date for pension obligations and plan assets from Dec. 31 to Sep. 30. The effect of this accounting change was not material.

Components of net pension expense, reconciliation of the funded status and the accrued pension liability are presented below for TECO Energy consolidated.

Pension Benefit Expense

(millions)	*2003*	*2002*	*2001*
Components of net periodic benefit expense			
Service cost (benefits earned during the period)	$ 14.3	$ 11.8	$ 11.2
Interest cost on projected benefit obligations	30.8	28.7	27.9
Expected return on assets	(42.1)	(42.9)	(42.0)
Amortization of:			
Transition obligation (asset)	(1.1)	(1.1)	(1.1)
Prior service cost (benefit)	(0.5)	(0.5)	(0.5)
Actuarial (gain) loss	1.4	(3.7)	(4.4)
Pension expense (benefit)	2.8	(7.7)	(8.9)
Special termination benefit charge	—	2.7	—
Additional amounts recognized	—	—	—
Net pension expense (benefit) recognized in the TECO Energy Consolidated Statements of Income (1)	$ 2.8	$ (5.0)	$ (8.9)
Assumptions used to determine net costs			
Discount rate	6.75%	7.50%	7.50%
Rate of compensation increase	4.82%	4.66%	4.69%
Expected return on plan assets	9.00%	9.00%	9.00%

(1) Tampa Electric Company's portion was $(1.9) million, ($7.8) million and ($10.4) million for 2003, 2002 and 2001, respectively.

The following table shows the funded status of the qualified and non-qualified pension plans for which the projected obligation exceeds the fair value to the plan assets:

Pension Plans – Projected Obligation Exceeds Plan Assets

(millions) Dec. 31,	2003	2002
Projected benefit obligation	$ 554.5	$ 455.1
Fair value of plan assets	391.8	371.9
Projected obligation in excess of plan assets	$ 162.7	$ 83.2
Accumulated benefit obligation	$ 480.0	$ 400.8

As of Dec. 31, 2003, for the qualified and non-qualified pension plans, the accumulated obligation exceeded the fair value of the plan assets. As of Dec. 31, 2002, the accumulated obligation exceeded the fair value of the plan assets for only the non-qualified pension plan. The table below shows the funded status at the end of 2003 and 2002 for the respective plans:

Pension Plans – Accumulated Obligation Exceeds Plan Assets

(millions) Dec. 31,	2003	2002 (1)
Projected benefit obligation	$ 480.0	$ 32.8
Fair value of plan assets	391.8	—
Accumulated obligation in excess of plan assets	$ 88.2	$ 32.8
Accumulated benefit obligation	$ 554.5	$ 41.3

(1) In 2002 only the non-qualified plan is presented due to the fact that the fair value of plan assets exceeded the accumulated obligation for the qualified plan.

Reconciliation of the funded status of the retirement plan and the accrued pension prepayment/(liability)

(millions)	*2003*	*2002*
Change in benefit obligation		
Net benefit obligation at prior measurement date	$ 455.1	$ 382.3
Service cost	14.3	11.8
Interest cost	30.8	28.7
Actuarial loss	89.7	58.3
Plan amendments	—	1.1
Special termination benefits	—	2.7
Curtailment	(1.9)	—
Gross benefits paid	(33.5)	(29.8)
Net benefit obligation at measurement date	$ 554.5	$ 455.1
Change in plan assets		
Fair value of plan assets at prior measurement date	$ 371.9	$ 428.0
Actual return on plan assets	51.7	(24.9)
Employer contributions	1.7	1.7
Gross benefits paid (including expenses)	(33.5)	(32.9)
Fair value of plan assets at measurement date	$ 391.8	$ 371.9
Funded status		
Fair value of plan assets	$ 391.8	$ 371.9
Benefit obligation	554.5	455.1
Funded status at measurement date	(162.7)	(83.2)
Net contributions after measurement date	6.7	0.4
Unrecognized net actuarial loss	165.6	88.9
Unrecognized prior service cost (benefit)	(6.9)	(7.4)
Unrecognized net transition obligation (asset)	(1.4)	(2.5)
Accrued liability at end of year	$ 1.3	$ (3.8)
Amounts recognized in the statement of financial position		
Prepaid benefit cost	$ 16.9	$ 14.8
Accrued benefit cost	(15.7)	(18.5)
Additional minimum liability	(82.7)	(13.8)
Intangible asset	1.3	1.5
Accumulated other comprehensive income	81.5	12.2
Net amount recognized at end of year	$ 1.3	$ (3.8)
Assumptions used in determining actuarial valuations		
Discount rate to determine projected benefit obligation	6.00%	6.75%
Rate of increase in compensation levels	4.25%	9.0%

Other Postretirement Benefits

Tampa Electric provides certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. The company contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and June 30, 2001 is limited to a defined dollar benefit based on years of service. On April 1, 2000, the company adopted changes to this program for participants retiring from the company on or after July 1, 2001. The company contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after July 1, 2001 is limited to a defined dollar benefit based on an age and service schedule. The impact of this amendment, including a change in the company's commitment for future retirees combined with a grandfathering provision for current retired participants, resulted in a reduction in the benefit obligation of $1.4 million in 2001. In 2004, TECO Energy expects to make a contribution of about $9.5 million to this program. Postretirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify the plans in whole or in part at any time.

On Dec. 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). Beginning in 2006, the new law adds prescription drug coverage to Medicare, with a 28% tax-free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. TECO Energy's current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs. The company is continuing to analyze the potential impact the Act may have on the company's FAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, expense and what, if any, plan design changes should be made with respect to the company's retiree medical program in response to the Act.

The following charts summarize the income statement and balance sheet impact, as well as the benefit obligations, assets, funded status and rate assumptions associated with other postretirement benefits.

Other Postretirement Benefit Expense

(millions)	*2003*	*2002*	*2001*
Components of net periodic benefit expense			
Service cost (benefits earned during the period)	$ 2.6	$ 2.4	$ 2.3
Interest cost on projected benefit obligations	9.3	8.6	8.4
Amortization of:			
Transition obligation (straight line over 20 years)	2.1	2.1	2.1
Prior service cost	1.7	1.7	1.7
Actuarial loss	1.0	0.1	0.3
Pension expense	16.7	14.9	14.8
Special termination benefits	—	0.6	—
Additional amounts recognized	0.1	(0.1)	—
Net periodic postretirement benefit expense	$ 16.8	$ 15.4	$ 14.8

The accumulated postretirement benefit obligation exceeds plan assets for the postretirement health and welfare benefits plan.

Reconciliation of the funded status of the postretirement benefit plan and the accrued liability

(millions)	*2003*	*2002*
Change in benefit obligation		
Net benefit obligation at prior measurement date	$ 138.8	$ 114.8
Service cost	2.6	2.4
Interest cost	9.3	8.6
Plan participants' contributions	1.0	0.8
Actuarial loss	3.1	17.3
Special termination benefits	—	0.6
Gross benefits paid	(8.0)	(5.7)
Net benefit obligation at measurement date	$ 146.8	$ 138.8
Change in plan assets		
Fair value of plan assets at prior measurement date	—	—
Employer contributions	7.0	4.9
Plan participants contributions	1.0	0.8
Gross benefits paid (including expenses)	(8.0)	(5.7)
Fair value of plan assets at measurement date	$ —	$ —
Funded status		
Funded status at measurement date	$ (146.8)	$ (138.8)
Net contributions after measurement date	1.8	1.5
Unrecognized net actuarial loss	31.5	29.5
Unrecognized prior service cost	18.7	20.3
Unrecognized net transition obligation	19.0	21.1
Accrued liability at end of year	$ (75.8)	$ (66.4)
Assumptions Used in Determining Actuarial Valuations		
Discount rate to determine projected benefit obligation	6.00%	6.75%

Employer contributions and benefits paid in the above tables include both those amounts contributed directly to, and paid directly from both plan assets and directly to plan participants. The assumed health care cost trend rate for medical costs was 11.5% in 2003 and decreases to 5.0% in 2013 and thereafter.

A 100 basis point increase in the medical trend rates would produce a 3 percent ($0.4 million) increase in the aggregate service and interest cost for 2003, and a 4 percent ($5.4 million) increase in the accumulated postretirement benefit obligation as of Sept. 30, 2003.

A 100 basis point decrease in the medical trend rates would produce a 2 percent ($0.3 million) decrease in the aggregate service and interest cost for 2003 and a 2 percent ($3.5 million) decrease in the accumulated postretirement benefit obligation as of Sept. 30, 2003.

12. Related Party Transactions

In February 2002, Tampa Electric and TECO-Panda Generating Company (TPGC) II, an affiliate of TECO Wholesale Generation, entered into an assignment and assumption agreement under which Tampa Electric obtained TPGC II's rights and interests to four combustion turbines being purchased from General Electric, and assumed the corresponding liabilities and obligations for such equipment. In accordance with the terms of the assignment and assumption agreement, Tampa Electric paid $62.5 million to TPGC II as reimbursement for amounts already paid to General Electric by TPGC II for such equipment. No gain or loss was incurred on the transfer. In the first quarter of 2003, Tampa Electric recorded a $48.9 million after-tax charge related to the cancellation of these turbine purchase commitments (see **Note 7**).

In the second and third quarters of 2003, Tampa Electric returned approximately $158 million of capital to TECO Energy. TECO Energy had previously contributed capital to Tampa Electric in support of Tampa Electric's construction program in the wholesale business, which was subsequently scaled back.

In October 2003, Tampa Electric signed a five-year contract renewal with a TECO Energy affiliate company, TECO Transport Corporation, for integrated waterborne fuel transportation services effective Jan. 1, 2004. The contract calls for inland river and ocean transportation along with river terminal storage and blending services for up to 5.5 million tons of coal annually through 2008. See **Note 3** for additional details.

A summary of activities between Tampa Electric Company and its affiliates follows:

Net transactions with affiliates:

(millions)	*2003*	*2002*	*2001*
Fuel and interchange related, net	$ 152.4	$ 144.9	$ 162.0
Administrative and general, net	$ 13.7	$ 10.7	$ 22.1

Amounts due from or to affiliates of the company at Dec. 31,

(millions)	*2003*	*2002*
Accounts receivable (1)	$ 4.5	$ 6.6
Accounts payable (1)	$ 13.3	$ 23.6

(1) Accounts receivable and accounts payable were incurred in the ordinary course of business and do not bear interest

13. Segment Information

Tampa Electric Company is a public utility operating within the state of Florida. Through its Tampa Electric division, it is engaged in the generation, purchase, transmission, distribution and sale of electric energy to more than 612,000 customers in West Central Florida. Its Peoples Gas System division is engaged in the purchase, distribution and marketing of natural gas for more than 299,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

Segment Information

(millions)	*Tampa Electric*	*Peoples Gas*	*Other & Eliminations*	*Tampa Electric Company*
2003				
Revenues – outsiders	$1,582.7	$ 408.4	$ —	$1,991.1
Sales to affiliates	3.4	—	(0.7)	2.7
Total revenues	$1,586.1	$ 408.4	$ (0.7)	$1,993.8
Depreciation	210.3	32.7	—	243.0
Restructuring costs (1)	9.9	4.1	—	14.0
Interest charge	85.0	15.6	—	100.6
Provision for taxes	48.1 (2)	15.2	—	63.3 (2)
Net income	$ 98.9	$ 24.5	$ —	$ 123.4
Total assets	4,191.3	651.5	(7.1)	4,835.7
Capital expenditures	$ 289.1	$ 42.6	$ —	$ 331.7

Segment Information – continued

(millions)	*Tampa Electric*	*Peoples Gas*	*Other & Eliminations*	*Tampa Electric Company*
2002				
Revenues – outsiders	$1,548.9	$ 318.1	$ —	$1,867.0
Sales to affiliates	34.3	—	(0.7)	33.6
Total revenues	$1,583.2	$ 318.1	$ (0.7)	$1,900.6
Depreciation	189.8	30.5	(0.2)	220.1
Restructuring costs (2)	16.6	—	—	16.6
Interest charge	51.5	14.8	—	66.3
Provision for taxes	85.7	14.7	—	100.4
Net income	$ 171.8	$ 100.4	$ —	$ 196.0
Total assets	4,135.0	650.2	(6.9)	4,778.3
Capital expenditures	$ 632.2	$ 53.4	$ —	$ 685.6
2001				
Revenues – outsiders	$1,380.1	$ 352.9	$ —	$1,733.0
Sales to affiliates	32.6	—	(0.9)	31.7
Total revenues	$1,412.7	$ 352.9	$ (0.9)	$1,764.7
Depreciation	173.4	27.9	—	201.3
Restructuring costs	—	—	—	—
Interest charge	60.8	14.3	—	75.1
Provision for taxes	83.5	14.2	—	97.7
Net income	$ 154.0	$ 23.1	$ —	$ 177.1
Total assets	3,693.0	605.0	(6.0)	4,292.0
Capital expenditures	$ 426.3	$ 73.0	$ —	$ 499.3

(1) See **Note 8** for a discussion of restructuring charges in 2003 and 2002.
(2) Net income for 2003 includes a $48.9 million after-tax charge (79.6 million pre-tax) asset impairment charge related to the turbine purchase cancellations (see **Note 7**).

14. Commitments and Contingencies

Capital Investments

For 2004, Tampa Electric expects to spend $182.9 million, consisting of $9.4 million (committed as of Dec. 31, 2003) for the completion of the repowering project at the Gannon Station, $18.2 million for environmental expenditures and $155.3 million to support system growth and generation reliability. Tampa Electric's estimated capital expenditures over the 2005-2008 period are projected to be $1,006.4 million, including $323.8 million for environmental expenditures.

Capital expenditures for PGS are expected to be about $40 million in 2004 and $160 million during the 2005-2008 period. Included in these amounts are approximately $25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing maintenance and system safety.

Legal Contingencies

Three lawsuits have been filed in the Circuit Court in Hillsborough County against Tampa Electric, in connection with the location of transmission structures in certain residential areas, by residents in the areas surrounding the structures. The high-voltage power lines are needed by Tampa Electric to move electricity to the northwest part of its service territory where population growth has been experienced. The residents are seeking to remove the poles or to receive monetary damages. Tampa Electric is working with the community to determine the feasibility of alternate routes or structures or some combination.

From time to time Tampa Electric Company is involved in various other legal, tax and regulatory proceedings before various courts, regulatory commissions, and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with FAS 5, *Accounting for Contingencies*, to provide for matters that are reasonably likely to result in an estimable, material loss. While the outcome of such proceedings is uncertain, management does not believe that the ultimate resolution of pending matters will have a material adverse effect on the company's results of operations or financial condition.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2003, Tampa Electric Company has estimated its ultimate financial liability to be $20 million, and this amount has been accrued in the company's financial

statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors, or Tampa Electric Company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric and other potentially responsible parties (PRPs) is based on each party's relative ownership interest in or usage of a site. Accordingly, Tampa Electric's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Long Term Commitments

Tampa Electric Company has commitments under long-term operating leases, primarily for building space, office equipment and heavy equipment. Total rental expense included in the Consolidated Statements of Income for the years ended Dec. 31, 2003, 2002 and 2001 was $6.2 million, $6.1 million and $6.1 million, respectively. The following table is a schedule of future minimum lease payments at Dec. 31, 2003 for all operating leases with noncancelable lease terms in excess of one year:

Future Minimum Lease Payments for Operating Leases

Year ended Dec. 31:	*Amount (millions)*
2004	$ 4.6
2005	4.6
2006	4.1
2007	2.5
2008	0.3
Later Years	0.2
Total minimum lease payments	$ 16.3

In 1994, Tampa Electric bought out a long-term coal supply contract which would have expired in 2004 for a lump sum payment of $25.5 million. In February 1995, the FPSC authorized the recovery of this buy-out amount plus carrying costs through the Fuel and Purchase Power Cost Recovery Clause over the 10-year period beginning Apr. 1, 1995. In each of the years 2003, 2002 and 2001, $2.7 million of buy-out costs were amortized to expense.

Guarantees and Letters of Credit

On Jan. 1, 2003, Tampa Electric Company adopted the prospective initial measurement provisions for certain types of guarantees, in accordance with FASB Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (an interpretation of FASB Statements No. 5, 57, and 107 and rescission of FASB Interpretation No. 34)*. Upon issuance or modification of a guarantee after Jan. 1, 2003, the company must determine if the obligation is subject to either or both of the following:

- Initial recognition and initial measurement of a liability; and/or
- Disclosure of specific details of the guarantee.

Generally, guarantees of the performance of a third party or guarantees that are based on an underlying (where such a guarantee is not a derivative subject to FAS 133) are likely to be subject to the recognition and measurement, as well as the disclosure provisions, of FIN 45. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation.

Alternatively, guarantees between and on behalf of entities under common control or that are similar to product warranties are subject only to the disclosure provisions of the interpretation. The company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

As of Dec. 31, 2003, Tampa Electric Company had outstanding letters of credit of $0.9 million, which guarantee performance to third parties related to debt service.

Tampa Electric Company also enters into commercial agreements in the normal course of business that typically contain standard indemnification clauses. Tampa Electric Company may sometimes agree to make payments to compensate or indemnify the counterparty for legal fees, environmental remediation costs and other similar costs arising from possible future events or changes in laws or regulations. These agreements cover a variety of goods and services, and have varying triggering events dependent on actions by third parties.

Tampa Electric Company is unable to estimate the maximum potential future exposure under these clauses because the events that would obligate Tampa Electric Company have not occurred, or if such event has occurred, Tampa Electric Company has not been notified of any occurrence. As claims are made or changes in laws or regulations indicate, an amount related to the indemnification is reflected in the financial statements.

Financial Covenants

A summary of Tampa Electric's significant financial covenants is as follows:

Tampa Electric Significant Financial Covenants

(millions) *Instrument*	*Financial Covenant (1)*	*Requirement/ Restriction*	*Calculation at Dec. 31, 2003*
Tampa Electric			
Mortgage bond indenture	Dividend restriction	Cumulative distributions cannot exceed cumulative net income plus $4	$5 unrestricted (2)
PGS senior notes	EBIT/interest (3)	Minimum of 2.0 times	3.5 times
	Restricted payments	Shareholder equity at least $500	$1,652
	Funded debt/capital	Cannot exceed 65%	50.5%
	Sale of assets	Less than 20% of total assets	—%
Credit facility	Debt/capital	Cannot exceed 60%	49.2%
	EBITDA/interest (3)	Minimum of 2.5 times	5.8 times
	Restriction on distributions	Limit on cumulative distributions and outstanding affiliate loans (4)	$483 unrestricted
6.25% senior notes	Debt/capital	Cannot exceed 60%	49.2%
	Limit on liens	Cannot exceed $787	$362

(1) As defined in applicable instrument.
(2) Reflects the determination as of Dec. 31, 2003, after giving effect to $158 million distributed to TECO Energy as a return of capital during 2003. There were $75 million of callable bonds outstanding under the indenture at Dec. 31, 2003.
(3) EBIT generally represents earnings before interest and taxes. EBITDA generally represents EBIT before depreciation and amortization. However, in each circumstance, the term is subject to the definition prescribed under the relevant legal agreements.
(4) Limits cumulative distributions after Oct. 31, 2003 and outstanding affiliate loans to an amount representing an accumulation of net income after May 31, 2003 and capital contributions from the parent after Oct. 31, 2003, plus $450 million.

15. New Accounting Pronouncements

Amendment to Derivatives Accounting

In April 2003, the FASB issued FAS 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, which clarifies the definition of a derivative and modifies, as necessary, FAS 133 to reflect certain decisions made by the FASB as part of the Derivatives Implementation Group (DIG) process. The majority of the guidance was already effective and previously applied by the company in the course of the adoption of FAS 133.

In particular, FAS 149 incorporates the conclusions previously reached in 2001 under DIG Issue C10, *"Can Option Contracts and Forward Contracts with Optionality Features Qualify for the Normal Purchases and Normal Sales Exception"*, and DIG Issue C15, *"Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity"*. In limited circumstances, when the criteria are met and documented, Tampa Electric Company designates option-type and forward contracts in electricity as a normal purchase or normal sale (NPNS) exception to FAS 133. A contract designated and documented as qualifying for the NPNS exception is not subject to the measurement and recognition requirements of FAS 133. The incorporation of the conclusions reached under DIG Issues C10 and C15 into the standard will not have a material impact on the consolidated financial statements of Tampa Electric Company.

FAS 149 establishes multiple effective dates based on the source of the guidance. For all DIG Issues previously cleared by the FASB and not modified under FAS 149, the effective date of the issue remains the same. For all other aspects of the standard, the guidance is effective for all contracts entered into or modified after June 30, 2003. The company does not anticipate that the adoption of the additional guidance in FAS 149 will have a material impact on the consolidated financial statements.

Financial Instruments with Characteristics of both Liabilities and Equity

In May 2003, the FASB issued FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*, which requires that an issuer classify certain financial instruments as a liability or an asset. Previously, many financial instruments with characteristics of both liabilities and equity were classified as equity. Financial instruments subject to FAS 150 include financial instruments with any of the following features:

- An unconditional redemption obligation at a specified or determinable date, or upon an event that is certain to occur;
- An obligation to repurchase shares, or indexed to such an obligation, and may require physical share or net cash settlement;
- An unconditional, or for new issuances conditional, obligation that may be settled by issuing a variable number of equity shares if either (a) a fixed monetary amount is known at inception, (b) the variability is indexed to something other than the fair value of the issuer's equity shares, or (c) the variability moves inversely to changes in the fair value of the issuer's shares.

The standard requires that all such instruments be classified as a liability, or an asset in certain circumstances, and initially measured at fair value. Forward contracts that require a fixed physical share settlement and mandatorily redeemable financial instruments must be subsequently re-measured at fair value on each reporting date.

This standard is effective for all financial instruments entered into or modified after May 31, 2003, and for all other financial instruments at the beginning of the first interim period beginning after June 15, 2003. The adoption of FAS 150 has had no material impact on the consolidated financial statements.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

During the period Jan. 1, 2002 to the date of this report, neither TECO Energy nor Tampa Electric Company has had or has filed with the Commission a report as to any changes in or disagreements with accountants on accounting principles or practices, financial statement disclosure, or auditing scope or procedure.

Item 9A. CONTROLS AND PROCEDURES

TECO Energy, Inc.

(a) **Evaluation of Disclosure Controls and Procedures**. TECO Energy's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of TECO Energy's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this annual report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, TECO Energy's disclosure controls and procedures are effective and designed to ensure that the information relating to TECO Energy (including its consolidated subsidiaries) required to be included in TECO Energy's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the requisite time periods.

(b) **Changes in Internal Controls**. There have not been any changes in TECO Energy's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, such controls.

Tampa Electric Company

(a) **Evaluation of Disclosure Controls and Procedures**. Tampa Electric Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of Tampa Electric's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Tampa Electric's disclosure controls and procedures are effective and designed to ensure that the information relating to Tampa Electric (including its consolidated subsidiaries) required to be included in Tampa Electric's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the requisite time periods.

(b) **Changes in Internal Controls**. There have not been any significant changes in Tampa Electric's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, such controls.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

(a) The information required by Item 10 with respect to the directors of the registrant is included under the caption "Election of Directors" on pages 1 through 2 of TECO Energy's definitive proxy statement, dated March 25, 2004, for its Annual Meeting of Shareholders to be held on April 28, 2004 (Proxy Statement) and is incorporated herein by reference.

(b) The information required by Item 10 concerning executive officers of the registrant is included under the caption "Executive Officers of the Registrant" on page 21 of this report.

(c) The information required by Item 10 concerning Section 16(a) Beneficial Ownership Reporting Compliance is included under that caption on page 20 of the Proxy Statement and is incorporated herein by reference.

(d) TECO Energy has had a code of ethics applicable to all of its employees and officers for many years. It was expanded to apply to the Board of Directors in 2002. The text of the *Standards of Integrity* is available on the company's website at www.tecoenergy.com under Investor Relations. Any amendments to or waivers of the *Standards of Integrity* for the benefit of any executive officer or director will also be posted on the website.

(e) Information regarding TECO Energy's Audit Committee is included on pages 3 and 19 of the Proxy Statement, and is incorporated herein by reference.

Item 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is included in the Proxy Statement beginning on page 6 under that caption and ending on page 11 just above the caption "Approval of the 2004 Equity Incentive Plan", and under the caption "Compensation of Directors" on page 3, and is incorporated herein by reference.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

The information required by Item 12 is included under the caption "Share Ownership" on pages 4 and 5 of the Proxy Statement and under the caption "Equity Compensation Plan Information" on page 15 of the Proxy Statement, and is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

The information required by Item 13 is included under the caption "Certain Relationships and Related Transactions" on page 4 of the Proxy Statement, and is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is included under the caption "Independent Public Accountants" on pages 19 and 20 of the Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(a) **Certain Documents Filed as Part of this Form 10-K**

1. Financial Statements
   - TECO Energy, Inc. Financial Statements – filed as part of Exhibit 13 of this report, and is hereby incorporated by reference.
   - Tampa Electric Company Financial Statements – See index on page 25
2. Financial Statement Schedules
   - Condensed Parent Company Financial Statements Schedule I – pages 54 – 57
   - TECO Energy, Inc. Schedule II – page 58
   - Tampa Electric Company Schedule II – page 59
3. Exhibits – See index beginning on page 63

(b) **Reports on Form 8-K – in process**

TECO Energy, Inc. filed or furnished the following reports on Form 8-K during the last quarter of 2003.

1. Current Report on Form 8-K of Oct. 23, 2003, filing under "Item 5. Other Events", to report TECO Energy, Inc.'s entering into on a Suspension Agreement in connection with TECO Energy's Construction Undertaking Agreements (Construction Undertakings) and other guaranty agreements for the Union and Gila River projects, and furnishing under "Item 12. Results of Operations and Financial Condition", TECO Energy's unaudited financial results for the three-month and nine-month periods ending Sept. 30, 2003.

2. Current Report on Form 8-K of Oct. 30, 2003, furnishing under "Item 12. Results of Operations and Financial Condition", unaudited financial and other unaudited financial data for the three-month, nine-month and 12-month periods ended Sept. 30, 2003 and 2002, and non-GAAP earnings per share information.

TECO Energy, Inc. filed or furnished the following reports on Form 8-K subsequent to Dec. 31, 2003.

1. Current Report on Form 8-K of Feb. 2, 2004, filing under "Item 5. Other Events", to announce that TECO Energy the Union and Gila River project companies and the lending banks had entered into a standstill agreement through Feb. 5, 2004 relating to matters covered by the Suspension Agreement.

2. Current Report on Form 8-K of Feb. 5, 2004, filing under "Item 5. Other Events", to announce TECO Energy's decision to exit from its ownership of the Union and Gila River projects and to cease further funding of these plants.

3. Current Report on Form 8-K of Feb. 9, 2004, furnishing under "Item 12. Results of Operations and Financial Condition", financial results for the three-month and twelve-month periods ended Dec. 31, 2003.

4. Current Report on Form 8-K of Mar. 3, 2004, furnishing under "Item 12. Results of Operations and Financial Condition", revised 2003 financial results for TECO Energy, Inc.

Tampa Electric Company did not file any reports on Form 8-K during or subsequent to the last quarter of 2003.

(c) The exhibits filed as part of this Form 10-K are listed on the Exhibit Index immediately preceding such Exhibits. The Exhibit Index is incorporated herein by reference.

SCHEDULE I – CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY
Condensed Balance Sheets

(millions) *Dec. 31.*	*2003*	*2002*
Assets		
Current assets		
Cash and cash equivalents	$ 28.0	$ 370.9
Restricted cash	6.9	—
Advances to affiliates	3,078.4	2,380.1
Accounts receivable from affiliates	3.4	—
Other current assets	11.4	13.0
Total current assets	3,128.1	2,764.0
Other assets		
Investment in subsidiaries	1,381.5	2,646.2
Deferred income taxes	293.5	220.7
Other assets	46.7	46.3
Total other assets	1,721.7	2,913.2
Total assets	$ 4,849.8	$ 5,677.2
Liabilities and capital		
Current liabilities		
Notes payable	$ 37.5	$ 350.0
Accounts payable to affiliates	0.3	19.1
Accounts payable	21.9	32.3
Interest payable	19.2	21.4
Other current liabilities	9.1	4.5
Total current liabilities	88.0	427.3
Other liabilities		
Advances from affiliates	233.9	221.0
Deferred income taxes	117.4	—
Long-term debt		
Junior subordinated	669.3	669.3
Others	1,958.8	1,656.5
Other liabilities	104.7	91.4
Total other liabilities	3,084.1	2,638.2
Capital		
Common equity	187.8	175.8
Additional paid in capital	1,220.8	1,094.5
Retained earnings	339.5	1,413.7
Accumulated other comprehensive income	(55.8)	(41.2)
Common equity	1,692.3	2,642.8
Unearned compensation	(14.6)	(31.1)
Total capital	1,677.7	2,611.7
Total liabilities and capital	$ 4,849.8	$ 5,677.2

The accompanying notes are an integral part of the condensed financial statements.

SCHEDULE I – CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY
Condensed Statements of Income

(millions) *For the years ended Dec. 31,*	*2003*	*2002*	*2001*
Revenues	$ 4.4	$ 6.7	$ 2.0
Expenses			
Administrative and general expenses	7.2	8.6	6.8
Restructuring charges	2.6	—	—
Total expenses	9.8	8.6	6.8
Income from operations	(5.4)	(1.9)	(4.8)
Loss on debt extinguishment	—	(34.1)	—
(Losses) earnings from investments in subsidiaries	(873.2)	363.8	308.7
Interest income (expense)			
Interest income			
Affiliates	139.3	120.0	72.9
Interest expense			
Affiliates	(43.0)	(40.1)	(17.5)
Others	(171.9)	(103.4)	(56.6)
Total interest expense	(75.6)	(23.5)	(1.2)
(Loss) income before income taxes	(954.2)	304.3	302.7
(Benefit) for income taxes	(48.0)	(25.8)	(1.0)
Net (loss) income from operations	(906.2)	330.1	303.7
Cumulative effect of change in accounting principle, net of tax	(3.2)	—	—
Net (loss) income	$ (909.4)	$ 330.1	$ 303.7

The accompanying notes are an integral part of the condensed financial statements.

SCHEDULE I – CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY
Condensed Statements of Cash Flows

(millions) *For the years ended Dec. 31.*	*2003*	*2002*	*2001*
Cash flows from operating activities	$ 10.2	$ (82.4)	$ (128.0)
Cash flows from investing activities			
Investment in subsidiaries	156.7	(232.4)	(408.2)
Dividends from subsidiaries	296.0	316.1	307.6
Net change in affiliate advances	(741.2)	(1,230.8)	(841.3)
Cash flows from investing activities	(288.5)	(1,147.1)	(941.9)
Cash flows from financing activities			
Dividends to shareholders	(165.2)	(215.8)	(184.2)
Common stock	136.6	572.6	348.4
Proceeds from long-term debt – others	296.8	1,510.9	1,012.2
Repayment of long-term debt – others	—	(600.0)	(153.2)
Net increase (decrease) in short-term debt	(312.5)	350.0	—
Equity contract adjustment payments	(20.3)	(15.3)	—
Cash flows from financing activities	(64.6)	1,602.4	1,023.2
Net (decrease) increase in cash and cash equivalents	(342.9)	372.9	(46.7)
Cash and cash equivalents at beginning of period	370.9	(2.0)	44.7
Cash and cash equivalents at end of period	$ 28.0	$ 370.9	$ (2.0)

The accompanying notes are an integral part of the condensed financial statements.

TECO ENERGY, INC.
PARENT COMPANY ONLY
NOTES TO CONDENSED FINANCIAL STATEMENTS

1. Basis of Presentation

TECO Energy, Inc., on a stand alone basis, (the parent company) has accounted for majority-owned subsidiaries using the equity basis of accounting. These financial statements are presented on a condensed basis. Additional disclosures relating to the parent company financial statements are included under the heading **Notes to Consolidated Financial Statements** in the **2003 Annual Report**, which information is hereby incorporated by reference and filed as part of **Exhibit 13**.

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles. Actual results could differ from those estimates.

2. Long-term Obligations

See **Note 7** to the TECO Energy **Consolidated Financial Statements** for a description and details of long-term debt obligations of the parent company. The preferred securities on TECO Energy's consolidated balance sheet are reflected as junior subordinated debt, as discussed in **Note 7** to the TECO Energy **Consolidated Financial Statements**, of $669.3 million on the parent company's financial statements.

3. Commitments and Contingencies

See **Note 20** to the TECO Energy **Consolidated Financial Statements** for a description of all material contingencies and guarantees outstanding of the parent company.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TECO ENERGY, INC
For the Years Ended Dec. 31, 2003, 2002 and 2001
(millions)

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Other Charges	Deductions(1)	Balance at End of Period
Allowance for Uncollectible Accounts:					
2003	$ 6.6	$ 7.0	$ (1.8) (2)	$ 7.3	$ 4.5
2002	$ 7.1	$ 9.4	$ 0.3	$ 10.2	$ 6.6
2001	$ 8.7	$ 8.1	$ (0.3)	$ 9.4	$ 7.1
Restructuring Cost Reserve Accounts:					
2003	$ 6.0	$ 24.6	$ —	$ 19.9	$ 10.7
2002	$ 0.2	$ 17.8	$ —	$ 12.0	$ 6.0
2001	$ 2.3	$ 0.1	$ —	$ 2.2	$ 0.2

(1) Write-off of individual bad debt accounts
(2) Includes $1.1 of bad debt reserves for Prior Energy and BGA that were moved to assets held for sale

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TAMPA ELECTRIC COMPANY
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended Dec. 31, 2003, 2002 and 2001
(millions)

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Other Charges	Deductions(1)	Balance at End of Period
Allowance for Uncollectible Accounts:					
2003	$ 1.1	$ 4.4	$ —	$ 4.4	$ 1.1
2002	$ 1.6	$ 7.7	$ —	$ 8.2	$ 1.1
2001	$ 2.0	$ 7.2	$ —	$ 7.6	$ 1.6
Restructuring Cost Reserve Accounts:					
2003	$ 5.1	$ 14.0	$ —	$ 13.4	$ 5.7
2002	$ 0.2	$ 16.6	$ —	$ 11.7	$ 5.1
2001	$ 2.3	$ 0.1	$ —	$ 2.2	$ 0.2

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(1) Write-off of individual bad debt accounts

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 15th day of March, 2004.

TECO ENERGY, INC.

By: /s R. D. FAGAN*

R. D. FAGAN, Chairman of the Board,
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on March 15, 2004:

Signature	Title
/s/ R. D. FAGAN R. D. FAGAN	Chairman of the Board, President, Director and Chief Executive Officer (Principal Executive Officer)
/s/ G. L. GILLETTE G. L. GILLETTE	Senior Vice President-Finance and Chief Financial Officer (Principal Financial Officer)
/s/ S. M. PAYNE S. M. PAYNE	Vice President-Corporate Accounting and Tax (Principal Accounting Officer)

Signature	Title	Signature	Title
C. D. AUSLEY* C. D. AUSLEY	Director	T. L. RANKIN* T. L. RANKIN	Director
S. L. BALDWIN* S. L. BALDWIN	Director	W. D. ROCKFORD* W. D. ROCKFORD	Director
J. L. FERMAN, JR.* J. L. FERMAN, JR.	Director	W. P. SOVEY* W. P. SOVEY	Director
L. GUINOT, JR.* L. GUINOT, JR.	Director	J. T. TOUCHTON* J. T. TOUCHTON	Director
I. D. HALL* I. D. HALL	Director	J. A. URQUHART* J. A. URQUHART	Director
S. W. HUDSON* S. W. HUDSON	Director	J. O. WELCH, JR. * J. O. WELCH, JR.	Director

*By: /s/ G. L. GILLETTE
G. L. GILLETTE, Attorney-in-fact

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 15th day of March, 2004.

TAMPA ELECTRIC COMPANY

By: /s R. D. FAGAN*

R. D. FAGAN, Chairman of the Board,
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on March 15, 2004:

Signature	Title
/s/ R. D. FAGAN* R. D. FAGAN	Chairman of the Board, President, Director and Chief Executive Officer (Principal Executive Officer)
/s/ G. L. GILLETTE* G. L. GILLETTE	Senior Vice President-Finance and Chief Financial Officer (Principal Financial Officer)
/s/ P. L. BARRINGER* P. L. BARRINGER	Vice President-Controller (Principal Accounting Officer)

Signature	Title	Signature	Title
C. D. AUSLEY* C. D. AUSLEY	Director	T. L. RANKIN* T. L. RANKIN	Director
S. L. BALDWIN* S. L. BALDWIN	Director	W. D. ROCKFORD* W. D. ROCKFORD	Director
J. L. FERMAN, JR.* J. L. FERMAN, JR.	Director	W. P. SOVEY* W. P. SOVEY	Director
L. GUINOT, JR.* L. GUINOT, JR.	Director	J. T. TOUCHTON* J. T. TOUCHTON	Director
I. D. HALL* I. D. HALL	Director	J. A. URQUHART* J. A. URQUHART	Director
S. W. HUDSON* S. W. HUDSON	Director	J. O. WELCH, JR. * J. O. WELCH, JR.	Director

*By: /s/ G. L. GILLETTE
G. L. GILLETTE, Attorney-in-fact

Supplemental Information to Be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act

No annual report or proxy material has been sent to Tampa Electric Company's security holders because all of its equity securities are held by TECO Energy, Inc.

INDEX TO EXHIBITS

Exhibit No.	Description	Page No.
3.1	Articles of Incorporation of TECO Energy, Inc., as amended on April 20, 1993 (Exhibit 3, Form 10-Q for the quarter ended March 31, 1993 of TECO Energy, Inc.).	*
3.2	Bylaws of TECO Energy, Inc., as amended effective Jan. 18, 2001 (Exhibit 3.2, Form 10-K 2000 of TECO Energy, Inc.).	*
3.3	Articles of Incorporation of Tampa Electric Company (Exhibit 3, to Registration Statement No. 2-70653).	*
3.2	Bylaws of Tampa Electric Company, as amended effective Apr. 16, 1997 (Exhibit 3 Form 10-Q for the quarter ended June 30, 1997 of Tampa Electric Company).	*
4.1	Indenture of Mortgage among Tampa Electric Company, State Street Trust Company and First Savings & Trust Company of Tampa, dated as of Aug. 1, 1946 (Exhibit 7-A to Registration Statement No. 2-6693).	*
4.2	Thirteenth Supplemental Indenture, dated as of Jan. 1, 1974, to Exhibit 4.1 (Exhibit 2-g-1, Registration Statement No. 2-51204).	*
4.3	Sixteenth Supplemental Indenture, dated as of Oct. 30, 1992, to Exhibit 4.1 (Exhibit 4.1, Form 10-Q for the quarter ended Sept. 30, 1992 of TECO Energy, Inc.).	*
4.4	Installment Purchase Contract between the Hillsborough County Industrial Development Authority and Tampa Electric Company, dated as of Jan. 31, 1984 (Exhibit 4.13, Form 10-K for 1993 of TECO Energy, Inc.).	*
4.5	First Supplemental Installment Purchase Contract, between Hillsborough County Industrial Development Authority and Tampa Electric Company, dated as of Aug. 2, 1984 ((Exhibit 4.14, Form 10-K for 1994 of TECO Energy, Inc.).	*
4.6	Second Supplemental Installment Purchase Contract, between Hillsborough County Industrial Development Authority and Tampa Electric Company, dated as of July 1, 1993 (Exhibit 4.3, Form 10-Q for the quarter ended June 30, 1993 of TECO Energy, Inc.).	*
4.7	Loan and Trust Agreement among the Hillsborough County Industrial Development Authority, Tampa Electric Company and NCNB National Bank of Florida, as trustee, dated as of Sept. 24, 1990 (Exhibit 4.1, Form 10-Q for the quarter ended Sept. 30, 1990 for TECO Energy, Inc.).	*
4.8	Loan and Trust Agreement among the Hillsborough County Industrial Development Authority, Tampa Electric Company and NationsBank of Florida, N.A., as trustee, dated as of Oct. 26, 1992 (Exhibit 4.2, Form 10-Q for the quarter ended Sept. 30, 1992 of TECO Energy, Inc.).	*
4.9	Loan and Trust Agreement among the Hillsborough County Industrial Development Authority, Tampa Electric Company and NationsBank of Florida, N.A., as trustee, dated as of June 23, 1993 (Exhibit 4.2, Form 10-Q for the quarter ended June 30, 1993 of TECO Energy, Inc.).	*
4.10	Loan and Trust Agreement among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company of Florida, N.A., as trustee, dated as of June 1, 2002. (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2002 of TECO Energy, Inc.).	*
4.11	Loan and Trust Agreement, , among the Polk County Industrial Development Authority, Tampa Electric Company and The Bank of New York, as trustee, dated as of Dec. 1, 1996 (Exhibit 4.22, Form 10-K for 1996 of TECO Energy, Inc.).	*
4.12	Installment Sales Agreement between the Plaquemines Port, Harbor and Terminal District (Louisiana) and Electro-Coal Transfer Corporation, dated as of Sept. 1, 1985 (Exhibit 4.19, Form 10-K for 1986 of TECO Energy, Inc.).	*
4.13	First Supplemental Installment Sales Agreement, between Plaquemines Port, Harbor, and Terminal District (Louisiana) and Electro-Coal Transfer Corporation, dated Dec. 20, 2000 (Exhibit 4.20, Form 10-K for 2000 of TECO Energy, Inc.).	*
4.14	Amended and Restated Reimbursement Agreement between TECO Energy, Inc. and Electro-Coal Transfer LLC, dated as of Apr. 5, 2001 (Exhibit 4.1, Form 8-K date Apr. 5, 2001 of TECO Energy, Inc.).	*
4.15	Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of July 1, 1998 (Exhibit 4.1, Registration Statement No. 333-55873).	*

4.16	Third Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of June 15, 2001 (Exhibit 4.2, Form 8-K dated June 25, 2001 of Tampa Electric Company).	*
4.17	Fourth Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Aug. 15, 2002 (Exhibit 4.2, Form 8-K dated Aug. 26, 2002 of Tampa Electric Company).	*
4.18	Note Purchase Agreement among Tampa Electric Company and the Purchasers party thereto, dated as of Apr. 11, 2003 (Exhibit 10.1, Form 8-K dated Apr. 14, 2003 for Tampa Electric Company).	*
4.19	364-Day Revolving Facility Credit Agreement dated as of Nov. 7, 2003, among Tampa Electric Company as Borrower, Citibank, N.A., as Administrative Agent, Citigroup Global Markets, Inc. and SunTrust Capital Markets, Inc., as Co-Lead Arrangers, SunTrust Bank, as Syndication Agent, Morgan Stanley Bank, and The Bank of New York, as Documentation Agents, and the lenders parties thereto as Lenders.	[ ]
4.20	3-Year Revolving Facility Credit Agreement dated as of Nov. 7, 2003, among Tampa Electric Company as Borrower, Citibank, N.A., as Administrative Agent, Citigroup Global Markets, Inc. and SunTrust Capital Markets, Inc., as Co-Lead Arrangers, SunTrust Bank, as Syndication Agent, Morgan Stanley Bank, and The Bank of New York, as Documentation Agents, and the lenders parties thereto as Lenders.	[ ]
4.21	Indenture between TECO Energy, Inc. and The Bank of New York, as trustee, dated as of Aug. 17, 1998 (Exhibit 4.1, Form 8-K dated Sept. 20, 2000 of TECO Energy, Inc.).	*
4.22	Second Supplemental Indenture dated as of Aug. 15, 2000 between TECO Energy, Inc. and The Bank of New York (Exhibit 4.1, Form 8-K dated Sept. 28, 2000 of TECO Energy, Inc.).	*
4.23	Third Supplemental Indenture dated as of Dec. 1, 2000 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.21, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.24	Amended and Restated Limited Liability Company Agreement of TECO Funding Company I, LLC dated as of Dec. 1, 2000 (Exhibit 4.24, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.25	Amended and Restated Trust Agreement of TECO Capital Trust I among TECO Funding Company I, LLC, The Bank of New York and The Bank of New York (Delaware) dated as of Dec. 1, 2000 (Exhibit 4.22, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.26	Guaranty Agreement between TECO Energy, Inc. and The Bank of New York, as trustee, dated as of Dec. 1, 2000 (Exhibit 4.25, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.27	Fourth Supplemental Indenture dated as of Apr. 30, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.28, Form 8-K dated May 1, 2001 of TECO Energy, Inc.).	*
4.28	Fifth Supplemental Indenture dated as of Sept. 10, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.16, Form 8-K dated Sept. 26, 2001 of TECO Energy, Inc.).	*
4.29	Sixth Supplemental Indenture dated as of Jan. 15, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.28, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.30	Purchase Contract Agreement between TECO Energy, Inc. and The Bank of New York, as Purchase Contract Agent, dated as of Jan. 15, 2002 (Exhibit 4.29, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.31	Amended and Restated Trust Agreement of TECO Capital Trust II among TECO Funding Company II, LLC, The Bank of New York and The Bank of New York (Delaware), dated as of Jan. 15, 2002 (Exhibit 4.31, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.32	Amended and Restated Limited Liability Agreement of TECO Funding Company II, LLC, dated as of Jan. 15, 2002 (Exhibit 4.33, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.33	Guarantee Agreement by and between TECO Energy, Inc., as Guarantor and The Bank of New York, dated as of Jan. 15, 2002 (Exhibit 4.35, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.34	Form of Remarketing Agreement by and between TECO Energy, Inc. and the Remarketing Agent (Exhibit 4.37, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.35	Pledge Agreement among TECO Energy, Inc., The Bank of New York, as Collateral Agent, Custodial Agent and Securities Intermediary and The Bank of New York, as Purchase Contract Agent dated as of Jan. 15, 2002 (Exhibit 4.38, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*

4.36	Seventh Supplemental Indenture dated as of May 1, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.15, Form 8-K dated May 13, 2002 of TECO Energy, Inc.).	*
4.37	Eighth Supplemental Indenture dated as of Nov. 20, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.1, Form 8-K dated Nov. 20, 2002 for TECO Energy, Inc.).	*
4.38	Ninth Supplemental Indenture dated as of June 10, 2003 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.15, Form 8-K dated June 13, 2003 of TECO Energy, Inc.).	*
4.39	Credit Agreement dated as of Nov. 14, 2001, among TECO Energy, Inc., as Borrower, Citibank, N.A., as Administrative Agent, Salomon Smith Barney Inc. and Banc of America Securities, LLC, as Co-Lead Arrangers, Banc of America, as Syndication Agent, the Bank of Nova Scotia, BNP Paribas and SunTrust Bank, as Co-Documentation Agents, JP Morgan Chase Bank, LC Issuing Bank, and the lenders parties thereto as Lenders (Exhibit 4.41, Form 10-K for 2001 of TECO Energy, Inc.).	*
4.40	Renewed Rights Agreement between TECO Energy, Inc. and The Bank of New York., as Rights Agent, as amended and restated as of Feb. 2, 2004 (Exhibit 1, Form 8-A/A, of TECO Energy, Inc. filed on Feb. 23, 2004).	*
4.41	Credit Agreement dated June 24, 2003, among TECO Energy, Inc., as Borrower, Bayerische Hypo-Und Vereinsbank AG, as Administrative Agent and Co-Lead Arranger, Dexia Credit Local, New York Agency, as Co-Lead Arranger and Syndication Agent, BMO Nesbitt Burns Financings, Inc., as Arranger, and Royal Bank of Canada, as Arranger (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2003 of TECO Energy, Inc.).	*
4.42	Amended and Restated Credit Agreement dated as of Dec. 19, 2003, among TECO Energy, Inc., Merrill Lynch Bank USA, as Administrative Agent, JP Morgan Chase Bank, as LC Issuing Bank, and the financial institutions parties thereto as lenders.	[ ]
10.1	TECO Energy Group Supplemental Executive Retirement Plan, as amended and restated as of July 1, 1998, as further amended as of July 15, 1998. (Exhibit 10.1, Form 10-K for 2001 of TECO Energy, Inc.).	*
10.2	TECO Energy Group Supplemental Retirement Benefits Trust Agreement, as amended and restated as of Jan. 1, 1998, as further amended as of July 15, 1998. (Exhibit 10.2, Form 10-K for 2001 of TECO Energy, Inc.).	*
10.3	Annual Incentive Compensation Plan for TECO Energy and subsidiaries, revised as of April 17, 2002. (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2002 for TECO Energy, Inc.).	*
10.4	TECO Energy Group Supplemental Disability Income Plan, dated as of March 20, 1998 (Exhibit 10.22, Form 10-K for 1988 of TECO Energy, Inc.).	*
10.5	Forms of Severance Agreement between TECO Energy, Inc. and certain officers, as amended and restated as of Oct. 22, 1999 (Exhibit 10.7, Form 10-K for 1999 of TECO Energy, Inc.).	*
10.6	Loan and Stock Purchase Agreement between TECO Energy, Inc. and Barnett Banks Trust Company, N.A., as trustee of the TECO Energy Group Savings Plan Trust Agreement (Exhibit 10.3, Form 10-Q for the quarter ended March 31, 1990 for TECO Energy, Inc.).	*
10.7	TECO Energy Directors' Deferred Compensation Plan, as amended and restated effective as of April 1, 1994 (Exhibit 10.1, Form 10-Q for the quarter ended March 31, 1994 for TECO Energy, Inc.).	*
10.8	TECO Energy Group Deferred Compensation Plan (previously the TECO Energy Group Retirement Savings Excess Benefit Plan), as amended and restated effective as of Oct. 17, 2001. (Exhibit 10.8, Form 10-K for 2001 of TECO Energy, Inc.).	*
10.9	Compensation Committee's Determinations Regarding Credit Rates for the TECO Energy Group Deferred Compensation Plan. (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2002 of TECO Energy, Inc.).	*
10.10	TECO Energy, Inc. 1996 Equity Incentive Plan as amended Apr. 18, 2001 (Exhibit 10.1, Form 10-Q for the quarter ended March 31, 2001 of TECO Energy, Inc.).	*
10.11	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1996 Equity Incentive Plan (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 1996 of TECO Energy, Inc.).	*
10.12	Form of Amendment to Nonstatutory Stock Option, dated as of July 15, 1998, under the TECO Energy, Inc. 1996 Equity Incentive Plan (Exhibit 10.3, Form 10-Q for the quarter ended Sept. 30, 1998 of TECO Energy, Inc.).	*
10.13	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1996 Equity Incentive Plan (Exhibit 10.5, Form 10-Q for the quarter ended June 30, 1999 of TECO Energy, Inc.).	*
10.14	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 1996 Equity Incentive Plan as amended and restated (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2003 of TECO Energy, Inc.).	*

10.15	TECO Energy, Inc. 1997 Director Equity Plan (Exhibit 10.1, Form 8-K dated April 16, 1997 of TECO Energy, Inc.).	*
10.16	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1997 Director Equity Plan (Exhibit 10, Form 10-Q for the quarter ended June 30, 1997 of TECO Energy, Inc.).	*
10.17	Supplemental Executive Retirement Plan for R. K. Eustace as of Jan. 15, 1997 (Exhibit 10.24, Form 10-K for 1997 of TECO Energy, Inc.).	*
10.18	Supplemental Executive Retirement Plan for R. D. Fagan as amended (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2001 of TECO Energy, Inc.).	*
10.19	Nonstatutory Stock Option granted to R. D. Fagan, dated as of May 24, 1999, under the TECO Energy, Inc. 1996 Equity Incentive Plan (Exhibit 10.3, Form 10-Q for the quarter ended June 30, 1999 of TECO Energy, Inc.).	*
10.20	Restricted Stock Agreement between TECO Energy, Inc. and R. D. Fagan, dated as of May 24, 1999 (Exhibit 10.4, Form 10-Q for the quarter ended June 30, 1999 of TECO Energy, Inc.).	*
10.21	Severance Agreement between TECO Energy, Inc. and R.D. Fagan, as amended and restated as of Jan. 28, 2003 (Exhibit 10.1, form 10-Q for the quarter ended March 31, 2003 of TECO Energy, Inc.).	*
10.22	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 1996 Equity Incentive Plan. (Exhibit 10.7, Form 10-Q for the quarter ended June 30, 2000 of TECO Energy, Inc.).	*
10.23	Form of 2002 Amendment to TECO Performance Shares Agreements between TECO Energy, Inc., and certain officers under the TECO Energy Inc. 1996 Equity Incentive Plan. (Exhibit 10.25, Form 10-K for 2001 of TECO Energy, Inc.).	*
10.24	Supplemental Executive Retirement Plan for R. Lehfeldt as of Apr. 17, 2002. (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2002 of TECO Energy, Inc.).	*
10.25	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 1996 Equity Incentive Plan, dated as of Jan. 28, 2003 (Exhibit 10.27, Form 10-K of 2002 for TECO Energy, Inc.).	*
10.26	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1997 Director Equity Plan, dated as of Jan. 29, 2003 (Exhibit 10.28, Form 10-K of 2002 for TECO Energy, Inc.).	*
10.27	Voluntary Retirement Agreement and General Release between TECO Power Services Corporation and Richard E. Ludwig, dated as of Oct. 15, 2003.	[ ]
10.28	Voluntary Retirement Agreement and General Release between TEO Energy, Inc. and Royston K. Eustace, dated as of Oct. 16, 2003.	[ ]
10.29	Consulting Agreement between TECO Energy, Inc., and Royston K. Eustace, amended and restated as of Mar. 11, 2004.	[ ]
10.30	Amended and Restated Construction Contract Undertaking by TECO Energy, Inc. in favor of Union Power Partners, L.P., as Borrower, and Citibank, N.A., as Administrative Agent under the Union Power Project Credit Agreement, dated as of May 14, 2002 (Exhibit 99.5 to Registration Statement No. 333-102019).	*
10.31	Amended and Restated Construction Contract Undertaking by TECO Energy, Inc. in favor of Panda Gila River, L.P., as Borrower, and Citibank, N.A., as Administrative Agent under the Gila River Project Credit Agreement, dated as of May 14, 2002 (Exhibit 99.4 to Registration Statement No. 333-102019).	*
10.32	Consent and Acceleration Agreement dated as of Feb. 7, 2002 by and among TECO Power Services Corporation, TECO Energy, Inc., TPS GP, Inc., TPS LP, Inc., Panda GS V, LLC, Panda GS VI, LLC, Panda Energy International, Inc. and Bayerische Hypo-Und Vereinsbank AG, New York Branch (Exhibit 10.38, Form 10-K for 2002 of TECO Energy, Inc.).	*
10.33	Suspension of Rights and Amendment Agreement dated Oct. 22, 2003, by and among Union Power Partners, L.P., and Panda Gila River, L.P., as Borrowers, TECO Energy, Inc., Societe Generale, as LC Bank, and Citibank, NA, as Administrative Agent (Exhibit 10.1, Form 10-Q for the quarter ended Sept. 30, 2003 of TECO Energy, Inc.).	*
10.34	Agreement to Acquire and Charter dated as of Dec. 21, 2001, among GTC Connecticut Statutory Trust, as Shipowner, Fleet Capital Corporation, as Owner Participant, Gulfcoast Transit Company, as Seller and Charterer and TECO Energy, Inc., as Guarantor.	[ ]
10.35	Demise charter dated as of Dec. 21, 2001, between State Street Bank And Trust Company of Connecticut, National Association , as trustee of the GTC Connecticut Statutory Trust, as Shipowner, and Gulfcoast Transit Company, as Charterer.	[ ]
10.36	First Amendment to Demise Charter dated as of Jan. 18, 2002, between State Street Bank And Trust Company of Connecticut, National Association, as trustee of the GTC Connecticut Statutory Trust, as Shipowner, and Gulfcoast Transit Company, as Charterer.	[ ]

10.37	Guarantee, dated as of Dec. 21, 2001, by TECO Energy, Inc., in favor of the Guaranteed Parties as defined therein.	[ ]
10.38	Agreement to Acquire and Charter dated as of Dec. 30, 2002, among TTC Trust, Ltd., as Shipowner, General Electric Capital Corporation, as Initial Owner Participant, TECO Barge Line, Inc., as Seller and Charterer, and TECO Energy, Inc. and TECO Transport Corporation, as Guarantors.	[ ]
10.39	Demise charter dated as of Dec. 30, 2002, between State Street Bank And Trust Company of Connecticut, National Association, as trustee of TTC Trust, Ltd., as Shipowner, and TECO Barge Line, Inc., as Charterer.	[ ]
10.40	Demise charter dated as of Dec. 30, 2002, between State Street Bank And Trust Company of Connecticut, National Association, as trustee of TTC Trust, Ltd., as Shipowner, and TECO Ocean Shipping, Inc., as Charterer.	[ ]
10.41	First Modification Agreement dated as of Mar. 28, 2003, among TTC Trust, Ltd., as Shipowner, General Electric Capital Corporation, as Initial Owner Participant, TECO Shipping, Inc., and TECO Barge Line, Inc., as Charterers, and TECO Energy, Inc. and TECO Transport Corporation, as Guarantors.	[ ]
10.42	Guarantee, dated as of Dec. 30, 2002, by TECO Energy, Inc., and TECO Transport Corporation, jointly and severally in favor of the Guaranteed Parties as defined therein.	[ ]
10.43	First Modification Agreement, dated as of Mar. 12, 2004, among State Street Bank And Trust Company of Connecticut, National Association, solely as Trustee of GTC Connecticut Statutory Trust, as Shipowner, Fleet Capital Corporation, as Owner Participant, TECO Ocean Shipping, Inc., as Charterers, and TECO Energy, Inc., and TECO Transport Corporation, as Guarantors.	[ ]
10.44	Second Modification Agreement, dated as of Mar. 9, 2004, among State Street Bank And Trust Company of Connecticut, National Association, solely as Trustee of TTC Trust, Ltd., as Shipowner, General Electric Capital Corporation and OFS Marine One, Inc., as Owner Participants, TECO Ocean Shipping, Inc., and TECO Barge Line, Inc., as Charterers, and TECO Energy, Inc., and TECO Transport Corporation as Guarantors.	[ ]
12.1	Ratio of Earnings to Fixed Charges – TECO Energy, Inc.	[ ]
12.2	Ratio of Earnings to Fixed Charges – Tampa Electric Company.	[ ]
13.	TECO Energy 2003 Annual Report to Shareholders	[ ]
21.	Subsidiaries of the Registrant.	[ ]
23.1	Consent of Independent Certified Public Accountants – TECO Energy, Inc.	[ ]
23.2	Consent of Independent Certified Public Accountants – Tampa Electric Company.	[ ]
24.1.1	Power of Attorney – TECO Energy, Inc.	[ ]
24.1.2	Power of Attorney – Tampa Electric Company.	[ ]
24.2.1	Certified copy of resolution authorizing Power of Attorney – TECO Energy, Inc.	[ ]
24.2.2	Certified copy of resolution authorizing Power of Attorney – Tampa Electric Company.	[ ]
31.1	Certification of the Chief Executive Officer of TECO Energy, Inc. pursuant to Securities Exchange Act Rules 13a-14 and 15d-14 as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	[ ]
31.2	Certification of the Chief Financial Officer of TECO Energy, Inc. pursuant to Securities Exchange Act Rules 13a-14 and 15d-14 as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	[ ]
31.3	Certification of the Chief Executive Officer of Tampa Electric Company pursuant to Securities Exchange Act Rules 13a-14 and 15d-14 as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	[ ]
31.4	Certification of the Chief Financial Officer of Tampa Electric Company to Securities Exchange Act Rules 13a-14 and 15d-14 as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	[ ]
32.1	Certification of the Chief Executive Officer and Chief Financial Officer of TECO Energy, Inc. pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (1)	[ ]
32.2	Certification of the Chief Executive Officer and Chief Financial Officer of Tampa Electric Company pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (1)	[ ]

(1) This certification accompanies the Annual Report on Form 10-K and is not filed as part of it.

* Indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. Exhibits filed with periodic reports of TECO Energy, Inc. and Tampa Electric Company were filed under Commission File Nos. 1-8180 and 1-5007, respectively.

Certain instruments defining the rights of holders of long-term debt of TECO Energy, Inc. and its consolidated subsidiaries authorizing in each case a total amount of securities not exceeding 10 percent of total assets on a consolidated basis are not filed herewith. TECO Energy, Inc. will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Certain instruments defining the rights of holders of long-term debt of Tampa Electric Company authorizing in each case a total amount of securities not exceeding 10 percent of total assets on a consolidated basis are not filed herewith. Tampa Electric Company will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Executive Compensation Plans and Arrangements

Exhibits 10.1 through 10.5 and 10.7 through 10.29 above are management contracts or compensatory plans or arrangements in which executive officers or directors of TECO Energy, Inc. participate.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

X Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2002

OR

___ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from _____ to _____

Commission File No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-8180	**TECO ENERGY, INC.** (a Florida Corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-4111	**59-2052286**
1-5007	**TAMPA ELECTRIC COMPANY** (a Florida Corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-4111	**59-0475140**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
TECO Energy, Inc.	
Common Stock, $1.00 par value	New York Stock Exchange
Common Stock Purchase Rights	New York Stock Exchange
Equity Security Units	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.
YES [X] NO [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K. [ ]

Indicate by check mark whether TECO Energy, Inc. is an accelerated filer (as defined in Exchange Act Rule 12b-2).
YES [X] NO [ ]

Indicate by check mark whether Tampa Electric Company is an accelerated filer (as defined in Exchange Act Rule 12b-2). YES [X] NO [ ]

The aggregate market value of TECO Energy, Inc.'s common stock held by nonaffiliates of the registrant as of June 28, 2002 was $3,862,495,376.

(continued)

The aggregate market value of Tampa Electric Company's common stock held by nonaffiliates of the registrant as of June 28, 2002 was zero.

The number of shares of TECO Energy, Inc.'s common stock outstanding as of February 28, 2003 was 176,049,947.

As of February 28, 2003, there were 10 shares of Tampa Electric Company's common stock issued and outstanding, all of which were held, beneficially and of record, by TECO Energy, Inc.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement relating to the 2003 Annual Meeting of Shareholders of TECO Energy, Inc. are incorporated by reference into Part III.

Tampa Electric Company meets the conditions set forth in General Instruction (I) (1) (a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format.

This combined Form 10-K represents separate filings by TECO Energy, Inc. and Tampa Electric Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Tampa Electric Company makes no representations as to the information relating to TECO Energy, Inc.'s other operations.

PART I

Item 1. BUSINESS.

TECO ENERGY

TECO Energy, Inc. (TECO Energy) was incorporated in Florida in 1981 as part of a restructuring in which it became the parent corporation of Tampa Electric Company. TECO Energy and its subsidiaries had 6,319 employees as of Dec. 31, 2002.

TECO Energy makes its SEC filings (Form 10-K, 10-Q and 8-K, and any amendments to those reports) and other information available free of charge on its web site as soon as reasonably practical after it has been electronically filed with the SEC. This information is available at the Investor Relations page of TECO Energy's web site at www.tecoenergy.com.

TECO Energy currently owns no operating assets but holds all of the common stock of Tampa Electric Company and directly, or through its subsidiary TECO Diversified, Inc., the other subsidiaries listed below. TECO Energy is a public utility holding company exempt from registration under the Public Utility Holding Company Act of 1935.

TECO Energy operates regulated utility companies and other unregulated businesses. TECO Energy's significant business segments are identified below.

Tampa Electric Company, a Florida corporation and TECO Energy's largest subsidiary, through its Tampa Electric division (Tampa Electric) provides retail electric service to more than 597,000 customers in West Central Florida with a net system generating capability of 3,784 megawatts (MW). Peoples Gas System (PGS), a division of Tampa Electric Company, is engaged in the purchase, distribution and marketing of natural gas for residential, commercial, industrial and electric power generation customers in Florida. With more than 281,000 customers, PGS has operations in Florida's major metropolitan areas. Annual natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) in 2002 was 1.3 billion therms.

TECO Transport Corporation, a Florida corporation, owns no operating assets but owns all of the common stock of four subsidiaries which transport, store and transfer coal and other dry-bulk commodities.

TECO Coal Corporation, a Kentucky corporation, owns no operating assets but owns all of the common stock of eight subsidiaries that own mineral rights, and own or operate surface and underground mines, synthetic fuel facilities, and coal processing and loading facilities in eastern Kentucky, Tennessee and southwestern Virginia.

TECO Power Services Corporation (TPS), a Florida corporation, has subsidiaries that have interests in independent power projects in Florida, Virginia, Hawaii, Arkansas, Mississippi, Texas, Arizona and Guatemala, and has investments in unconsolidated affiliates that participate in independent power projects and electric distribution in other parts of the U.S. and Guatemala.

TECO Energy's other unregulated companies include TECO Energy Services, Inc. (formerly TECO BGA, Inc. and BCH Mechanical, Inc. and its affiliated companies), TECO Gas Services, Inc., TECO Properties Corporation, Prior Energy Corporation, TECO Propane Ventures, LLC (TPV), TECO Partners, Inc. and TECO Investments, Inc. Except for TECO Investments, these operating companies are organized under TECO Solutions, Inc., a Florida corporation. The TECO Solutions' subsidiaries provide engineering and energy services to customers primarily in Florida; mechanical contracting, air conditioning, electrical and plumbing systems and repair and maintenance services in Florida; and gas management and marketing services to large municipal, industrial and power generation customers throughout the Southeast.

Revenues for TECO Energy's significant business segments follow for the years indicated. For additional financial information regarding TECO Energy's significant business segments, see **Notes to the Consolidated Financial Statements - Note Q, Segment Information.**

Revenues from Continuing Operations

(millions)	*2002*	*2001*	*2000*
Tampa Electric	$ 1,583.2	$ 1,412.7	$ 1,353.8
Peoples Gas System	318.1	352.9	314.5
Total regulated businesses	1,901.3	1,765.6	1,668.3
TECO Power Services	309.8	287.1	199.1
TECO Transport	254.6	274.9	269.8
TECO Coal	317.1	303.4	232.8
Other unregulated businesses	122.1	106.9	81.8
	2,904.9	2,737.9	2,451.8
Other and eliminations	(229.1)	(249.8)	(228.7)
	$ 2,675.8	$ 2,488.1	$ 2,223.1

TECO Coalbed Methane, Inc., an Alabama corporation, had developed jointly with another entity the natural gas potential of Alabama's Black Warrior Basin. In December 2002, TECO Energy sold substantially all of its coalbed methane assets to the Municipal Gas Authority of Georgia. TECO Coalbed Methane's results are accounted for as discontinued operations for all periods reported. Revenues from the discontinued operations of TECO Coalbed Methane were $39.7 million, $55.0 million and $43.0 million for the years ended Dec. 31, 2002, 2001 and 2000, respectively.

TAMPA ELECTRIC--Electric Operations

Tampa Electric Company was incorporated in Florida in 1899 and was reincorporated in 1949. Tampa Electric Company is a public utility operating within the state of Florida. Through its Tampa Electric division, it is engaged in the generation, purchase, transmission, distribution and sale of electric energy. The retail territory served comprises an area of about 2,000 square miles in West Central Florida, including Hillsborough County and parts of Polk, Pasco and Pinellas Counties, and has an estimated population of over one million. The principal communities served are Tampa, Winter Haven, Plant City and Dade City. In addition, Tampa Electric engages in wholesale sales to utilities and other resellers of electricity. It has three electric generating stations in or near Tampa, one electric generating station in southwestern Polk County, Florida and two electric generating stations (one of which is on long-term standby) located near Sebring, a city located in Highlands County in South Central Florida.

Tampa Electric had 2,700 employees as of Dec. 31, 2002, of which 936 were represented by the International Brotherhood of Electrical Workers and 288 were represented by the Office and Professional Employees International Union.

In 2002, approximately 48 percent of Tampa Electric's total operating revenue was derived from residential sales, 29 percent from commercial sales, 10 percent from industrial sales and 13 percent from other sales, including bulk power sales for resale.

The sources of operating revenue and megawatt-hour sales for the years indicated were as follows:

Operating Revenue

(millions)	*2002*	*2001*	*2000*
Residential	$ 753.9	$ 659.8	$ 613.3
Commercial	459.6	409.7	377.1
Industrial-Phosphate	74.3	57.0	61.6
Industrial-Other	83.8	71.8	62.6
Other retail sales of electricity	117.4	103.0	95.0
Sales for resale	67.7	82.4	109.1
Other	26.5	29.0	35.1
	$ 1,583.2	$ 1,412.7	$ 1,353.8

Megawatt-hour Sales

(millions)	*2002*	*2001*	*2000*
Residential	8,046	7,594	7,369
Commercial	5,832	5,685	5,541
Industrial	2,612	2,329	2,390
Other retail sales of electricity	1,435	1,368	1,338
Sales for resale	1,084	1,499	2,564
	19,009	18,475	19,202

No significant part of Tampa Electric's business is dependent upon a single customer or a few customers, the loss of any one or more of whom would have a significant adverse effect on Tampa Electric. IMC-Agrico, a large phosphate producer, is Tampa Electric's largest customer and represents less than 3 percent of Tampa Electric's 2002 base revenues.

Tampa Electric's business is not highly seasonal, but winter peak loads are experienced due to electric heating, fewer daylight hours and colder temperatures, and summer peak loads are experienced due to use of air conditioning and other cooling equipment.

Regulation

The retail operations of Tampa Electric are regulated by the Florida Public Service Commission (FPSC), which has jurisdiction over retail rates, quality of service and reliability, issuances of securities, planning, siting and construction of facilities, accounting and depreciation practices, and other matters.

In general, the FPSC's pricing objective is to set rates at a level that allows the utility to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The costs of owning, operating and maintaining the utility system, other than fuel, purchased power, conservation and certain environmental costs, are recovered through base rates. These costs include operation and maintenance expenses, depreciation and taxes, as well as a return on Tampa Electric's investment in assets used and useful in providing electric service (rate base). The rate of return on rate base, which is intended to approximate Tampa Electric's weighted cost of capital, primarily includes its costs for debt, deferred income taxes at a zero cost rate and an allowed return on common equity. Base rates are determined in FPSC rate setting hearings which occur at irregular intervals at the initiative of Tampa Electric, the FPSC or other parties. See the discussion of the FPSC-approved agreements covering 1995 through 1999 in the **Regulation – Tampa Electric Rate Stabilization Strategy** section of **Management's Discussion & Analysis of Financial Condition & Results of Operations (MD&A)**.

Since the expiration of the agreements noted above, Tampa Electric is not under a new stipulation. Therefore, its rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties.

Fuel, purchased power, conservation and certain environmental costs are recovered through levelized monthly charges established pursuant to the FPSC's cost recovery clauses. These charges, which are reset annually in an FPSC proceeding, are based on estimated costs of fuel, environmental compliance, conservation programs and purchased power and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs from the projected charges. The FPSC may disallow recovery of any costs that it considers imprudently incurred.

In September 2002, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery rates for the period January through December 2003. In November, the FPSC approved Tampa Electric's requested changes. In February 2003, Tampa Electric filed to revise the fuel cost recovery rates for the period April through December 2003 due to higher projected fuel prices. In March 2003, the FPSC approved Tampa Electric's revised rates. See **Regulation – Cost Recovery Clauses** section of **MD&A**.

Tampa Electric is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in various respects, including wholesale power sales, certain wholesale power purchases, transmission services, and accounting and depreciation practices. See the **Regulation – Federal Energy Regulatory Commission (FERC) Restructuring Initiatives** and **Transmission Rates** sections of **MD&A**.

Federal, state and local environmental laws and regulations cover air quality, water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters. See **Environmental Matters** on pages 6 through 8.

TECO Transport sells transportation services, and TECO Power Services sells generating capacity and energy, to Tampa Electric and other third parties. The transactions between Tampa Electric and these affiliates and the prices paid by Tampa Electric are subject to regulation by the FPSC and FERC, and any charges deemed to be imprudently incurred may be disallowed for recovery from Tampa Electric's customers. See the **Regulation – Utility Competition: Electric** section of **MD&A**. Except for transportation services performed by TECO Transport under the U.S. bulk cargo preference program, the prices charged by TECO Transport to third-party customers are not subject to regulatory oversight. See also **TECO Power Services** on pages 11 and 12.

Competition

Tampa Electric's retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of natural gas and propane for residential and commercial customers and self-generation which is available to larger users of electric energy. Such users may seek to expand their options through various initiatives including legislative and/or regulatory changes that would permit competition at the retail level. Tampa Electric intends to take all appropriate actions to retain and expand its retail business, including managing costs and providing high-quality service to retail customers.

In 1999, the FERC approved a market-based sales tariff for Tampa Electric, which allows Tampa Electric to sell excess power at market prices within Florida. The FERC had already approved market-based prices for interstate sales for Tampa Electric and the other investor-owned utilities (IOUs) operating in the state; however, Tampa Electric is the only IOU in the state with intrastate market-based sales authority.

There is presently active competition in the wholesale power markets in Florida, and this is increasing largely as a result of the Energy Policy Act of 1992 and related federal initiatives. For independent power producers, this Act removed certain regulatory barriers and required utilities to transmit power from such producers, utilities and others to wholesale customers as more fully described below.

FERC requires transmission system owners to operate an Open Access Non-discriminatory Transmission, Standard Costs, Same-time Information System (OASIS) providing, via the Internet, access to transmission service information (including price and availability) and to rely exclusively on their own OASIS system for such information for purposes of their

own wholesale power transactions. This rule works to open access for wholesale power flows on transmission systems and requires utilities such as Tampa Electric, which own transmission facilities, to provide services to wholesale transmission customers comparable to those they provide to themselves on comparable terms and conditions, including price. Among other things, the rules require transmission services to be unbundled from power sales and owners of transmission systems to take transmission service under their own transmission tariffs. To facilitate compliance, owners must maintain Standards of Conduct to ensure that personnel involved in marketing wholesale power are functionally separated from personnel involved in transmission services and reliability functions. Tampa Electric, together with other utilities, has an OASIS system and believes it is in compliance with the Standards of Conduct. See **Regulation - Transmission Rates** section of **MD&A**.

In December 1999, the FERC issued Order No. 2000, dealing with Regional Transmission Organizations (RTOs). This rule is driven by the FERC's continuing effort to effect open access to transmission facilities in large, regional markets. In FERC filings in October and December 2000, Tampa Electric and two of the other IOUs operating in Florida agreed to form an RTO, GridFlorida LLC. As proposed, the RTO would independently control the transmission assets of the filing utilities, as well as other utilities in peninsular Florida that choose to join. The FERC tentatively approved GridFlorida in March 2001, but has not finally ruled on a May 2001 compliance filing of Tampa Electric's and the other two applicants.

In May 2001, the FPSC questioned the prudence of the three filing utilities joining GridFlorida as conditionally approved by FERC. The three utilities requested and the FPSC granted the opening of an accelerated docket regarding the prudence of GridFlorida. In December 2001, the FPSC ruled that, while the three IOUs were prudent in their actions to set up GridFlorida, the FPSC was not satisfied with the transmission owning features of GridFlorida nor with the proposal that any of the filing utilities transfer ownership of their assets to GridFlorida. Accordingly, the FPSC ordered the three IOUs to file a revised, compliance version of GridFlorida reflecting the FPSC's views in the December 2001 order, which was filed with the FPSC in late March 2002. After reviewing the compliance filing, the FPSC issued another order in September 2002 approving in part and setting for further hearing the remaining issues. In October 2002, the State of Florida Office of Public Counsel filed an appeal of the FPSC orders to the Florida Supreme Court. The case is still pending. Tampa Electric continues to take an active role in monitoring and influencing the development of GridFlorida as well as other possible RTOs in the southeast region.

In July 2002, FERC issued a Notice of Proposed Rulemaking on "Standard Market Design" which seeks to develop new rules to remedy remaining undue discrimination in transmission and other industry practices, establish standard market design rules to encourage and facilitate wholesale competition and resolve pending issues related to RTOs and other matters. While that rulemaking has yet to be completed, it has elicited substantial negative reaction from several regions, states, parts of the industry and members of Congress. If enacted as proposed, it would increase competition for generation in the wholesale markets. While FERC indicated it intended to have a final rule in place by 2003, the schedule has been delayed and a new date has not been set.

Florida Governor Jeb Bush established the 2020 Energy Study Commission in 2000 to address several issues by December 2001, including current and future reliability of electric and natural gas supply, emerging energy supply and delivery options, electric industry competition, environmental impacts of energy supply, energy conservation and fiscal impacts of energy supply options on taxpayers and energy providers. The Study Commission completed its efforts and published its final report in December 2001. The Study Commission's final recommendations include, among other things, elimination of barriers to entry for merchant power generators, an open competitive wholesale electric market, transfer of regulated generating assets to unregulated affiliates or sale to others, Florida electric system reliability and consumer protection. No action was taken in the 2002 legislative session with regard to those recommendations. It is unclear at this time when or if any legislation regarding those recommendations will be proposed in future legislative sessions or, if proposed, the likelihood of it being passed.

Fuel

Approximately 95 percent of Tampa Electric's generation of electricity for 2002 was coal-fired, with oil representing approximately 2 percent and natural gas representing approximately 3 percent. Tampa Electric used its generating units to meet approximately 83 percent of the system load requirements with the remaining 17 percent coming from purchased power. A lower level of coal generation as a percentage of total generation is anticipated for 2003 as a result of Gannon's repowering to Bayside Power Station.

Tampa Electric's average delivered fuel cost per million Btu and average delivered cost per ton of coal burned have been as follows:

Average cost per million Btu:	*2002*	*2001*	*2000*	*1999*	*1998*
Coal	$ 1.93	$ 2.06	$ 1.92	$ 2.00	$ 1.99
Oil	$ 5.33	$ 5.79	$ 5.33	$ 3.09	$ 3.14
Gas (Natural)	$ 5.86	$ 4.84	$ 5.49	--	--
Composite	$ 2.11	$ 2.19	$ 2.07	$ 2.03	$ 2.03
Average cost per ton of coal burned	$ 45.04	$ 47.53	$ 44.36	$ 44.63	$ 44.44

Tampa Electric's generating stations burn fuels as follows: Gannon Station burns low-sulfur coal and No. 2 fuel oil; Big Bend Station, which has sulfur dioxide scrubber capabilities, burns a combination of low-sulfur coal, petroleum coke and coal of a somewhat higher sulfur content and No. 2 fuel oil; Polk Power Station burns high-sulfur coal, which is gasified and subjected to sulfur and particulate matter removal prior to combustion. natural gas and oil; Hookers Point Station burns low-sulfur oil; and Phillips Station burns oil of a somewhat higher sulfur content.

Coal. Tampa Electric used approximately 7.1 million tons of coal during 2002 and estimates that its coal consumption will be about 6.7 million tons for 2003. During 2002, Tampa Electric purchased approximately 58 percent of its coal under long-term contracts with five suppliers, and approximately 42 percent of its coal in the spot market. Tampa Electric expects to obtain approximately 74 percent of its coal requirements in 2003 under long-term contracts with six suppliers and the remaining 26 percent in the spot market. This temporary change in the balance of long-term versus spot contracts is due to declining spot coal needs at Gannon Station in connection with the repowering to Bayside Power Station. Tampa Electric's remaining long-term contracts provide for revisions in the base price to reflect changes in a wide range of cost factors and for suspension or reduction of deliveries if environmental regulations should prevent Tampa Electric from burning the coal supplied, provided that a good faith effort has been made to continue burning such coal. For information concerning transportation services and sales of coal by affiliated companies to Tampa Electric, see the **TECO Transport** section on page 13 and the **TECO Coal** section on pages 13 and 14.

In 2002, approximately 59 percent of Tampa Electric's coal supply was deep-mined, approximately 33 percent was surface-mined and the remainder was a processed oil by-product known as petroleum coke. Federal surface-mining laws and regulations have not had any material adverse impact on Tampa Electric's coal supply or results of its operations. Tampa Electric, however, cannot predict the effect of any future mining laws and regulations.

Oil. Tampa Electric has supply agreements through Dec. 31, 2003 for No. 2 fuel oil for its Polk, Gannon and Big Bend Stations at prices based on Gulf Coast Cargo spot indices. No. 6 fuel oil is purchased on the spot market for its Phillips Stations.

Natural Gas. In early 2003, Tampa Electric will complete its contracts for 60 percent of its expected gas needs for the 2003 summer period. The remaining 40 percent will be procured on the short-term spot market. Tampa Electric has long-term firm transportation capacity in place for its expected needs.

Franchises

Tampa Electric holds franchises and other rights that, together with its charter powers, give it the right to carry on its retail business in the localities it serves. The franchises give Tampa Electric rights to the use of rights of way and other public property to place its facilities, and are irrevocable and not subject to amendment without the consent of Tampa Electric, although, in certain events, they are subject to forfeiture.

Florida municipalities are prohibited from granting any franchise for a term exceeding 30 years. All of the municipalities, except for the cities of Tampa and Winter Haven, have reserved the right to purchase Tampa Electric's property used in the exercise of its franchise if the franchise is not renewed; otherwise, based on judicial precedent, Tampa Electric is able to keep its facilities in place subject to reasonable rules and regulations imposed by the municipalities.

Tampa Electric has franchise agreements with 13 incorporated municipalities within its retail service area. These agreements have various expiration dates ranging from November 2005 to March 2021.

Franchise fees payable by Tampa Electric, which totaled $27.3 million in 2002, are calculated using a formula based primarily on electric revenues and are collected on customers' bills.

Utility operations in Hillsborough, Pasco, Pinellas and Polk Counties outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the county commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates for the Hillsborough County and Pinellas County agreements. The agreements covering electric operations in Polk and Pasco counties expire in 2004 and 2023, respectively.

Environmental Matters

Consent Decree

Tampa Electric Company, in cooperation with the Environmental Protection Agency (EPA) and the U.S. Department of Justice, signed a Consent Decree which became effective October 5, 2000, and a Consent Final Judgment with the Florida Department of Environmental Protection (FDEP), effective December 7, 1999. Pursuant to these agreements, allegations of violations of New Source Review requirements of the Clean Air Act were resolved, provision was made for environmental controls and pollution reductions, and Tampa Electric began implementing a comprehensive program that will dramatically decrease emissions from the company's power plants.

The emission reduction requirements included specific detail with respect to the availability of flue gas desulfurization systems (scrubbers) to help reduce sulfur dioxide (SO2), projects for nitrogen oxide (NOx) reduction efforts on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Station to natural gas. When these units are repowered, the station will be renamed the Bayside Power Station and will have total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled electric generation. Tampa Electric anticipates commercial operation for the first repowered Bayside unit by May 1, 2003. The repowering of the second unit is scheduled for completion by May 1, 2004. By May 1, 2005, Tampa Electric must decide whether to install NOx controls, repower, or shutdown Big Bend Unit 4, and it must implement the chosen methodology by June 1, 2007. By May 1, 2007, Tampa Electric will decide whether to install NOx controls, repower, or shutdown Big Bend Units 1, 2 and 3 and it must implement the chosen methodology beginning in 2008. Tampa Electric's capital investment forecast includes amounts in the 2006 and 2007 period for compliance with the NOx reduction requirements.

Emission Reductions

Since 1998, Tampa Electric has reduced annual SO2, NOx, and particulate matter (PM) emissions from its facilities by 105,418 tons, 11,206 tons, and 1,113 tons, respectively.

Reductions in SO2 emissions were primarily accomplished through the installation of scrubber systems on Big Bend Units 1 and 2. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3. Currently, the scrubbers at Big Bend Station remove more than 95 percent of the SO2 emissions from the flue gas streams. In addition, reductions in NOx have been accomplished through combustion tuning and optimization projects at Big Bend and Gannon Stations.

Particulate matter (PM) is controlled at Big Bend and Gannon Stations through the use of electrostatic precipitators, which remove more than 99.9 percent of the PM generated during the combustion process.

Significant reductions in emissions outlined in the consent decree and consent final judgment will result from the ongoing repowering of the Gannon to Bayside Power Station and, should Tampa Electric decide to continue to burn coal, the installation of additional NOx emissions controls on all Big Bend Units. By 2010, these projects will result in the additional phased reduction of SO2 by 47,467 tons per year, NOx by 50,488 tons per year, and PM by 1,981 tons per year. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO2, NOx, and PM emissions by 87 percent, 89 percent, and 60 percent, respectively, below 1998 levels. With these improvements in place, Tampa Electric's facilities will meet the same standards required of new power generating facilities and help to significantly enhance the quality of the air in the community.

In November 2000, the FPSC approved recovery, through the Environmental Cost Recovery Clause of costs incurred to improve the availability and removal efficiency for its Big Bend 1, 2 and 3 scrubbers, to reduce PM emissions, and for early NOx emissions reduction projects. The approved cost recovery for these various environmental projects through customers' bills began in January 2001.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of December 31, 2002, Tampa Electric Company has estimated its ultimate financial liability to be approximately $20 million, and this amount has been reflected in the consolidated financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are recoverable through rates and are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors or Tampa Electric Company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other potentially responsible parties (PRPs) is based on each parties' relative ownership interest in or usage of a site. Accordingly, Tampa Electric Company's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Expenditures

During the five years ended Dec. 31, 2002, Tampa Electric spent $141.7 million excluding the Gannon repowering, on capital additions to meet environmental requirements, including $20.3 million at the Polk Power Station and approximately $83 million to install a new scrubber system at Big Bend Units 1 and 2 to meet Phase 2 SO2 emissions reduction requirements

under the Clean Air Act Amendments of 1990. Tampa Electric spent an estimated $9.4 million in 2002 on environmental projects. Environmental expenditures are estimated at $4.9 million for 2003 and $20 million in total for 2004 through 2007. These totals exclude amounts required to comply with the EPA Consent Decree, which are discussed above.

In 2002, Tampa Electric spent approximately $9.4 million for compliance with EPA consent decree requirements at Big Bend Station for reduction of NOx and PM emissions and to improve the scrubber systems to reduce SO2 emissions. Should Tampa Electric choose to continue to burn coal at Big Bend Station, approximately $127.8 million will be spent during 2003 through 2007 for further reduction of NOx emissions. Estimated expenditures for the continued improvement of electrostatic precipitators for PM emissions reductions are $4.3 million during 2003 through 2007. Tampa Electric has also spent $550.0 million, excluding allowance for funds used during construction (AFUDC) and dismantlement, on projects leading to the repowering of the company's coal-fired Gannon Station to fire natural gas, to meet the EPA Consent Decree condition of eliminating coal firing at Gannon Station.

PEOPLES GAS SYSTEM--Gas Operations

Peoples Gas System (PGS) operates as the Peoples Gas System division of Tampa Electric Company. PGS is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in the State of Florida.

PGS uses three interstate pipelines to receive gas for sale or other delivery to customers connected to its distribution system. PGS does not engage in the exploration for or production of natural gas. PGS operates a natural gas distribution system that serves over 281,000 customers. The system includes approximately 9,000 miles of mains and over 4,500 miles of service lines. (See **Franchise** section on page 10 for a list of service areas.)

In 2002, the total throughput for PGS was 1.3 billion therms. Of this total throughput, 12 percent was gas purchased and resold to retail customers by PGS, 74 percent was third party supplied gas delivered for retail customers, and 14 percent was gas sold off-system. Industrial and power generation customers consumed approximately 70 percent of PGS' annual therm volume, commercial customers used approximately 25 percent and the balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations generally comprise 25 percent of total revenues. New residential construction including natural gas and conversions of existing residences to gas have steadily increased since the late 1980's.

Natural gas has historically been used in many traditional industrial and commercial operations throughout Florida, including production of products such as steel, glass, ceramic tile and food products. Gas climate control technology is expanding throughout Florida, and commercial/industrial customers, including schools, hospitals, office complexes and churches, are utilizing this technology.

Within the PGS operating territory, large cogeneration facilities utilize gas-fired technology in the production of electric power and steam. Over the past three years, the company has transported, on average, about 299 million therms annually to facilities involved in cogeneration.

Revenues and therms for PGS for the years ended Dec. 31, are as follows:

	Revenues			*Therms*		
(millions)	*2002*	*2001*	*2000*	*2002*	*2001*	*2000*
Residential	$ 76.6	$ 88.2	$ 73.2	60.2	58.8	57.6
Commercial	122.3	163.6	145.8	327.6	308.9	292.1
Industrial	80.3	50.7	51.7	423.8	346.5	374.1
Power Generation	11.4	11.3	10.7	492.6	403.5	418.6
Other revenues	27.5	39.1	33.0	--	--	--
Total	$ 318.1	$ 352.9	$ 314.4	1,304.2	1,117.7	1,142.4

PGS had 635 employees as of Dec. 31, 2002. A total of 71 employees in six of PGS' 15 operating divisions are represented by various union organizations.

Regulation

The operations of PGS are regulated by the FPSC separate from the regulation of Tampa Electric's electric operations. The FPSC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters.

In general, the FPSC sets rates at a level that allows a utility such as PGS to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The basic costs of providing natural gas service, other than the costs of purchased gas and interstate pipeline capacity, are recovered through base rates. Base rates are designed to recover the costs of owning, operating and maintaining the utility system. The rate of return on rate base, which is intended to approximate PGS' weighted cost of capital, primarily includes its cost for debt, deferred income taxes at a zero cost rate, and an allowed return on common equity. Base rates are determined in FPSC proceedings which occur at irregular intervals at the initiative of PGS, the FPSC or other parties.

On June 27, 2002, PGS requested a $22.6 million annual base revenue increase. On Dec. 17, 2002, the FPSC authorized PGS to increase annual base revenues by $12.05 million. The new rates allow for a return on equity range of 10.25 to 12.25 percent with an 11.25 percent midpoint, which is the same as its previously allowed return on equity, and a capital structure of 57.43 percent equity. The increase went into effect on Jan. 16, 2003. Since its last rate increase 10 years ago, PGS has added more than 100,000 customers and expanded its pipeline system from 5,000 miles to 9,000 miles.

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the Purchased Gas Adjustment (PGA) clause. This charge is designed to recover the costs incurred by PGS for purchased gas, and for holding and using interstate pipeline capacity for the transportation of gas it sells to its customers. These charges are adjusted monthly based on a cap approved annually in an FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs and usage from the projected charges for prior periods. For a description of the most recent adjustment, see the **Regulation - Cost Recovery Clauses** section of **MD&A**.

In addition to its base rates and purchased gas adjustment clause charges for system supply customers, PGS customers (except interruptible customers) also pay a per-therm charge for all gas consumed to recover the costs incurred by PGS in developing and implementing energy conservation programs, which are mandated by Florida law and approved and supervised by the FPSC. PGS is permitted to recover, on a dollar-for-dollar basis, expenditures made in connection with these programs if it demonstrates that the programs are cost effective for its ratepayers.

In February 2000, the FPSC approved a rule that required natural gas utilities to offer transportation-only service to all non-residential customers. The net result of the unbundling is a shift from commodity sales to transportation sales. PGS continues to receive its base rate for distribution regardless of whether a customer decided to opt for transportation-only service or continue bundled service. PGS had over 9,500 transportation customers as of Dec. 31, 2002.

In addition to economic regulation, PGS is subject to the FPSC's safety jurisdiction, pursuant to which the FPSC regulates the construction, operation and maintenance of PGS' distribution system. In general, the FPSC has implemented this by adopting the Minimum Federal Safety Standards and reporting requirements for pipeline facilities and transportation of gas prescribed by the U.S. Department of Transportation in Parts 191, 192 and 199, Title 49, Code of Federal Regulations.

PGS is also subject to federal, state and local environmental laws and regulations pertaining to air and water quality, land use, noise and aesthetics, solid waste and other environmental matters.

Competition

PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity. In general, PGS faces competition from other energy source suppliers offering fuel oil, electricity and in some cases, propane. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high quality service to customers.

In Florida, gas service is unbundled for all non-residential customers. In November 2000, PGS implemented its "NaturalChoice" program offering unbundled transportation service to all eligible customers. This means that non-residential customers can purchase commodity gas from a third party but continue to pay PGS for the transportation of the gas.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by competing companies seeking to sell alternate fuels or transport gas through other facilities, thereby bypassing PGS facilities. In response to this competition, PGS has developed various programs, including the provision of transportation services at discounted rates. See the **Regulation - Utility Competition:Gas** section of **MD&A**.

Gas Supplies

PGS purchases gas from various suppliers depending on the needs of its customers. The gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has reserved firm transportation capacity for delivery by PGS to its customers.

Gas is delivered by Florida Gas Transmission Company (FGT) through more than 56 interconnections (gate stations) serving PGS' operating divisions. In addition, PGS' Jacksonville Division receives gas delivered by the South Georgia Natural Gas Company (South Georgia) pipeline through two gate stations located northwest of Jacksonville.

In May 2002, Gulfstream Natural Gas Pipeline initiated service and is the first new pipeline serving peninsular Florida since 1959. PGS entered into a service agreement for capacity in 2002 and plans to bring gas from the Gulfstream pipeline into its system at four locations by the end of 2003.

Companies with firm pipeline capacity receive priority in scheduling deliveries during times when the pipeline is operating at its maximum capacity. PGS presently holds sufficient firm capacity to permit it to meet the gas requirements of its system commodity customers, except during localized emergencies affecting the PGS distribution system and on abnormally cold days.

Firm transportation rights on an interstate pipeline represent a right to use the amount of the capacity reserved for transportation of gas on any given day. PGS pays reservation charges on the full amount of the reserved capacity whether or not it actually uses such capacity on any given day. When the capacity is actually used, PGS pays a volumetrically-based usage charge for the amount of the capacity actually used. The levels of the reservation and usage charges are regulated by FERC. PGS actively markets any excess capacity available on a day-to-day basis to partially offset costs recovered through the Purchased Gas Adjustment Clause.

PGS procures natural gas supplies using base load and swing supply contracts with various suppliers along with spot market purchases. Pricing generally takes the form of either a variable price based on published indices, or a fixed price for the contract term.

Neither PGS nor any of the interconnected interstate pipelines have storage facilities in Florida. PGS occasionally faces situations when the demands of all of its customers for the delivery of gas cannot be met. In these instances, it is necessary that PGS interrupt or curtail deliveries to its interruptible customers. In general, the largest of PGS' industrial customers are in the categories that are first curtailed in such situations. PGS' tariff and transportation agreements with these customers give PGS the right to divert these customers' gas to other higher priority users during the period of curtailment or interruption. PGS pays these customers for such gas at the price they paid their suppliers, or at a published index price, and in either case pays the customer for charges incurred for interstate pipeline transportation to the PGS system.

Franchises

PGS holds franchise and other rights with approximately 100 municipalities throughout Florida. These include the cities of Lakeland, Jacksonville, Daytona Beach, Eustis, Fort Myers, Ocala, Brooksville, Orlando, Tampa, St. Petersburg, Sarasota, Avon Park, Frostproof, Palm Beach Gardens, Pompano Beach, Fort Lauderdale, Hollywood, North Miami, Miami Beach, Miami, and Panama City. These franchises give PGS a right to occupy municipal rights-of-way within the franchise area. The franchises are irrevocable and are not subject to amendment without the consent of PGS, although in certain events, they are subject to forfeiture.

Municipalities are prohibited from granting any franchise for a term exceeding 30 years. Several franchises contain purchase options with respect to the purchase of PGS' property located in the franchise area, if the franchise is not renewed; otherwise, based on judicial precedent, PGS is able to keep its facilities in place subject to reasonable rules and regulations imposed by the municipalities.

PGS' franchise agreements with the incorporated municipalities within its service area have various expiration dates ranging from June 2003 through April 2031.

In March 2000, the City of Lakeland (City) filed suit against PGS and sought a declaration that it had the right to purchase PGS facilities located within the city limits. In October 2002, the City decided that it no longer desired to pursue owning the gas utility in Lakeland and agreed to voluntarily dismiss the lawsuit. The City and PGS entered into a new 10-year franchise agreement, similar in terms and conditions to the majority of the agreements PGS has with other municipalities.

Franchise fees payable by PGS, which totaled $6.2 million in 2002, are calculated using various formulas which are based principally on natural gas revenues. Franchise fees are collected from only those customers within each franchise area.

Utility operations in areas outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the county commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates and these rights are, therefore, considered perpetual.

Environmental Matters

PGS' operations are subject to federal, state and local statutes, rules and regulations relating to the discharge of materials into the environment and the protection of the environment generally that require monitoring, permitting and ongoing expenditures.

Tampa Electric Company is one of several potentially responsible parties for certain superfund sites and, through PGS, for certain superfund and former manufactured gas plant sites. See the previous discussion in the **Environmental Matters** section of **Tampa Electric - Electric Operations** on page 7.

Expenditures. During the five years ended Dec. 31, 2002, PGS has not incurred any material capital expenditures to meet environmental requirements, nor are any anticipated for 2003 through 2007.

TECO POWER SERVICES

TECO Power Services (TPS) has subsidiaries that have interests in independent power projects in Florida, Virginia, Hawaii, Mississippi, Arkansas, Texas, Arizona and Guatemala, and has an investment in an unconsolidated affiliated entity that participates in an independent power project in the Czech Republic. TPS had 398 employees as of Dec. 31, 2002.

Like Tampa Electric, the U.S. operations of TPS are subject to federal, state and local environmental laws and regulations covering air quality, water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters.

Hardee Power Partners (Hardee Power), a Florida limited partnership whose general and limited partners are wholly owned subsidiaries of TPS, owns the Hardee Power Station, a 370-megawatt combined cycle electric generating facility located in Hardee County, Florida, which began commercial operation in 1993. In 1993, Hardee Power entered into 20-year power supply agreements for all the capacity and energy of the Hardee Power Station, with Tampa Electric and Seminole Electric Cooperative (Seminole Electric), a Florida electric cooperative that provides wholesale power to ten electric distribution cooperatives. Under the Seminole Electric agreements, Hardee Power agreed to supply Seminole Electric with an additional 145 megawatts of capacity during the first ten years of the contract, which ended on Dec. 31, 2002. This additional capacity was purchased from Tampa Electric's coal-fired Big Bend Unit Four for resale to Seminole Electric. The 75-megawatt capacity expansion completed at Hardee Power Station in May 2000 is expected to serve Tampa Electric through 2012. The expansion consists of a General Electric combustion turbine operating in simple-cycle mode.

TPS owns 100 percent of Central Generadora Electrica San Jose, Ldta. (CGESJ), the owner of a project located in Guatemala, which consists of a single-unit pulverized-coal baseload facility (the San Jose Power Station) including port modifications to accommodate the importation of coal. This facility is the first coal-fueled plant in Central America and meets environmental standards set by the World Bank. In 1996, CGESJ signed a U.S. dollar-denominated power sales agreement (PPA) with Empresa Eléctrica de Guatemala, S.A. (EEGSA), a private distribution and generation company, to provide 120 megawatts of capacity for 15 years beginning in 2000. In 2001, CGESJ signed an option with EEGSA to extend that PPA for five years for approximately $2.5 million. In 2002, CGESJ began to transfer the port assets to Tecnologia Maritima, S.A. (TEMSA), a new TPS wholly-owned subsidiary. This transaction is expected to be completed in the first quarter of 2003. TEMSA, in addition to receiving the coal shipments for CGESJ, will be providing unloading services to third parties. Political risk insurance has been obtained for currency inconvertibility, expropriation and political violence covering up to 100 percent of TPS' equity investment and economic returns.

Tampa Centro Americana de Electricidad, Limitada (TCAE), an entity 96.06-percent owned by TPS Guatemala One, Inc., a subsidiary of TPS and the owners of the Alborada Power Station, have a U.S. dollar-denominated PPA with EEGSA to provide 78 megawatts of capacity for a 15-year period ending in 2010. In 2001, TCAE signed an option with EEGSA to extend that PPA for five years at the end of its current term for approximately $2.9 million. EEGSA is responsible for providing the fuel for the plant, with TPS providing assistance in fuel administration. TPS had originally obtained $29 million of limited recourse financing from OPIC for the Alborada Power Station. In 2002, TCAE paid off its loan with OPIC with a portion of the proceeds from a non-recourse $30 million loan from Banco Industrial, a local bank in Guatemala. Political risk insurance has been obtained for currency inconvertibility, expropriation and political violence covering up to 100 percent of TPS' equity investment and economic returns.

EEGSA serves more than 630,000 customers. EEGSA's service territory includes the capital of Guatemala, Guatemala City. In 1998, a consortium that includes TPS, Iberdrola, an electric utility in Spain, and Electricidade de Portugal, an electric utility in Portugal, completed the purchase of an 80-percent ownership interest in EEGSA for $520 million. TPS owns a 24 percent interest in this consortium and contributed $100 million in equity. The consortium obtained limited-recourse debt financing for a portion of the purchase price. TPS has obtained political risk insurance for currency inconvertibility, expropriation and political violence covering up to 100 percent of TPS' equity investment and economic returns.

In 1998, TM Power Ventures LLC (TMPV) was created by TPS and Mosbacher Power Partners, Ltd. (Mosbacher Power), an independent power company headquartered in Houston, to jointly develop, own and operate domestic and international independent power projects. Under this arrangement, TPS provided capital and technical expertise to Mosbacher Power. In 1998, TPS, through TMPV, made certain loans to two existing projects under development by Mosbacher Power. Also in 1998, TPS, through TMPV, acquired approximately a 13 percent interest in a re-powered independent power project in the Czech Republic (the ECKG project). The facility completed its expansion to a total of 344 megawatts in the first quarter of 2000 and is currently in operation. In 2002, TPS purchased Mosbacher Power's minority ownership interest in TMPV, thereby giving TPS a 100% ownership interest in TMPV. As part of the purchase, TPS received principal and interest due on its loans to Mosbacher Power. Also in 2002, TPS recorded a $5.8 million after-tax charge to adjust the valuation of the investment in the ECKG project in connection with the proposed sale of that investment.

TPS, through TMPV, has a 100-percent economic interest in Commonwealth Chesapeake Power Station (CCC), a 315-megawatt power plant on the Delmarva Peninsula of Virginia. The first phase of 134 megawatts went into service in the third quarter of 2000, and the second phase went into service in August 2001.

In the first quarter of 2001, TPS sold its minority interest in EGI, a Bermuda-based energy development firm. As part of the sale, TPS took an after-tax charge of $6.1 million ($9.3 million pre-tax) to adjust the asset valuation of the investment.

TPS is a 50-percent owner in the Hamakua Energy Project, a 60-megawatt combined cycle cogeneration facility in Hamakua, Hawaii. The facility was constructed and placed into service during 2000. TPS and J.A. Jones Ventures jointly own and operate the project under a 30-year power purchase agreement with Hawaii Electric Light Company.

In September 2000, TPS provided a $93-million investment in the form of a loan related to Panda Energy International's (Panda) Texas Independent Energy Projects (TIE). In February 2002, TPS provided an additional investment in the form of a loan in the amount of $44 million. These loans converted in accordance with their terms into an ownership interest on Jan. 3, 2003. The conversion gives TPS an opportunity for an effective economic interest of up to 75 percent of Panda's 50-percent interest in the aggregate of 2,000-megawatts in these projects. The two projects, known as Guadalupe and Odessa, are located in Texas and operate as gas-fired, combined-cycle units. The projects were brought on line in phases beginning in December 2000, with all the capacity in service in August 2001.

In October 2000, TPS acquired from Genpower LLC full ownership of two independent power projects being developed in Arkansas and Mississippi with combined capacity of the two plants to be nearly 1,200 megawatts. The two 599-megawatt facilities, known as the Dell and McAdams projects, were designed to be natural gas-fired combined-cycle plants. Construction of these two projects was suspended in 2002. Construction on these plants was suspended at the end of 2002 due to low energy prices in the markets that these plants were expected to serve. Market conditions will be monitored to determine when these plans will be completed. At the time of suspension, approximately $690 million had been invested in these plants and TPS estimated at that time that the construction cost to complete these projects would be approximately $100 million. (See the **TECO Power Services-Construction** section of **MD&A.**)

In November 2000, TPS announced a joint venture with Panda to build, own and operate two natural gas power plants located in Arkansas and Arizona, known as the Union and Gila River projects. After taking into account the preferred return, TPS' economic interest in the projects is estimated at 75-percent over the life of the projects. The 2,200-megawatt Union plant in Union County, Arkansas is under construction. The first phase began commercial operation in January 2003, and commercial operation of the entire facility is expected in the second quarter of 2003. It is expected to sell power primarily to utilities and industrial customers in Arkansas, Louisiana, eastern Texas and Mississippi. The other project, in Gila Bend, Arizona, is also under construction. The first phase is expected to begin commercial operation in the second quarter of 2003 with commercial operation of the entire facility in the third quarter of 2003. Electricity from this 2,145-megawatt plant is planned to be sold in Arizona, Southern California, Nevada and New Mexico. In February 2002, TPS entered into an agreement requiring TPS to purchase 100 percent of Panda's interest in the joint venture for $60 million in 2007, unless Panda chooses to remain a partner by canceling the agreement and paying a cancellation fee. (**See Transactions with Related and Certain Other Parties** section of **MD&A.**)

In June 2001, TPS and Panda closed on a bank financing for the Union and Gila River power stations. This $2.175 billion bank financing included $1.675 billion in five-year non-recourse debt and $500 million in equity bridge loans guaranteed by TECO Energy. Equity contributions from the joint venture, which TECO Energy has guaranteed, will be required to fund additional construction costs of up to approximately $62 million. The equity bridge financing must be repaid in four equal installments. The first $125 million installment was paid in October 2002. The second installment is due in April 2003, and the third and fourth payments are due coincident with the conversion of the construction loans to term loans, which is expected shortly after Phase 4 completion (expected in the third quarter of 2003). The TPS equity investment in these projects at commercial operation is expected to be approximately $1.2 billion. (See the **TECO Power Services-Construction** section of **MD&A.**)

In March 2001, TPS acquired American Electric Power's (AEP) Frontera Power Station, located near McAllen, Texas. Frontera is a 477-megawatt natural gas-fired combined-cycle plant. Frontera is capable of selling power domestically, as well as into the Mexican power market, through a direct interconnection with Comision de Federal Electricidad, the Mexican power authority.

Competition and Markets

The power plants that TPS is operating and constructing are located in markets with a history of high load growth. However, the general U.S. economic slowdown in 2001 and 2002 slowed the growth in demand for power in some of these markets. In addition, the slowdown of electricity deregulation initiatives across the U.S., including the markets that TPS will be serving, caused by the failure of deregulation in California, has allowed the traditional, incumbent utilities to continue to operate older, less efficient generating facilities in lieu of purchasing power from newer, more efficient independent power plants. These factors, combined with excess generating capacity that is either being built or has come on line in many markets, has depressed both spot and forward prices. Accordingly, TPS has ceased work on any new power plant developments, and is active in its efforts to mitigate its merchant exposure.

TPS' ultimate long-term strategy for selling the output of these plants is to enter into three- to five-year contracts with load serving entities, or ultimate customers where it is allowed, for up to 50 percent of the output of the plants. TPS would contract another 25 percent of the output in the shorter term (less than one-year market) with the remaining 25 percent sold

in the spot market. In the meantime, until longer-term contracts can be signed, TPS is selling the output of these plants under a mix of spot market sales and shorter-term transactions. The shorter-term transactions are primarily forward sales of on-peak energy at prices reflective of current forward curves. TECO Energy's policy is to balance power contract commitments with necessary purchases of natural gas in order to estimate the margins for such sales at the time of commitment. (See the **TECO Power Services – Energy Markets** section of **MD&A.**)

See the discussion of the risks applicable to TPS in the **Investment Considerations** section of **MD&A**. For financial information about geographic areas, see **Note Q** to the **Consolidated Financial Statements.**

TECO TRANSPORT

TECO Transport owns all of the common stock of four subsidiaries which transport, store and transfer coal and other dry-bulk commodities. These subsidiaries include TECO Ocean Shipping, Inc. (Ocean Shipping, previously Gulfcoast Transit Company), TECO Barge Line, Inc. (TECO Barge, previously Mid-South Towing Company), TECO Bulk Terminal, LLC (Bulk Terminal, previously Electro-Coal Transfer, LLC) and TECO Towing Company. TECO Transport currently owns no operating assets. TECO Transport and its subsidiaries had 997 employees as of Dec. 31, 2002.

TECO Transport's subsidiaries perform substantial services for Tampa Electric. In 2002, approximately 57 percent of TECO Transport's revenues were from third-party customers and approximately 43 percent were from Tampa Electric. The pricing for services performed by TECO Transport's operating companies for Tampa Electric is based on a fixed-price per ton, generally adjusted quarterly for changes in certain fuel and price indices. Most of the third-party utilization of the ocean-going barges is for domestic and international movements of other dry-bulk commodities and domestic phosphate movements. Both the terminal and river transport operations handle a variety of dry-bulk commodities for third party customers.

A substantial portion of TECO Transport's business is dependent upon Tampa Electric, phosphate customers, steel industry customers, grain customers, coal and petroleum coke customers, and participation in the U.S. Government's cargo preference programs.

Ocean Shipping transports products in the Gulf of Mexico and worldwide, and TECO Barge operates on the Mississippi, Ohio and Illinois rivers and their tributaries. Their primary competitors are other barge and shipping lines and railroads, as well as a number of other companies offering transportation services on the waterways used by TECO Transport's subsidiaries. Ocean Shipping is the largest US flag coastwise bulk operator based on capacity, while TECO Barge is in the top ten, based on number of barges, of companies in its business. To date, physical and technological improvements have allowed ship and barge operators to maintain competitive rate structures with alternate methods of transporting bulk commodities when the origin and destination of such shipments are contiguous to navigable waterways.

Bulk Terminal operates the largest major transfer and storage terminal on the Gulf coast. Demand for the use of such terminals is dependent upon customers' use of water transportation versus alternate means of moving bulk commodities and the demand for these commodities. Competition consists primarily of mid-stream operators and other land-based terminals.

Competition within TECO Transport's markets is based primarily on geographic markets served, pricing, and service level. The majority of the ocean and all of the river business is subject to the Jones Act, which prohibits the use of non-US flag vessels for movement between US ports.

The business of TECO Transport's subsidiaries, taken as a whole, is not subject to significant seasonal fluctuation, but is sensitive to economic conditions.

The Interstate Commerce Act exempts from regulation water transportation of certain dry-bulk commodities. In 2002, all transportation services provided by TECO Transport's subsidiaries were within this exemption.

TECO Transport's subsidiaries are subject to the provisions of the Clean Water Act of 1977 which authorizes the Coast Guard and the EPA to assess penalties for oil and hazardous substance discharges. Under this Act, these agencies are also empowered to assess clean-up costs for such discharges. In 2002, TECO Transport spent $0.2 million for environmental compliance. Environmental expenditures are estimated at $0.3 million in 2003, primarily for work on solid waste disposal and storm water drainage at the Bulk Terminal facility in Louisiana and for expenses related to oil and bilge water disposal at its river-barge repair facility in Illinois.

TECO COAL

TECO Coal owns no operating assets but holds all of the common stock of Gatliff Coal Company, Rich Mountain Coal Company, Clintwood Elkhorn Mining Company, Pike-Letcher Land Company, Premier Elkhorn Coal Company, Bear Branch Coal Company and Perry County Coal Corporation. The TECO Coal subsidiaries own or control mineral rights, and own or operate surface and underground mines, synthetic fuel facilities and coal processing and loading facilities in eastern Kentucky, Virginia and Tennessee. TECO Coal intends to sell the majority of its interest in the synthetic fuel production facilities in 2003, but retain responsibility for operating the facilities. (See the **Strategy and Outlook** section of **MD&A.**)

TECO Coal and its subsidiaries had 676 employees as of Dec. 31, 2002.

In 2002, TECO Coal subsidiaries sold 9.4 million tons of coal, with approximately 99 percent, or 9.3 million tons, sold to parties other than Tampa Electric. Of the total sold, 3.8 million tons were produced and sold as synthetic fuel.

In November 2000, TECO Coal acquired Perry County Coal Corporation, which owns or controls in excess of 21 million tons of low sulfur reserves and operates both deep and surface contract mines along with a preparation plant and two loadouts. Perry County produced and sold 2.4 million tons of coal in 2002.

In January 2000, TECO Coal purchased synthetic fuel (synfuel) facilities which were relocated to the Premier Elkhorn and Clintwood Elkhorn mines. The 3.8 million tons of synfuel produced in 2002 replaced some of TECO Coal's conventional coal production in 2002. Sales of the fuel processed through these types of facilities are eligible for non-conventional fuels tax credits under Section 29 of the Internal Revenue Code, which are available through 2007. TECO Coal received a Private Letter Ruling from the Internal Revenue Service confirming that the facilities produce a qualified fuel eligible for Section 29 tax credits available for the production of such non-conventional fuels.

The Section 29 tax credit is determined annually and is estimated to be $1.08 per million Btu in 2002, and was $1.08 per million Btu in 2001 and $1.06 per million Btu in 2000. This rate escalates with inflation but could be limited by domestic oil prices. In 2002, domestic oil prices would have had to exceed $49 per barrel for the limitation to have been effective. In 2002, TECO Coal's Section 29 tax credits were $107.3 million, compared to $86.2 million in 2001 and $52.1 million in 2000.

Primary competitors of TECO Coal's subsidiaries are other coal suppliers, many of which are located in Central Appalachia. To date, TECO Coal has been able to compete for coal sales by mining high-quality steam and specialty coals and by effectively managing production and processing costs.

The operations of underground mines, including all related surface facilities, are subject to the Federal Coal Mine Safety and Health Act of 1977. TECO Coal's subsidiaries are also subject to various Kentucky, Tennessee and Virginia mining laws which require approval of roof control, ventilation, dust control and other facets of the coal mining business. Federal and state inspectors inspect the mines to ensure compliance with these laws. TECO Coal believes it is in substantial compliance with the standards of the various enforcement agencies. It is unaware of any mining laws or regulations that would materially affect the market price of coal sold by its subsidiaries.

TECO Coal's subsidiaries are subject to various federal, state and local air and water pollution standards in their mining operations. In 2002, TECO Coal spent approximately $4.5 million on environmental protection and reclamation programs. TECO Coal expects to spend a similar amount in 2003 on these programs.

Coal mining operations are also subject to the Surface Mining Control and Reclamation Act of 1977 which places a charge of $0.15 and $0.35 on every net ton of underground and surface coal mined, respectively, to create a fund for reclaiming land and water adversely affected by past coal mining. Other provisions establish standards for the control of environmental effects and reclamation of surface coal mining and the surface effects of underground coal mining and requirements for federal and state inspections.

TECO SOLUTIONS

TECO Solutions was formed to support TECO Energy's strategy of offering customers (primarily in Florida) a comprehensive and competitive package of energy services and products, including energy-efficient engineering and construction and gas management services. Operating companies under TECO Solutions include TECO Energy Services, Inc. (formerly TECO BGA, Inc. and BCH Mechanical, Inc. and its affiliated companies), Prior Energy Corporation, TECO Gas Services Inc., TECO Properties Corporation, TECO Propane Ventures LLC (TPV) and TECO Partners, Inc., with total employees of 714 as of Dec. 31, 2002.

TECO Energy Services is comprised of TECO BGA and BCH Mechanical and its affiliated companies (BCH). TECO BGA is an engineering energy services company headquartered in Tampa. It has six offices in Florida and one in California. It provides engineering, construction management and energy services to more than 300 customers, including public schools, universities, health care facilities and other governmental facilities throughout Florida and California.

BCH, one of Florida's leading mechanical contracting firms, is headquartered in Largo, Florida and has offices in Cocoa Beach and Ft. Lauderdale. It provides air-conditioning, electrical and plumbing systems, and repair and maintenance services to more than 750 institutional and commercial customers throughout Florida.

Prior Energy, a leading natural gas management company, is headquartered in Mobile, Alabama and serves customers throughout the Southeast. Prior Energy handles all facets of natural gas energy management services for large industrial, power generation utilities, municipal and other governmental agency customers, including natural gas acquisition and supply management, transportation management, asset management and consulting services. Prior Energy owns no operating assets.

TECO Gas Services provides gas management and marketing services similar to Prior Energy for large municipal, industrial, commercial and cogeneration facilities primarily in Florida. TECO Gas Services has provided gas management services for an increasing customer base as Peoples Gas System makes its "NaturalChoice" option for unbundled service available to more non-residential customers. TECO Gas Services owns no operating assets.

TPV holds TECO Energy's propane business investment. In 2000, TECO Energy combined its propane operations with three other southeastern propane companies to form U.S. Propane. In a series of transactions, U.S. Propane combined with Heritage Holdings, Inc. As a result, TPV owns a 38-percent interest in the general partner that manages Heritage Propane Partners, L.P. (NYSE:HPG) and that general partner owns an approximate 29-percent limited partnership interest in Heritage Propane Partners, L.P. TPV owns no operating assets.

TECO COALBED METHANE

TECO Coalbed Methane had developed jointly with another entity the natural gas potential of Alabama's Black Warrior Basin.

Production from TECO Coalbed Methane's reserves was eligible for Section 29 non-conventional fuels tax credits through 2002. The credit is estimated to be $1.10 per million Btu for 2002 and was $1.08 per million Btu in 2001 and $1.06 per million Btu in 2000. This rate escalated with inflation but could be limited by domestic oil prices. In 2002, domestic oil prices would have had to exceed $49 per barrel for this limitation to have been effective. In 2002, TECO Coalbed Methane's Section 29 tax credits were $15.9 million, compared to $16.1 million in 2001. TECO Coalbed Methane's operations are subject to federal, state and local regulations for air emissions and water and waste disposal.

In September 2002, TECO Energy initiated activities to sell the TECO Coalbed Methane gas assets. That sale was substantially completed in December 2002 to the Municipal Gas Authority of Georgia. Proceeds for the sale were $140 million, of which $42 million was paid in cash at closing and $98 million was paid in January 2003. TECO Coalbed Methane's results are accounted for as discontinued operations for all periods reported.

Item 2. PROPERTIES.

TECO Energy believes that the physical properties of its operating companies are adequate to carry on their businesses as currently conducted. The properties of Tampa Electric and the subsidiaries of TECO Power Services are generally subject to liens securing long-term debt.

TAMPA ELECTRIC

At Dec. 31, 2002, Tampa Electric had five electric generating plants and five combustion turbine units in service with a total net winter generating capability of 3,784 megawatts, including Big Bend (1,759-MW capability from four coal units), Gannon (1,107-MW capability from six coal units), Hookers Point (90-MW capability from five oil units), Phillips (37-MW capability from two diesel units), Polk (260-MW capability from one integrated gasification combined cycle (IGCC) unit)) and three combustion turbine units (CTs) located at the Big Bend (165-MW) and two CTs at Polk (360-MW). Additionally, Tampa Electric has 6-MW of generating capability from generation units located at the Howard Curren Advanced Waste Water Treatment Plant in the City of Tampa. Tampa Electric also leases various distributive generation units (50-MW) at Hookers Point. The capability indicated represents the demonstrable dependable load carrying abilities of the generating units during winter peak periods as proven under actual operating conditions. Units at Hookers Point went into service from 1948 to 1955, at Gannon from 1957 to 1967, and at Big Bend from 1970 to 1985. The Polk IGCC unit began commercial operation in September 1996. In 1991, Tampa Electric purchased two power plants (Dinner Lake and Phillips) from the Sebring Utilities Commission (Sebring). Dinner Lake (11-MW capability from one natural gas unit) and Phillips were placed in service by Sebring in 1966 and 1983, respectively. In March 1994, Dinner Lake Station was placed on long-term reserve standby and was retired from service in January 2003. Hookers Point Station's Unit 5 (67-MW) was placed on long-term standby in January 2001. All units at Hookers Point were retired from service in January 2003.

Engineering for repowering Gannon Station began in 2000 (see the **Environmental Compliance** section of **MD&A**), and the company anticipates that commercial operation for the first repowered unit will occur by May 1, 2003. The repowering of an additional unit is scheduled to be completed by May 1, 2004. When these units are repowered, the station will be renamed the Bayside Power Station. Total station capacity is expected to increase to about 1,800 megawatts.

Tampa Electric owns 187 substations having an aggregate transformer capacity of 17,677,068 KVA. The transmission system consists of approximately 1,200 pole miles of high voltage transmission lines, and the distribution system consists of 7,019 pole miles of overhead lines and 3,143 trench miles of underground lines. As of Dec. 31, 2002, there were 597,146 meters in service. All of this property is located in Florida.

All plants and important fixed assets are held in fee except that title to some of the properties is subject to easements, leases, contracts, covenants and similar encumbrances and minor defects of a nature common to properties of the size and character of those of Tampa Electric.

Tampa Electric has easements for rights-of-way adequate for the maintenance and operation of its electrical transmission and distribution lines that are not constructed upon public highways, roads and streets. It has the power of eminent domain under Florida law for the acquisition of any such rights-of-way for the operation of transmission and distribution lines. Transmission and distribution lines located in public ways are maintained under franchises or permits.

Tampa Electric has a long-term lease for its office building in downtown Tampa which serves as headquarters for TECO Energy, Tampa Electric and numerous other TECO Energy subsidiaries.

PEOPLES GAS SYSTEM

PGS' distribution system extends throughout the areas it serves in Florida and consists of approximately 13,500 miles of pipe, including approximately 9,000 miles of mains and over 4,500 miles of service lines. Mains and service lines are maintained under rights-of-way, franchises or permits.

PGS' operating divisions are located in fourteen markets throughout Florida. While most of the operations and administrative facilities are owned, a small number are leased.

TECO POWER SERVICES

Hardee Power has a lease for approximately 1,300 acres of land in Hardee and Polk Counties, Florida, on which the Hardee Power Station is located. The lease has a term that runs through 2012 with options to extend the term for up to an additional 20 years.

TM Delmarva, LLC has a 100-percent economic interest in Commonwealth Chesapeake Company, LLC, which owns approximately 105 acres of land outside of New Church, in Accomack County, Virginia on which the 315-megawatt oil-fired single cycle Commonwealth Chesapeake Power Station is located.

TPS Dell, LLC, owns approximately 100 acres in the City of Dell in Mississippi County, Arkansas, on which the 599-megawatt gas-fired combined-cycle Dell electric generation plant has been under construction. TPS McAdams, LLC, owns approximately 210 acres of land in McAdams and Sallis in Attala County, Mississippi, on which the 599-megawatt gas-fired combined cycle McAdams electric generation plant has been under construction. Construction on these projects was suspended at the end of 2002 due to projected low energy prices in the markets these plants were expected to serve. Markets will be monitored to determine when these plants will be completed.

TPS, through its subsidiary TPS Hamakua Land, Inc., has a 50-percent interest in Hamakua Land Partnership, LLP, which owns 140 acres in Hawaii on which the Hamakua Energy Project is located. TPS Guatemala One, Inc. has a 96.06-percent interest in TCAE, which owns 7 acres in Guatemala on which the Alborada Power Station is located. TPS San Jose, LDC has a 100-percent ownership in a project entity, CGESJ, which owns 190 acres in Guatemala on which the San Jose Power Station is located.

Frontera Generation, LP owns 40 acres of land in Hidalgo County, Texas on which the 477-megawatt gas-fired combined cycle Frontera electric generation plant is located.

TPS has a 50-percent ownership interest in TECO-Panda Generating Company, LP, which owns two power plant projects: Union Power Partners, LP and Panda Gila River, LP. Union Power Partners owns 330 acres of land in Union County, Arkansas, on which the approximately 2,200 MW gas-fired combined-cycle Union electric generation plant is under construction. The first 550-megawatt power block of Union began operating in January 2003. Panda Gila River, LP owns approximately 1,099 acres of land in Maricopa County, Arizona, on which the approximately 2,145-megawatt gas-fired combined-cycle Gila River electric generation plant is under construction.

TECO TRANSPORT

TECO Bulk Terminal's storage and transfer terminal is on a 1,070-acre site fronting on the Mississippi River, approximately 40 miles south of New Orleans. Bulk Terminal owns 342 of these acres in fee, with the remainder held under long-term leases.

TECO Barge operates a fleet of 18 towboats and 727 river barges, approximately 69 percent of which it owns, on the Mississippi, Ohio and Illinois rivers. This includes three towboats and 110 covered river barges chartered in March 1998 under a five-year agreement which provides for the acquisition of these assets at the conclusion of the charter term. TECO Barge owns 15 acres of land fronting on the Ohio River at Metropolis, Illinois on which its operating offices, warehouse and repair facilities are located. Fleeting and repair services for its barges and those of other barge lines are performed at this location. Additionally, TECO Barge performs fleeting and supply activities at leased facilities in Cairo, Illinois.

As of Dec. 31, 2002, TECO Ocean Shipping owned and operated a fleet of 10 ocean-going tug/barge units, a 33,500 short ton ocean-going ship, a 40,900 short ton ocean-going ship, and a 41,400 short ton ocean-going ship, with a combined cargo capacity of over 420,000 tons.

TECO COAL

TECO Coal, through its subsidiaries, controls approximately 203,000 acres of coal reserves and mining property in Kentucky, Virginia and Tennessee.

Property

Gatliff Coal Company controls approximately 35,000 acres of coal and mining properties and has operations in Campbell County, Tennessee, as well as in Bell, Knox and Whitley Counties, Kentucky. In eastern Kentucky, Bear Branch Coal Company and Perry County Coal Corporation control 50,000 acres of coal reserves and operate in Perry, Knot and Leslie Counties. Additionally in eastern Kentucky, Premier Elkhorn Coal Company and Pike-Letcher Land Company are located in Letcher and Pike Counties where they control 50,000 acres of properties. Clintwood Elkhorn Mining also operates in Pike County, Kentucky, as well as Buchannan County, Virginia. Clintwood Elkhorn controls 68,000 acres of property.

In situations where property is controlled by lease, the lease terms are sufficient to ensure that the reserves for the associated operation can be mined within the initial lease term. If, however, extensions are necessary, provisions have been made within the original lease, whereby extensions may be granted upon payment of minimum royalties.

Facilities

Coal mined by the operating companies of TECO Coal is processed and shipped from facilities located at each of the operating companies, with Clintwood Elkhorn having two facilities, one at Biggs, Kentucky and one at Hurley, Virginia. The equipment at each facility is in good condition and regularly maintained by qualified personnel. Major expansions are currently on-going at the Perry County Coal facility that will enable the plant to meet the additional production requirements brought about by the opening of the Bear Branch Elkhorn 4-seam underground mine. The following is a summary of the TECO Coal processing facilities.

Company	*Facility*	*Location*	*Railroad Service*	*Utility Service*
Gatliff Coal	Gatliff Plant	Gatliff, KY	CSX Railroad	Cumberland Valley Electric/ Jellico Electric Power
Clintwood Elkhorn	Clintwood #2 Plant	Biggs, KY	Norfolk Southern	American Electric Power
Clintwood Elkhorn	Clintwood #3 Plant	Hurley, VA	Norfolk Southern	American Electric Power
Premier Elkhorn	Burk Branch Plant	Myra, KY	CSX Railroad	American Electric Power
Perry County Coal	Perry County Plant	Hazard, KY	CSX Railroad	American Electric Power

Significant projects initiated in 2002 include: an underground mine at Bear Branch, an underground mine at Premier Elkhorn, and a surface operation at Clintwood Elkhorn.

Coal Reserves

As of Dec. 31, 2002, the TECO Coal operating companies have a combined estimated 224.5 million tons of recoverable reserves, all of which are assigned. The reserves are proven and probable. All of the reserves consist of High Vol A Bituminous coal. Reserves are generally considered to be tonnages that are proven and probable and meet the generally accepted mining criteria including, but not limited to, mining height, preparation plant recovery and strip ratio. These reserves are generally projected to be mined and sold at a profit, based on year-end price and cost levels. When calculating reserves, TECO Coal has assumed the following recovery rates for the various mining methods.

	Mining Recovery Rates
Underground	55%
Contour, Surface	85%
Point Removal/Mt. Top	90%
Auger	30%
Highwall Miner	50%

The following is a summary of the qualities associated with each of the operations.

Company	BTU/lb.	Average Quality % Ash	Average Quality % Sulfur	Assigned Reserves % Owned	Assigned Reserves % Leased	Surface Reserves (000s)	Underground Reserves (000s)	Total Reserves (000s)
Gatliff Coal	14,586	3.84	0.96	0	100	2,700	10,908	13,608
Perry County Coal	14,076	7.74	0.97	0	100	4,703	16,489	21,192
Bear Branch	14,223	6.70	0.99	0	100	--	70,558	70,558
Premier Elkhorn Coal/ Pike Letcher Land (1)	13,976	6.78	1.16	90	10	19,882	55,879	75,761
Clintwood Elkhorn Mining	14,282	7.51	1.06	10	90	12,641	30,785	43,426
Total Reserves	14,159	6.81	1.06			39,926	184,619	224,545

(1) The Premier Elkhorn/Pike Letcher Land reserves were reduced from the 2001 amounts due to unfavorable economic conditions.

The following table shows a further breakdown of product by geographic region with projected market type.

Region/Company	Product	BTU/lb.	% Ash	% Sulfur	Reserves (000s)	% by Region
Eastern Kentucky						
Gatliff Coal	Steam coal	14,586	3.84	0.96	13,608	6.06
Perry County Coal	Steam coal	14,076	7.74	0.97	21,192	9.44
Bear Branch Coal	Steam coal	14,223	6.70	0.99	70,558	31.42
Premier/Pike Letcher Land	Steam coal	13,976	6.78	1.16	75,761	33.74
Clintwood	Steam coal	12,713	13.40	1.08	1,500	0.67
Clintwood	Metallurgical coal	14,429	6.51	1.08	20,626	9.19
					203,245	90.52
Southwestern Virginia						
Clintwood	Steam coal	12,713	13.40	1.08	7,159	4.96
Clintwood	Metallurgical coal	14,621	5.37	1.01	14,141	4.52
					21,300	9.48
Total					224,545	100.00

TECO Coal's reserves are based on over 1,700 data points, including drill holes, prospect measurements, and mine measurements. Reserve classification is determined by evaluation of engineering and geologic information along with economic analysis. These reserves are adjusted periodically to reflect fluctuations in the economics in the market and/or changes in engineering parameters and/or geologic conditions. The information is assembled by qualified geologists and engineers located throughout the company. The information is constantly updated to reflect new data for existing property as well as new acquisitions and depleted reserves. Information is entered into a computer modeling program from which preliminary reserves estimations are generated. Final determinations of reserves are made after in-house geologists have reviewed the computer models and adjusted the grids to better reflect regional trends.

TECO COALBED METHANE

The sale of TECO Coalbed Methane's gas assets was substantially completed in December 2002, and the final proceeds were paid in January 2003. (See **Business - TECO Coalbed Methane** section.) TECO Coalbed Methane's gas production for 2002 was 14.2 billion cubic feet (Bcf), at an effective gas price, including the effect of hedging, of about $2.80 per thousand cubic feet (Mcf) compared to production of 15 Bcf in 2001 at an effective gas price, including the effects of hedging, of about $3.66 Mcf.

Item 3. LEGAL PROCEEDINGS.

TM Power Ventures, LLC ("TMPV") a subsidiary of TECO Power Services Corporation, holds a membership and an ownership interest in Commonwealth Chesapeake Company, L.L.C. ("CCC"), owner of the Commonwealth Chesapeake project located in Virginia on the Delmarva Peninsula ("CCP"). TPS, through TMPV, currently has a 100-percent ownership interest in CCP as a result of TPS' purchase of Mosbacher Power Partners minority interest in TMPV in 2002. (See page 11). TMPV has been arbitrating certain disputes with NCP of Virginia, LLC ("NCP"), a member in CCC. In addition to its membership interest in CCC entitling NCP to a priority distribution in recognition of certain contributions it made to CCP, NCP has an option to acquire up to a 50-percent economic interest in CCP. The arbitration panel issued an interim award finding in favor of NCP on issues it alleged to have adversely affected NCP's ability to find an investor to support the exercise of its option to acquire an ownership interest and establishing as the remedy a buyout of NCP's interests, including its option to acquire the ownership interest, the related terminal value of such ownership, and its right to receive priority distributions. The panel directed the parties to provide information with respect to the value of NCP's interest and file briefs by Feb. 14, 2003 focusing on the appropriate discount rate to apply and changes, if any, to the methodology set out by the panel, with reply briefs to be filed by March 21, 2003. A final award is anticipated to be issued thereafter establishing the buyout price. Based on the language of the interim award and the methodology established for calculating the value of NCP's interest, the Company believes that, if properly calculated, the buyout price will be commercially reasonable and will not have a material impact on the Company's earnings or cash requirements; however, the briefs filed by the respective parties indicate a wide disparity in both the value of the buyout and the methodologies used. The Company believes the buyout plus attorneys fees to be less than $10 million, while NCP has claimed a value of approximately $50 million. Accordingly, the amount the panel will establish for the buyout cannot be determined at this time.

See also the **Enron Related Matters** and **Superfund and Former Manufactured Gas Plant Sites** sections of **MD&A**.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

No matter was submitted during the fourth quarter of 2002 to a vote of TECO Energy's security holders, through the solicitation of proxies or otherwise.

EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages, current positions and principal occupations during the last five years of the current executive officers of TECO Energy are described below.

Name	Age	Current Positions and Principal Occupations During Last Five Years
Robert D. Fagan	58	Chairman of the Board, President and Chief Executive Officer, December 1999 to date; President and Chief Executive Officer, May 1999 to December 1999; and prior thereto, President of PP&L Global, Inc. (diversified energy company), Fairfax, Virginia.
William N. Cantrell	50	President of TECO Solutions, September 2000 to date and President of Peoples Gas System June 1997 to date.
Royston K. Eustace	61	Senior Vice President-Business Development, April 1998 to date; and prior thereto, Vice President-Strategic Planning and Business Development.
Gordon L. Gillette	43	Senior Vice President-Finance and Chief Financial Officer, April 2001 to date; Vice President-Finance and Chief Financial Officer, April 1998 to April 2001; Vice President-Regulatory Affairs, April 1997 to April 1998.
Richard Lehfeldt	51	Senior Vice President-External Affairs, November 1999 to date; and prior thereto, Vice President and Assistant General Counsel of Edison Mission Energy (independent power company), Irvine, California.
Richard E. Ludwig	57	President of TECO Power Services Corporation, April 1989 to date.
Sheila M. McDevitt	56	Senior Vice President-General Counsel, April 2001 to date; Vice President-General Counsel, January 1999 to April 2001; and prior thereto, Vice President-Assistant General Counsel.
John B. Ramil	47	Executive Vice President - TECO Energy, Inc., December 2002 to date and President of Tampa Electric Company, April 1998 to date; Vice President-Finance and Chief Financial Officer, November 1997 to April 1998.
D. Jeffrey Rankin	56	President of TECO Transport Corporation, October 1987 to date.
J. J. Shackleford	56	President of TECO Coal Corporation, March 1986 to date.

There is no family relationship between any of the persons named above. The term of office of each officer extends to the meeting of the Board of Directors following the next annual meeting of shareholders, scheduled to be held on April 22, 2003, and until such officer's successor is elected and qualified.

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PART II

Item 5. MARKET PRICE OF AND DIVIDENDS ON THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

The following table shows the high and low sale prices for shares of TECO Energy common stock, which is listed on the New York Stock Exchange, and dividends paid per share, per quarter.

		1st Quarter	*2nd Quarter*	*3rd Quarter*	*4th Quarter*
2002					
	High	$ 28.940	$ 29.050	$ 24.710	$ 16.480
	Low	$ 23.400	$ 22.700	$ 14.200	$ 10.020
	Close	$ 28.630	$ 24.750	$ 15.880	$ 15.470
	Dividend	$ 0.345	$ 0.355	$ 0.355	$ 0.355
2001					
	High	$ 32.125	$ 32.970	$ 31.650	$ 28.300
	Low	$ 26.100	$ 28.780	$ 25.530	$ 24.750
	Close	$ 29.960	$ 30.500	$ 27.100	$ 26.240
	Dividend	$ 0.335	$ 0.345	$ 0.345	$ 0.345

The approximate number of shareholders of record of common stock of TECO Energy as of Feb. 28, 2003 was 23,482.

TECO Energy's primary source of funds to pay dividends to its common stockholders is dividends from its operating companies, including Tampa Electric Company. Tampa Electric's first mortgage bonds and certain long-term debt issues at PGS contain provisions that limit the payment of dividends on the common stock of Tampa Electric Company. Substantially all of Tampa Electric Company's retained earnings were available for dividends throughout 2002. (See **Restrictions on Dividend Payments and Transfer of Assets** section in **Note A** to the **Consolidated Financial Statements**.)

TECO Energy's 10.5% 5-year notes issued in November 2002 contain covenants that will, among other things, in the event of certain debt ratings downgrades, require TECO Energy to achieve certain debt service coverage levels in order to pay dividends or distributions or make certain investments, and limit additional liens and issue additional indebtedness. (See **Covenants in Financing Agreements** section of **MD&A**.)

In addition, if TECO Energy exercises its rights to defer payments on its subordinated notes issued in connection with the issuances of trust preferred securities by TECO Capital Trusts I and II, TECO Energy will be prohibited from paying cash dividends on its common stock until the unpaid distributions on the subordinated notes are made.

All of Tampa Electric Company's common stock is owned by TECO Energy, Inc. and, therefore, there is no market for the stock. Tampa Electric Company pays dividends substantially equal to its net income applicable to common stock to TECO Energy. Such dividends totaled $197.4 million in 2002 and $171.8 million for 2001. See **Note A – Restrictions on Dividend Payments and Transfer of Assets** in the **Consolidated Notes to the Financial Statements** for Tampa Electric Company for a description of restrictions on dividends on its common stock.

See **Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management** for the tabular disclosure of TECO Energy's Equity Compensation plans.

Item 6. SELECTED FINANCIAL DATA.

(millions, except per share amounts) *Year ended Dec. 31,*	*2002*	*2001*	*2000*	*1999*	*1998*
Revenues	$ 2,675.8	$ 2,488.1	$ 2,223.1	$ 1,932.6	$ 1,905.1
Net income from continuing operations	$ 298.2 (1)	$ 273.8 (1)	$ 227.5 (1)	$ 179.2 (2)	$ 179.2 (3)
Income from discontinued operations	26.1	21.9	12.6	(16.3)	10.3
Income tax benefit - discontinued operations	(5.8)	(8.0)	(10.8)	(23.2)	(17.0)
Net income from discontinued operations	31.9	29.9	23.4	6.9	27.3
Net income	$ 330.1 (1)	$ 303.7 (1)	$ 250.9 (1)	$ 186.1 (2)	$ 206.5 (3)
Total assets	$ 8,637.8	$ 6,763.4	$ 5,774.3	$ 4,733.0	$ 4,218.3
Long-term debt	$ 3,324.3	$ 1,842.5	$ 1,374.6	$ 1,207.8	$ 1,279.6
Earnings per share (EPS) -- basic:					
From continuing operations	$ 1.95 (1)	$ 2.04 (1)	$ 1.81 (1)	$ 1.37 (2)	$ 1.36 (3)
From discontinued operations	.20	.22	.18	.05	.21
EPS basic	$ 2.15 (1)	$ 2.26 (1)	$ 1.99 (1)	$ 1.42 (2)	$ 1.57 (3)
Dividends paid per common share (4)	$ 1.41	$ 1.37	$ 1.33	$ 1.285	$ 1.225

(1) Includes other non-operating items affecting net income (see **Note L** to the **Consolidated Financial Statements**).
(2) Includes the effect of charges, which reduced net income by $19.6 million and earnings per share by $0.15 in 1999.
(3) Includes the effect of charges, which reduced net income by $19.6 million and earnings per share by $0.15 in 1998.
(4) Dividend paid on TECO Energy common stock.

Item 7. MANAGEMENT'S DISCUSSION & ANALYSIS OF FINANCIAL CONDITION & RESULTS OF OPERATIONS.

This Management's Discussion and Analysis contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. These forward-looking statements include references to TECO Energy's anticipated capital investments, financing requirements, project completion dates, future transactions and other plans. Certain factors that could cause actual results to differ materially from those projected in these forward-looking statements include the following: energy price changes affecting TECO Power Services' (TPS') merchant plants; TPS' ability to sell the output of the merchant plants operating or under construction at a premium to the forward curve prices and to obtain power contracts to reduce earnings volatility; any unanticipated need for additional debt or equity capital that might result from lower than expected cash flow or higher than projected capital requirements; TECO Energy's ability to successfully complete the sale of its synthetic fuel and gasification facilities to successfully complete its cash generation plan; and TECO Energy's ability to maintain credit ratings sufficient to avoid posting letters of credit relating to TPS' construction loans and to avoid providing additional assurances to counterparties. Other factors include: general economic conditions, particularly those in Tampa Electric's service area affecting energy sales; weather variations affecting energy sales and operating costs; potential competitive changes in the electric and gas industries, particularly in the area of retail competition; regulatory actions affecting Tampa Electric, Peoples Gas System or TPS; commodity price changes affecting the competitive positions of Tampa Electric and Peoples Gas System, as well as the margins at TECO Coal; changes in and compliance with environmental regulations that may impose additional costs or curtail some activities; TPS' ability to successfully construct and operate its projects on schedule and within budget; the ability of TECO Energy's subsidiaries to operate equipment without undue accidents, breakdowns or failures; interest rates, credit ratings and other factors that could impact TECO Energy's ability to obtain access to sufficient capital on satisfactory terms; and TECO Coal's ability to successfully operate its synthetic fuel production facilities in a manner qualifying for Section 29 federal income tax credits, the use of which could be limited by TECO Energy's taxable income or by changes in law, regulation or administration. Some of these factors and others are discussed more fully under **"Investment Considerations."**

2002 Earnings Summary

	2002	*Change*	*2001*	*Change*	*2000*
Consolidated revenues (millions)	$ 2,675.8	7.5%	$ 2,488.1	11.9%	$ 2,223.1
Earnings per share – basic					
Continuing operations	$ 1.95	-4.4%	$ 2.04	12.7%	$ 1.81
Discontinued operations	.20	-9.1%	.22	22.2%	.18
Earnings per share	$ 2.15	-4.9%	$ 2.26	13.6%	$ 1.99
Earnings per share – diluted					
Continuing operations	$ 1.95	-3.4%	$ 2.02	12.8%	$ 1.79
Discontinued operations	.20	-9.1%	.22	22.2%	.18
Earnings per share	$ 2.15	-4.0%	$ 2.24	13.7%	$ 1.97
Net income from continuing operations (millions)	$ 298.2	8.9%	$ 273.8	20.3%	$ 227.5
Average common shares outstanding					
Basic (millions)	153.2(3)	13.9%	134.5(2)	6.8%	125.9(1)
Diluted (millions)	153.3(3)	13.2%	135.4(2)	7.2%	126.3(1)
Return on average common equity(4)	14.3%		16.5%		16.7%

(1) Average shares outstanding reflects the repurchase of 1.6 million shares in 2000.

(2) Average shares outstanding for 2001 reflects the issuance of 8.625 million shares in March 2001 and 3.5 million shares in October 2001.

(3) Average shares outstanding for 2002 reflects the issuance of 15.525 million shares in June 2002 and 19.385 million shares in October 2002.

(4) Includes results from Discontinued operations (TECO Coalbed Methane).

TECO Energy's revenues increased by more than 7 percent in 2002 to $2.7 billion; revenues in 2001 increased 11.9 percent to $2.5 billion. In 2002, net income from continuing operations rose almost 9 percent to $298.2 million, up from $273.8 million in 2001. Net income from continuing operations was $227.5 million in 2000. Earnings per share - basic from continuing operations were $1.95 per share in 2002 compared with $2.04 per share in 2001. The number of average shares outstanding at Dec. 31, 2002 was almost 14 percent higher than at Dec. 31, 2001. Earnings per share – basic from continuing operations were $1.81 in 2000.

Included in the 2002 results from continuing operations are a $34.1-million pretax ($20.9 million after-tax) charge related to a debt refinancing and a $5.8 million after-tax asset valuation charge related to the proposed sale of TPS' minority interest in power generating facilities in the Czech Republic. Excluding these unusual items, non-Generally Accepted Accounting Principles (GAAP), or pro forma, net income from continuing operations rose 19 percent to $324.9 million or from $2.04 per share in 2001 to $2.12 per share in 2002. Results from discontinued operations reflect results at the coalbed methane business, which was sold in December 2002.

Total net income and earnings per share, including continuing operations and discontinued operations, were $330.1 million and $2.15 per share, respectively. Total non-GAAP net income and earnings per share, excluding the debt refinancing and asset valuation charges and the $7.7 million gain on the sale of TECO Coalbed Methane, were $349.1 million and $2.28 per share, respectively.

The 2002 results reflect continued customer growth and increased energy usage in the Florida utility operations, higher allowance for funds used during construction (AFUDC – non-cash credit to income with a corresponding increase in utility plant which represents the cost of borrowed funds and a reasonable return on the equity funds used for construction) at Tampa Electric, improved results at TPS, and increased synthetic fuel production at TECO Coal. These improvements were partially offset by lower results at TECO Transport.

Net income from continuing operations in 2001 was $273.8 million, up more than 20 percent from $227.5 million in 2000. These results reflected continued customer growth and increased energy usage in the Florida operations, higher AFUDC at Tampa Electric, an 18 percent increase in net income at TPS from the new generation projects acquired or brought on line in 2000 and 2001 and improved results from the Guatemalan operations, and higher conventional coal production and prices and increased synthetic fuel production at TECO Coal. These improvements were partially offset by higher interest expense associated with increased borrowing levels and a $6.1 million after-tax asset valuation charge related to TPS' sale of its interest in Energia Global International, Ltd. (EGI).

Strategy and Outlook

In late 1999, TECO Energy announced a three-pronged business strategy which was to focus on its Florida operations, which include Tampa Electric, Peoples Gas System (PGS) and the Florida energy services businesses, TECO Solutions; to expand its domestic independent power operations at TPS; and to use the returns of its family of other profitable unregulated businesses to support growth. Since that time, the company has undertaken a number of initiatives to advance the announced strategy. These initiatives include continued development of the regulated electric and gas businesses in Florida, including significant additions to Tampa Electric's electric generation facilities, development of independent power generation projects in the Sunbelt of the United States and continued good operations and returns from its family of other unregulated businesses. However, conditions in energy markets and the independent power business have changed since then.

In 2001, future wholesale power prices declined significantly in markets across the country due to a combination of the slowing of wholesale electric competition; uneconomic dispatch; the U.S. economic slowdown; and the large amount of new generating capacity either completed or under construction and expected to come online in 2002 and 2003. The price outlook remained weak throughout 2002 and the prospects for price recovery in 2003 are uncertain. The low power prices have caused weaker earnings expectations from independent power projects and have caused some developers to cancel or delay projects in some markets.

In light of the capital required to complete the committed regulated and unregulated power plant projects, during 2002 TECO Energy took a number of steps to provide the needed cash while, at the same time, strengthening its balance sheet. These steps included accessing the capital markets for funding, initiating other cash generation measures and reducing capital expenditures. During 2002, the company issued new common equity on two occasions totaling $553 million in net proceeds. In January 2002, the company issued $436 million in net proceeds of mandatorily convertible equity units, which will convert to TECO Energy common shares in January 2005. In addition, the company has reduced its capital expenditure forecast for 2002 through 2004 on two separate occasions. The first reduction in January 2002 totaled approximately $700 million, primarily through delaying, for an extended period, generation projects that were not yet under construction for TPS and Tampa Electric. The second reduction was effected in September as part of a comprehensive cash business plan.

In September 2002, the company announced a preliminary 2003 business plan that focused on the generation of cash to support the construction of the Union and Gila River power stations at TPS and the Gannon to Bayside repowering project at Tampa Electric so as to avoid accessing the capital markets for incremental debt in 2003. This was done in the face of downgrades by equity analysts and the credit rating agencies of both TECO Energy and other companies in the energy sector. The industry's situation deteriorated in late 2002 to the state of a severe credit crisis, highlighting the importance of TECO Energy's execution of the announced plan.

The major components of the plan included: 1) a reduction of capital expenditures of $250 million, including the suspension of construction of the Dell and McAdams power stations, changing the timing of the completion of Bayside Unit 2 and general capital spending reductions at all of the companies, which allowed TECO Energy to sustain its previously forecasted capital expenditure levels; 2) $400 million from the sale of the TECO Coalbed Methane gas assets, the proposed sale of the majority of its interest in facilities that produce synthetic fuel which qualify for Section 29 tax credits at TECO Coal, and the proposed sale of the coal gasification unit at Tampa Electric's Polk Power Station; and 3) $250 million of cash from other financial transactions or asset sales including the repatriation of cash and additional cash from non-recourse refinancing on generating facilities in Guatemala. In addition, TECO Energy ceased work on any new development in the independent power area beyond the already announced and initiated activities.

TECO Energy expects an extended period of lower earnings and to be in a weaker financial position during the current cycle of low wholesale power prices. As previously discussed, the company took decisive steps during 2002 to improve its financial position. The company will continue to take steps as necessary to position itself for a return to a stronger financial position and to a return to earnings growth in the future.

During this period of low wholesale power prices, TECO Energy expects to continue to benefit from deriving the majority of net income and cash flow from its regulated businesses, Tampa Electric and PGS, which operate in one of the highest growth utility markets in the nation. In 2003, about 75 percent of net income is expected to come from regulated utility operations in Florida. Growth is expected to continue in Florida because the state's economy, with its small industrial base, was not impacted by the economic slowdown to the same degree as some manufacturing-based areas of the country.

Operating Results

Management's Discussion & Analysis of Financial Condition & Results of Operations utilize TECO Energy's consolidated financial statements, which have been prepared in accordance with GAAP, to analyze the financial condition of the company.

TECO Energy's reported operating results are affected by a number of critical accounting policies that include such items as accounting for regulated activities, accounting for derivatives, asset impairment testing, accounting for unconsolidated affiliates and others. (See the **Critical Accounting Policies and Estimates** section.)

The following table shows the unconsolidated revenues, net income and earnings per share contributions from continuing operations of the significant business segments. (See **Note Q** to the **Consolidated Financial Statements.**)

(millions) Except per share amounts	*2002*	*Change*	*2001*	*Change*	*2000*
Unconsolidated Revenues (1)					
Regulated Companies					
Tampa Electric	$ 1,583.2	12.1%	$ 1,412.7	4.4%	$ 1,353.8
Peoples Gas System	318.1	-9.9%	352.9	12.2%	314.5
Total Regulated	$ 1,901.3	7.7%	$ 1,765.6	5.8%	$ 1.668.3
Unregulated Companies					
TECO Power Services	$ 309.8	7.9%	$ 287.1	44.2%	$ 199.1
TECO Transport	254.6	-7.4%	274.9	1.9%	269.8
TECO Coal	317.1	4.5%	303.4	30.3%	232.8
Other unregulated businesses	122.1	14.2%	106.9	30.5%	81.8
Total Unregulated	$ 1,003.6	3.2%	$ 972.3	24.1%	$ 783.5
Net Income (2)					
Regulated Companies					
Tampa Electric	$ 171.8	11.6%	$ 154.0	6.6%	$ 144.5
Peoples Gas System	24.2	4.8%	23.1	6.0%	21.8
Total Regulated	196.0	10.7%	177.1	6.5%	166.3
Unregulated Companies					
TECO Power Services	34.1	26.8%	26.9	18.0%	22.8
TECO Transport	21.0	-23.9%	27.6	-5.5%	29.2
TECO Coal	76.5	29.7%	59.0	76.1%	33.5
Other unregulated businesses	6.8	70.0%	4.0	233.3%	1.2
Total Unregulated	138.4	17.8%	117.5	35.5%	86.7
Financing/Other	(36.2)	74.0%	(20.8)	-18.4%	(25.5)
Net income from continuing operations	298.2	8.9%	273.8	20.3%	227.5
Discontinued operations	31.9	6.7%	29.9	27.7%	23.4
Net income total	$ 330.1	8.7%	$ 303.7	21.0%	$ 250.9
Earnings per Share - Basic (2)					
Regulated Companies					
Tampa Electric	$ 1.12	-2.6%	$ 1.15	—	$ 1.15
Peoples Gas System	.16	-5.9%	.17	—	.17
Total Regulated	1.28	-3.0%	1.32	—	1.32
Unregulated Companies					
TECO Power Services	.22	10.0%	.20	11.1%	.18
TECO Transport	.14	-30.0%	.20	-13.0%	.23
TECO Coal	.50	13.6%	.44	63.0%	.27
Other unregulated businesses	.04	33.3%	.03	200%	.01
Total Unregulated	.90	3.4%	.87	26.1%	.69
Financing/Other	(.23)	53.3%	(.15)	-25.0%	(.20)
EPS from continuing operations	1.95	-4.4%	2.04	12.7%	1.81
Discontinued operations	.20	-9.0%	.22	22.2%	.18
EPS Total	$ 2.15	-4.9%	$ 2.26	13.6%	$ 1.99

(1) Revenues for all periods have been adjusted to reflect the presentation of energy marketing related revenues on a net basis, the reclassification of TECO Coalbed Methane results to discontinued operations, and the reclassification of earnings from equity investments from Revenues to Other Income.

(2) Beginning in 2001, segment net income was reported on a basis that included internally allocated financing costs. Prior period net income has been reclassified to reflect estimated internally allocated financing costs that would have been attributable to such prior periods. Internally allocated finance costs for 2002, 2001 and 2000 were at pretax rates of 7%, 7%, and 6.75%, respectively, based on the average investment in each subsidiary.

Tampa Electric - Electric Operations

Tampa Electric Results

Tampa Electric's net income increased almost 12 percent in 2002, reflecting continued good residential and commercial customer growth, increased sales to phosphate customers and more favorable summer weather, partially offset by lower sales to other utilities and higher operations and maintenance expenses. The equity component of AFUDC, primarily from the Gannon to Bayside Units 1 and 2 repowering project, increased to $24.9 million, compared to $6.6 million in 2001.

Tampa Electric's net income increased almost 7 percent in 2001, reflecting good customer growth, slightly higher residential and commercial per-customer energy usage, and a favorable customer mix, partially offset by higher operations, maintenance and depreciation expenses. In addition, AFUDC equity, primarily from the Gannon to Bayside Units 1 and 2 repowering project, increased to $6.6 million, compared with $1.6 million in 2000.

Net income increased in both 2002 and 2001 while operating income decreased due to higher AFUDC and lower interest expense which affect net income but not operating income.

Summary of Operating Results

(millions)	*2002*	*Change*	*2001*	*Change*	*2000*
Revenues	$ 1,583.2	12.1%	$ 1,412.7	4.4%	$ 1,353.8
Other operating expenses	212.3	11.3%	190.7	1.3%	188.3
Maintenance	108.7	9.2%	99.5	3.5%	96.1
Depreciation	189.8	9.5%	173.4	7.3%	161.6
Taxes, other than income	112.3	7.2%	104.8	6.2%	98.7
Non-fuel operating expenses	623.1	9.6%	568.4	4.4%	544.7
Fuel	424.1	22.4%	346.5	7.1%	323.5
Purchased power	253.7	21.0%	209.7	9.2%	192.1
Total fuel expense	677.8	21.9%	556.2	7.9%	515.6
Total operating expenses	$ 1,300.9	15.7%	$ 1,124.6	6.1%	$ 1,060.3
Operating income	$ 282.3	-2.0%	$ 288.1	-1.8%	$ 293.5
Net income	$ 171.8	11.6%	$ 154.0	6.6%	$ 144.5

Tampa Electric Operating Revenues

The economy in Tampa Electric's service area continued to grow in 2002, aided by the region's relatively low labor rates, attractive cost of living and affordable housing. The Tampa metropolitan area's employment grew slightly in 2002, in spite of the continued U.S. economic slowdown. The local Tampa area unemployment rate rose to 4.2 percent in November 2002, up slightly from 4.0 percent in December 2001, compared to 5.0 percent for the State of Florida and 6.0 percent for the nation. The Tampa area, with its diverse service-based economy, did not experience the same drop in economic activities as those areas of the country with manufacturing-based economies. Tampa Electric experienced minimal impact by the slowdown in the tourist industry because the areas served are not as sensitive to changes in the tourist industry as some other areas of Florida.

Retail megawatt hour sales rose 5.6 percent in 2002, primarily from increased residential and commercial sales from higher numbers of customers, higher per-customer usage and warmer-than-normal summer weather. Electricity sales to the lower-margin industrial customers in the phosphate industry increased 18.2 percent in 2002 after a 10.9 percent decline in 2001. The phosphate industry saw increased demand and improved pricing worldwide which led to increased production in 2002. In 2001, the phosphate industry experienced a second year of a worldwide slowdown due to overcapacity and reduced usage that contributed to temporary facility closures during the year and the permanent closure of one phosphate processing facility. The company's phosphate customers have indicated that they expect to vary production to maintain stable prices in 2003. Revenues from phosphate sales represented slightly less than 3 percent of base revenues in 2002 and 2001. Non-phosphate industrial sales increased in 2002 and 2001, primarily reflecting continued economic growth in the area.

Base rates for all customers were unchanged in 2002. However, Tampa Electric refunded $6.4 million to customers in 2002 related to 1999 revenues held subject to refund under agreements between the Florida Public Service Commission (FPSC), the Office of Public Counsel and Tampa Electric. Fuel-related revenues increased in 2002 under the FPSC approved fuel adjustment clause due to the recovery of a previous underrecovery of fuel expense in 2001 and increased customer usage. (See the **Regulation** section.)

Sales to other utilities for resale declined in 2002, primarily as a result of lower coal-fired generating unit availability due to more planned maintenance outages.

Based on expected growth from continued population increases and business expansion, Tampa Electric expects retail energy sales growth of approximately 2.5 percent annually over the next five years, with combined energy sales growth in the residential and commercial sectors of more than 3 percent annually. Tampa Electric's forecasts indicate that summer retail demand growth is expected to average more than 100 megawatts per year for the next five years.

These growth projections assume continued local area economic growth even in the current national economic climate, normal weather and a continuation of the current market structure. (See the **Investment Considerations** section.)

Megawatt-Hour Sales

(thousands)	*2002*	*Change*	*2001*	*Change*	*2000*
Residential	8,046	6.0%	7,594	3.1%	7,369
Commercial	5,832	2.6%	5,685	2.6%	5,541
Industrial	2,612	12.2%	2,329	-2.6%	2,390
Other	1,435	4.9%	1,368	2.2%	1,338
Total retail	17,925	5.6%	16,976	2.0%	16,638
Sales for resale	1,084	-27.7%	1,499	-41.5%	2,564
Total energy sold	19,009	2.9%	18,475	-3.8%	19,202
Retail customers (average)	590.2	2.5%	575.8	2.8%	560.1

Tampa Electric Operating Expenses

Operating expenses increased almost 16 percent in 2002, reflecting higher fuel costs from an increased amount of power generated with higher-cost oil and natural gas, increased purchased power due to lower unit availability, higher Other operating expenses due to higher employee benefit costs and costs associated with a 7 percent reduction in the workforce, higher depreciation from normal plant additions to serve the growing customer base and the addition of a new peaking combustion turbine at the Polk Power Station in mid-2002, and accelerated depreciation associated with phasing out coal-related assets at the Gannon Power Station.

Operating expenses increased 6 percent in 2001, reflecting higher fuel costs from higher coal prices, increased purchased power costs due to lower unit availability, higher maintenance expenses associated with increased planned outages on coal-fired generating units, and higher depreciation from normal plant additions and accelerated depreciation associated with phasing out coal-related assets at the Gannon Power Station.

Non-fuel operations and maintenance expenses are expected to decrease in 2003 as a result of workforce reductions in 2002 and the repowering of the Gannon Station to natural gas with its lower manpower and maintenance requirements.

Depreciation expense is projected to increase in 2003, and in the future, from normal plant additions and the first phase of the Gannon to Bayside repowering project entering service in mid-2003. (See the **Environmental Compliance** section.)

Fuel costs increased 22 percent in 2002 despite lower coal costs, reflecting primarily increased generation with oil and natural gas due to lower coal unit availability. Natural gas and oil prices increased significantly in the second half of 2002. Average coal costs, on a cents-per-million Btu basis, decreased 6 percent in 2002 after a 7 percent increase in 2001. Purchased power expense increased in 2002 due to lower unit availability, primarily as a result of planned maintenance outages on base load generating units and unplanned outages during peak load periods. The effects of higher fuel and purchased power costs are also reflected in the higher operating revenues, as these costs are recovered through the fuel adjustment clause.

Nearly all of Tampa Electric's own generation over the last three years has been produced from coal, and the fuel mix is expected to continue to be substantially comprised of coal until mid-year 2003, when the first of two repowered units at Bayside is scheduled to begin operating on natural gas. (See the **Environmental Compliance** section.) On a total energy supply basis, company generation accounted for 83 percent, 84 percent and 92 percent of the total system energy requirements in 2002, 2001 and 2000, respectively.

Peoples Gas System

PGS is the largest investor-owned gas distribution utility in Florida. It serves more than 281,000 customers in all of the major metropolitan areas of Florida.

PGS net income rose almost 5 percent in 2002. Contributing to these results were 4.1 percent customer growth, operations and maintenance expenses which were essentially unchanged from 2001, and higher volumes sold for off-system sales and higher volumes transported for power generation customers which more than offset the impact of mild winter weather.

Lower gas prices in the first half of 2002 made the use of natural gas more attractive for large customers than during the period of high prices in the first half of 2001. Gas prices increased in the second half of 2002 and into early 2003, but the differential between natural gas and other fuels has remained relatively constant, therefore, fuel switching is not expected to the same degree as was experienced in 2001.

PGS' net income rose 6 percent in 2001 from 4 percent customer growth and increased gas transported for off-system sales. The high cost of gas early in 2001 had a negative impact on sales to larger interruptible and power generation customers, many of whom have the ability to switch to alternative fuels or to alter consumption patterns.

Historically the natural gas market in Florida has been underserved with the lowest market penetration in the southeastern U.S. PGS is expanding its gas distribution system into areas of Florida not previously served and within areas currently served.

Summary of Operating Results

(millions)	*2002*	*Change*	*2001*	*Change*	*2000*
Revenues	$ 318.1	-9.9%	$ 352.9	12.2%	$ 314.5
Cost of gas sold	149.0	-20.1%	186.4	18.7%	157.0
Operating expenses	115.6	.2%	115.4	4.4%	110.5
Operating income	$ 53.5	4.7%	$ 51.1	8.7%	$ 47.0
Net Income	$ 24.2	4.8%	$ 23.1	6.0%	$ 21.8
Therms sold - by customer segment					
Residential	60.2	2.4%	58.8	2.1%	57.6
Commercial	327.6	6.0%	308.9	5.8%	292.1
Industrial	423.8	22.3%	346.5	-7.4%	374.1
Power Generation	492.6	22.1%	403.5	-3.6%	418.6
Total	1,304.2	16.7%	1,117.7	-2.2%	1,142.4
Therms sold - by sales type					
System Supply	332.5	13.8%	292.2	-8.9%	320.6
Transportation	971.7	17.7%	825.5	.4%	821.8
Total	1,304.2	16.7%	1,117.7	-2.2%	1,142.4
Customers (thousands) - average	277.5	4.1%	266.6	4.1%	256.2

Residential and commercial therm sales increased from more than 4 percent customer growth in 2002, more than offsetting mild winter weather. Therm sales to large industrial and power generation customers also increased, primarily from significantly lower gas prices in the first half of 2002.

Residential therm sales increased in 2001, the result of more than 4 percent customer growth and increased per-customer usage. Commercial therm sales also increased, primarily from increased per-customer use.

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a Purchased Gas Adjustment (PGA) clause approved by the Florida Public Service Commission annually.

In Florida, natural gas service is unbundled for all non-residential customers, affording these customers the opportunity to purchase gas from any provider. The net result of this unbundling is a shift from commodity sales to transportation sales. Because commodity sales are included in operating revenues at the cost of the gas on a pass-through basis, there is no net financial impact to the company when a customer shifts to transportation-only sales. PGS markets its services to these customers through its "NaturalChoice" program. At year-end 2002, 9,500 customers had elected to take service under this program.

Operating expenses were essentially unchanged from 2001 levels. This achievement represents significant cost reduction efforts in all areas of the company to offset the effect of the mild winter weather.

In 2001, operation and maintenance expenses were essentially unchanged from 2000 levels, while depreciation expense increased 8 percent, in line with the increased capital expenditures made over the past several years to expand the system.

On June 27, 2002, PGS requested a $22.6-million annual base revenue increase. On Dec. 17, 2002, the FPSC authorized PGS to increase annual base revenues by $12.05 million. The new rates allow for a return on equity range of 10.25 to 12.25 percent with an 11.25 percent midpoint, which is the same as its previously allowed return on equity, and a capital structure of 57.43 percent equity. The increase went into effect on Jan. 16, 2003. Since its last rate increase 10 years ago, PGS has added more than 100,000 customers and expanded its pipeline system from 5,000 miles to 9,000 miles.

In May 2002, Gulfstream Natural Gas Pipeline initiated service. This interstate pipeline starts in Mobile Bay, Alabama, crosses the Gulf of Mexico and comes ashore in Florida just south of Tampa. Gulfstream is the first new pipeline serving peninsular Florida since 1959. This pipeline increases gas transportation capacity into Florida by 50 percent. PGS entered into a service agreement for capacity in 2002, which increases in 2003 and 2004. The addition of the Gulfstream pipeline enhances reliability of service and helps to meet the capacity needs for PGS' growing customer base.

PGS expects increases in sales volumes and corresponding revenues in 2003, and continued customer additions and related revenues from its expansion efforts throughout the state of Florida. These growth projections assume continued local economic growth, normal weather and other factors. (See the **Investment Considerations** section.)

TECO Power Services

Net income increased almost 27 percent in 2002 to $34.1 million from higher earnings from construction-related and loan agreements with Panda Energy International (Panda), a full year of ownership of the Frontera Power Station and higher capacity payments due to higher prices and generation at the Guatemalan generating units. The improved results were partially offset by a $5.8-million after-tax charge related to the proposed sale of TPS' minority interest in generating assets in the Czech Republic, higher operations and maintenance expense, lower energy prices and sales from the Commonwealth Chesapeake Station and higher financing costs.

Net income increased 18 percent in 2001 to $26.9 million from higher earnings from the Hamakua, Commonwealth Chesapeake, and Guatemalan generating stations and higher returns on TPS' investment through Panda in the Texas Independent Energy (TIE) projects. The improved operating performance was partially offset by weak results at the Frontera Station, which was acquired in March 2001, due to low power prices in the Texas market; increased financing costs; higher development costs; and a $6.1-million after-tax valuation reserve recognized in connection with the sale of TPS' minority interest in EGI, which owns small generating projects in Central America.

Summary of Operating Results

(millions)	*2002*	*Change*	*2001*	*Change*	*2000*
Revenues	$ 309.8	7.9%	$ 287.1	44.2%	$ 199.1
Operations, maintenance and A&G	73.1	8.9%	67.1	24.3%	54.0
Purchase power pass through	31.1	4.4%	29.8	-1.0%	30.1
Depreciation	28.1	-1.1%	28.4	53.5%	18.5
Taxes, other than income	8.4	15.1%	7.3	135.5%	3.1
Non-fuel operating expenses	140.7	6.1%	132.6	25.4%	105.7
Fuel	118.6	8.1%	109.7	60.9%	68.2
Total operating expense	259.3	7.0%	242.3	39.3%	173.9
Operating income	$ 50.5	12.7%	$ 44.8	77.8%	$ 25.2
Net income	$ 34.1	26.8%	$ 26.9	18.0%	$ 22.8
Generation					
Megawatt hours (thousands)	3,411	10.4%	3,089	89.2%	1,633

Increases in energy generation reflect incremental new capacity coming into service either in phases or part year in 2000 and 2001 or acquired in 2001 with full year results reflected in 2002. Increases in operations, maintenance and administrative and general (A&G) expenses reflect the increased manpower and facilities and a full year of operations of the energy marketing and management group. Increases in these expenses over the three-year period reflect the increased size of the generating portfolio, which increased from three operating plants in January 2000 to five at Dec. 31, 2002.

Increases in income and operating expenses related to the Union and Gila River power stations in 2003 and 2004 are expected to be reflected in TPS' financial results on a net basis assuming these facilities continue to be accounted for as unconsolidated affiliates. (See the **Off-Balance Sheet Financing** section.) However, operations, maintenance and A&G expenses are expected to increase because of increased staffing in the energy marketing and management group related to these two plants.

In 2003, TPS began negotiations to revise an equipment purchase contract. TPS may complete these negotiations by as early as the end of the first quarter 2003. If executed, the contract revision could result in a non-cash pretax charge of $12 to $24 million.

TPS Project Summary

Project	*Location*	*Size MW*	*TPS Economic Interest*	*TPS Net Size MW*	*In Service/ Participation Date (1)*
Operating:					
Hardee Power Station	Florida	370	100%	370	1/93, 5/00
Alborada Power Station	Guatemala	78	96%	75	9/95
Empresa Eléctrica de Guatemala S.A.(EEGSA) (a distribution utility)	Guatemala		24%		9/98(4)
San José Power Station	Guatemala	120	100%	120	1/00
Hamakua Energy Project	Hawaii	60	50%	30	8/00, 12/00
Frontera Power Station	Texas	477	100%	477	5/00, 3/01(4)
Odessa and Guadalupe	Texas	2,000	(2)	750	9/00, 8/01
Commonwealth Chesapeake Power Station	Virginia	315	100%	315	9/00, 8/01
Sub-total operating		3,420		2,137	
Under Construction:					
Union	Arkansas	2,200	(3)	1,650	1/03-6/03
Gila River	Arizona	2,145	(3)	1,609	2/03-8/03
Sub-total construction		4,345		3,259	
Total		7,765		5,396	
Suspended:					
Dell	Arkansas	599	100%		
McAdams	Mississippi	599	100%		
		1,198			

(1) Unless otherwise indicated, each date appearing in this column is an in-service date. When more than one in-service date appears, it indicates when different phases of the project went into operation. For projects under construction, a range of dates indicates when the first and last phases are expected to enter service under TECO Energy's current plans.

(2) Based on the effect of the preferred return, the effective economic interest is estimated at 75 percent of Panda's 50-percent interest in these projects over the life of the projects.

(3) Based on the effect of the preferred return, the effective economic interest is estimated at 75 percent over the life of the project.

(4) Dates on which TPS acquired its economic interest in the project.

Construction Activities

In 2000, TPS focused its efforts on the development or acquisition of domestic energy projects. TPS has net ownership interest in almost 5,400 megawatts of projects either operating or under construction.

In September 2000, TPS invested $93 million in the form of a loan to Panda's TIE, which are the Odessa and Guadalupe power stations. An additional $44 million was loaned to Panda in the first quarter of 2002 bringing the total investment to $137 million. The interest earned on the loan to TIE is reflected in 2002, 2001 and 2000 earnings.

These loans converted in accordance with their terms into an ownership interest on Jan. 3, 2003 which is to be accounted for under the equity method. The conversion gives TPS an opportunity to have an effective economic interest estimated at 75 percent of Panda's 50-percent interest in these projects over the life of the projects. Based on information available from the other owners of these projects, these projects have realized lower than expected earnings and cash flows due to over capacity in the Texas market, uneconomic dispatch, and market design, and that trend is expected to continue in 2003. TPS is evaluating its options relative to its ownership position in these projects and is targeting to structure its interest in such a manner that it will cover its cash costs in 2003 and mitigate any impact on earnings.

In October 2000, TPS acquired two 599-megawatt, natural gas-fired, combined-cycle projects, Dell and McAdams, located in Arkansas and Mississippi, respectively. Construction commenced on these projects in 2001 but was suspended at the end of 2002 due to projected low energy prices in the markets that these plants were expected to serve. Interest will not be capitalized during the construction postponement period. The carrying costs associated with these suspended plants are expected to reduce TPS earnings in 2003. Market conditions will be monitored to determine when these plants will be completed. At the time of suspension, approximately $690 million had been invested in these plants. At the time of suspension, it was estimated that the construction cost to complete these projects would be approximately $100 million.

In November 2000, TPS entered into a 50/50 joint venture with Panda to build, own and operate the 2,200-megawatt Union Power Station in Arkansas and the 2,145-megawatt Gila River Power Station in Arizona. The partnership agreement calls for TPS to contribute all project equity and for TPS to earn a preferred return on the investment in these projects, which, over the projects' life, could give TPS an effective economic interest estimated at 75 percent. Construction commenced on these projects in 2001. Each of these projects is expected to begin operation in four power blocks, beginning with the first 550-megawatt power block of Union which began operating in January 2003 and ending with the 540-megawatt final power block of Gila River expected in August of 2003. At Dec. 31, 2002, the TPS investment in these projects was $1.2 billion of project equity including the remaining $375 million equity bridge loan balance and $55 million already contributed related to the TECO Energy construction undertaking, described below. At Dec. 31, 2001, TPS had invested $624 million in these projects including $500 million of the equity bridge loan.

In December 2001, Enron Corp., a large energy trading and services company, filed for protection under the U.S. Bankruptcy Code. An Enron subsidiary, NEPCO, was serving as the construction contractor for the Union, Gila River, Dell and McAdams power stations. Enron guaranteed certain of NEPCO's obligations under the construction contracts. The Union and Gila River power stations have financing in place with a syndicate of banks. The Dell and McAdams power stations are wholly owned by TPS and have not been financed.

As part of Enron's centralized cash management procedure, Enron swept NEPCO's cash before it was applied to pay project costs. Enron's bankruptcy permitted the project lenders to stop funding construction costs for the Union and Gila River projects until the condition was cured or waived. TPS received approval from the project lenders on a plan that allowed funding to resume.

The plan involved TECO Energy replacing Enron as the guarantor of certain of NEPCO's obligations under the construction contracts for these two projects, including payment by TECO Energy of any project cost overruns (estimated at $62 million remaining at Dec. 31, 2002, against which TECO Energy could offset the unused construction contingency amount remaining after completion of construction) and guaranteeing the completion of construction. The plan also provided for TECO Energy to replace the letter of credit furnished by Enron that had been drawn upon and acceleration of project cash commitments to mid-year 2002, resulting in TECO Energy's total investment essentially being complete by the end of 2002 rather than mid-2003 as originally planned.

Under a series of agreements with TECO Panda Generating Co. (TPGC), NEPCO continued construction and engineering of all four plants until SNC Lavalin Constructors Inc., a large Canadian engineering and construction firm, replaced it as the contractor in May 2002. SNC Lavalin hired essentially all of NEPCO's management and staff, and construction continued without interruption. The agreements with SNC Lavalin provide for the projects to be completed on a cost-plus-fee basis, with the fee portion at-risk until the projects are completed.

In February 2002, the TPS and Panda affiliates that comprise the joint venture that owns the Union and Gila River projects entered into a purchase arrangement for TPS to purchase and Panda to sell Panda's interest in the joint venture in 2007 for $60 million. Panda has the right to cancel the purchase arrangement by paying TPS $20 million, or a lesser amount under certain circumstances. The purchase arrangement could result in TPS' purchase of the interest prior to 2007 if Panda defaults on a bank loan made to Panda using the purchase arrangement as collateral or if TECO Energy permits its debt-to-capital ratio to exceed 65.0 percent, permits its EBITDA/interest ratio to fall below 1.5 times or it defaults on the payment of indebtedness in excess of $50 million. TECO Energy's debt-to-capital ratio at Dec. 31, 2002 was 55.9 percent and its EBITDA/interest ratio was 3.6 times.

In March 2001, TPS acquired the Frontera Power Station located near McAllen, Texas. This 477-megawatt, natural gas-fired, combined-cycle plant, began combined-cycle operation in May 2000 and has a 150-megawatt transmission connection to the Federal Electricity Commission of Mexico. In the second and third quarters of 2002, the facility sold energy and ancillary services to the Electric Reliability Council of Texas (ERCOT). During the fourth quarter the facility provided reliability-must-run (RMR) services under contract to ERCOT. Since the RMR contract was not renewed for the first quarter of 2003, the plant was shut down for scheduled maintenance. The first quarter is expected to have lower opportunities than other quarters for sales to ERCOT, Mexico or other customers due to weather.

In February 1999, TPS invested in EGI, a company with energy interests in Latin America. In the first quarter 2001, TPS recognized a $6.1-million after-tax charge as part of the sale of its interest in EGI. TPS no longer has any ownership interest in EGI.

Energy Markets

The power plants that TPS is operating and constructing are located in markets with a history of high load growth. However, the general U. S. economic slowdown in 2001 and 2002 slowed the growth in demand for power in some of these markets. In addition, the slowdown of electricity deregulation initiatives across the United States, including the markets that TPS will be serving, caused by the failure of deregulation in California, has allowed the traditional, incumbent utilities to continue to operate older, less efficient generating facilities in lieu of purchasing power from newer, more efficient independent power plants. These factors have combined with aggressive plans by the independent power industry to add merchant power facilities to cause excess generating capacity that is either being built or has come on line in many markets. This excess supply

has depressed both spot and forward wholesale power prices. Based on current forward curve prices for 2003, the combined returns for the Union and Gila River power stations are expected to be below earnings break-even, but are anticipated to be close to covering cash costs. If cash costs are not covered, the non-recourse project finance lenders are required to fund the payments of these costs with additional non-recourse debt up to $80 million through a debt-service reserve. The forward curve prices represent the market price for on-peak energy that a seller would expect to receive if future energy was sold today. The forward curve for electricity prices reflects the price for energy that is delivered on a standard schedule. Because TPS' assets can be dispatched with some flexibility and sales of ancillary services are possible, the forward curve price may understate the realized price or profit margin.

Studies by numerous outside groups, such as Cambridge Energy Research Associates, Standard & Poor's and others, present conflicting outlooks on power price improvement. Some experts indicate that 2003 should be the low point for power prices while others indicate that power prices may remain low beyond 2004. Continued low power prices for the output from TPS' merchant plants in 2004 would decrease net income at TPS from 2003 levels, and could require cash payments to cover any fixed costs of the plants not covered by the project debt-service reserves or cash generated at the projects.

TPS' ultimate long-term strategy for selling the output of these plants is to enter into three- to five-year contracts with load serving entities, or ultimate customers where it is allowed, for up to 50 percent of the output of the plants. TPS would contract another 25 percent of the output in the shorter term (less than one-year market) with the remaining 25 percent sold in the spot market. In the meantime, until longer-term contracts can be signed, TPS is selling the output of these plants under a mix of spot market sales and shorter-term transactions. The shorter-term transactions are primarily forward sales of on-peak energy at prices reflective of current forward curves. TECO Energy's policy is to balance power contract commitments with necessary purchases of natural gas so as to know the margins for such sales at the time of commitment. These sales usually do not include the value for capacity payments, ancillary services, dispatchability and the premium associated with owning physical assets. These incremental value components are often captured in the spot market at the time of physical sales or through more structured transactions.

In 2001, TPS activated its TECO EnergySource (TES) subsidiary to enter into power marketing and fuel procurement transactions for the longer-term contracts. Initially, TPS retained power marketers, such as Aquila for the Union and Gila River power stations, to market the output planned for the spot market. Aquila has decided to exit the power marketing business and TPS intends to assume full responsibility for the output marketing and fuel procurement transactions. TES is actively seeking both short- and long-term contracts with purchasers for the output from the Union and Gila River power stations and the Frontera Power Station.

TES is contracting to purchase or supply electricity and natural gas, primarily at specified delivery points and specified future dates (i.e., fixed-price forward sales and purchase contracts). In some cases TES is utilizing financial instruments such as futures and contracts traded on the NYMEX and swaps and other types of financial instruments traded in the over-the-counter markets to manage its exposure to electricity and natural gas price fluctuations.

The use of these types of contracts allows TPS to manage and hedge its contractual commitments and to reduce its exposure relative to the volatility of spot market prices. TPS' and TES' use of futures, options, swaps or other financial instruments was minimal in 2002 due to the low volume of energy sales.

TPS normally balances its fixed-price physical and financial fuel purchase and energy sales contracts in terms of contract volumes and the timing of performance and delivery obligations. Net open positions may exist for short periods due to the origination of new transactions. When net open positions exist, TPS will be exposed to fluctuating market prices. All fuel purchase and energy sales contracts and open positions are monitored closely by the TECO Energy risk management function, which is independent of the TPS' energy management group.

In addition to price risk, credit risk is inherent in TPS' energy risk management activities. The marketing business may be exposed to counterparty credit risk from a counterparty not fulfilling its obligations. Credit policies and procedures, administered by TECO Energy, attempt to limit overall credit risk. The credit procedures include a thorough review of potential counterparties' financial position, collateral requirements under certain circumstances, monitoring net exposure to each counterparty and the use of standardized agreements.

TPS is currently not required to post cash collateral for fuel purchases or as a counterparty for energy sales. In the event of a TECO Energy credit downgrade to non-investment grade, TPS would be required to post cash collateral for energy management activities. Dec. 31, 2002 positions would require the posting of $9.3 million of cash collateral in the event of a downgrade.

Significant factors that could influence results at TPS include construction of its new projects on schedule and on budget, energy prices in its markets, the ability to earn a premium above forward curve prices, weather, domestic economic conditions and commodity price changes. (See the **Investment Considerations** section.)

TECO Transport

Net income declined 24 percent in 2002 to $21.0 million, compared with $27.6 million in 2001. TECO Transport's results reflect continued weakness in the U.S. economy as low levels of imported raw materials reduced northbound river shipments and drove pricing lower for all river shipments. These conditions also reduced volumes of petroleum coke and steel-related product volumes through the transfer terminal. These conditions combined to more than offset increased ocean-going phosphate shipments and lower repair and fuel costs.

Net income declined 6 percent in 2001. Increased phosphate and other product shipments, higher revenue from outside services at TECO Barge Line, and lower fuel prices were more than offset by lower U.S. government grain program shipments, higher costs primarily related to depreciation, and lower shipments of steel-related products handled by TECO Bulk Terminal. Results for 2000 included an after-tax gain of approximately $1.5 million associated with the disposition of an ocean-going asset.

After a late start to U.S. government grain shipments in 2002, volume and pricing improved in the fourth quarter. The pattern of an intense but short annual period for moving grain shipments in the fall and winter is expected to repeat in 2003. Northbound river shipments of steel-related raw materials are expected to improve in 2003 as the U.S. economy improves. Southbound river shipments of grain products are expected to increase slightly in 2003, with a small increase in pricing expected. Even with the expected price increase, grain freight rates are expected to remain below historical levels, which will impact the pricing for all commodities moved on the rivers. In the meantime, TECO Transport expects to move increased volumes of fertilizers and petroleum coke northbound on the river system.

The phosphate fertilizer industry experienced an increase in worldwide demand in 2002 after a period of reduced demand in 2001 and 2000, which resulted in increased shipments of raw phosphate rock between Tampa and Louisiana. The outlook for TECO Ocean Shipping is for a slight increase in phosphate demand in 2003. Lower shipments for Tampa Electric and higher fuel and employee-related health care and pension costs are expected in 2003.

TECO Transport expects to continue diversifying into new markets and cargoes. Future growth at TECO Transport is dependent on improved pricing, higher asset utilization, and asset additions at both the river and ocean-going businesses. Significant factors that could influence results include weather, bulk commodity prices, fuel prices and domestic and international economic conditions. (See the **Investment Considerations** section.)

TECO Coal

Net income increased 30 percent in 2002, to $76.5 million, driven primarily by better margins and higher synthetic fuel (synfuel) production and sales and the resulting higher Section 29 tax credits. Production of synthetic fuel at TECO Coal qualifies for Section 29 tax credits for non-conventional fuel production.

Synfuel production increased to 3.8 million tons in 2002 compared with 3.2 million tons and 1.9 million tons in 2001 and 2000, respectively. The net benefit increased to approximately $77 million in 2002 compared with $58 million in 2001 and approximately $30 million in 2000. Synfuel production displaced some of the conventional coal production in all years.

Net income at TECO Coal increased 76 percent in 2001, driven primarily by better margins and higher synfuel production, increased coal production from Perry County Coal, Inc.'s mining facilities acquired in late 2000, and higher metallurgical coal prices in the second half of the year. 2001 was the first full year of production for the synfuel production facilities which entered service late in the second quarter of 2000.

In 2002, coal sales, including synfuel, decreased to 9.3 million tons from 10.1 million tons in 2001 due to soft market conditions. In 2003, total coal sales are expected to increase slightly due to more normal supply and demand in the market. Synfuel volumes are expected to increase to more than 5 million tons and conventional coal production is expected to decline to offset the higher synfuel production in 2003. In 2003, TECO Coal intends to sell the majority of its interest in the synfuel production facilities, but retain responsibility for operating the facilities. (See the **Strategy and Outlook** section.)

Metallurgical coal contracts, which normally renew in the first quarter of the year, resulted in lower prices in 2002 after a strong pricing environment in 2001. Prices are expected to remain near current levels in 2003. Steam coal pricing declined industry wide in the first quarter of 2002, due to high utility inventory levels as a result of the mild winter weather. TECO Coal, however, contracts much of its steam coal production for the coming year late in the preceding year and was less affected by the price declines than those companies that sell a higher percentage in the spot markets. Later in the year, after inventories were reduced to more normal levels, coal prices strengthened and contract renewals for 2003 were achieved at prices only slightly lower than 2002 levels.

In January 2000, TECO Coal purchased synfuel facilities from Headwaters Technologies, Inc. The facilities were relocated to the company's Premier Elkhorn and Clintwood Elkhorn mines in Kentucky, and were producing by the second quarter of 2000. These facilities produce synfuel from coal, coal fines and waste coal using a technology licensed from Headwaters. The facilities were subsequently sited at all three of TECO Coal's complexes.

TECO Coal has received private letter rulings from the Internal Revenue Service regarding the production of synfuel from its facilities. The private letter rulings confirm that the facilities are located appropriately and produce a qualified fuel eligible for Section 29 tax credits which are available for the production of such non-conventional fuels through 2007.

Significant factors that could influence TECO Coal's results include weather, general economic conditions, commodity price changes, continued generation of Section 29 tax credits, the sale of interest in the synfuel production facilities, the ability to use Section 29 tax credits and changes in laws, regulations or administration. (See the **Investment Considerations** section.)

Other Unregulated Companies

In 2002, net income for the other unregulated companies increased 70 percent to $6.8 million driven primarily by the full-year results of Prior Energy Corp., TECO Energy's end-use gas marketing company acquired in November 2001. In 2001, net income increased due to a full year of results from BCH Mechanical, which was acquired in September 2000.

Other unregulated companies include TECO Energy Services (formerly TECO BGA, Inc., and BCH Mechanical, Inc. and its affiliated companies), TECO Gas Services, TECO Properties, Prior Energy Corp., TECO Propane Ventures (TPV), TECO Partners and TECO Investments. Except for TECO Investments, these operating companies are organized under TECO Solutions, which was formed to offer customers (primarily in Florida) a comprehensive package of energy services and products including energy-efficient engineering and construction and gas management services.

In November 2001, TECO Solutions acquired Prior Energy Corp., a leading natural gas management company. Serving customers throughout the Southeast, Prior Energy handles all facets of natural gas energy management services for large industrial, power generation utility, municipal and other governmental agency customers, including natural gas acquisition and supply management, transportation management, asset management and consulting services.

TPV holds the company's propane business investment. In 2000, TECO Energy combined its propane operations with three other southeastern propane companies to form U.S. Propane. In a series of transactions, U.S. Propane combined with Heritage Holdings, Inc. As a result, TPV owns a 38-percent interest in the general partner that manages Heritage Propane Partners, L.P. (NYSE:HPG) and that general partner owns an approximate 29-percent limited partnership interest in Heritage Propane Partners.

Liquidity, Capital Resources

Sources of cash for TECO Energy and its operating companies in 2002 totaled $3.4 billion, including operating cash flows of $656 million and proceeds from the sale of debt and equity securities of $2.8 billion. Cash was used to fund $1.7 billion of capital spending (net of $103 million from asset sales), debt maturities of $788 million and refinancings of $162 million, net reduction of short-term debt of $278 million and dividends to common shareholders of $216 million. TECO Energy began the year with $109 million in cash and cash equivalents and ended the year with $411 million in cash and cash equivalents and $460 million of unused capacity available under the bank credit facilities at TECO Energy and Tampa Electric. The increased year-end cash position was attributable in part to the conversion of the TECO Energy bank credit facility to a term loan and other cash generating activities.

TECO Energy met 2001 cash needs with a mix of internally generated funds, short- and long-term borrowings and proceeds from the sale of equity. Cash from operations was $503 million, and net cash from financing was $614 million after common dividends of $184 million. Capital spending totaled $1.1 billion in 2001.

In light of the accelerated equity commitments for the Union and Gila River projects under the bank financing plan, an unexpected deterioration in the bank project finance market which caused a planned financing to not materialize, and the capital requirements for committed regulated and unregulated projects, TECO Energy took several steps to strengthen its balance sheet in 2002 and provide cash for its construction program. In January 2002, the company reduced its previous capital expenditure forecast for 2002 through 2004 by about $700 million, primarily by delaying indefinitely generation projects that were not yet under construction for TPS and Tampa Electric, including the Bayside Units 3 and 4 repowering projects announced in the fall of 2001.

In September 2002, TECO Energy announced additional plans to meet its 2003 construction commitments without raising incremental debt, identifying a total amount required of $900 million. By the end of 2002, TECO Energy had completed 70 percent of its $900 million target by: 1) reducing by $250 million capital spending projections (which included amounts higher than earlier estimates); 2) selling the TECO Coalbed Methane gas assets for $140 million, with $42 million received in December and the remainder received in January 2003; 3) realizing $55 million of cash from repatriation and additional cash from non-recourse-financing of the Guatemalan generating assets; and 4) raising $207 million from the sale of common equity in October.

Tampa Electric has signed a letter of intent for the sale of its gasifier unit, and TECO Coal is continuing discussions with potential buyers of interests in its synthetic fuel production facilities. Completion of these activities, which will complete the 2003 funding plan, is expected late in the first quarter or early in the second quarter of 2003.

Estimated cash needs for 2003 include capital spending of $727 million for normal renewal and replacement capital as well as project commitments of Tampa Electric and TPS, including $375 million related to payment of the Union and Gila River projects equity bridge loan. (See the **Summary of Contractual Obligations** section.) Long-term debt maturities of $127 million are due in 2003, and a bank term loan of $350 million matures in November. TECO Energy expects to rely on cash on hand and internally generated cash from operations and from asset sales to fund these cash needs and the payment of dividends to shareholders. (See the **Bank Credit Facilities and Covenants in Financing Agreements** sections.) Based on its cash flow forecasts, TECO Energy expects to have at least $600 million of cash and capacity under the bank credit facilities at the end of the first, second and third quarters of 2003 and, if it renews its bank facilities in full, at the end of 2003.

TECO Energy has identified in this Management's Discussion & Analysis (including in **Investment Considerations**), several factors that could cause its operating cash flow to be lower than forecasted. One of these factors is the margins it may realize for production from its merchant power facilities. Because of TECO Energy's expansion in the merchant power business, its cash flow has become increasingly dependent upon power margins.

TECO Energy has not made a contribution to its defined benefit pension plan since the 1995 plan year because investment returns have been more than sufficient to cover liability growth. Negative stock market returns over the past three years have reduced the over-funding of the defined benefit plan. Based on plan asset values at Jan. 1, 2003, it is estimated that TECO Energy will be required to make a $15 million contribution to its defined benefit plan in September 2004. (See **Note K** to the **Consolidated Financial Statements**.)

Bank Credit Facilities

At Dec. 31, 2002, TECO Energy had a bank credit facility of $350 million, and Tampa Electric had a bank credit facility of $300 million, with maturity dates of November 2004 and November 2003, respectively. Both were undrawn at Dec. 31, 2002, except for outstanding letters of credit under the TECO Energy facility. In November 2002, TECO Energy converted another $350 million bank credit line then in effect into a one-year term loan due November 2003. TECO Energy expects to have discussions with the bank-lending group with the objective of renewing the facility before the loan matures.

The TECO Energy bank credit facility maturing November 2004 includes a $250 million sublimit for letters of credit capacity. At Dec. 31, 2002, $180 million of letters of credit were outstanding against that line, primarily related to the construction of the Union and Gila River power stations. These letters of credit of $62 million and $88 million for Union and Gila River, respectively, were replacements for the letters of credit posted by Enron and drawn by the TPS/Panda joint venture following Enron's bankruptcy filing. In addition, at Dec. 31, 2002, TECO Energy and its subsidiaries had $5 million of letters of credit outside of its bank credit line facility outstanding. (See the **Covenants** in **Financing Agreements** section.)

The Tampa Electric bank credit facility requires commitment fees of 15 basis points, and drawn amounts are charged interest at LIBOR plus 85-97.5 basis points at current credit ratings. The TECO Energy credit facility requires commitment fees of 15-20 basis points and drawn amounts incur interest expense at LIBOR plus 35-60 basis points at current credit ratings. TECO Energy expects that the cost of its facility will increase upon renewal.

The September 2002 downgrade by Standard & Poor's Ratings Service (S&P) of TECO Energy's commercial paper program to A-3 eliminated TECO Energy's access to the commercial paper market. Tampa Electric continues to have access to the commercial paper market with its A2/P1/F2 rated commercial paper program and had $11 million of commercial paper outstanding at Dec. 31, 2002. The lack of access to the commercial paper market has caused TECO Energy to utilize its bank credit facilities for short-term borrowing needs.

Credit Ratings/Senior Unsecured Debt

	Fitch	*Moody's*	*Standard & Poor's*
Tampa Electric	A–	A2	BBB
TECO Finance / TECO Energy	BBB	Baa2	BBB-

In September 2002, Moody's Investor Services, Inc. (Moody's), S&P and Fitch Investor Services, Inc. (Fitch). lowered the ratings on the senior unsecured debt securities of TECO Energy, TECO Finance and Tampa Electric. The outlook assigned to TECO Energy by Moody's and S&P is negative while the outlook assigned by Fitch is stable. The ratings actions were attributed to increased debt levels and the changing risk profile associated with the expansion of TECO Energy's investment in merchant generation facilities through TPS, as well as the required capital outlays of Tampa Electric, the outlook for low power prices in the merchant energy sector and the negative impacts on earnings and cash flow, and the additional risks and obligations undertaken by TECO Energy with respect to the Union and Gila River power stations. These downgrades followed downgrades in 2001 and 2000 by all of the rating agencies due to the changing risk profile of TECO Energy related to the increased emphasis on merchant power.

These downgrades and any future downgrades may affect TECO Energy's ability to borrow and may increase financing costs, which may decrease earnings. TECO Energy's interest expense is likely to increase when maturing debt is replaced with new debt with higher interest rates due to the lower credit ratings.

Summary of Contractual Obligations

The following table lists the obligations of TECO Energy and its subsidiaries for cash payments to repay debt, lease payments and unconditional commitments related to capital expenditures. This table does not include contingent obligations discussed in the following table.

Contractual Obligations

		Payments Due by Period			
(millions)	*Total*	*2003*	*2004*	*2005-2007*	*After 2007*
Long-term debt	$ 3,426.1	$ 101.8	$ 31.9	$ 1,048.9	$ 2,243.5
Capital lease obligation	25.3	25.3	—	—	—
Operating leases/rentals	230.4	27.8	26.9	63.0	112.7
Unconditional purchase obligations/commitments (1)	563.0	461.6	41.4	60.0(3)	—
Other long-term obligations (2)	649.1	—	—	449.1	200.0
Total contractual obligations	$ 4,893.9	$ 616.5	$ 100.2	$ 1,621.0	$ 2,556.2

(1) Includes the expected repayment of $375 million on the TECO Energy guaranteed equity bridge loan at TPS for the construction of the Union and Gila River power stations.

(2) Includes the expected redemption of company preferred securities held as assets of TECO Capital Trusts I and II.

(3) TPS' obligation to purchase Panda's interest in the Union and Gila River power stations in 2007, unless Panda buys out that purchase agreement in advance. (See the **TECO Power Services – Construction Activities** section.)

Summary of Contingent Obligations

The following table summarizes the letters of credit and guarantees outstanding that are not included in the Summary of Contractual Obligations table above and not otherwise included in the company's Consolidated Financial Statements.

		Commitment Expiration			
(millions)	*Total (2)*	*2003*	*2004*	*2005-2007*	*After 2007*
Letters of Credit (1)	$ 185.0	$ 128.0	$ 27.1	$ —	$ 29.9
Guarantees:					
Debt related	23.7	—	—	—	23.7
Construction undertaking (3)	60.0	60.0	—	—	—

(1) Expected final expiration date with annual renewals.

(2) Expected maximum exposure.

(3) The construction undertaking of $60 million reflected in the table represents the estimated maximum probable exposure associated with completing construction of the Union and Gila River power stations if actual costs exceed current estimates and in-service dates are delayed beyond current estimates. This contingent obligation estimate is net of retainage letters of credit posted for these projects. This estimate will decline rapidly as construction progresses and units are brought into service. (See the **TECO Power Services – Construction Activities** section.)

Covenants in Financing Agreements

In order to utilize their respective bank credit facilities, TECO Energy and Tampa Electric must meet certain financial tests. TECO Energy's credit facilities and the financing arrangements of TPS' Union and Gila River power stations require that at each quarter-end TECO Energy's debt-to-capital ratio, as defined in the applicable agreements, not exceed 65%. Under Tampa Electric's 364-day credit facility, renewed in November 2002, its debt-to-capital ratio may not exceed 60 percent at the end of the applicable quarter and its earnings before interest, taxes, depreciation and amortization (EBITDA) to interest coverage ratio (as defined in the agreement) can not be less than 2.5 times. Certain long-term debt at PGS contains a prohibition on the incurrence of funded debt if Tampa Electric's debt-to-capital ratio, as defined in the applicable agreement, exceeds 65%. The PGS debt also contains a Tampa Electric interest coverage requirement, as defined in the applicable agreement, of 2.0 times or greater for four consecutive quarters, and certain TPS financing arrangements require a TECO Energy consolidated interest coverage, as defined in the applicable agreement, equal to or exceeding 3.0 times for the twelve-month period ended each quarter. At Dec. 31, 2002, TECO Energy's and Tampa Electric's debt-to-capital ratios, as applicable,

were 55.9 percent and 43.9 percent, respectively, and interest coverage, as applicable, was 3.6 times and 7.8 times, respectively. TECO Energy expects that renewal of its facility will require covenants similar to Tampa Electric's.

The TECO Energy guarantees of the Union and Gila River power stations equity bridge financing, equity contribution agreement and construction undertaking require that TECO Energy maintain senior unsecured credit ratings of not less than BBB and Baa3 or BBB- and Baa2. TECO Energy's current ratings are at the minimum required level. A further downgrade from either S&P or Moody's would trigger a failure to meet that requirement, thereby requiring the delivery of letters of credit, which the company currently estimates could approximate $450 million, to secure the obligations. In the event of a downgrade, under the terms of the construction contract guarantees, TECO Energy is required to deliver letters of credit in an amount equal to the full construction contract price and any change orders and cost overruns or such lesser amount satisfactory to the majority of the lenders for the Gila River and Union power stations. TECO Energy believes that the amounts required would be based on the estimated amounts reasonably necessary to cover the remaining payment and performance obligations under the construction contracts. As of January 2002, when documenting the construction contract guarantees with the lenders for the Gila River and Union power projects, the maximum amount necessary to cover the payment and performance obligations of the contractor was estimated to be approximately $310 million, net of approximately $150 million in letters of credit previously issued to the lenders as security for the projects. Based on the construction status as of Dec. 31, 2002, TECO Energy estimates the maximum amount necessary to cover the payment and performance obligations of the contractor to be approximately $60 million, net of the approximately $150 million in letters of credit previously issued as security. This $60 million is included in the $450 million amount referenced above. The amount of the letters of credit that would be required to be delivered declines as equity is contributed to the projects, the bridge loan is repaid and the levels of construction completion increase.

TECO Energy's 10.5% 5-year notes issued in November 2002 contain covenants that will, among other things, in the event of certain debt ratings downgrades, require TECO Energy to achieve certain debt service coverage levels in order to pay dividends or distributions or make certain investments, and limit additional liens and issue additional indebtedness. The covenants apply only if either the notes are rated non-investment grade by either S&P or Moody's or the notes are rated below the levels required by the equity bridge loan and Union and Gila River construction undertaking while those obligations are outstanding. If these covenants become applicable, the coverage requirement would restrict TECO Energy from paying dividends or distributions or making certain investments unless cumulative EBITDA to interest coverage is at least 1.7 times.

Capital Investments

	Actual	*Forecast*			
$ (millions)	*2002*	*2003*	*2004*	*2005-2007*	*2003-2007 Total*
Florida Operations	$ 662	$ 272	$ 266	$ 725	$ 1,263
Independent Power	1,027	424	25	75	524
Transportation	25	15	21	61	97
Other	50	16	23	55	94
Total	$ 1,764	$ 727	$ 335	$ 916	$ 1,978

TECO Energy's 2002 capital investments of $1,764 million (without reduction for asset sale proceeds of $103 million) included $597 million for Tampa Electric (excluding $35 million of AFUDC), $54 million for PGS and $11 million for the unregulated Florida operations. Tampa Electric's electric division capital investments in 2002 were $169 million for equipment and facilities to meet its growing customer base and generating equipment maintenance, $343 million for the repowering and conversion of the coal-fired Gannon Station to the natural gas-fired Bayside Station (see the **Environmental Compliance** section), and $85 million for the 180 MW Polk Unit 3 peaking combustion turbine and future generation expansion requirements. Capital expenditures for PGS were approximately $39 million for system expansion and approximately $12 million for maintenance of the existing system. TECO Transport invested $25 million in 2002 for river barge replacements and capitalized maintenance of ocean-going vessels. TECO Coal's capital expenditures included $48 million for the expansion of production at Perry County and Clintwood as well as normal equipment replacements. TPS' capital investments totaled $1,027 million, primarily related to the Union, Gila River, Dell and McAdams power stations. This $1,027 million includes $672 million classified as Other Non-Current Investments, shown as notes receivable from TPGC (see the **Transactions With Related and Certain Other Parties** section), which represents TECO Energy's equity contributions for the Union and Gila River projects. The Union and Gila River contributions are initially made in the form of loans to TECO-Panda Generating Company (TPGC) and become equity as the units' specified phases come into service.

TPS expenditures represent the equity funding of project costs and exclude amounts funded by non-recourse project financing for the Union and Gila River power stations, which amounted to $627 million in 2002. (See **TECO Power Services – Construction Activity** and **Item 3. Legal Proceedings** sections.)

Asset sale proceeds of $103 million in 2002 included proceeds from the sale of TECO Coalbed Methane's assets, real estate sales, and TECO Transport's sale and lease-back of vessels and barges accounted for as an operating lease.

TECO Energy estimates capital spending for ongoing operations, without reduction for proceeds from asset sales, to be $727 million for 2003, $335 million for 2004 and $916 million during the 2005-2007 period. TECO Energy's funding plan for these expenditures includes the asset sales described in the **Strategy and Outlook** section.

For 2003, Tampa Electric's electric division expects to spend $232 million, consisting of $78 million for the repowering project at the Gannon Station and $154 million to support system growth and generation reliability. At the end of 2002, Tampa Electric had outstanding commitments of about $119 million for the Gannon Power Station repowering project. Tampa Electric's total capital expenditures over the 2004-2007 period are projected to be $841 million, including $67 million for the repowering project and $141 million for compliance with the Environmental Consent Decree. (See the **Environmental Compliance** section.)

Capital expenditures for PGS are expected to be about $40 million in 2003 and $160 million during the 2004-2007 period. Included in these amounts are approximately $25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety.

TPS expects to invest $424 million in 2003 primarily for the completion of the Union and Gila River power stations. These investments include $375 million to repay the outstanding amounts due under the project company's equity bridge loan guaranteed by TECO Energy, which is expected to be repaid in three $125 million installments in the second, third and fourth quarters of 2003.

The other unregulated companies expect to invest $31 million in 2003 and $160 million during the 2004-2007 period. Included in these amounts is normal renewal and replacement capital including coal mining equipment.

Financing Activity

TECO Energy's 2002 year-end capital structure, excluding the effect of unearned compensation, was 53.7 percent debt, 9.1 percent company preferred securities and 37.2 percent common equity. TPS typically finances its power projects with non-recourse project debt. Excluding this non-recourse debt of $232.4 million, the year-end capital structure was 52.1 percent debt, 9.4 percent company preferred securities and 38.5 percent common equity.

In 2002, TECO Energy was active in the debt and equity capital markets raising $1 billion through the sale of equity or equity-linked securities and issuing $1.8 billion of debt to refinance $788 million of maturing debt, to refinance $162 million of higher-cost debt, to reduce short-term borrowing by $278 million and to fund capital investments at the operating companies. These transactions and financings in 2002 and 2001 are detailed in the following table.

Date	*Security*	*Company*	*Net Proceeds (millions)*	*Coupon*	*Use*
Dec. 2002	7-year non-recourse bank loan	TECO Power Services	$30	6%	Refinance Alborada Power Station and general corporate purposes
Nov. 2002	5-year notes	TECO Energy	$352	10.5%	Repay short- and long-term debt, and general corporate purposes
Oct. 2002	Common Equity	TECO Energy	$207	—	Repay short-term debt
Aug. 2002	5-year notes	Tampa Electric	$149	5.375%	Repay maturing long-and short-term debt, and general corporate purposes
Aug. 2002	10-year notes	Tampa Electric	$394	6.375%	Repay maturing long-and short-term debt, and general corporate purposes
Jun. 2002	Pollution control bonds	Tampa Electric	$61	5.1%	Refinance higher cost debt
Jun. 2002	Pollution control bonds	Tampa Electric	$86	5.5%	Refinance higher cost debt
Jun. 2002	Common Equity	TECO Energy	$346	—	Repay short-term debt, and general corporate purposes
May 2002	5-year notes	TECO Energy	$297	6.125%	Repay maturing short-term debt, and general corporate purposes
May 2002	10-year notes	TECO Energy	$397	7.0%	Repay maturing short-term debt, and general corporate purposes
Jan. 2002	Mandatorily Convertible equity units	TECO Energy	$436	9.5%	Repay short-term debt, and general corporate purposes
Oct. 2001	Common Equity	TECO Energy	$93	—	General corporate purposes
Sept. 2001	10-year notes	TECO Energy	$206	7.2 %	Repay maturing debt, and general corporate purposes
Jun. 2001	11-year notes	Tampa Electric	$247	6.875%	Repay long- and short-term debt, and general corporate purposes
May 2001	1-year notes	TECO Energy	$399	Variable	Repay short-term debt
May 2001	10-year notes	TECO Energy	$396	7.2%	Repay short-term debt, and general corporate purposes
Apr. 2001	6-year notes	TECO Transport	$111	5.0%	Convert floating rate debt to fixed rate debt
Mar. 2001	Common Equity	TECO Energy	$232	—	Repay short-term debt, and general corporate purposes

Off-Balance Sheet Financing

Unconsolidated affiliates in which TPS has a 50% ownership interest or less have non-recourse project debt balances as follows at Dec. 31, 2002. This debt is recourse only to the unconsolidated affiliate, and TECO Energy has no debt payment obligations with respect to these financings. Although TECO Energy is not obligated on the debt, TECO Energy's equity interest in those unconsolidated affiliates and its commitments with respect to those power projects are at risk if those projects are not successfully developed.

Affiliate	*Affiliate Debt Balance (millions)*	*TPS Ownership Interest*
Union & Gila River	$ 1,175	50%
EEGSA	$ 200	24%
Hamakua	$ 86	50%

The equity method of accounting is used to account for investments in partnership and corporate entities in which TECO Energy or its subsidiary companies do not have either a majority ownership or exercise control. On Jan. 17, 2003, the Financial Accounting Standards Board issued FASB Interpretation (FIN) No. 46, Consolidation of Variable Interest Entities, an interpretation of ARB No. 51, which requires a new approach in determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as variable interest entities or VIEs. Based on a preliminary review, TECO Energy believes it is reasonably possible that FIN 46 may impact the accounting for certain unconsolidated affiliates. (See the **Other Accounting Standards – Variable Interest Entities** section.)

In June 2001, TPS and its joint venture partner, Panda, closed on a $2.175 billion syndicated bank financing for the construction of the Union and Gila River power stations. The financing includes $1.675 billion in five-year non-recourse debt (including facilities for letters of credit) and $500 million in equity bridge loans guaranteed by TECO Energy of which $125 million was repaid in 2002. Pricing for the non-recourse segment is 162.5 basis points over LIBOR during the construction period and increases to 175 basis points for year one of operation and 200 basis points for years two and three.

The TPGC debt balance is expected to reach $1.4 billion upon completion of construction of the Union and Gila River power stations in 2003.

In addition, TECO Energy has other debt-related items totaling $23.7 million. These facilities are not included in liabilities on TECO Energy's consolidated balance sheet, but do represent payment obligations of TECO Energy.

In March 2001, TPS converted the third-party construction financing for the Hamakua Power Station into a synthetic equipment operating lease with a term of five years. The lessor is an unaffiliated entity.

Critical Accounting Policies and Estimates

The following accounting policies are considered critical in the view of management. These critical accounting policies require that critical estimates be made based on the assumptions and judgment of management. The preparation of consolidated financial statements requires management to make various estimates and assumptions that affect revenues, expenses, assets, liabilities and disclosure of contingencies. The policies and estimates identified below are the more significant accounting policies and estimates used in the preparation of TECO Energy's consolidated financial statements. These estimates and assumptions are based on historical experience and on various other factors that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and judgments under different assumptions or conditions.

See the **Notes to the Consolidated Financial Statements** for a description of TECO Energy's accounting policies and the estimates and assumptions used in the preparation of the Consolidated Financial Statements.

Asset Impairments

TECO Energy and its subsidiaries periodically evaluate whether there has been a permanent impairment of an asset as follows:

- Long-lived assets, when indicators of impairment exist, in accordance with Financial Accounting Standard No. (FAS) 121, Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of, and beginning in 2002, with FAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets; and
- Recognized goodwill and other intangible assets with indefinite lives, annually in accordance with FAS 142. (See the **Goodwill and Other Intangible Assets** section.)

The company believes that the accounting estimate related to asset impairments is a critical estimate for the following reasons: 1) it is highly susceptible to change each reporting period as management is required to make assumptions based on expectations of the results of operations for significant/indefinite future periods and/or the then-current market conditions in such periods; 2) electricity markets continue to experience significant price uncertainty with respect to market fundamentals; 3) the ongoing expectations of management regarding the future use of the asset; and 4) the impact of an impairment on reported assets and earnings would be material. The company's assumptions relating to future results of operations are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities. (See **Notes A, C** and **S** to the **Consolidated Financial Statements**.)

Long-Lived Assets

TECO Energy adopted FAS 144, with no significant impact on earnings, effective Jan. 1, 2002. During the year ended Dec. 31, 2002, the company evaluated certain merchant generation plants for impairment in accordance with FAS 144. The company concluded that the sum of the undiscounted expected future cash flows (excluding interest charges) from each individual plant exceeded the then-current carrying value of the plant. In accordance with FAS 144, the company did not recognize an impairment charge. If an impairment charge were required to be recognized, the amount of the loss would be determined by calculating the difference of the fair value and the then-current carrying value of the asset.

Goodwill and Other Intangible Assets

Prior to 2002, goodwill was amortized each year. As of Dec. 31, 2001, TECO Energy had $166 million of goodwill, net of accumulated amortization of $10 million. The adoption of FAS 142 on Jan. 1, 2002 resulted in the elimination of approximately $5 million of annual amortization. (See **Notes C** and **S** to the **Consolidated Financial Statements.**)

In accordance with the transition provisions of FAS 142, TECO Energy evaluated all reporting units where goodwill is recorded for impairment. Reporting units are generally determined as one level below the operating segment level; however, reporting units with similar characteristics may be grouped under the accounting standard for the purpose of determining the impairment, if any, of goodwill and other intangible assets. For each reporting unit evaluated, the fair value exceeded the carrying value, including goodwill, as of the valuation date, Jan. 1, 2002. During 2002, in accordance with the ongoing requirements of the standard, the company evaluated all reporting units where goodwill is recorded for impairment. The fair value for the reporting units evaluated was generally determined using discounted cash flow models appropriate for the business model of each significant group of assets within each reporting unit. No impairment loss was recorded during 2002 for goodwill or other intangible assets with indefinite lives.

Asset Retirement Obligations

In July 2001, the FASB issued FAS 143, Accounting for Asset Retirement Obligations, which requires the recognition of a liability at fair value for an asset retirement obligation in the period in which it is incurred. Retirement obligations associated with long-lived assets included within the scope of FAS 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are included in the scope of the standard only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its future value. The corresponding amount capitalized at inception is depreciated over the useful life of the asset. The liability must be revalued each period based on current market prices. FAS 143 is effective for fiscal years beginning after June 15, 2002. The company estimates that the adoption of FAS 143 will result in a non-cash increase to net property, plant and equipment of approximately $8 million, a non-cash increase to asset retirement obligation of approximately $10 million, and, as a cumulative effect of change in accounting principle, a non-cash pretax charge of approximately $2 million.

Asset retirement obligations are comprised of significant estimates which, if different, could materially impact the results of TECO Energy. The company believes these are critical estimates because: 1) the fair value of the costs associated with meeting the obligation are impacted by assumptions on discount rates and estimated profit mark-ups by third-party contractors; 2) probability factors associated with the future sale, abandonment or retirement of an asset must be forecasted and considered in the calculations; 3) the expectations and intent of management regarding the future use of long-lived assets; and 4) the impact of the recognition of an asset impairment obligation could be significant. Upon adoption, effective Jan. 1, 2003, TECO Energy and affiliates are maintaining controls and periodically reviewing all new legal arrangements and contractual commitments to ensure that any new potential asset retirement obligations are reviewed and recognized as appropriate. (See **Note A** to the **Consolidated Financial Statements.**)

Unconsolidated Affiliates

TECO Energy has investments in unconsolidated affiliates that are accounted for using the equity method of accounting. See the **Other Accounting Standards** section for a detailed discussion of the accounting policies for unconsolidated affiliates, the anticipated impact of the adoption of a new accounting policy (FIN 46) for consolidation of certain legal entities, and critical assumptions and judgments which must be made regarding the application of the accounting policies. (See **Note A** to the **Consolidated Financial Statements.**)

Employee Postretirement Benefits

TECO Energy has a funded non-contributory defined benefit retirement plan covering substantially all employees. The company's policy is to fund the plan based on actuarially determined contributions within the guidelines set by the Employee Retirement Income Security Act of 1974, as amended (ERISA), for the minimum annual contribution and the maximum allowable as a tax deduction by the IRS. Plan assets are invested in a mix of equity and fixed income securities. In addition, TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. In addition, the company has unfunded supplemental executive retirement benefit plans—non-qualified, non-contributory defined benefit retirement plans available to certain senior management.

The determination of the benefit expense is a critical estimate due to the following factors: 1) management must make significant assumptions regarding the discount rate, return on assets, rate of salary increases and health care cost trend rates; 2) costs are based on actual employee demographics, including the turnover rate, retirement rate, mortality rate, employment periods, compensation levels and age, each of which are subject to change in any given period; 3) the plan provisions may be changed by management action in future periods; and 4) the impact of changes in any of these assumptions is likely to result in a material impact on the recorded pension obligation and expense. Management reviews these assumptions periodically to reflect the company's actual experience.

The discount rate for pension cost purposes is the rate at which the pension obligations could be effectively settled. At Dec. 31, 2002, the discount rate used for actuarial purposes was 6.75%, as determined by reference to Moody's Aa bond rate as of Sep. 30, 2002. A hypothetical 25 basis point change in the discount rate would impact pension expense by approximately $2 million.

The assumed rate of return on assets is the weighted average of expected long-term asset return assumptions. In selecting an assumed rate of return on plan assets, the company considers past performance and economic forecasts for the types of investments held by the plan. At Dec. 31, 2002, the return on assets used for actuarial purposes was 9%. A hypothetical 25 basis point change in the return on assets would impact pension expense by approximately $1 million.

The assumed health care cost trend rate was 12.5% in 2002 and decreases to 5.0% in 2013 and thereafter. A 100 basis point increase in the trend rate would impact the aggregate service and interest cost by $1.1 million for 2002 and the accumulated postretirement benefit obligation by $9.5 million, and a 100 basis point decrease in the trend rate would impact the aggregate service and interest cost by ($0.5) million for 2002 and the accumulated postretirement benefit obligation by ($5.0) million, as of Sept. 30, 2002. (See **Note K** to the **Consolidated Financial Statements**.)

Derivative Instruments and Hedging

From time to time, TECO Energy enters into derivative instruments to reduce the exposure to market risks. The company does not enter into derivatives for speculative purposes. See the **Quantitative and Qualitative Disclosures About Market Risk** section for a discussion of the accounting policy for derivatives and hedging activities, variables used in estimating the fair value of derivative instruments, assumptions made with respect to forecasted transactions, and a discussion of the strategy and objectives related to the use of energy derivatives to mitigate various exposures to risk and uncertainty. (See **Notes A** and **B** to the **Consolidated Financial Statements**.)

Deferred Income Taxes

TECO Energy uses the liability method in the measurement of deferred income taxes. Under the liability method, the company estimates its current tax exposure and assesses the temporary differences resulting from differing treatment of items, such as depreciation for financial statement and tax purposes. These differences are reported as deferred taxes measured at current rates in the consolidated financial statements. The company assesses the likelihood that deferred tax assets will be recovered from future taxable income and to the extent recovery of some portion or all of the deferred tax asset is not believed to be likely, the company would establish a valuation allowance.

At Dec. 31, 2002, TECO Energy had deferred income tax assets of $340 million attributable primarily to alternative minimum tax credit carryover of Section 29 non-conventional fuels tax credits and property-related items. The carrying value of the company's deferred income tax assets assumes that the company will be able to realize this asset as an offset to future income taxes payable. The company periodically reviews the deferred income tax assets and, to the extent that recovery would be determined to be unlikely, a valuation reserve would be charged to income. The company believes that the accounting estimate related to deferred income taxes, and any related valuation allowance, is a critical estimate for the following reasons: 1) recoverability of future Section 29 non-conventional fuel tax credits is dependent on the generation of sufficient taxable income to use these credits; and 2) administrative actions of the Internal Revenue Service or the U.S. Treasury or changes in law or regulation could eliminate or reduce the availability of Section 29 tax credits. A change in the recoverability of Section 29 tax credits could have a material impact on reported assets and results of operations. (See **Notes A** and **M** to the **Consolidated Financial Statements**.)

Cost Capitalization

During 2002, TECO Energy devoted resources to the completion and construction of additional generation capacity at Tampa Electric and TPS, extension of the transmission network and enhancement to the system's reliability at Tampa Electric, expansion of the pipeline distribution infrastructure at PGS, normal river barge replacement at TECO Transport and expansion of production capacity at TECO Coal. The cost of additions, including improvements and replacements of property is charged to plant. TECO Energy capitalizes direct costs and certain indirect costs, including the cost of debt and equity capital as appropriate, associated with its construction and retirement activity as prescribed by generally accepted accounting principles and recognized policies prescribed or permitted by the FPSC and/or the FERC. (See the **Regulation** section.)

The amount of capitalized overhead construction costs is based upon analysis of company and affiliate construction activity. Costs are capitalized based on the activity level of resources allocated to construction activities. As a result, the company's net income could be impacted by the manner and timing of the deployment of resources to construction activities. However, total cash flow is not impacted by the allocation of these costs to the various construction or maintenance activities. Due to the magnitude of construction undertakings, fluctuations in net income, as a result of cost capitalization, could be significant. Capitalized costs will be expensed as a component of depreciation when the assets are placed in service. (See **Notes A and D to the Consolidated Financial Statements.**)

Depreciation Expense

TECO Energy provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage, of depreciable property over its estimated service life. The provision for utility plant in service, expressed as a percentage of the original cost of depreciable property, was 4.2% for 2001 and 2002. The company believes the estimated service life corresponds to the anticipated physical life for most assets. However, the company's estimation of service life is a critical estimate for the following reasons: 1) forecasting the salvage value for long-lived assets over a long timeframe is subjective; 2) changes may take place that could render a technology obsolete or uneconomical; and 3) a change in the useful life of a long-lived asset could have a material impact on reported results of operations and reported assets. Although it is difficult to predict values far into the future, TECO Energy has a long history of actual costs and values that are considered in reaching a conclusion as to the appropriate useful life of an asset. (See **Note A to the Consolidated Financial Statements.**)

Regulatory Accounting

Tampa Electric's and PGS' retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the FERC. (See the **Regulation** section.) As a result, the regulated utilities qualify for the application of FAS 71, *Accounting for the Effects of Certain Types of Regulation*. This statement recognizes that the actions of a regulator can provide reasonable assurance of the existence of an asset or liability. Regulatory assets and liabilities arise as a result of a difference between generally accepted accounting principles and the accounting principles imposed by the regulatory authorities. Regulatory assets generally represent incurred costs that have been deferred as they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers from previous collections for costs that are not likely to be incurred.

TECO Energy periodically assesses whether the regulatory assets are probable of future recovery by considering factors such as regulatory environment changes, recent rate orders to other regulated entities in the same jurisdiction, the current political climate in the state, and the status of any pending or potential deregulation legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered by rates. A change in these assumptions may result in a material impact on reported assets and the results of operations. (See **Notes A and D to the Consolidated Financial Statements.**)

Revenue Recognition

TECO Energy and its subsidiaries recognize revenues, except as discussed below, on a gross basis when the risks and rewards of ownership have transferred to the buyer and the products are physically delivered or services provided. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The determination of the physical delivery of energy sales to individual customers is based on the reading of meters, which occurs on a regular basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading may be estimated and the corresponding unbilled revenue is estimated. Unbilled revenue is estimated each month primarily based on historical experience, customer-specific factors, customer rates, and daily generation volumes, as applicable. These revenues are subsequently adjusted to reflect actual results.

Revenues for regulated activities at Tampa Electric and PGS are subject to the actions of regulatory agencies. (See the **Regulation** section.)

The percentage of completion method is used to recognize revenues for certain transportation services at TECO Transport and for long-term engineering or construction-type contracts at TECO Energy Services (formerly known as TECO BGA and BCH Mechanical). The percentage of completion method requires management to make estimates regarding the distance traveled and/or time elapsed for TECO Transport and total costs and work-in-progress for TECO Energy Services. Revenue is recognized by comparing the estimated current total distance traveled or work completed with the total distance or cost estimate for each project. Each month, revenue recognition and realized profit are adjusted to reflect only the percentage of distance traveled or work completed.

Revenues for energy marketing services at Prior Energy and TECO Gas Services are presented on a net basis in accordance with Emerging Issues Task Force No. (EITF) 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*, to reflect the nature of the contractual relationships with customers and suppliers. Revenues for risk management and merchant power sales at TPS are reported on a gross basis, except for gains or losses related to hedge accounting, which are reported net of the hedged item or transaction.

TECO Energy estimates certain amounts related to revenues on a variety of factors, as described above. Actual results may be different from these estimates. (See **Note A** to the **Consolidated Financial Statements**.)

Other Accounting Standards

Business Combinations

In June 2001, the FASB issued FAS 141, *Business Combinations*. FAS 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. TECO Energy has applied the provisions of FAS 141 since June 30, 2001 to all business combinations initiated after that date. (See the **Goodwill and Other Intangible Assets** section and **Note S** to the **Consolidated Financial Statements**.)

Lease Accounting Amendment

In April 2002, the FASB issued FAS 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. In addition to rescinding the aforementioned statements, FAS 145 amends FAS 13, *Accounting for Leases*, to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The implementation of FAS 145 has not had a significant impact on TECO Energy's results.

Exit or Disposal Costs

In July 2002, the FASB issued FAS 146, *Accounting for Costs Associated with Exit or Disposal Activities*, which addresses the accounting for costs under certain circumstances, including costs to terminate a contract that is not a capital lease, costs to consolidate facilities or relocate employees, and termination benefits provided to employees that are involuntarily terminated under the terms of a one-time benefit arrangement that is not an ongoing benefit arrangement or an individual deferred compensation contract. FAS 146 is effective for disposal activities initiated after Dec. 31, 2002 with early adoption allowed. (See **Note T** to the **Consolidated Financial Statements**.)

Gains and Losses on Energy Trading Contracts

On Oct. 25, 2002, the Emerging Issues Task Force issued EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, which eliminates mark-to-market accounting for certain energy trading contracts and changes the presentation of gains and losses for certain derivative contracts. The measurement provisions of the issue are effective for all fiscal periods beginning after Dec. 15, 2002. The net presentation provisions are effective for all financial statements issued after Dec. 15, 2002. In accordance with the recommended transition provisions, TECO Energy reclassified certain amounts in prior periods to present gains and losses on a net basis. (See **Note A** to the **Consolidated Financial Statements**.) The adoption of the measurement provisions is not expected to have a material impact.

Guarantor's Accounting and Disclosure Requirements for Guarantees

In November 2002, the FASB issued FIN 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Guarantees of Indebtedness of Others (an interpretation of FAS No. 5, 57 and 107 and rescission of FAS Interpretation No. 34)*, which modifies the accounting and enhances the disclosure of certain types of guarantees. FIN 45 requires that upon issuance of certain guarantees, the guarantor must recognize a liability for the fair value of the obligation it assumes under the guarantee. FIN 45's provisions for the initial recognition and measurement are to be applied to guarantees issued or modified after Dec. 31, 2002. The disclosure requirements are effective for financial statements of annual periods that end after Dec. 15, 2002. (See **Note R** to the **Consolidated Financial Statements**.)

Stock-Based Compensation

In December 2002, the FASB issued FAS 148, *Accounting for Stock-Based Compensation – Transition and Disclosure, an amendment of FASB Statement No. 123.* This standard amends FAS 123, *Accounting for Stock-Based Compensation*, to provide alternative methods of transition for companies that voluntarily change to the fair value based method of accounting for stock-based employee compensation. It also requires prominent disclosure about the effects on reported net income of the company's accounting policy decisions with respect to stock-based employee compensation in both annual and interim financial statements. The transition provisions and annual disclosure requirements are effective for all fiscal years ending after Dec. 15, 2002, while the interim period disclosure requirements are effective for all interim periods beginning after Dec. 15, 2002. TECO Energy does not anticipate the adoption of the disclosure provisions of this standard to have a material impact. (See **Note I** to the **Consolidated Financial Statements**.)

Variable Interest Entities

The equity method of accounting is used to account for investments in partnership and corporate entities in which TECO Energy or its subsidiary companies do not have either a majority ownership or exercise control. On Jan. 17, 2003, the FASB issued FIN 46, *Consolidation of Variable Interest Entities*, an interpretation of ARB No. 51, which requires a new approach in determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as variable interest entities or VIEs. A legal entity is considered a VIE if it does not have sufficient equity at risk to finance its own activities without relying on financial support from other parties. If the legal entity is a VIE, then the reporting entity that is the primary beneficiary must consolidate it. Even if a reporting entity is not obligated to consolidate a VIE, then certain disclosures must be made about the VIE if the reporting entity has a significant variable interest. Certain transition disclosures are required for all financial statements issued after Jan. 31, 2003. The on-going disclosure and consolidation requirements are effective for all interim financial periods beginning after Jun. 15, 2003.

The determination of the applicability of FIN 46 is complex and requires management to make significant assumptions related to: 1) the reasonable possibility that an entity may be a VIE in which the company has a significant variable interest at Dec. 31, 2002; 2) the rights, obligations, and activities of all other equity investors in the potential VIE; 3) the anticipated variability in the potential VIE's net income or loss, the fair value of its assets not already included in net income or loss, and certain fees paid to related and unrelated third parties; and 4) the magnitude of the company's variable interest as compared to the variable interests of all other variable interest holders. Each of these assumptions could significantly impact the conclusion of the company to consolidate the legal entity.

Based on a preliminary review, TECO Energy believes it is reasonably possible that FIN 46 may impact the accounting for certain unconsolidated affiliates. Management is continuing to assess the extent of the relationships and obtain adequate information upon which to base appropriate conclusions. Below is a discussion of the legal entities existing as of Dec. 31, 2002 that TECO Energy considers to be possibly subject to either: 1) additional disclosure requirements; or 2) consolidation by the company, in accordance with FIN 46.

TPS entered into a joint venture, TPGC, to build, own and operate the Union and Gila River power stations. As of Dec. 31, 2002, TPGC is a development stage partnership that may meet the definition of a VIE. The third-party debt financing at TPGC is non-recourse and does not create an estimated loss exposure to TECO Energy. The estimated maximum theoretical loss exposure is approximately the current and guaranteed equity investment in the partnership. (See the **TECO Power Services – Construction Activities** section, the **Capital Investments** section, **Project Financing of Unconsolidated Affiliates** section and **Notes A, N** and **R** to the **Consolidated Financial Statements**.)

TPS completed a transaction whereby certain equipment at the Hardee Power Station was sold to a third party (the Lessor) and leased back under an operating lease agreement with an initial term of 12 years. The original cost of the equipment was $46.6 million. The sole purpose of the Lessor is to own and lease back the equipment to Hardee Power. The lease financing arrangement includes $41.6 million of subordinated debt and $1.4 million of equity contributed by an unrelated third party. If the Lessor were to be consolidated, TPS estimates that it would incur after-tax incremental expenses of approximately $9.5 million over the 12-year term of the lease. (See **Note R** to the **Consolidated Financial Statements.**)

TECO Properties formed two limited liability companies with project developers which may meet the definition of a VIE. Hernando Oaks, LLC was formed by TECO Properties with the Pensacola Group to buy and develop a residential community in Hernando County, Florida. Hernando Oaks, LLC had total assets at Dec. 31, 2002 of $18.9 million. TECO Properties' estimated maximum theoretical loss exposure is its equity investment in this project of approximately $9.7 million.

B-T One, LLC is a limited liability company formed by TECO Properties with Boyd Development Co., the project developer, to develop a residential community. B-T One, LLC had total assets at Dec. 31, 2002 of $13.1 million. TECO Properties' estimated maximum theoretical loss exposure is its equity investment in this project of approximately $7.5 million.

TECO Propane Ventures (TPV) has an investment in a partnership formed to combine propane operations with the propane operations of three third-party entities. At Dec. 31, 2002, the estimated maximum theoretical loss exposure faced by TPV is its equity investment of approximately $35.1 million and $9.5 million of other potential liabilities. (See the **Other Unregulated Companies** section and **Note S** to the **Consolidated Financial Statements**.)

TECO Transport entered into two separate sale-leaseback transactions for certain vessels which were recognized as sales at the time of each transaction, and are currently recognized as operating leases for the assets. The sale-leaseback transactions were entered into with a third party that may meet the definition of a VIE. TECO Transport currently leases two ocean-going tugboats, four ocean-going barges, five river towboats and 49 river barges. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable equipment to meet contractual obligations. (See **Note R** to the **Consolidated Financial Statements**.)

TECO Energy Services formed a partnership to construct, own and operate a water cooling plant to produce and distribute chilled water to customers via a local distribution loop for use, primarily, in air conditioning systems. The partnership may meet the definition of a VIE in accordance with FIN 46. The estimated maximum theoretical loss exposure associated with this partnership is its equity investment of approximately $3.6 million.

In November 2000, TECO Energy established TECO Capital Trust I (Trust I) for the sole purpose of issuing Trust Preferred Securities (TRuPS) and using the proceeds to purchase company preferred securities from TECO Funding Company I, LLC (TECO Funding). Trust I may be a VIE in accordance with FIN 46. TECO Energy has guaranteed the payments to the holders of the company preferred securities and indirectly, the payments to the holders of the TRuPS, as a result of their beneficial interest in the company preferred securities. In January 2002, TECO Energy sold 17.965 million units of mandatorily convertible equity units in the form of 9.5% equity units at $25 per unit. Each equity unit consisted of $25 in principal amount of a trust preferred security of TECO Capital Trust II (Trust II), a Delaware business trust formed for the purpose of issuing these securities and using the proceeds to purchase company preferred securities from TECO Funding Company II, LLC. Trust II may meet the definition of a VIE in accordance with FIN 46. The estimated maximum loss exposure is not expected to be incrementally significant to obligations currently recognized by TECO Energy for activities associated with Trust I or Trust II. (See **Note G** to the **Consolidated Financial Statements**.)

As a result of the conversion of a loan to a Panda subsidiary on Jan. 3, 2003, TPS has an equity interest in the TIE projects. (See the **TECO Power Services — Construction Activities** section.) The estimated maximum theoretical loss exposure is TPS' equity investment of $137 million. (See **Note N** to the **Consolidated Financial Statements**.)

Non-Operating Items Impacting Net Income From Continuing Operations

2002 Items

In 2002, TECO Energy's results included a $3.0-million after-tax charge at TECO Investments related to an aircraft leased to US Airways, which has filed for bankruptcy. Results at TPS include a $5.8-million after-tax asset valuation charge for the proposed sale of its interests in generating facilities in the Czech Republic. Results at TECO Energy include a $34.1-million pretax ($20.9-million after-tax) charge related to a debt refinancing.

2001 Items

In 2001, TECO Energy's results included charges to adjust asset valuations totaling $7.2 million after-tax. The adjustments included a $6.1-million after-tax charge related to the sale of TPS' minority interests in EGI, which owns smaller power generation projects in Central America, and a $1.1-million after-tax charge related to the sale of leveraged leases at TECO Investments.

2000 Items

In 2000, TECO Energy's results included an $8.3-million after-tax gain from the US Propane and Heritage Propane transactions offset by after-tax charges of $5.2 million to adjust the value of leveraged leases and $3.8 million to adjust property values at TECO Properties.

Discontinued Operations

In September 2002, as a component of its cash raising plans, TECO Energy initiated activities to sell the TECO Coalbed Methane gas assets. That sale was substantially completed in December 2002 to the Municipal Gas Authority of Georgia. Proceeds from the sale were $140 million, of which $42 million was paid in cash at closing and $98 million was paid in January 2003. TECO Coalbed Methane's results are accounted for as discontinued operations for all periods reported.

TECO Coalbed Methane's 2002 net income was $31.4 million including a $7.7-million after-tax net gain on the $42 million portion of the sale proceeds. These results reflect production of 14.2 billion cubic feet (Bcf), compared to 15 Bcf in 2001 at an effective gas price, including the effects of hedging, of about $2.80 per thousand cubic feet (Mcf), an almost 20 percent lower realized price than in 2001.

2001 net income increased as a result of higher gas prices which more than offset naturally declining production. Effective gas prices, including the effects of hedging, increased 33 percent to $3.66 per Mcf and production was 15 Bcf. Effective Jan. 1, 2001, TECO Energy had derivatives in place at TECO Coalbed Methane that qualified for cash flow hedge accounting treatment under FAS 133. As a result of the adoption of FAS 133, TECO Energy recorded an initial derivative liability of $19.0 million and an after-tax reduction to OCI of $12.6 million.

Production from TECO Coalbed Methane's reserves was eligible for Section 29 non-conventional fuels tax credits through 2002. The credit is estimated to be $1.10 per million Btu for 2002 and was $1.08 per million Btu in 2001, $1.06 per million Btu in 2000. This rate escalated with inflation but could be limited by domestic oil prices. In 2002, domestic oil prices would have had to exceed $49 per barrel for this limitation to have been effective. In 2002, TECO Coalbed Methane's Section 29 tax credits were $15.9 million, compared to $16.1 million in 2001.

Other Income (Expense)

In 2002, Other Income (Expense) of $47.2 million included $60.7 million from construction-related and loan agreements with Panda Energy and earnings on the equity investment in EEGSA at TPS, and income from the investment in TPV, partially offset by the $9.4 million pretax ($5.8 million after-tax) asset valuation charge for TPS' proposed sale of its minority interest in generating facilities in the Czech Republic and a $34.1 million ($20.9 million after-tax) pretax charge related to a TECO Energy debt refinancing completed in 2002.

In 2001, Other Income (Expense) of $51.9 million included $27.1 million from construction-related and loan agreements with Panda Energy and earnings on the equity investment in EEGSA at TPS, and income from the investment in TPV, partially offset by a $9.9 million pretax ($6.1 million after-tax) charge for TPS' sale of its minority interest in EGI.

Equity AFUDC at Tampa Electric, which is included in Other Income, was $24.9 million in 2002, $6.6 million in 2001 and $1.6 million in 2000. AFUDC is expected to be about $20 million in 2003 before declining in 2004, primarily reflecting Tampa Electric's growing investment in the Gannon to Bayside repowering. With the conversion of the loan to Panda Energy related to the TIE projects to an ownership interest, (see the **TECO Power Services – Construction Activities** section) the interest income related to these loans will be eliminated in 2003.

Interest Charges

Interest expense was $147.1 million in 2002 compared with $164.0 million in 2001 and $167.6 million in 2000. The decline in 2002 was primarily because of lower short-term debt rates and balances and a favorable settlement with the Internal Revenue Service regarding disputed income tax amounts for which interest had been previously paid, partially offset by higher distributions on preferred securities due to the issuance of mandatorily convertible equity units in January 2002. The slight decrease in 2001 was primarily because of lower short-term debt rates.

Income Taxes

Income taxes decreased in 2002, reflecting greater non-taxable AFUDC equity and a substantial increase in tax credits associated with the production of non-conventional fuels. In 2001 income tax expense decreased, reflecting higher taxable income offset by an increase in tax credits associated with the production of non-conventional fuels. Income tax expense as a percentage of income from continuing operations before taxes was –14.8 percent in 2002, –0.8 percent in 2001 and 11.4 percent in 2000.

The cash payment for federal income taxes, as required by the alternative minimum tax rules, was $71.9 million, $52.4 million and $83.9 million in 2002, 2001 and 2000, respectively.

Total income tax expense was reduced by the Federal tax credit related to the production of non-conventional fuels, under Section 29 of the Internal Revenue Code. This tax credit totaled $107.3 million in 2002, $86.2 million in 2001 and $52.1 million in 2000. These tax credits are generated annually on qualified production at TECO Coal through Dec. 31, 2007, subject to changes in law, regulation or administration that could impact the qualification of Section 29 tax credits.

The tax credit is determined annually and is estimated to be $1.08 per million Btu for 2002 and was $1.08 per million Btu in 2001 and $1.06 per million Btu in 2000. This rate escalates with inflation but could be limited by domestic oil prices. In 2002, domestic oil prices would have had to exceed $49 per barrel for this limitation to have been effective.

In 2002, 2001 and 2000, the decreased income tax expense also reflected the impact of increased overseas operations with deferred U.S. tax structures. The decrease related to these deferrals was $8.1 million, $7.2 million and $9.3 million for 2002, 2001 and 2000, respectively.

The income tax effect of gains and losses from the discontinued operations of TECO Coalbed Methane is shown as a component of results from discontinued operations.

Enron Related Matters

TPS has filed a claim in the Enron bankruptcy proceeding associated with the NEPCO "swept cash" (see the **TECO Power Services – Construction Activities** section) for the four projects in the amount of $214 million. This is a gross amount and does not take into account efficiencies in the projects and other similar credits. The bankruptcy judge appointed an examiner in October 2002 to evaluate whether the "swept cash" lost by all NEPCO customers at the time of the bankruptcy can be traced from NEPCO to Enron and then to Enron's use of the funds. That report is expected by the end of the first quarter of 2003, and if it is favorable, the judge should require that the amount of the traceable funds be returned to the bankrupt estate of NEPCO. This result would improve significantly TPS' likelihood of recovering most of the cash. Since the appointment of the examiner, TPS and others have filed adversary proceedings in the bankruptcy.

TECO Energy has negotiated an agreement with Enron, pending approval of the Creditors Committee, to settle the previously reported $3.5 million of potential trade payables exposure as a result of the Enron bankruptcy. Action by the Creditors Committee is expected by the end of March 2003. The net financial impact of the agreement is reflected in consolidated net income and no future financial impact is expected.

Environmental Compliance

Consent Decree

Tampa Electric Company, in cooperation with the Environmental Protection Agency (EPA) and the U.S. Department of Justice, signed a Consent Decree which became effective Oct. 5, 2000, and a Consent Final Judgment with the Florida Department of Environmental Protection (FDEP), effective Dec. 7, 1999. Pursuant to these agreements, allegations of violations of New Source Review requirements of the Clean Air Act were resolved, provision was made for environmental controls and pollution reductions, and Tampa Electric began implementing a comprehensive program that will dramatically decrease emissions from its power plants.

The emission reduction requirements included specific detail with respect to the availability of flue gas desulfurization systems (scrubbers) to help reduce sulfur dioxide (SO2), projects for nitrogen oxides (NOx) reduction efforts on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Station to natural gas. When these units are repowered, the station will be renamed the Bayside Power Station and will have total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled electric generation. Tampa Electric anticipates commercial operation for the first repowered Bayside unit by May 1, 2003. The repowering of the second unit is scheduled for completion by May 1, 2004. By May 1, 2005, Tampa Electric must decide whether to install NOx controls, repower, or shutdown Big Bend Unit 4, and it must implement the chosen methodology by June 1, 2007. By May 1, 2007, Tampa Electric will decide whether to install NOx controls, repower, or shutdown Big Bend Units 1, 2 and 3 and it must implement the chosen methodology beginning in 2008. Tampa Electric's capital investment forecast includes amounts in the 2006 and 2007 period for compliance with the NOx reduction requirements.

Emission Reductions

Since 1998, Tampa Electric has reduced annual SO2, NOx, and particulate matter (PM) emissions from its facilities by 105,418 tons, 11,206 tons, and 1,113 tons, respectively.

Reductions in SO2 emissions were primarily accomplished through the installation of scrubber systems on Big Bend Units 1 and 2. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3. Currently, the scrubbers at Big Bend Station remove more than 95 percent of the SO2 emissions from the flue gas streams. In addition, reductions in NOx have been accomplished through combustion tuning and optimization projects at Big Bend and Gannon Stations.

Particulate matter is controlled at Big Bend and Gannon Stations through the use of electrostatic precipitators, which remove more than 99.9 percent of the PM generated during the combustion process.

Significant reductions in emissions outlined in the consent decree and consent final judgment will result from the ongoing repowering of the Gannon to Bayside Power Station and, should Tampa Electric decide to continue to burn coal, the installation of additional NOx emissions controls on all Big Bend Units. By 2010, these projects will result in the additional phased reduction of SO2 by 47,467 tons per year, NOx by 50,488 tons per year, and PM by 1,981 tons per year. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO2, NOx, and PM emissions by 87 percent, 89 percent, and 60 percent, respectively, below 1998 levels. With these improvements in place, Tampa Electric's facilities will meet the same standards required of new power generating facilities and help to significantly enhance the quality of the air in the community.

In November 2000, the FPSC approved recovery, through the Environmental Cost Recovery Clause of costs incurred to improve the availability and removal efficiency for its Big Bend 1, 2 and 3 scrubbers, to reduce PM emissions, and for early NOx emissions reduction projects. The approved cost recovery for these various environmental projects through customers' bills started in January 2001.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2002, Tampa Electric Company has estimated its ultimate financial liability to be approximately $20 million, and this amount has been reflected in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors, or Tampa Electric Company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other potentially responsible parties (PRPs) is based on each parties' relative ownership interest in or usage of a site. Accordingly, Tampa Electric Company's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Regulation

Tampa Electric Rate Stabilization Strategy

Tampa Electric's objectives of stabilizing prices from 1996 through 1999 and securing fair earnings opportunities during this period were accomplished through a series of agreements entered into in 1996 with Florida's Office of Public Counsel (OPC) and the Florida Industrial Power Users Group (FIPUG), which were approved by the FPSC. Prior to these agreements, the FPSC approved a plan submitted by Tampa Electric to defer certain 1995 revenues.

In general, under these agreements Tampa Electric was allowed to defer revenues in 1995 and 1996 during the construction of Polk Unit 1 and recognize these revenues in 1997 and 1998 after commercial operation of the unit. Other components of the agreements were a base rate freeze through 1999 and refunds to customers totaling $50 million during the period from October 1996 through December 1998, while Tampa Electric was allowed recovery of the capital costs incurred for the Polk Unit 1 project.

In October 2000, the FPSC staff recommended a refund of $6.1 million for the final year of the agreements. OPC objected to certain interest expenses recognized in 1999 that were associated with prior years' tax positions and used to calculate the amount to be refunded. Following a review by the FPSC staff, the FPSC agreed in December 2000 that the original $6.1 million was to be refunded to customers. In February 2001, OPC protested the FPSC's decision. The FPSC held hearings on the issue in August 2001 and upheld its original decision. In January 2002, the OPC filed a motion with the FPSC asking for reconsideration of its decision, alleging the FPSC relied on erroneous information. This was not granted, and Tampa Electric made refunds of about $6.4 million associated with 1999 in 2002.

Since the expiration of the agreements, Tampa Electric is not under a new stipulation. Therefore, its rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue earning within its allowed ROE range.

Peoples Gas Rate Proceeding

On Jun. 27, 2002, PGS filed a petition with the FPSC to increase its service rates. The requested rates would have resulted in a $22.6 million annual base revenue increase, reflecting a ROE midpoint of 11.75 percent.

On the date of the FPSC hearing, PGS agreed to a settlement with all parties involved, and a final Commission order was granted on Dec. 17, 2002. The company received authorization to increase annual base revenues by $12.05 million. The new rates allow for an 11.25 percent midpoint ROE and a capital structure with 57.43 percent equity and were effective after Jan. 16, 2003.

Cost Recovery Clauses

In September 2002, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery clause rates for the period January through December 2003. In November, the FPSC approved Tampa Electric's requested changes. In February 2003, Tampa Electric filed to revise the fuel cost recovery rates for the period April through December 2003 due to higher projected fuel prices. In March 2003, the FPSC approved Tampa Electric's revised rates. Accordingly, Tampa Electric's residential customer rate per 1,000-kilowatt hours increased to $94.14. The rates include projected costs associated with environmental projects required under the EPA Consent Decree and the FDEP Consent Final Judgment. They also reflect natural gas purchases for the company's repowered Bayside Unit 1.

During 2002, PGS' purchased gas adjustment remained stable, as no significant natural gas spikes occurred. The actual purchased gas adjustment rate paid by consumers was significantly lower than the FPSC approved cap. In December 2002, PGS' purchased gas adjustment cap for 2003 was approved as filed.

Utility Competition: Electric

Tampa Electric's retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of self-generation available to larger users of electric energy. Such users may seek to expand their alternatives through various initiatives, including legislative and/or regulatory changes that would permit competition at the retail level. Tampa Electric intends to retain and expand its retail business by managing costs and providing high-quality service to retail customers.

There is presently active competition in Florida's wholesale power markets, increasing largely as a result of the Energy Policy Act of 1992 and related federal initiatives. However, the state's Power Plant Siting Act, which sets the state's electric energy and environmental policy and governs the building of new generation involving steam capacity of 75 megawatts or more, requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits.

In February 2002, the FPSC began holding workshops to discuss suggested changes to an associated rule originally adopted by the FPSC in 1994, requiring investor-owned electric utilities (IOUs) to issue Requests for Proposals (RFP) prior to filing a petition for Determination of Need. The RFP process has been used as a tool to measure the cost-effectiveness of new generation. After a series of workshops, a rule hearing was held in December 2002 and, as a result, the FPSC made modifications to the rule that provide a mechanism for expedited dispute resolution; allow bidders to submit new bids whenever the IOU revises its costs estimates for its self-build option; require IOUs to disclose the methodology and criteria to be used to evaluate the bids; and provide more stringent standards for the IOUs to recover costs overruns in the event the self-build option is deemed the most cost-effective. The new rule will become effective for requests for proposal for applicable capacity additions, prospectively.

Regional Transmission Organization (RTO)

In December 1999, the Federal Energy Regulatory Commission (FERC) issued Order No. 2000, encouraging the development of RTOs. This rule was driven by the FERC's continuing effort to increase open access to transmission facilities in large, regional markets.

The peninsular Florida IOUs made joint RTO filings to the FERC in October and December 2000. In the filing, Tampa Electric agreed with the other Florida IOUs to form an RTO to be known as GridFlorida LLC. GridFlorida would independently control the transmission assets of the filing utilities, as well as other utilities in the region that choose to join. The RTO would be an independent, investor-owned organization that would have control of the planning and operations of the bulk power transmission systems of the utilities within peninsular Florida. In addition, GridFlorida was proposed to be a transmission company that would own transmission assets. Tampa Electric planned to contribute its transmission assets to GridFlorida in exchange for a passive interest.

In March 2001, the FERC conditionally approved GridFlorida. In May 2001, the FPSC decided to investigate whether the peninsular Florida IOUs were prudent in complying with FERC's Order No. 2000. In October 2001, the FPSC ruled that, while the companies were prudent in forming GridFlorida, the FPSC was not satisfied with the transmission-owning features of the GridFlorida filing nor with the proposal that any of the filing utilities transfer ownership of their assets to GridFlorida. Accordingly, the FPSC ordered the companies to develop a new RTO model.

In September 2002, the FPSC issued an order which gave final approval to some aspects of the latest GridFlorida proposal; set some items for further discussion by parties and the FPSC; and set a hearing to address market design. The applicants filed joint testimony that addressed the principles for developing a Florida-specific market design that is consistent with the principles identified in the FERC's proposed order on standard market design.

In October 2002, the process was held in abeyance after the OPC filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the IOUs and by approving GridFlorida, they were doing just that. Tampa Electric and the other peninsular IOUs will take varying roles to support the FPSC and their prudence determinations. Oral arguments are expected during the first half of 2003, and a decision by the Florida Supreme Court is not expected until late 2003. All activity in development of GridFlorida has ceased pending the outcome of the case

and the resolution of certain issues by the FPSC subsequent to that outcome.

Federal Energy Regulatory Commission (FERC) Restructuring Initiatives

The FERC has increased its focus on creating a more efficient electric industry, and it has begun several key initiatives since its RTO order in late 1999 (see the **Regional Transmission Organization** section). These include the development of a Standard Market Design (SMD) for electric wholesale markets; standard generator interconnection terms, conditions and pricing; enhanced affiliate standards of conduct; and more comprehensive public information initiatives. The most significant of these initiatives relates to development of a SMD through rulemaking that will provide certain structural changes to how transmission service is provided, accessed and priced. A final rule in this matter is expected sometime in 2003. TECO Energy, through its appropriate operating companies, is active in providing comments on all initiatives and plans to remain active in ensuring its positions are fairly represented. Many of the initiatives being proposed by the FERC would be beneficial both to Tampa Electric and TPS.

TPS Federal and State Regulatory and Legislative Involvement

Along with TECO Energy's active involvement in restructuring initiatives, TPS has been proactively involved in regulatory and legislative forums in the markets in which it competes including Arizona, Texas, Arkansas, Mississippi, and Louisiana. This has included repeal in part and sometimes in total of wholesale and retail deregulation rules and laws in Arizona and Arkansas.

Arizona Public Service (APS), the largest investor-owned electric utility in the state, filed with the Arizona Corporation Commission (ACC) a request for a partial variance from the state's competition rules established in 1999. APS requested that it be exempt from its obligation, beginning on Jan. 1, 2003, to purchase at least 50 percent (about 3,000 MW) of its load requirements through a formal, arms-length, competitive procurement process and sought instead to purchase almost all of its load requirements from its unregulated affiliate, Pinnacle West Energy Corporation (PWEC). APS asserted that, due to the California crisis and the Enron collapse, the competitive wholesale market was not mature or reliable enough to meet its needs, so it should be permitted to execute a 28-year power purchase agreement between itself and PWEC. Tucson Electric Power Company (TEP) filed a similar variance request with the ACC, although it only sought a postponement of the implementation date, not a long-term power purchase agreement with an affiliated entity. The two requests were stayed by the ACC in late April 2002, and a docket was opened to review the future of competition in Arizona. In August 2002, the Commission ordered APS not to divest its current rate-based generating facilities to its affiliate, and to continue to participate in a parallel proceeding to determine what portion of its needs will be competitively bid for delivery beginning in the summer of 2003.

Regarding the competitive procurement process, the ACC Staff held numerous workshops, followed by a hearing in November 2002 to determine the amount and procedures for APS' and TEP's acquisition of their power requirements. TPS has been active in all aspects of the state's proceedings. A final determination is expected during the first quarter of 2003 with the competitive procurement process slated to begin by spring.

During this year's legislative session, the Arkansas Legislature will consider repealing its earlier legislation, which was to initiate retail electric deregulation in Arkansas sometime between October 2003 and October 2005. The incumbent IOUs are advocating a complete repeal of retail deregulation and/or a ten-year postponement of its implementation date. The large consumers and the independent power producers are lobbying for a recommitment to wholesale deregulation in Arkansas, access to the state's transmission grid, and a "pilot" project for large customers to be able to shop for power in the interim. TPS is supporting this approach while also aligning with other independent power producers to analyze the beneficial impacts to ratepayers from implementing a region-wide, security-constrained, economic dispatch, with consideration given for units' efficiency and environmental characteristics, including emissions. This is a strategy for displacing the region's older, less efficient, more polluting generating units so that state-of-the-art, gas-fired, combined-cycle units, such as Union Power Partners, can serve the growing needs of the area. This is a strategy that TPS has advanced at the federal level and other markets it serves.

In Texas, TPS has taken an active role on ERCOT committees, in proceedings at the Public Utility Commission of Texas (PUCT) and in the Legislature, whose session begins in mid-January. Transmission congestion is a major concern in the ERCOT market, and has negatively affected Frontera's ability to economically operate. Several initiatives within the ERCOT committees and at the PUCT are underway to address these ongoing congestion problems.

Frontera appealed specific ERCOT protocols with the PUCT, because of inadequate compensation for ERCOT's high usage levels of Frontera's units during times of regional congestion. Originally, the intent of the protocols was to allow ERCOT to acquire energy and capacity, when only critically necessary and on an infrequent basis from the region's existing generating units. Due to local transmission congestion in the Rio Grande Valley, Frontera was frequently requested by ERCOT to start-up and relieve the region's congestion. Frontera, however was not compensated sufficiently for providing this ancillary service in 2002. The appeal process is underway and is expected to be concluded by the end of the first quarter of 2003.

Transmission Rates

In October 2002, Tampa Electric submitted a FERC filing to change its transmission and ancillary services rates under the company's open access transmission tariff. These rates apply to wholesale transmission users of Tampa Electric's transmission system and do not affect retail service rates. In December, the FERC accepted the filing and set the matter for settlement negotiations and a potential hearing should the settlement process fail. Settlement discussions began in January 2003.

Utility Competition: Gas

Although PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity.

In Florida, gas service is unbundled for all non-residential customers. In November 2000, PGS implemented its "NaturalChoice" program offering unbundled transportation service to all eligible customers. This means that non-residential customers can purchase commodity gas from a third party but continue to pay PGS for the transportation of the gas.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by companies seeking to sell gas directly, by transporting gas through other facilities, thereby bypassing PGS facilities. In response to this competition, PGS has developed various programs, including the provision of transportation services at discounted rates.

In general, PGS faces competition from other energy source suppliers offering fuel oil, electricity and in some cases, propane. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high-quality service to customers.

In March 2000, the City of Lakeland (City) filed suit against PGS and sought a declaration that it had the right to purchase PGS facilities located within the city limits. In October 2002, the City decided that it no longer desired to pursue owning the gas utility in Lakeland and agreed to voluntarily dismiss the lawsuit. The City and PGS entered into a new 10-year franchise agreement, similar in terms and conditions to the majority of the agreements PGS has with other municipalities.

Corporate Governance

Recently, legislation, rules and proposed rules and guidelines were issued by the United States Congress, the Securities and Exchange Commission (SEC), the New York Stock Exchange (NYSE) and other interested groups designed to ensure corporate accountability, improve corporate governance and restore investor confidence. In 2002, the NYSE issued proposed standards for listed companies; the SEC issued the requirement that the largest public companies certify quarterly financial reports, one of 18 directives issued from December 2001 through December 2002. Also in 2002, the President signed the Sarbanes-Oxley Act which, among other things, requires certification of financial statements with criminal penalties for filing false statements.

These rules and proposals require independence by the Board of Directors, define committees of the Board of Directors with charters and review processes, require an internal audit function, a code of ethics for the chief executive officers, senior financial officers and directors, adequate internal controls to detect fraud, adequate training for members of the Board of Directors, increased oversight of financial disclosure by the Audit Committee of the Board, a shorter time period to report insider selling of company shares and other important items.

For many years, TECO Energy's Board of Directors has primarily consisted of independent directors, the committee structures recommended in the various proposals were already in place and the company has an effective internal audit function. In addition, the company has had a code of ethics for all officers and employees, and it was expanded to include the Board of Directors in 2002. TECO Energy has always had controls for full and complete financial reporting and disclosure, and in response to the new requirements, they have been formalized and are reviewed for effectiveness quarterly.

TECO Energy's CEO and CFO certified its first and second quarter Reports on Form 10-Q for 2002, all interim Reports on Form 8-K and its Annual Report on Form 10-K for 2001 as required by the SEC in August 2002. The certifications, which contained no exceptions, attested to the accuracy of the reports and were signed following a review by the Audit Committee of the company's Board of Directors. In compliance with the Sarbanes-Oxley Act, certifications of the company's second and third quarter Reports on Form 10-Q have been filed with the SEC.

In addition, the CEO and CFO evaluated the effectiveness of the company's disclosure controls and procedures in conjunction with the filing of quarterly financial statement certifications, as required under the new legislation, and found that the disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the company required to be included in the company's reports. Processes are in place to meet these requirements on a quarterly basis.

Transactions with Related and Certain Other Parties

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests that are reported in TECO Energy's annual proxy statement and Tampa Electric's annual regulatory filings. These transactions, primarily for legal services, were not material for the periods ended Dec. 31, 2002 and 2001. There are no material transactions of this type where the payments are in excess of those that would be paid under an arms-length transaction. TECO Energy has interests in unconsolidated affiliates, which are discussed in **the TECO Power Services, Other Unregulated Companies** and **Off-Balance Sheet Financing** sections.

Tampa Electric and TECO-Panda Generating Company (TPGC) II entered into an assignment and assumption agreement whereby Tampa Electric obtained TPGC II's rights and interests to four combustion turbines being purchased from General Electric, and assumed the corresponding liabilities and obligations for such equipment. In accordance with the terms of the assignment and assumption agreement, Tampa Electric paid $62.5 million to TPGC II as reimbursement for amounts already paid to General Electric by TPGC II for such equipment.

TPS Arkansas Operations Company and TPS Arizona Operations Company, both wholly-owned subsidiaries of TPS, had a combined receivable from Union and Gila River of $0.8 million as of Dec. 31, 2002.

In addition, TPS recognized income on the non-TPS portion of notes receivable from unconsolidated affiliates in which TPS holds joint venture interests and from credit support for the TPGC joint venture (see **Notes A** and **N** to the **Consolidated Financial Statements**). The notes receivable from unconsolidated affiliates include:

($ millions)	*Rate*	*Dec. 31, 2002*	*Dec. 31, 2001*
Notes receivable from:			
Panda Energy	14%	$ 137.0	$ 92.7
Energeticke Centrum Kladno	6%	1.4	—
Mosbacher Power Partners L.P.	12%	—	13.1
Mosbacher Power Partners L.P.	9%	13.7	21.1
Mosbacher Power Partners L.P.	12%	—	6.2
EEGSA	6.81% (1)	11.1	10.9
TPGC - Gila River	7.79% (1)	369.5	37.5
TPGC - Union Power	6.58% (1)	426.3	86.7

(1) Current rate at Dec. 31, 2002.

TPS' position in the Odessa and Guadalupe power stations in Texas was in the form of a $137 million loan to a Panda Energy International subsidiary, which is a partner in TIE at Dec. 31, 2002. This loan converted into an ownership interest on Jan. 3, 2003. The conversion gives TPS an opportunity to have an effective economic interest estimated at 75 percent of Panda's 50-percent interest in these projects (approximately 1,000 MW) over the life of the projects. TPS is evaluating its options relative to its ownership position in these projects and is targeting to structure its interest in such a manner that it will cover its cash costs in 2003 and mitigate any impact on earnings at TPS in 2003. (See **Strategy and Outlook** section.)

In February 2002, the TPS and Panda affiliates that comprise the joint venture that owns the Union and Gila River projects entered into an arrangement obligating TPS to purchase and Panda to sell Panda's interest in the joint venture in 2007 for $60 million. Panda has the right to cancel the purchase arrangement by paying TPS $20 million or a lesser amount under certain circumstances. The purchase arrangement can result in TPS' purchase of the interest prior to 2007 if Panda defaults on a bank loan made to Panda using the purchase arrangement as collateral or if TECO Energy permits its debt-to-capital ratio to exceed 65.0 percent, permits its EBITDA/interest ratio to fall below 1.5 times or it defaults on the payment of indebtedness in excess of $50 million. TECO Energy's debt-to-capital ratio at Dec. 31, 2002 was 55.9 percent and its EBITDA/interest ratio was 3.6 times.

Investment Considerations

The following are certain factors that could affect TECO Energy's future results. They should be considered in connection with evaluating forward-looking statements contained in this report and otherwise made by or on behalf of TECO Energy because these factors could cause actual results and conditions to differ materially from those projected in those forward-looking statements.

Financing Risks

TECO Energy has substantial indebtedness, which could adversely affect its financial condition and financial flexibility.

In recent years, TECO Energy has significantly expanded its indebtedness. This increase in debt levels has increased the amount of fixed charges TECO Energy is obligated to pay. The level of indebtedness and restrictive covenants contained in its debt obligations could limit its ability to obtain additional financing or refinance existing debt.

Some of TECO Energy's debt obligations contain financial covenants related to debt-to-capital ratios and interest coverage that could prevent the repayment of subordinated debt and the payment of dividends if those payments would cause a violation of the covenants. (See **Covenants in Financing Agreements** section.) TECO Energy's failure to comply with any of these covenants, as well as its ratings maintenance covenants discussed below, or to meet its payment obligations, could result in an event of default which, if not cured or waived, could result in the acceleration of other outstanding debt obligations. TECO Energy may not have sufficient working capital or liquidity to satisfy its debt obligations in the event of an acceleration of all or a significant portion of its outstanding obligations. Additionally, such an acceleration would also affect the company's ability to pay dividends. Furthermore, if TECO Energy had to defer interest payments on its subordinated notes that support the distributions on its outstanding trust preferred securities, TECO Energy would be prohibited from paying cash dividends on its common stock until all unpaid distributions on the subordinated notes were made.

TECO Energy also incurs obligations in connection with the operations of its subsidiaries and affiliates, which do not appear on the balance sheet, including in connection with the development of power projects by unconsolidated affiliates. These obligations take the form of guarantees, letters of credit and contractual commitments, as are described in the sections titled **Off-Balance Sheet Financing** and **Liquidity, Capital Resources**. In addition, TECO Energy's unconsolidated affiliates from time to time incur non-recourse debt to finance their power projects. Although TECO Energy is not obligated on that debt, its investments in those unconsolidated affiliates and its commitments with respect to those power projects are at risk if the projects are not successfully developed.

TECO Energy's financial condition and ability to access capital and pay dividends may be materially adversely affected by further ratings downgrades.

In September 2002, Moody's, S&P, Inc. and Fitch, lowered their ratings on the senior unsecured debt securities of TECO Energy.

Those downgrades and any future downgrades may affect TECO Energy's ability to borrow and may increase its financing costs, which may decrease earnings. TECO Energy is also likely to experience greater interest expense than it may have otherwise if, in future periods, it replaces maturing debt with new debt bearing higher interest rate spreads due to its lower credit ratings. In addition, such downgrades could adversely affect TECO Energy's relationships with customers and counterparties.

In addition to affecting the cost of borrowing, lower credit ratings may affect the amount of indebtedness, types of financing structures and debt markets that are available. Finally, TECO Energy's failure to comply with its ratings maintenance covenants could result in an event of default under certain of its debt obligations, which if not cured or waived, could result in the acceleration of other outstanding debt obligations and would affect its ability to pay dividends. (See **Bank Credit Facilities** and **Covenants in Financing Agreements** sections.)

If TECO Energy is unable to reduce capital expenditures or successfully complete planned asset sales and other transactions to the extent anticipated, its financial condition and results could be adversely affected.

Part of TECO Energy's business plan for 2003 includes reducing previously anticipated capital expenditures by approximately $250 million in order to maximize cash flows and reduce the need for external financings. TECO Energy cannot be sure that it will be successful in achieving reductions in that amount. The business plan also includes the sale of the majority of its interest in facilities that produce synthetic fuel which qualifies for Section 29 tax credits at TECO Coal and Tampa Electric's Polk Power Station's coal gasification unit. TECO Energy cannot be certain, however, that it will find purchasers or realize the expected value of these transactions with the anticipated impact on its cash flow position. Depending on the success of these planned expenditure reductions and asset sales transactions, TECO Energy may need to seek external financings, which, in the case of debt financings, could adversely affect its balance sheet strength and apply downward pressure on the credit ratings, and, in the case of equity financings, could have a dilutive effect to equity holders and earnings-per-share results.

Because TECO Energy is a holding company, it is dependent on cash flow from its subsidiaries, which may not be available in the amounts and at the times it is needed.

TECO Energy is a holding company and dependent on cash flow from its subsidiaries to meet its cash requirements that are not satisfied from external funding sources. Some subsidiaries have indebtedness containing restrictive covenants which, if violated, would prevent them from making cash distributions to TECO Energy. In particular, Tampa Electric's first

mortgage bonds indenture contain restrictions on distributions on its common stock, and certain long-term debt at Tampa Electric's PGS division prohibits payment of dividends to TECO Energy if Tampa Electric Company's consolidated shareholders' equity is not at least $500 million. At Dec. 31, 2002, Tampa Electric's unrestricted retained earnings available for dividends on its common stock were approximately $189 million and its consolidated shareholders' equity was approximately $1.8 billion. Also, TECO Energy's wholly-owned subsidiary, TECO Diversified, the holding company for TECO Transport, TECO Coal and TECO Solutions, has a guarantee related to a coal supply agreement that could limit the payment of dividends to TECO Energy.

TECO Energy is vulnerable to interest rate changes and may not have access to capital at favorable rates, if at all.

Changes in interest rates and capital markets generally affect TECO Energy's cost of borrowing and access to these markets. TECO Energy cannot be sure that it will be able to accurately predict the effect those changes will have on the cost of borrowing or access to capital markets.

Independent Power Project Risks

TPS' existing and planned power plants are affected by market conditions, and it may not be able to sell power at prices that enable it to recover its investments in the plants.

TPS is currently operating, constructing and investing in power plants that do not currently have long-term contracts for the sale of power. These power plants may sell at least a portion of their power based on market conditions at the time of sale, so TPS cannot predict with certainty:

- the amount or timing of revenue it may receive from power sales from operating plants;
- the differential between the cost of operations (in particular, natural gas prices) and power sales revenue;
- the effect of competition from other suppliers of power;
- regulatory actions that may affect market behavior, such as price limitations or bidding rules imposed by the FERC or reimposition of regulation in power markets;
- the demand for power in a market served by its plants relative to available supply;
- the availability of transmission to accommodate the sale of power; or
- whether TPS will recover its initial investment in these plants.

At present, several of the wholesale markets supplied by so-called "merchant" power plants are experiencing significant pricing declines due to excess supply and weak economies. Consequently, only a portion of the projected output of TPS' plants has been hedged for 2003 and 2004. TPS' results could be adversely affected if it is unable to sufficiently sell the output of its plants at a premium to forward curve prices or if TECO Energy needs to write off any capital already invested in projects.

TECO Energy's forecast assumes that TPS will manage these risks by:

- optimizing among a mix of forward on-peak energy sales, daily and hourly spot market sales of capacity, energy and ancillary services, and longer-term structured transactions;
- avoiding short positions; and
- retaining flexibility to defer, if and where possible and advisable, construction of output capacity in a market that has become oversupplied.

However, TECO Energy cannot be sure how successfully it will be able to implement these risk management measures. For instance, in oversupplied markets, entering into forward contracts could be difficult.

TPS may be unable to successfully complete and finance current and future projects on schedule and within budget.

TPS currently has new power generating facilities under construction. The construction of these facilities, as well as any future construction projects, involves risks of shortages and inconsistent qualities of equipment and material, labor shortages and disputes, engineering problems, work stoppages, unanticipated cost increases, and environmental or geological problems. In addition, the development of independent power plants involves considerable risks, including successful siting, permitting, financing and construction, contracting for necessary services, fuel supplies and power sales and performance by project partners. Any of these events could delay a project's construction schedule or increase its costs, which may impact TPS' ability to generate sufficient cash flow and service its related non-recourse project debt.

TPS marketing and risk management policies may not work as planned, and it may suffer economic losses despite such policies.

TPS actively manages the market risk inherent in its energy and fuel positions. Nonetheless, adverse changes in energy and fuel prices may result in losses in earnings or cash flows and adversely affect the balance sheet. TPS marketing and risk management procedures may not always be followed or may not work as planned. As a result, it cannot predict with precision the impact that its marketing, trading and risk management decisions may have on its business, operating results or financial position. In addition, to the extent it does not cover the entire exposure of assets or positions to market price volatility,

or the hedging procedures do not work as planned, fluctuating commodity prices could cause sales and net income to be volatile.

TPS' marketing and risk management activities also are exposed to the credit risk that counterparties to its transactions will not perform their obligations. Should counterparties to these arrangements fail to perform, TPS may be forced to enter into alternative hedging arrangements, honor underlying commitments at then-current market prices or otherwise satisfy its obligations on unfavorable terms. In that event, its financial results would likely be adversely affected.

General Business and Operational Risks

General economic conditions may adversely affect TECO Energy's businesses.

TECO Energy's businesses are affected by general economic conditions. In particular, the projected growth in Tampa Electric's service area and in Florida is important to the realization of Tampa Electric's and PGS' forecasts for annual energy sales growth. An unanticipated downturn in the local area's or Florida's economy could adversely affect Tampa Electric's or PGS' expected performance.

TECO Energy's unregulated businesses, particularly TECO Transport, TECO Coal and TPS, are also affected by general economic conditions in the industries and geographic areas they serve, both nationally and internationally. TPS' investment in Empresa Eléctrica de Guatemala, S.A. depends on growth in the relevant service areas and in annual energy sales.

Potential competitive changes may adversely affect TECO Energy's gas and electricity businesses.

The U.S. electric power industry has been undergoing restructuring. Competition in wholesale power sales has been introduced on a national level. Some states have mandated or encouraged competition at the retail level and, in some situations, required divestiture of generating assets. While there is active wholesale competition in Florida, the retail electric business has remained substantially free from direct competition. Changes in the competitive environment occasioned by legislation, regulation, market conditions or initiatives of other electric power providers, particularly with respect to retail competition, could adversely affect Tampa Electric's business and its performance.

The gas distribution industry has been subject to competitive forces for several years. Gas services provided by PGS are now unbundled for all non-residential customers. Because PGS earns margins on distribution of gas, but not on the commodity itself, unbundling has not negatively impacted PGS results. However, future structural changes that cannot be predicted could adversely affect PGS.

TECO Energy's gas and electricity businesses, both utility and independent, are highly regulated and any changes in regulatory structures could lower revenues or increase costs or competition.

Tampa Electric, TPS and PGS operate in highly regulated industries. Retail operations, including the prices charged, are regulated by the FPSC, and Tampa Electric's and TPS' wholesale power sales and transmission services are subject to regulation by the FERC. Changes in regulatory requirements or adverse regulatory actions could have an adverse effect on their performance by, for example, increasing competition or costs, threatening investment recovery or impacting rate structure.

TECO Energy's businesses are sensitive to variations in weather and have seasonal variations.

Most of TECO Energy's businesses are affected by variations in general weather conditions and unusually severe weather. Tampa Electric's, PGS' and TPS' energy sales are particularly sensitive to variations in weather conditions. Those companies forecast energy sales on the basis of normal weather, which represents a long-term historical average. Significant variations from normal weather could have a material impact on energy sales. Unusual weather, such as hurricanes, could adversely affect operating costs and sales.

PGS, which has a single winter peak period, is more weather sensitive than Tampa Electric, which has both summer and winter peak periods. Mild winter weather in Florida can be expected to negatively impact results at PGS.

Variations in weather conditions also affect the demand and prices for the commodities sold by TECO Coal, as well as electric power sales from TPS' merchant power plants. TECO Transport is also impacted by weather because of its effects on the supply of and demand for the products transported. Severe weather conditions could interrupt or slow service and increase operating costs of those businesses.

Electric power marketing may be seasonal. For example, in some parts of the country, demand for, and market prices of, electricity peak during the hot summer months, while in other parts of the country such peaks occur in the cold winter months. As a result, power marketing results may fluctuate on a seasonal basis. The pattern of this fluctuation may change depending on the nature and location of the facilities operated and the terms under which they sell electricity.

Commodity price changes may affect the operating costs and competitive positions of TECO Energy's businesses.

Most of TECO Energy's businesses are sensitive to changes in coal, gas, oil and other commodity prices. Any changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services.

In the case of Tampa Electric, currently fuel costs used for generation are mostly affected by the cost of coal. Future fuel costs will be impacted by the cost of natural gas as well as coal. Tampa Electric is able to recover the cost of fuel through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

Regarding wholesale sales of electricity, the ability to make sales and margins on power sales is currently affected by the cost of coal to Tampa Electric, particularly as it compares to the cost of gas and oil to other power producers.

In the case of TPS, results are impacted by changes in the market price for electricity. The profitability of merchant power plants is heavily dependent on the price for power in the markets they serve. Wholesale power prices are set by the market assuming a cost for the input energy and conversion efficiency, but the fixed costs may not be reflected in the price for spot, or excess power.

In the case of PGS, costs for purchased gas and pipeline capacity are recovered through retail customers' bills, but increases in gas costs affect total retail prices and therefore, the competitive position of PGS relative to electricity, other forms of energy and other gas suppliers.

TECO Energy relies on some transmission and distribution assets that it does not own or control to deliver wholesale electricity as well as natural gas. If transmission is disrupted, or if capacity is inadequate, its ability to sell and deliver power and natural gas may be hindered.

TECO Energy depends on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity and natural gas it sells to the wholesale market, as well as the natural gas it sells and purchases for use in its electric generation facilities. If transmission is disrupted, or if capacity is inadequate, the ability to sell and deliver products and satisfy contractual and service obligations may be hindered.

The FERC has issued regulations that require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, there is the potential that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electric power as desired. TECO Energy cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities in specific markets.

In addition, the independent system operators that oversee the transmission systems in certain wholesale power markets have from time to time been authorized to impose price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the profitability of TECO Energy's wholesale power marketing business.

The uncertain outcome regarding the creation of regional transmission organizations, or RTOs, may impact operations, cash flows or financial condition.

Tampa Electric is continuing to make progress towards the development of its RTO, which would independently control the transmission assets of participating utilities in peninsular Florida. Given the regulatory uncertainty of the ultimate timing, structure and operations of GridFlorida or an alternate combined transmission structure, TECO Energy cannot predict what effect its creation will have on future consolidated results of operations, cash flow or financial condition.

TECO Energy may be unable to take advantage of its existing tax credits.

TECO Energy derives a portion of its net income from Section 29 tax credits related to the production of non-conventional fuels. Although TECO Energy currently plans to sell a significant portion of the production facilities, until and unless TECO Energy successfully does so, the use of these tax credits is dependent on the generation of sufficient taxable income against which to use the credits. TECO Energy's forecast assumes that it will generate sufficient taxable income to use these credits. These credits, and their sale value, could be impacted by or become unavailable due to administrative actions of the Internal Revenue Service or the U.S. Treasury or changes in law, regulation or administration.

Problems with operations could cause TECO Energy to incur substantial costs.

Each of TECO Energy's subsidiaries is subject to various operational risks, including accidents or equipment breakdown or failure and operations below expected levels of performance or efficiency. As operators of power generation facilities, Tampa Electric and TPS could incur problems such as the breakdown or failure of power generation equipment, transmission lines, pipelines or other equipment or processes which would result in performance below assumed levels of output or efficiency. TECO Energy's forecast assumes normal operations and normal maintenance periods for its subsidiaries' facilities.

The international projects and operations of TPS and TECO Ocean Shipping are subject to risks that could result in losses or increased costs.

TPS is involved in several international projects. These projects involve numerous risks that are not present in domestic projects, including expropriation, political instability, currency exchange rate fluctuations, repatriation restrictions, and regulatory and legal uncertainties. TECO Energy's forecast assumes that TPS will manage these risks through a variety of risk mitigation measures, including specific contractual provisions, teaming with strong international and local partners, obtaining non-recourse financing and obtaining political risk insurance where appropriate.

TECO Ocean Shipping is exposed to operational risks in international ports, primarily in the form of its need to obtain suitable labor and equipment to safely discharge its cargoes in a timely manner. TECO Energy's forecast assumes that TECO Ocean Shipping will manage these risks through a variety of risk mitigation measures, including retaining agents with local knowledge and experience in successfully discharging cargoes and vessels similar to those used.

Changes in the environmental laws and regulations to which TECO Energy's regulated businesses are subject could increase costs or curtail activities.

TECO Energy's businesses are subject to regulation by various governmental authorities dealing with air, water and other environmental matters. Changes in compliance requirements or the interpretation by governmental authorities of existing requirements may impose additional costs or require curtailment of some businesses' activities.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Risk Management Infrastructure

TECO Energy and its affiliates are subject to various types of market risk in the course of daily operations, as discussed below. The company has adopted an enterprise-wide approach to the management and control of market and credit risk. Middle Office risk management functions, including credit risk management and risk control, are independent of each transacting entity (Front Office) and report to the Chief Financial Officer of TECO Energy. Front Office functions report to the various operating company presidents responsible for energy transaction activities.

The TECO Energy Risk Management Policy (Policy) governs all energy transacting activity at TECO Energy. The Policy is approved by the TECO Energy Board of Directors and administered by a Risk Authorizing Committee (RAC) that is comprised of senior management, chaired by TECO Energy's Chief Executive Officer (CEO), and advised by the Vice President of Energy Risk Management. Within the bounds of the Policy, the RAC approves specific hedging strategies, new transaction types or products, limits, and transacting authorities. The Policy further requires that, for all merchant generation asset management activities, power sales and gas purchases must be substantially matched, and that the volume of power sales commitments is limited to the volume of owned and available generating capacity. Transaction activity is reported daily and measured against limits. For all other commodity risk management activities, derivative transaction volumes are limited to the anticipated volume for customer sales or supplier procurement activities.

The TECO Energy Authorizing Committee, directed by the CEO of TECO Energy, administers the risk management policy with respect to interest rate risk exposures. Under the policy for interest rate risk management the committee operates and oversees transaction activity. Interest rate derivative transaction activity is directly correlated to borrowing activities.

Risk Management Objectives

The Front Office is responsible for reducing and mitigating the market risk exposures which arise from the ownership of physical assets and contractual obligations, such as merchant power plants, debt instruments and firm customer sales contracts. The primary objectives of the risk management organization, the Middle Office, is to quantify, measure and monitor the market risk exposures arising from the activities of the Front Office and the ownership of physical assets. In addition, the Middle Office is responsible for enforcing the limits and procedures established under the approved risk management policies. Based on the policies approved by the company's Board of Directors and the procedures established by the RAC, from time to time TECO Energy enters into futures, forwards, swaps and option contracts for the following purposes:

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric, PGS, TECO Gas Services and Prior Energy;
- To limit the exposure to interest rate fluctuations on debt issuances at TECO Energy and its other affiliates;
- To limit the exposure to electricity, natural gas and fuel oil price fluctuations related to the operations of natural gas-fired and fuel oil-fired power plants at TPS; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport.

TECO Energy uses derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective in using derivative instruments for regulated operations is to reduce the impact of market price

volatility on ratepayers. For unregulated operations, the company uses derivative instruments primarily to optimize the value of physical assets, primarily including generation capacity and natural gas delivery.

Derivative and Hedge Accounting

Effective Jan. 1, 2001, TECO Energy adopted FAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as subsequently amended and interpreted. FAS 133 requires TECO Energy and its affiliates to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of other comprehensive income (OCI) or in net income, depending on the designation of those instruments. The effect of the adoption of FAS 133, at Jan. 1, 2001 on continuing operations was not material.

The accounting literature establishes specific criteria and requirements in order to apply hedge accounting. Due to the strict criteria and extensive requirements, certain derivatives do not qualify for hedge accounting, even though the derivative may efficiently and economically reduce the exposure to a particular type of risk. For accounting purposes, a derivative may only be designated as one of the following, resulting in the prescribed treatment in the financial statements:

Non-hedge: derivative must be recorded on the balance sheet at fair value; changes in the fair value of the derivative are recorded as a net gain or loss in earnings.

Cash Flow Hedge: derivative must be recorded on the balance sheet at fair value; changes in the fair value of the derivative are initially recorded in OCI; when the hedged item or anticipated hedged transaction impacts earnings, the current deferred gain or loss recorded in OCI is reclassified to earnings as an offset to the revenue or cost of the hedged item or anticipated hedged transaction.

Fair Value Hedge: derivative must be recorded on the balance sheet at fair value; changes in the fair value of the derivative are recorded in earnings; the hedged item is adjusted on the balance sheet to reflect the change in fair value from the hedge designation date; changes in the fair value of the hedged item are recorded as an offset to the change in fair value of the derivative recorded in earnings.

The designation of a derivative as either a cash flow or fair value hedge is dependent on the effectiveness of the derivative at offsetting the changes in future cash flows or fair value of the designated hedged transaction or item. The majority of the company's derivatives are used to reduce the variability in cash flows for anticipated sales or purchases of energy as a result of subsequent price movements (cash flow hedges). For example, a derivative to purchase natural gas at a fixed price may be designated as a cash flow hedge of the variability of future cash flows associated with an anticipated purchase of natural gas for the same time period. When the forecasted physical purchases of natural gas occurs, the gain or loss on the derivative, which has been deferred in OCI, will be reclassified to the income statement to adjust the actual purchase price to the committed fixed price of natural gas under the derivative instrument. Amounts recorded in OCI related to an effective designated cash flow hedge must be reclassified to current earnings if the anticipated hedged transaction is no longer probable of occurring.

Designation of a hedging relationship requires management to make assumptions about the future probability of the timing and amount of the transaction, and the future effectiveness of the derivative instrument in offsetting the change in fair value or cash flows of the hedged item or transaction. The determination of fair value is dependent upon certain assumptions and judgments. (See **Unregulated Companies** section below, and **Notes A** and **B** to the **Consolidated Financial Statements.**)

Interest Rate Risk

TECO Energy is exposed to changes in interest rates primarily as a result of its borrowing activities. TECO Energy or its affiliates may enter into futures, swaps and option contracts, in accordance with the approved risk management policies and procedures, to moderate this exposure to interest rate changes and achieve a desired level of fixed and variable rate debt. As of Dec. 31, 2002, a hypothetical 10% increase in TECO Energy's weighted average interest rate on its variable rate debt during 2003, as compared to 2002, would not result in a material impact on pretax earnings. Comparatively, as of Dec. 31, 2001 a hypothetical 10% increase in TECO Energy's weighted average interest rate on its variable rate debt and required refinancings during 2002, as compared to 2001, would have resulted in an estimated $3.2 million decrease in pretax earnings. These amounts were determined based on the variable rate obligations existing on the indicated date at TECO Energy and its subsidiaries. The reduction of the sensitivity to hypothetical interest rate movements is due to the amount of variable rate debt outstanding and substantially lower debt maturities. Due to the uncertainty of future events, as discussed in the **Investment Considerations** section, and management's responses to those events, the sensitivities assume no changes to TECO Energy's financing structure. A hypothetical 10% change in interest rates would increase the fair value of long-term debt 5.6 percent at Dec. 31, 2002. A hypothetical 10% change in interest rates would not have a significant impact on the estimated fair value of TECO Energy's long-term debt at Dec. 31, 2001. (See **Financing Activity** section, and **Notes E** and **F** to the **Consolidated Financial Statements.**)

Credit Risk

TECO Energy has adopted a rigorous process for the establishment of new trading counterparties. This process includes an evaluation of each counterparty's financial statements with particular attention paid to liquidity and capital

resources, establishment of counterparty-specific credit limits, optimization of credit terms, and execution of standardized enabling agreements. TECO Energy's Credit Guidelines require transactions with counterparties below investment grade to be collateralized. The Credit Guidelines are administered and monitored within the Middle Office, independent of the Front Office.

Financial instability and significant uncertainties relating to liquidity in the entire merchant energy sector have increased the perceived credit risk. Credit exposures for merchant generation activities are calculated, compared to limits and reported to management on a daily basis. Contracts with different legal entities of the same counterparty are consolidated and managed as appropriate, considering the legal structure and any netting agreements in place. Below is a summary of TECO Energy's credit risk exposure on energy contracts related to merchant generation activities at Dec. 31, 2002.

(millions) *Rating(1)*	*Exposure Before Credit Collateral(2)*	*Credit Collateral(3)*	*Net Exposure*	*Number of Counterparties >10% (4)*	*Net Exposure Counterparties >10%(4)*
Investment grade	$ 13.1	—	$ 13.1	4	$ 12.7
Split rating	—	—	—	—	—
Non-investment grade	—	—	—	—	—
No external ratings (internally rated)					
Investment grade	<0.1	—	<0.1	—	—
Non-investment grade	—	2.5	—	—	—
Total	$ 13.1	$ 2.5	$ 13.1	4	$ 12.7

(1) Ratings are principally determined based on publicly available credit ratings, as determined by independent ratings agencies. If the counterparty has provided a guarantee by a higher rated entity, the assigned rating is that of the guarantor. Included in Investment grade are those counterparties with a minimum S&P or Fitch's rating of BBB- or higher and a Moody's rating of Baa3 or higher.

(2) Exposure before credit collateral includes the fair value of net energy contract assets for open positions and the net account receivable for realized energy contracts. Exposures are offset by a legal counterparty where legally enforceable netting and setoff arrangements are in place.

(3) Credit collateral is required from time-to-time based on contractual provisions and may generally include cash deposits and letters of credit. At Dec. 31, 2002, credit collateral was required from two non-investment grade counterparties. However, TECO EnergySource was not exposed to these counterparties based on the unrealized fair value of the open energy contracts at Dec. 31, 2002.

(4) The number of counterparties that individually, after considering legally enforceable netting arrangements, represent a significant concentration of credit risk (i.e., more than 10% of the total credit exposure) at TECO EnergySource. Also, the combined exposure, less credit collateral, if any, of each significant concentration.

Commodity Risk

TECO Energy and its affiliates face varying degrees of exposure to commodity risks—including coal, natural gas, fuel oil and other energy commodity prices. Any changes in prices could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. The company assesses and monitors risk using a variety of state-of-the-art measurement tools. Management uses different risk measurement and monitoring tools based on the degree of exposure of each operating company to commodity risk.

Regulated Utilities

At Tampa Electric, fuel costs used for generation are currently most affected by the cost of coal. Future fuel costs will be impacted by the cost of natural gas, in addition to coal, as the repowering of the Gannon Station is completed. (See the **Environmental Compliance** section.) PGS is primarily subject to costs for purchased gas and pipeline capacity. Increasing costs for the regulated utilities impact their competitive position in the marketplace versus other energy sources and suppliers.

Currently, Tampa Electric and PGS are subject to relatively little commodity price risk exposure. This is primarily due to the fact that commodity price increases due to changes in market conditions for fuel, purchased power and natural gas are recovered through cost recovery clauses, with no anticipated effect on earnings. Commodity price risk is mitigated by the use of long-term fuel supply agreements, prudent operation of plant facilities to reduce the reliance on purchased power, and derivative instruments designated as cash flow hedges of anticipated purchases of natural gas. At Dec. 31, 2002 and 2001, a change in commodity prices would not have a material impact on earnings for Tampa Electric or PGS.

Unregulated Companies

Most of the unregulated subsidiaries at TECO Energy are subject to significant commodity risk. These include TECO Coal, TECO Transport, TECO Gas Services, Prior Energy and TPS. The unregulated companies do not speculate using derivative instruments. However, not all derivative instruments receive hedge accounting treatment due to the strict requirements and narrow applicability of the accounting literature to dynamic transactions, as discussed above in the **Derivative and Hedge Accounting** section.

TECO Coal is exposed to commodity price risk through coal sales as a part of its daily operations. Fixed price sales agreements are used, where possible and economical, to mitigate the variability in coal prices. At Dec. 31, 2002 and 2001, a hypothetical 10% change in the average annual market price of coal for each year would have resulted in a decrease to pretax earnings of approximately $5 million and $15 million, respectively.

Fuel price risk exists at TECO Transport as a result of periodic purchases of diesel fuel. Haulage and freight agreements often include fuel price adjustments to transfer the risk of market fuel price movements to the customer. TECO Transport also utilizes derivative instruments to reduce the risk of price variability for anticipated fuel purchases in excess of purchases subject to fuel adjustment clauses. As of Dec. 31, 2002, substantially all of the projected fuel price risk for 2003 was removed via price adjustment clauses and a derivative instrument. As a result, a hypothetical 10% change in the average annual market price of fuel would not result in a material impact on pretax earnings as of Dec. 31, 2002 and would have resulted in an impact to pretax earnings of approximately $1 million as of Dec. 31, 2001.

Prior Energy and TECO Gas Services are exposed to variability in natural gas prices as a result of their commitments to purchase from suppliers and deliver physical natural gas to customers. Prior Energy and TECO Gas Services generally enter into fixed price agreements to provide procurement and fuel optimization services to customers. At the same time, derivative instruments and fixed price purchase agreements from suppliers are used to meet customers' requirements. As a result, a hypothetical change in natural gas prices would not have had a material impact for such operations as of Dec. 31, 2002 and 2001.

Prior Energy also provides hedge management and storage solutions for customers. Derivative instruments are carefully used to reduce or eliminate natural gas price risk associated with these activities. As of Dec. 31, 2002 and 2001, a hypothetical 10% change in natural gas prices would not result in a material impact on earnings.

For TPS, results of operations are impacted primarily by changes in the market prices for electricity and natural gas. The profitability of merchant power plants is heavily dependent on the spread between electric and gas prices (spark spread) in the markets they serve.

The spark spread calculates the relative profitability of converting gas into electricity, which exists as the best indicator of a gas-fired plant's profitability. The variable cost of producing electricity is primarily a function of gas commodity prices and the heat rate of the plant. The heat rate is the measure of efficiency in converting the input fuel into electricity. When the conversion price equals the market price, the spark spread would be zero. A power plant operating at this level would theoretically break even with respect to variable costs.

Wholesale power prices are set by the market assuming a cost for the input energy and conversion efficiency, but the fixed costs are not necessarily reflected in the market-observed spark spread. TPS uses derivative instruments to reduce the commodity price risk exposure of the merchant plants. The commodity price risk of each plant is managed on both a portfolio and asset-specific basis. The following table summarizes the impact of a hypothetical 10% change in commodity prices on the fair value of merchant energy derivative contracts at Dec. 31, 2002 and Dec. 31, 2001.

Sensitivity of the Fair Value of Merchant Energy Derivative Contracts

(millions)	*Dec. 31, 2002*	*Dec. 31, 2001*
Change in Fair Value due to a 10%(1):		
Decrease in natural gas prices	$ (16.9)	$(4.0)
Increase in electricity prices	(24.4)	— (2)
Increase in electricity and natural gas prices	(7.5)	— (2)

(1) Reflects the fair value associated with merchant energy derivative contracts only. The change shown for the contracts due to price movements would be more than offset by a change in the fair value of the underlying physical plant assets.

(2) No material impact.

Below is a summary of the percentage of merchant plant output and fuel requirements hedged.

Estimated Merchant Plant Hedging Information

	2003	*2004*
Forecasted plant output and fuel requirements hedged	37%	15%

The following tables summarize the changes in and the fair value balances of energy derivative assets (liabilities) for the years ended Dec. 31, 2001 and 2002.

Changes in Fair Value of Energy Derivatives (millions)

Net fair value of derivatives as of Dec. 31. 2000	$ (19.0)
Net change in unrealized fair value of derivatives	(29.2)
Changes in valuation techniques and assumptions	—
Realized net settlement of derivatives	21.1
Net fair value of derivatives as of Dec. 31, 2001	(27.1)
Net change in unrealized fair value of derivatives	4.7
Changes in valuation techniques and assumptions	—
Realized net settlement of derivatives	30.8
Net fair value of derivatives as of Dec. 31, 2002	$ 8.4

Roll-Forward of Energy Derivatives Net Assets (Liabilities) (millions)

Total energy contracts net assets (liabilities) as of Dec. 31, 2000	$ (19.0)
Change in fair value of net derivative assets (liabilities):	
Recorded in OCI	(1.2)
Recorded in earnings	21.1
Net option premium payments	2.3
Net purchase (sale) of existing contracts	(30.3)
Total energy contracts net assets (liabilities) as of Dec. 31, 2001	(27.1)
Change in fair value of net derivative assets (liabilities):	
Recorded in OCI	4.7
Recorded in earnings	30.8
Net option premium payments	—
Net purchase (sale) of existing contracts	—
Net fair value of derivatives as of Dec. 31, 2002	$ 8.4

When available, the company uses quoted market prices to record the fair value of energy derivative contracts. However, certain energy derivative contracts are not exchange-traded, but rather, are traded in the over-the-counter (OTC) market, through multiple-party on-line trading platforms, or in the bilateral market. TECO Energy uses industry-accepted valuation techniques based on pricing models or matrix pricing for energy derivative contracts when third-party price data is infrequent or not available. Prices, inputs, assumptions and the results of valuation techniques are validated by the Middle Office, independently of the Front Office, on a daily basis. Significant inputs and assumptions used by the company to determine the fair value of energy derivative contracts are: 1) the physical delivery location of the commodity; 2) the correlation between different basis points and/or different commodities; 3) rational, economic behavior in the markets and by counterparties; 4) on- and off-peak curve shapes and correlations; 5) observed market information; and 6) volatility forecasts for and between commodities. Mathematical approaches are applied on a frequent basis to validate and corroborate the results of valuation calculations.

Below is a summary table of sources of fair value, by maturity period, for energy derivative contracts at Dec. 31, 2002.

Maturity and Source of Energy Derivative Contracts Net Assets(Liabilities) at Dec. 31, 2002

Contracts Maturing in	*2003*	*2004*	*Total fair Value*
Source of Fair Value (millions)			
Actively quoted prices	$ 8.7	$ 0.1	$ 8.8
Other external sources(1)	(0.3)	(0.1)	(0.4)
Model Prices(2)	—	—	—
Total	$ 8.4	$ —	$ 8.4

(1) Information from external sources includes information obtained from over-the-counter brokers, industry price services or surveys and multiple-party on-line platforms.

(2) Model prices are used for determining the fair value of energy derivatives where price quotes are infrequent or the market is illiquid. Significant inputs to the models are derived from market observable data and actual historical experience.

For all unrealized energy derivative contracts, the valuation is an estimate based on the best available information. Actual cash flows could be materially different from the estimated value upon maturity.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

TECO ENERGY, INC.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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All other financial statement schedules have been omitted since they are not required, are inapplicable or the required information is presented in the financial statements or notes thereto.

Report of Independent Certified Public Accountants

To the Board of Directors and Shareholders of TECO Energy, Inc.,

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of TECO Energy, Inc. and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the Notes C and B to the Consolidated Financial Statements, the Company adopted the provisions of Financial Accounting Standard 142, *Goodwill and Other Intangible Assets* on January 1, 2002 and Financial Accounting Standard 133, *Accounting for Derivative Instruments and Hedging* on January 1, 2001, respectively.

/s/ PricewaterhouseCoopers LLP
Tampa, Florida
January 22, 2003 except for the information in Note U as to which the date is January 30, 2003.

TECO ENERGY, INC.
Consolidated Balance Sheets

Assets (millions) *Dec. 31,*	*2002*	*2001*
Current assets		
Cash and cash equivalents	$ 411.1	$ 108.5
Restricted cash	1.6	1.6
Receivables, less allowance for uncollectibles of $6.6 million and $7.1 million at Dec. 31, 2002 and 2001, respectively	422.7	358.6
Current notes receivable	235.1	92.7
Inventories, at average cost		
Fuel	113.7	87.3
Materials and supplies	96.1	83.2
Prepayments and other current assets	42.9	44.4
Total current assets	1,323.2	776.3
Property, plant and equipment		
Utility plant in service		
Electric	5,054.4	4,861.1
Gas	746.7	699.4
Construction work in progress	1,556.8	897.0
Other property	857.4	865.1
Property, plant and equipment, at original cost	8,215.3	7,322.6
Accumulated depreciation	(2,751.3)	(2,572.0)
	5,464.0	4,750.6
Property held for sale (net)	—	87.6
Total property, plant and equipment (net)	5,464.0	4,838.2
Other assets		
Other investments	845.3	210.4
Investment in unconsolidated affiliates	149.2	172.9
Goodwill	193.7	165.8
Deferred income taxes	340.2	242.0
Regulatory assets	163.2	198.3
Deferred charges and other assets	159.0	159.5
Total other assets	1,850.6	1,148.9
Total assets	$ 8,637.8	$ 6,763.4

The accompanying notes are an integral part of the consolidated financial statements.

TECO ENERGY, INC.
Consolidated Balance Sheets

Liabilities and Capital (millions) *Dec. 31,*	*2002*	*2001*
Current liabilities		
Long-term debt due within one year	$ 127.1	$ 788.8
Notes payable	360.5	638.9
Accounts payable	377.4	267.4
Current derivative liability	3.9	33.5
Customer deposits	94.6	86.3
Interest accrued	49.8	35.6
Taxes accrued	95.9	71.7
Total current liabilities	1,109.2	1,922.2
Other liabilities		
Deferred income taxes	495.0	498.7
Investment tax credits	27.5	32.3
Regulatory liabilities	98.1	106.2
Deferred credits and other liabilities	322.9	189.9
Long-term debt, less amount due within one year	3,324.3	1,842.5
Total other liabilities	4,267.8	2,669.6
Preferred securities		
Company preferred securities	649.1	200.0
Capital		
Common equity (400 million shares authorized; 175.8 million and 139.6 million outstanding at Dec. 31, 2002 and 2001, respectively)	175.8	139.6
Additional paid in capital	1,094.5	600.7
Retained earnings	1,413.7	1,298.0
Accumulated other comprehensive (loss) income	(41.2)	(22.4)
Common equity	2,642.8	2,015.9
Unearned compensation	(31.1)	(44.3)
Total capital	2,611.7	1,971.6
Total liabilities and capital	$ 8,637.8	$ 6,763.4

The accompanying notes are an integral part of the consolidated financial statements.

TECO ENERGY, INC.
Consolidated Statements of Income

(millions, except per share amounts) *Year Ended Dec. 31,*	*2002*	*2001*	*2000*
Revenues			
Regulated electric and gas (includes franchise fee and gross receipts taxes of $73.8 million in 2002, $71.1 million in 2001 and $59.7 million in 2000)	$ 1,867.0	$ 1,733.0	$ 1,635.9
Unregulated	808.8	755.1	587.2
Total revenues	2,675.8	2,488.1	2,223.1
Expenses			
Regulated operations			
Fuel	312.7	218.2	201.2
Purchased power	202.3	144.7	124.5
Cost of natural gas sold	148.9	186.4	157.0
Other	273.8	250.0	247.1
Other operations	710.4	689.8	546.9
Maintenance	162.1	151.3	140.0
Depreciation	303.4	288.2	258.0
Taxes, other than income	173.2	161.3	147.9
Total expenses	2,286.8	2,089.9	1,822.6
Income from operations	389.0	398.2	400.5
Other income (expense)			
Allowance for other funds used during construction	24.9	6.6	1.6
Other income (expense)	62.4	38.6	13.9
Loss on debt refinancing	(34.1)	—	—
Earnings from equity investments	(6.0)	6.7	7.7
Total other income (expense)	47.2	51.9	23.2
Interest charges			
Interest expense	147.1	164.0	167.6
Distribution on preferred securities	38.9	17.0	—
Allowance for borrowed funds used during construction	(9.6)	(2.6)	(0.7)
Total interest charges	176.4	178.4	166.9
Income before provision for income taxes	259.8	271.7	256.8
Provision (benefit) for income taxes	(38.4)	(2.1)	29.3
Net income from continuing operations	298.2	273.8	227.5
Discontinued operations			
Income from discontinued operations	26.1	21.9	12.6
Income tax benefit	(5.8)	(8.0)	(10.8)
Total discontinued operations	31.9	29.9	23.4
Net income	$ 330.1	$ 303.7	$ 250.9
Average common shares outstanding during year			
– Basic	153.2	134.5	125.9
– Diluted	153.3	135.4	126.3
Earnings per average common share outstanding			
From continuing operations			
– Basic	$ 1.95	$ 2.04	$ 1.81
– Diluted	$ 1.95	$ 2.02	$ 1.79
Net income			
– Basic	$ 2.15	$ 2.26	$ 1.99
– Diluted	$ 2.15	$ 2.24	$ 1.97

The accompanying notes are an integral part of the consolidated financial statements.

TECO ENERGY, INC.
Consolidated Statements of Comprehensive Income

(millions, except per share amounts) *Year Ended Dec. 31,*	*2002*	*2001*	*2000*
Net income	$ 330.1	$ 303.7	$ 250.9
Other comprehensive (loss) income, net of tax			
Foreign currency translation adjustments	(1.2)	—	—
Net unrealized losses on cash flow hedges	(13.2)	(19.2)	—
Minimum pension liability adjustments	(4.4)	0.3	2.0
Other comprehensive (loss) income, net of tax	(18.8)	(18.9)	2.0
Comprehensive income	$ 311.3	$ 284.8	$ 252.9

The accompanying notes are an integral part of the consolidated financial statements.

TECO ENERGY, INC.
Consolidated Statements of Cash Flows

(millions, except per share amounts) *Year Ended Dec. 31,*	*2002*	*2001*	*2000*
Cash flows from operating activities			
Net income	$ 330.1	$ 303.7	$ 250.9
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation	303.4	288.2	258.0
Deferred income taxes	(96.5)	(102.9)	(77.6)
Investment tax credits, net	(4.8)	(4.9)	(4.8)
Allowance for funds used during construction	(34.5)	(9.2)	(2.3)
Amortization of unearned compensation	13.9	9.7	9.2
Gain on asset sales, pretax	(15.1)	—	(13.6)
Equity in earnings of unconsolidated affiliates	15.3	(3.1)	(7.6)
Asset valuation adjustment, pretax	14.1	11.1	14.2
Deferred recovery clause	72.2	(19.0)	(68.7)
Refund to customers	(6.4)	—	(13.2)
Receivables, less allowance for uncollectibles	(64.1)	57.1	(95.5)
Inventories	(39.4)	(22.8)	7.5
Taxes accrued	24.1	16.4	17.6
Interest accrued	14.2	(6.3)	25.5
Accounts payable	98.3	(51.3)	42.6
Other	30.9	36.0	44.1
Cash flows from operating activities	655.7	502.7	386.3
Cash flows from investing activities			
Capital expenditures	(1,065.2)	(965.9)	(688.4)
Allowance for funds used during construction	34.5	9.2	2.3
Purchase of minority interest	(9.9)	—	(52.6)
Purchase of business	—	(315.8)	(31.3)
Net proceeds from sales of assets	103.3	43.2	61.3
Investment in unconsolidated affiliates	(7.6)	27.6	(7.7)
Other non-current investments	(715.6)	95.7	(333.4)
Cash flows from investing activities	(1,660.5)	(1,106.0)	(1,049.8)
Cash flows from financing activities			
Dividends	(215.8)	(184.2)	(167.4)
Common stock	572.6	348.4	18.3
Purchase of treasury stock	—	—	(29.9)
Proceeds from long-term debt	1,758.4	1,255.9	394.9
Repayment of long-term debt	(949.7)	(236.5)	(145.6)
Net increase (decrease) in short-term debt	(278.4)	(570.0)	395.3
Issuance of preferred securities	435.6	—	200.0
Equity contract adjustment payments	(15.3)	—	—
Cash flows from financing activities	1,307.4	613.6	665.6
Net increase in cash and cash equivalents	302.6	10.3	2.1
Cash and cash equivalents at beginning of year	108.5	98.2	96.1
Cash and cash equivalents at end of year	$ 411.1	$ 108.5	$ 98.2
Supplemental disclosure of cash flow information			
Cash paid during the year for			
Interest (net of amounts capitalized)	$ 160.2	$ 178.1	$ 166.7
Income taxes	$ 71.9	$ 52.4	$ 83.9

The accompanying notes are an integral part of the consolidated financial statements.

TECO ENERGY, INC.
Consolidated Statements of Common Equity

(millions)	*Shares(1)*	*Common Stock*	*Additional Paid-in Capital*	*Treasury Stock*	*Retained Earnings*	*Accumulated Other Comprehensive Income (Loss)*	*Unearned Compensation*	*Total Common Equity*
Balance, Dec. 31, 1999	126.7	$ 132.1	$ 368.9	$(114.8)	$1,091.8	$ (5.5)	$ (54.7)	$ 1,417.8
Net income for 2000					250.9			250.9
Other comprehensive income, after tax						2.0		2.0
Common stock issued	1.2	1.2	26.8				(3.9)	24.1
Treasury shares purchased	(1.6)			(29.9)				(29.9)
Cash dividends declared					(167.4)			(167.4)
Amortization of unearned compensation							9.2	9.2
Tax benefits–ESOP dividends and stock options			1.6		1.8			3.4
Performance shares							(3.2)	(3.2)
Balance, Dec. 31, 2000	126.3	133.3	397.3	(144.7)	1,177.1	(3.5)	(52.6)	1,506.9
Net income for 2001					303.7			303.7
Other comprehensive (loss) income, after tax						(18.9)		(18.9)
Common stock issued	13.3	6.3	203.2	144.7			(5.8)	348.4
Cash dividends declared					(184.2)			(184.2)
Amortization of unearned compensation							9.7	9.7
Tax benefits–ESOP dividends and stock options			0.2		1.4			1.6
Performance shares							4.4	4.4
Balance, Dec. 31, 2001	139.6	139.6	600.7	—	1,298.0	(22.4)	(44.3)	1,971.6
Net income for 2002					330.1			330.1
Other comprehensive (loss) income, after tax						(18.8)		(18.8)
Common stock issued	36.2	36.2	544.4				(8.0)	572.6
Cash dividends declared					(215.8)			(215.8)
Amortization of unearned compensation							13.9	13.9
Convertible preferred stock – present value of contract adjustment payments			(53.1)					(53.1)
Tax benefits– ESOP dividends and stock options			2.5		1.4			3.9
Performance shares							7.3	7.3
Balance, Dec. 31, 2002	175.8	$ 175.8	$1,094.5	$ —	$1,413.7	$ (41.2)	$ (31.1)	$ 2,611.7

The accompanying notes are an integral part of the consolidated financial statements.
(1) TECO Energy had 400 million shares of $1 par value common stock authorized in 2002, 2001 and 2000.

A. Summary of Significant Accounting Policies

The significant accounting policies for both utility and diversified operations are as follows:

Principles of Consolidation

The consolidated financial statements include the accounts of TECO Energy, Inc. (TECO Energy or the company) and its wholly-owned subsidiaries.

The equity method of accounting is used to account for investments in partnership arrangements in which TECO Energy or its subsidiary companies do not have majority ownership or exercise control.

The proportional share of expenses, revenues and assets reflecting TECO Coalbed Methane's undivided interest in joint venture property is included in the consolidated financial statements. Results of operations for TECO Coalbed Methane are included in discontinued operations.

All significant intercompany balances and intercompany transactions have been eliminated in consolidation.

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles.

Cash Equivalents

Cash equivalents are highly liquid, high-quality investments purchased with an original maturity of three months or less. The carrying amount of cash equivalents approximated fair market value because of the short maturity of these instruments.

Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates are accounted for using the equity method of accounting. At Dec. 31, 2002, these investments included TECO Propane Ventures' (TPV) 38 percent ownership interest in US Propane, TECO Power Services' (TPS) 24 percent ownership interest in Empresa Eléctrica de Guatemala, S.A. (EEGSA), the Guatemalan electric utility, TPS' 50 percent voting interest in the TECO-Panda Generating Company, L.P. (TPGC), TPS' 50 percent ownership interest in the Hamakua Power Station in Hawaii, TECO Energy Services' 50 percent ownership interest in a chiller plant project, TECO Partners' 65 percent ownership interest in Litestream Technologies, a fiber optic cable project, and TECO Properties' 50 percent ownership interest in four real estate projects (See Note T). At Dec. 31, 2001, the investment in unconsolidated affiliates included the US Propane, EEGSA, TPGC, Hamakua and real estate investments.

Summary financial information for TPGC, a development stage enterprise, as of Dec. 31, 2002 and 2001 is presented in the following table. Results from operations were primarily attributable to financing and general administrative costs associated with construction activities.

Summary Financial Information for TPGC

(millions) Dec. 31,	*2002*	*2001*
Current assets	$ 53.5	$ 102.6
Non-current assets	$ 3,114.7	$ 1,854.1
Current liabilities	$ 596.9	$ 372.8
Non-current liabilities	$ 2,790.6	$ 1,686.6
(millions) For the year ended Dec. 31,	*2002*	*2001*
Net revenues	$ 0.7	$ 0.5
Operating loss	$ (22.0)	$ (5.4)
Loss available for allocation to partners	$ (22.0)	$ (5.4)

Other Investments

Other investments, which include longer-term passive investments, at Dec. 31, 2002 and 2001 were as follows:

Other Investments

(millions) Dec. 31,	*Rate*	*Due Date*	*2002*	*2001*
Notes receivable from:				
Panda Energy(1)	14.00%	1/3/03	$ 137.0	$ 92.7
Energeticke Centrum Kladno	6.00%	10/31/10	1.4	—
Mosbacher Power Partners L.P.	12.00%	5/16/02	—	13.1
Mosbacher Power Partners L.P.	9.00%	8/1/08	13.7	21.1
Mosbacher Power Partners L.P.	12.00%	5/16/02	—	6.2
EEGSA	6.81%(2)	9/11/07	11.1	10.9
TECO-Panda Generating Company, L.P.	7.79%(2)	11/30/04	369.5	37.5
TECO-Panda Generating Company, L.P.	6.58%(2)	11/30/04	426.3	86.7
Municipal Gas Authority of Georgia(3)	1.38%	3/31/03	98.1	—
Investment in Energy Center Kladno Generating (ECKG)(4)	—	—	13.6	18.2
Continuing Investments in Leveraged Leases	—	—	9.4	15.6
Other investments	—	—	0.3	1.1
			1,080.4	303.1
Current notes receivable			235.1	92.7
Other non-current investments			$ 845.3	$ 210.4

(1) On Jan. 3, 2003, this note receivable converted to an ownership interest (see **Note N**).

(2) Current rate at Dec. 31, 2002.

(3) Received payment of this note receivable on Jan. 30, 2003 (see **Note U**).

(4) 13.35% ownership interest in an electric generating power project in the Czech Republic.

These financial investments have no quoted market prices and, accordingly, a reasonable estimate of fair market value could not be made without incurring excessive costs. However, the company believes by reference to stated interest rates and security description, the fair value of these assets would not differ significantly from the carrying value.

Deferred Credits and Other Liabilities

Other deferred credits primarily include the accrued post-retirement benefit liability, the pension liability, deferred gains and the liability for future contract adjustment payments related to the mandatorily convertible equity securities.

Revenue Recognition

TECO Energy recognizes revenues in accordance with the Securities and Exchange Commission's Staff Accounting Bulletin (SAB) 101, *Revenue Recognition in Financial Statements*. The criteria outlined in SAB 101 are that a) there is persuasive evidence that an arrangement exists; b) delivery has occurred or services have been rendered; c) the fee is fixed and determinable; and d) collectibility is reasonably assured. Except as discussed below, TECO Energy and its subsidiaries recognize revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The regulated utilities' (Tampa Electric Company and Peoples Gas System) retail businesses and the prices charged to customers are regulated by the Florida Public Service Commission (FPSC). Tampa Electric's wholesale business is regulated by the Federal Energy Regulatory Commission (FERC). As a result, the regulated utilities qualify for the application of Financial Accounting Standard No. (FAS) 71, *Accounting for the Effects of Certain Types of Regulation*. See **Note D** for a discussion of the applicability of FAS 71 to the company. Revenues for certain transportation services at TECO Transport are recognized using the percentage of completion method, which includes estimates of the distance traveled and/or the time elapsed, compared to the total estimated contract.

Revenues for long-term engineering or construction-type contracts at TECO Energy Services (formerly TECO BGA and BCH Mechanical) are recognized on a percentage of completion basis, which includes estimates of the total costs for the project compared to the estimated work progress already completed for the contract. Each month, revenue recognition and realized profit are adjusted to reflect only the percentage of the estimated costs that have been completed.

Revenues for energy marketing operations at Prior Energy and TECO Gas Services are presented on a net basis in accordance with Emerging Issues Task Force No. (EITF), 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent and EITF 02-3, Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, to reflect the nature of the contractual relationships with customers and suppliers. As a result, costs netted against revenues were $539.4 million, $105.5 million and $28.4 million, respectively, for 2002, 2001 and 2000.

Revenues and Fuel Costs

Revenues include amounts resulting from cost recovery clauses which provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs for Tampa Electric and purchased gas, interstate pipeline capacity and conservation costs for Peoples Gas System (PGS). These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over-recovery or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. Over-recoveries of costs are recorded as deferred credits, and under-recoveries of costs are recorded as deferred charges.

In 1994, Tampa Electric bought out a long-term coal supply contract which would have expired in 2004 for a lump sum payment of $25.5 million. In February 1995, the FPSC authorized the recovery of this buy-out amount plus carrying costs through the Fuel and Purchased Power Cost Recovery Clause over the 10-year period beginning Apr. 1, 1995. In each of the years 2002, 2001 and 2000, $2.7 million of buy-out costs were amortized to expense.

Certain other costs incurred by the regulated utilities are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed.

The regulated utilities accrue base revenues for services rendered but unbilled to provide a closer matching of revenues and expenses.

Tampa Electric's objectives of stabilizing prices from 1996 through 1999 and securing fair earnings opportunities during this period were accomplished through a series of agreements entered into in 1996 with Florida's Office of Public Counsel (OPC) and the Florida Industrial Power Users Group, which were approved by the FPSC. Prior to these agreements, the FPSC approved a plan submitted by Tampa Electric to defer certain 1995 revenues.

In general, under these agreements Tampa Electric was allowed to defer revenues in 1995 and 1996 during the construction of Polk Unit 1 and recognize these revenues in 1997 and 1998 after commercial operation of the unit. Other components of the agreements were a base rate freeze through 1999 and refunds to customers totaling $50 million during the period October 1996 through December 1998 while Tampa Electric was allowed recovery of the capital costs incurred for the Polk Unit 1 project.

In October 2000, the FPSC staff recommended a refund of $6.1 million for the final year of the agreements. OPC objected to certain interest expenses recognized in 1999 that were associated with prior years' tax positions and used to calculate the amount to be refunded. Following a review by the FPSC staff, the FPSC agreed in December 2000 that the original $6.1 million was to be refunded to customers. In February 2001, OPC protested the FPSC's decision. The FPSC held hearings on the issue in August 2001 and upheld its original decision. In January 2002, the OPC filed a motion with the FPSC asking for reconsideration of its decision, alleging the FPSC relied on erroneous information. This was not granted and Tampa Electric made refunds associated with 1999 earnings in 2002. Over the terms of the agreements, the company refunded in total about $69 million.

Since the expiration of the agreements, Tampa Electric is not under a new stipulation. Therefore, its rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue earning within its allowed ROE range.

On June 27, 2002, PGS filed a petition with the FPSC to increase its service rates. The requested rates would have resulted in a $22.6 million annual base revenue increase, reflecting a ROE midpoint of 11.75 percent.

On the date of the FPSC hearing, PGS agreed to a settlement with all parties involved, and a final FPSC order was granted on Dec. 17, 2002. PGS received authorization to increase annual base revenues by $12.05 million. The new rates allow for an ROE range of 10.25 to 12.25 percent with an 11.25 percent midpoint ROE and a capital structure with 57.43 percent equity. The increase went into effect on Jan. 16, 2003.

Purchased Power

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. For the years ended Dec. 31, 2002, 2001 and 2000, Tampa Electric purchased power of $202.3 million, $144.7 million and $124.5 million, respectively. These purchased power costs are recoverable through an FPSC-approved cost recovery clause.

TPS, through its wholly-owned subsidiary, Hardee Power Partners (Hardee), has agreements with Seminole Electric Cooperative and Tampa Electric to supply all the power and capacity of its Hardee Power Station for 20 years beginning in 1993. Under the Seminole agreement, Hardee agreed to supply Seminole with an additional 145 megawatts of capacity during the first 10 years of the contract, which ended on Dec. 31, 2002. This additional capacity was purchased from Tampa Electric's Big Bend Unit 4 for resale to Seminole. To meet other firm commitment contracts, TPS' merchant plants may also purchase power from time to time. Total unregulated purchased power for 2002, 2001 and 2000 was $51.3 million, $34.0 million and $30.1 million, respectively.

Planned Major Maintenance

TECO Energy accounts for planned maintenance projects by expensing the costs as incurred. Planned major maintenance projects that do not increase the overall life or value of the related assets are expensed. When the major maintenance materially increases the life or value of the underlying asset, the cost is capitalized. While normal maintenance outages covering various components of the plants generally occur on at least a yearly basis, major overhauls occur less frequently.

Tampa Electric expenses major maintenance costs as incurred. Concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with FPSC and FERC regulations.

At TPS, each of the San Jose and Alborada plants in Guatemala has a long-term power purchase agreement (PPA) with EEGSA. A major maintenance revenue recovery component is implicit in the capacity payment portion of the PPA for each plant. Accordingly, a portion of each monthly fixed capacity payment is deferred to recognize the portion that reflects recovery of future planned major maintenance expenses. Actual maintenance costs are expensed when incurred with a like amount of deferred recovery revenue recognized at the same time. All other TPS operating projects expense major maintenance costs when incurred.

Depreciation

TECO Energy provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage, of depreciable property over its estimated service life. The provision for utility plant in service, expressed as a percentage of the original cost of depreciable property, was 4.2% for 2002 and 2001, and 4.1% for 2000.

The original cost of utility plant retired or otherwise disposed of and the cost of removal less salvage are charged to accumulated depreciation. The implementation of FAS 143, *Accounting for Asset Retirement Obligations* in 2003 will result in the carrying amount of long-lived assets being increased, and this adjusted capitalized amount depreciated over the useful life of the asset. (See **Note T – Accounting for Asset Retirement Obligations.**)

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

TECO Coal and TECO Transport incur most of TECO Energy's total excise taxes, which are accrued as an expense and reconciled to the actual cash payment of excise taxes. As general expenses, they are not specifically recovered through revenues. Excise taxes paid by the regulated utilities are not material and are expensed when incurred.

The regulated utilities are allowed to recover certain costs incurred from customers through prices approved by the regulatory process. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statement of Income. These amounts totaled $73.8 million, $71.1 million and $59.7 million, respectively, for 2002, 2001 and 2000. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statement of Income in Taxes, other than income. For 2002, 2001 and 2000 these totaled $73.7 million, $71.0 million and $59.8 million, respectively.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2002, 2001 and 2000. Total AFUDC for 2002, 2001 and 2000 was $34.5 million, $9.2 million, and $2.3 million, respectively. The base on which AFUDC is calculated excludes construction work in progress which has been included in rate base.

Interest Capitalized

Interest costs for the construction of non-utility facilities are capitalized and depreciated over the service lives of the related property. TECO Energy capitalized $63.2 million, $23.0 million and $6.5 million of interest costs in 2002, 2001 and 2000, respectively.

Deferred Income Taxes

TECO Energy utilizes the liability method in the measurement of deferred income taxes. Under the liability method, the temporary differences between the financial statement and tax bases of assets and liabilities are reported as deferred taxes measured at current tax rates. Tampa Electric and PGS are regulated, and their books and records reflect approved regulatory treatment, including certain adjustments to accumulated deferred income taxes and the establishment of a corresponding regulatory tax liability reflecting the amount payable to customers through future rates.

Investment Tax Credits

Investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property.

Asset Impairments

Effective Jan. 1, 2002, TECO Energy and its subsidiaries adopted FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which supersedes FAS 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of.* FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a segment of a business.

The company periodically assesses whether there has been a permanent impairment of its long-lived assets and certain intangibles held and used by the company, in accordance with FAS 144, and prior to 2002 with FAS 121.

TECO Energy recorded after-tax charges of $8.8 million, $7.2 million and $9.0 million in 2002, 2001 and 2000, respectively, to adjust asset valuations (see **Note L**).

Reporting on the Costs of Start-up Activities

In 1998, the American Institute of Certified Public Accountants (AICPA) issued Statement of Position (SOP) 98-5, *Reporting on the Costs of Start-up Activities*. It requires costs of start-up activities and organization costs to be expensed as incurred. Start-up activities are broadly defined as those one-time activities related to events such as opening a new facility, conducting business in a new territory and organizing a new entity. Some costs, such as the costs of acquiring or constructing long-lived assets and bringing them into service, are not subject to SOP 98-5. Start-up costs, as defined by SOP 98-5, are expensed as incurred.

Foreign Operations

The functional currency of the company's foreign investments is primarily the U.S. dollar. Transactions in the local currency are remeasured to the U.S. dollar for financial reporting purposes. The aggregate remeasurement gains or losses included in net income in 2002, 2001 and 2000 were not significant.

The investments are generally protected from any significant currency gains or losses by the terms of the power sales agreements and other related contracts, in which payments are defined in U.S. dollars.

Restrictions on Dividend Payments and Transfer of Assets

Dividends on TECO Energy's common stock are at the discretion of its Board of Directors. Should TECO Energy exercise its right to defer payments on its subordinated notes issued in connection with the issuance of trust preferred securities by TECO Capital Trust I or TECO Capital Trust II, TECO Energy would be prohibited from paying cash dividends on its common stock until the unpaid distributions on the subordinated notes are made. TECO Energy has not exercised that right. In addition, TECO Energy's $380 million note indenture contains covenants which would apply only if either 1) notes are rated below BBB- by Standard & Poor's (S&P) or below Baa3 by Moody's or 2) notes are rated below Special Ratings Trigger (minimum of BBB- by S&P and Baa2 by Moody's or BBB by S&P and Baa3 by Moody's) if TECO Energy construction undertakings for the TECO/Panda projects are not substantially discharged. These covenants include limitation on restricted payments, limitations on certain liens and limitation on indebtedness.

The primary sources of funds to pay dividends on TECO Energy's common stock are dividends from its operating companies. Tampa Electric's first mortgage bond indenture and certain long-term debt at PGS contain restrictions that limit the payment of dividends on the common stock of Tampa Electric. Tampa Electric's first mortgage bond indenture does not limit loans or advances. In addition, TECO Diversified, Inc., a wholly-owned subsidiary of TECO Energy and the holding company for TECO Transport, TECO Coal, TECO Coalbed Methane and TECO Solutions, has a guarantee related to a coal supply agreement that limits the payment of dividends to its common shareholder, but does not limit loans or advances. As of Dec. 31, 2002 and 2001, the balances restricted as to transfers to the parent company in the form of loans, advances or cash dividends were less than 25 percent of consolidated common equity. (See **Note R.**)

Lease Accounting Amendment

In April 2002, the Financial Accounting Standards Board (FASB) issued FAS 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. In addition to rescinding the aforementioned statements, FAS 145 amends FAS 13, *Accounting for Leases*, to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The implementation of FAS 145 has not had a significant impact on the company's results.

Reclassifications

Certain prior year amounts were reclassified to conform with current year presentation.

B. Derivatives and Hedging

From time to time, TECO Energy enters into futures, forwards, swaps and option contracts for the following purposes:

- To hedge the selling price for the physical production of natural gas at TECO Coalbed Methane;
- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric, PGS and Prior Energy;
- To limit the exposure to interest rate fluctuations on debt issuances at TECO Energy and its other affiliates;
- To limit the exposure to electricity, natural gas and fuel oil price fluctuations related to the operations of natural gas-fired and fuel oil-fired power plants at TPS; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport.

TECO Energy uses derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers. For unregulated operations, the company uses derivative instruments primarily to optimize the value of physical assets, including generation capacity, natural gas production, and natural gas delivery.

The risk management policies adopted by TECO Energy provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operating companies.

Effective Jan. 1, 2001, the company adopted FAS 133, *Accounting for Derivative Instruments and Hedging Activities*. The new standard requires companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of other comprehensive income (OCI) or in net income, depending on the designation of those instruments. The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or the loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of its reclassification. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the amount paid or received on the underlying physical transaction. Additionally, amounts defined in OCI related to an effective designated cash flow hedge must be reclassified to current earnings if the anticipated hedged transaction is no longer probable of occurring. At adoption, the company had derivatives in place at TECO Coalbed Methane that qualified for cash flow hedge accounting treatment under FAS 133, and recorded an opening swap liability of $19.0 million and an after-tax reduction to OCI of $12.6 million.

At Dec. 31, 2002, the company had derivative assets totaling $12.5 million and liabilities totaling $4.1 million. At Dec. 31, 2001, the company had derivative assets totaling $9.9 million and liabilities totaling $37.0 million. At Dec. 31, 2002 and 2001, accumulated OCI included $32.4 million and $19.2 million, respectively, of unrealized after-tax losses, representing the fair value of cash flow hedges whose transactions will occur in the future, including an unrealized loss of $37.3 million and $11.2 million for 2002 and 2001, respectively, on an equity investee's interest rate swap and other fuel hedges designated as cash flow hedges. Amounts recorded in OCI reflect the value of derivative instruments designated as hedges, based on market prices as of the balance sheet date. These amounts are expected to fluctuate with movements in market prices and may or may not be realized as a loss upon future reclassification from OCI.

As of Dec. 31, 2002, TECO Energy had transactions in place to hedge commodity price risk and interest rate risk that qualify for cash flow hedge accounting treatment under FAS 133. During 2002, TECO Energy reclassified net pretax losses of $29.0 million to earnings for cash flow hedges, compared to pretax losses of $19.7 million in 2001. Amounts reclassified from OCI were primarily related to cash flow hedges of physical purchases of natural gas and physical sales of electricity. For these types of hedge relationships, the loss on the derivative, reclassified from OCI to earnings, is offset by the reduced expense arising from lower prices paid for spot purchases of natural gas. Conversely, reclassification of a gain from OCI to earnings is offset by the increased cost of spot purchases of natural gas.

As a result of 1) the suspension of construction on the Dell and McAdams power plants at TPS, and 2) the maintenance activity on the Frontera Power Station at TPS in early 2003, the company discontinued hedge accounting for purchases of natural gas and sales of electricity which are no longer anticipated to take place within two months of the originally designated time period for delivery. The discontinuation of hedge accounting resulted in a reclassification of a pretax gain of $0.2 million from OCI to earnings, reflecting the fair value of the related derivatives as of the discontinuation date. This gain is included in the net pretax loss reported above for 2002. Gains and losses on these derivative instruments subsequent to the discontinuation of hedge accounting treatment were recorded in earnings.

Based on the fair values at Dec. 31, 2002, pretax gains of $7.1 million are expected to be reversed from OCI to the Consolidated Statement of Income within the next twelve months. However, these gains and other future reclassifications from OCI, will fluctuate with movements in the underlying market price of the derivative instruments. Excluding interest rate risk exposures, the company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2004.

At Dec. 31, 2002 and 2001, TECO Energy had transactions in place to hedge gas storage inventory that qualify for fair value hedge accounting treatment under FAS 133. During 2002, the company recognized pretax gains of $0.7 million compared to $0.1 million in 2001. For the years ended Dec. 31, 2002 and 2001, the company also recognized pretax losses of $2.4 million and $1.5 million, respectively, relating to derivatives that do not qualify for cash flow or fair value hedge treatment that are marked to market.

C. Goodwill and Other Intangible Assets

Effective Jan. 1, 2002, TECO Energy and its subsidiaries adopted FAS 141, *Business Combinations*, and FAS 142, *Goodwill and Other Intangible Assets*. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting. With the adoption of FAS 142, goodwill is no longer subject to amortization. Rather, goodwill is subject to an annual assessment for impairment by applying a fair-value-based test. Under the new rules, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented, or exchanged, regardless of the acquiror's intent to do so. These intangible assets are required to be amortized over their useful lives.

The amount of goodwill included on the consolidated balance sheets at Dec. 31, 2002 and 2001 was $193.7 million and $165.8 million, respectively, net of accumulated amortization of $9.5 million. Amortization of goodwill ceased effective Jan. 1, 2002 with the adoption of FAS 142, resulting in savings of approximately $5 million of annual amortization expense. Results for 2001 and 2000 included $4.8 million and $2.7 million of goodwill amortization expense, respectively.

The amount of intangible assets included in deferred charges and other assets on the Consolidated Balance Sheet at Dec. 31, 2002 was $11.1 million, which is net of accumulated amortization of $35.4 million, and at Dec. 31, 2001 was $28.5 million, which was net of accumulated amortization of $12.3 million. Amortizable intangible assets of $4.4 million at Dec. 31, 2002 represent customer backlog and supply agreements related to the Prior Energy acquisition in November 2001. The company is amortizing these intangibles over the current year period. Amortization expense of $23.1 million and $12.3 million, respectively, was recorded in 2002 and 2001. There were no intangible assets at Dec. 31, 2000. Unamortizable intangible assets of $6.7 million at Dec. 31, 2002 represent licenses held by TPS related to gasification technologies.

TECO Energy continues to review recorded goodwill and intangibles as required under FAS 142, and has not identified any impairments. The reconciliation of reported net income and earnings per share to adjusted net income excluding goodwill amortization expense for 2002, 2001 and 2000 follows:

Pro Forma Effect of FAS 142 Adoption

(millions, except per share amounts)	*2002*	*2001*	*2000*
Net income:			
As reported	$ 330.1	$ 303.7	$ 250.9
Add: Goodwill amortized, net of tax	—	3.7	2.4
Adjusted net income	$ 330.1	$ 307.4	$ 253.3
Earnings per share – basic:			
As reported	$ 2.15	$ 2.26	$ 1.99
Add: Goodwill amortized, net of tax	—	.03	.02
Adjusted basic earnings per share	$ 2.15	$ 2.29	$ 2.01
Earnings per share – diluted:			
As reported	$ 2.15	$ 2.24	$ 1.97
Add: Goodwill amortized, net of tax	—	.03	.02
Adjusted diluted earnings per share	$ 2.15	$ 2.27	$ 1.99

D. Regulatory Assets and Liabilities

Tampa Electric and PGS maintain their accounts in accordance with recognized policies of the FPSC. In addition, Tampa Electric maintains its accounts in accordance with recognized policies prescribed or permitted by the FERC. These policies conform with generally accepted accounting principles in all material respects.

Tampa Electric and PGS apply the accounting treatment permitted by FAS 71, *Accounting for the Effects of Certain Types of Regulation*. Areas of applicability include: deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel; purchased power, conservation and environmental costs; and deferral of costs as regulatory assets when cost recovery is ordered over a period longer than a fiscal year, to the period that the regulatory agency recognizes them. Details of the regulatory assets and liabilities as of Dec. 31, 2002 and 2001 are presented in the following table:

Regulatory Assets and Liabilities

(millions) Dec. 31,	*2002*	*2001*
Regulatory assets:		
Regulatory tax asset (1)	$ 54.9	$ 41.3
Other:		
Cost recovery clauses	34.7	105.2
Coal contract buy-out (2)	5.4	8.1
Unamortized refinancing costs (3)	35.9	13.7
Environmental remediation	20.3	22.3
Competitive rate adjustment	7.4	5.9
Other	4.6	1.8
	108.3	157.0
Total regulatory assets	$ 163.2	$ 198.3
Regulatory liabilities:		
Regulatory tax liability (1)	$ 36.6	$ 43.1
Other:		
Deferred allowance auction credits	2.1	1.1
Cost recovery clauses	2.2	0.5
Revenue refund	—	6.3
Environmental remediation	20.3	22.3
Transmission and distribution storm reserve	36.0	32.0
Deferred gain on property sales (4)	0.9	0.9
	61.5	63.1
Total regulatory liabilities	$ 98.1	$ 106.2

(1) Related primarily to plant life. Includes excess deferred taxes of $20.9 million and $24.6 million as of Dec. 31, 2002 and 2001, respectively.

(2) Amortized over a 10-year period ending December 2004.

(3) Unamortized refinancing costs:

Related to debt transactions as follows (millions):	Amortized until:
$ 155.0	2003
$ 51.6	2005
$ 22.1	2007
$ 25.0	2011
$ 50.0	2011
$ 150.0	2012
$ 150.0	2012
$ 85.9	2014
$ 25.0	2021
$ 100.0	2022

(4) Amortized over a 5-year period with various ending dates.

E. Long-Term Debt *(millions)* *Dec. 31,*	*Due*	*2002*	*2001*
TECO Energy			
Notes: 5.31% for 2001 (1)	2002	$ —	$ 200.0
Notes: 7.2% (effective rate of 7.38%) (2)	2011	600.0	600.0
Floating rate notes: 5.2% for 2001 (1)	2002	—	400.0
Notes: 6.125% (effective rate of 6.31%) (2)	2007	300.0	—
Notes: 7% (effective rate of 7.08%) (2)	2012	400.0	—
Notes: 10.5% (effective rate of 12.29%) (2)	2007	380.0	—
		1,680.0	1,200.0

E. Long-Term Debt-continued *(millions)* *Dec. 31,*	*Due*	*2002*	*2001*
Tampa Electric			
First mortgage bonds (issuable in series):			
7.75% (effective rate of 7.96%)	2022	75.0	75.0
6.125% (effective rate of 6.61%)	2003	75.0	75.0
Installment contracts payable (3):			
5.75%	2002	—	22.5
7.875% Refunding bonds (4)	2002	—	25.0
8% Refunding bonds(4)	2002	—	100.0
6.25% Refunding bonds (effective rate of 6.81%) (5)	2034	86.0	86.0
5.85% (effective rate of 5.88%)	2030	75.0	75.0
5.1% Refunding bonds (effective rate of 5.78%) (6)	2013	60.7	—
5.5% Refunding bonds (effective rate of 6.35%) (6)	2023	86.4	—
4% for 2002 (effective rate of 4.21%) and variable rate of 1.45% for 2001 (1) (7)	2025	51.6	51.6
4% for 2002 (effective rate of 4.16%) and variable rate of 1.47% for 2001 (1) (7)	2018	54.2	54.2
4.25% for 2002 (effective rate of 4.43%) and variable rate of 1.52% for 2001 (1) (7)	2020	20.0	20.0
Notes: 5.86% (1)	2002	—	100.0
Notes: 6.875% (effective rate of 6.98%) (2)	2012	210.0	210.0
Notes: 6.375% (effective rate of 7.34%) (2)	2012	330.0	—
Notes: 5.375% (effective rate of 5.58%) (2)	2007	125.0	—
		1,248.9	894.3
Peoples Gas System			
Senior Notes (8)			
10.35%	2007	4.2	5.0
10.33%	2008	5.6	6.4
10.3%	2009	7.2	7.8
9.93%	2010	7.4	8.0
8%	2012	25.4	27.5
Notes: 5.86% (1)	2002	—	50.0
Notes: 6.875% (effective rate of 6.98%) (2)	2012	40.0	40.0
Notes: 6.375% (effective rate of 7.34%) (2)	2012	70.0	—
Notes: 5.375% (effective rate of 5.58%) (2)	2007	25.0	—
		184.8	144.7
Diversified companies			
Dock and wharf bonds, 5% (3)	2007	110.6	110.6
Non-recourse secured facility notes, Series A: 7.8%	2003-2012	111.0	118.5
Non-recourse secured facility notes: 9.875%	2002	—	17.1
Non-recourse secured facility notes, variable rate: 4.63% for 2002 and 5.43% for 2001 (1)	2003-2007	50.1	57.9
Non-recourse secured facility notes: 10.1%	2003-2009	16.4	16.9
Non-recourse secured facility notes: 9.629%	2003-2010	24.8	28.0
Non-recourse secured facility note, variable rate: 6.88% for 2002 (1)	2004-2009	16.0	—
Non-recourse secured facility note, variable rate: 5% for 2002 (1)	2004-2009	14.0	—
Capital lease: implicit rate of 8.5%	2003	25.3	27.6
		368.2	376.6
TECO Finance			
Medium-term notes payable: 7.54% for 2001 (1)	2002	—	9.0
Unamortized debt premium (discount), net		(30.5)	6.7
		3,451.4	2,631.3
Less amount due within one year (9)		127.1	788.8
Total long-term debt		$ 3,324.3	$1,842.5

(1) Composite year-end interest rate.
(2) These notes are subject to redemption in whole or in part, at any time, at the option of the company.
(3) Tax-exempt securities.
(4) Proceeds of these bonds were used to refund bonds with interest rates of 11.625%–12.625%. For accounting purposes, interest expense has been recorded using blended rates of 8.28%–8.66% on the original and refunding bonds, consistent with regulatory treatment.
(5) Proceeds of these bonds were used to refund bonds with an interest rate of 9.9% in February 1995. For accounting purposes, interest expense has been recorded using a blended rate of 6.52% on the original and refunding bonds, consistent with regulatory treatment.
(6) Proceeds of these bonds were used to refund bonds with interest rates of 5.75%–8%.
(7) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002.
(8) These long-term debt agreements contain various restrictive covenants, including provisions related to interest coverage, maximum levels of debt to total capitalization and limitations on dividends.
(9) Of the amount due in 2003, $0.8 million may be satisfied by the substitution of property in lieu of cash payments.

TECO Transport entered into a capital lease agreement with Midwest Marine Management Company in March 1998 for the charter of additional capacity. This lease covers 110 river barges and three towboats, classified as property, plant and equipment on the balance sheet; the corresponding $35 million five-year lease commitment was recorded as long-term debt on the balance sheet. The future minimum lease payments under the capitalized lease as of Dec. 31, 2002 are $25.8 million. This represents $25.3 million present value of net minimum lease payments and $0.5 million of interest, all due in 2003.

Substantially all of the property, plant and equipment of Tampa Electric is pledged as collateral to secure its first mortgage bonds and certain pollution control equipment is pledged to secure certain installment contracts payable. TECO Energy's maturities and annual sinking fund requirements of long-term debt for the years 2004, 2005, 2006 and 2007 are $31.9 million, $35.7 million, $38.0 million and $975.2 million, respectively. Of these amounts $0.8 million per year for 2004 through 2007 may be satisfied by the substitution of property in lieu of cash payments.

At Dec. 31, 2002, total long-term debt had a carrying amount of $3,324.3 million and an estimated fair market value of $3,288.7 million. The estimated fair market value of long-term debt was based on quoted market prices for the same or similar issues, on the current rates offered for debt of the same remaining maturities, or for long-term debt issues with variable rates that approximate market rates, at carrying amounts. The carrying amount of long-term debt due within one year approximated fair market value because of the short maturity of these instruments.

F. Short-Term Debt

At Dec. 31, 2002 and 2001, notes payable consisted of the following:

Notes Payable

(millions) Dec. 31,	*2002*	*2001*
Credit facilities outstanding	$ 350.0	$ —
Commercial paper	10.5	638.9
Total notes payable	$ 360.5	$ 638.9

The weighted average interest rate on outstanding notes payable at Dec. 31, 2002 and 2001 was 1.88% and 1.99%, respectively.

At Dec. 31, 2002 and 2001, the following credit facilities and related borrowings existed:

Credit Facilities

(millions)	Dec. 31, 2002 Credit Facilities	Dec. 31, 2002 Borrowings Outstanding	Dec. 31, 2002 Letters of Credit Outstanding	Dec. 31, 2001 Credit Facilities	Dec. 31, 2001 Borrowings Outstanding	Dec. 31, 2001 Letters of Credit Outstanding
Tampa Electric						
1-year facility	$ 300.0	$ —	$ —	$ 300.0	$ —	$ —
TECO Energy						
1-year facility	350.0	350.0	—	350.0	—	—
TECO Energy						
3-year facility	350.0	—	179.8	350.0	—	—
Totals	$ 1,000.0	$ 350.0	$ 179.8	$ 1,000.0	$ —	$ —

Tampa Electric's credit facility has a maturity date of November 2003. TECO Energy's one-year facility also matures in November 2003 and its 3-year facility matures in November 2004. These credit facilities require facility fees ranging from 15 to 20 basis points. Within its 3-year facility, TECO Energy has $250 million of capacity to issue letters of credit. These letters of credit require issuance fees of 12.5 basis points and lenders fees of 55 basis points.

In order to utilize the credit facilities, TECO Energy's debt-to-capital ratio, as defined in the credit agreement, may not exceed 65.0% at the end of the applicable quarter. At Dec. 31, 2002, TECO Energy's debt-to-capital ratio was 55.9%. Under Tampa Electric's credit facility, Tampa Electric's debt-to-capital ratio may not exceed 60.0% measured at the end of the applicable quarter and its earnings before interest, taxes, depreciation and amortization (EBITDA) to interest coverage ratio must be at least 2.5 times. At Dec. 31, 2002, Tampa Electric's debt-to-capital ratio was 43.9% and its EBITDA to interest coverage ratio was 7.8 times. (See **Note R.**)

G. Preferred Securities

In November 2000, TECO Energy established TECO Capital Trust I (the Trust) for the sole purpose of issuing Trust Preferred Securities (TRuPS) and using the proceeds to purchase company preferred securities from TECO Funding Company I, LLC (TECO Funding). On Dec. 20, 2000, the Trust issued 8 million shares of $25 par, 8.5% TRuPS, due 2041, with an aggregate liquidation value of $200 million. Currently, all 8 million shares of the TRuPS are outstanding. Each TRuPS represents an undivided beneficial interest in the assets of the Trust. The Trust used the proceeds from the sale of the TRuPS to purchase a corresponding amount of company preferred securities of TECO Funding. TECO Funding used the proceeds from the sale of the company preferred securities to the Trust of $200 million and the sale of $6.2 million of its common securities to TECO Energy, to purchase $206.2 million of 8.5% junior subordinated notes of TECO Energy, due 2041. The junior subordinated notes are the sole assets of TECO Funding and the company preferred securities are the sole assets of the Trust. TECO Energy's proceeds from the sale of the junior subordinated notes were used to reduce the commercial paper balances of TECO Finance and for general corporate purposes. TECO Energy has guaranteed the payments to the holders of the company preferred securities and indirectly, the payments to the holders of the TRuPS, as a result of their beneficial interest in the company preferred securities. Distributions are payable quarterly in arrears on January 31, April 30, July 31, and October 31 of each year. Distributions were $17.0 million and $14.6 million in 2002 and 2001, respectively. No distributions were made in 2000.

The junior subordinated notes may be redeemed at the option of TECO Energy at any time on or after Dec. 20, 2005 at 100% of their principal amount plus accrued interest through the redemption date. If TECO Energy redeems the junior subordinated notes in full before their maturity date, then TECO Funding is required to redeem the company preferred securities and common securities, in accordance with their terms. If TECO Energy redeems the junior subordinated notes in part but not in full before their maturity date, then TECO Funding will redeem the company preferred securities in full prior to any payment being made on the common securities. Upon any liquidation of the company preferred securities, holders of the TRuPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends through the date of redemption.

In January 2002, TECO Energy sold 17.965 million mandatorily convertible equity security units in the form of 9.5% equity units at $25 per unit resulting in $436 million of net proceeds. Each equity unit consisted of $25 in principal amount of a trust preferred security of TECO Capital Trust II, a Delaware business trust formed for the purpose of issuing these securities, with a stated liquidation amount of $25 and a contract to purchase shares of common stock of TECO Energy in January 2005 at a price per share of between $26.29 and $30.10 based on the market price at that time. The equity units represent an indirect interest in a corresponding amount of TECO Energy 5.11% subordinated debt. The holders of these contracts are entitled to quarterly contract adjustment payments at the annualized rate of 4.39% of the stated amount of $25 per year through and including Jan. 15, 2005. The net proceeds from the offering were used to repay short-term debt and for general corporate purposes.

H. Preferred Stock

Preferred stock of TECO Energy – $1 par 10 million shares authorized, none outstanding.
Preference stock of Tampa Electric – no par 2.5 million shares authorized, none outstanding.
Preferred stock of Tampa Electric – no par 2.5 million shares authorized, none outstanding.
Preferred stock of Tampa Electric – $100 par value 1.5 million shares authorized, none outstanding.

I. Common Stock

Stock-Based Compensation

In April 1996, the shareholders approved the 1996 Equity Incentive Plan (the "1996 Plan"). The 1996 Plan superseded the 1990 Equity Incentive Plan (the "1990 Plan"), and no additional grants will be made under the 1990 Plan. The rights of the holders of outstanding options under the 1990 Plan were not affected. The purpose of the 1996 Plan is to attract and retain key employees of the company, to provide an incentive for them to achieve long-range performance goals and to enable them to participate in the long-term growth of the company. The 1996 Plan amended the 1990 Plan to increase the number of shares of common stock subject to grants by 3,750,000 shares, expand the types of awards available to be granted and specify a limit on the maximum number of shares with respect to which stock options and stock appreciation rights may be made to any participant under the plan. Under the 1996 Plan, the Compensation Committee of the Board of Directors may award stock grants, stock options and/or stock equivalents to officers and key employees of TECO Energy and its subsidiaries.

The Compensation Committee has discretion to determine the terms and conditions of each award, which may be subject to conditions relating to continued employment, restrictions on transfer or performance criteria.

In 2002, under the 1996 Plan, 1,769,880 stock options were granted, with a weighted average option price of $27.97 and a maximum term of 10 years. In addition, 255,242 shares of restricted stock were awarded, each with a weighted average fair value of $27.97. Compensation expense recognized for stock grants awarded under the 1996 Plan was $1.7 million, $2.8 million and $4.6 million in 2002, 2001 and 2000, respectively. Half the stock grants awarded in 2002 and all of the stock grants awarded in 2001 and 2000 are performance shares, restricted subject to meeting specified total shareholder return goals, vesting in three years with final payout ranging from zero to 200% of the original grant. Adjustments are made to reflect contingent shares which could be issuable based on current period results. The consolidated balance sheets at Dec. 31, 2002 and 2001 reflected a ($6.3) million and a $1.1 million liability respectively, classified as other deferred credits, for these contingent shares. The remaining stock grants are restricted subject generally to continued employment, with the 2002 stock grants vesting in three years, the 1998 stock grants vesting in five years, and the 1997 and 1996 stock grants vesting at normal retirement age.

In April 2001, the shareholders approved an amendment to the 1996 Plan to increase the number of shares of common stock subject to grants by 6.3 million.

Stock option transactions during the last three years under the 1996 Plan and the 1990 Plan (collectively referred to as the "Equity Plans") are summarized as follows:

Stock Options - Equity Plans

	Option Shares (thousands)	*Weighted Avg. Option Price*
Balance at Dec. 31, 1999	3,827	$ 22.64
Granted	1,264	$ 21.33
Exercised	(488)	$ 20.15
Cancelled	(44)	$ 23.61
Balance at Dec. 31, 2000	4,559	$ 22.54
Granted	1,268	$ 31.39
Exercised	(605)	$ 21.53
Cancelled	(32)	$ 26.88
Balance at Dec. 31, 2001	5,190	$ 24.79
Granted	1,770	$ 27.97
Exercised	(487)	$ 20.93
Cancelled	(57)	$ 27.03
Balance at Dec. 31, 2002	6,416	$ 25.94
Exercisable at Dec. 31, 2002	0	—
Available for future grant at Dec. 31, 2002	4,288	

As of Dec. 31, 2002, the 6.4 million options outstanding under the Equity Plans are summarized below.

Stock Options Outstanding at Dec. 31, 2002

Option Shares (thousands)	*Range of Option Prices*	*Weighted Avg. Option Price*	*Weighted Avg. Remaining Contractual Life*
2,099	$19.44-$22.48	$21.16	6 Years
705	$23.55-$25.97	$24.07	4 Years
3,612	$27.56-$31.58	$29.08	8 Years

In April 1997, the Shareholders approved the 1997 Director Equity Plan (the "1997 Plan"), as an amendment and restatement of the 1991 Director Stock Option Plan (the "1991 Plan"). The 1997 Plan supersedes the 1991 Plan, and no additional grants will be made under the 1991 Plan. The rights of the holders of outstanding options under the 1991 Plan will not be affected. The purpose of the 1997 Plan is to attract and retain highly qualified non-employee directors of the company and to encourage them to own shares of TECO Energy common stock. The 1997 Plan is administered by the Board of Directors. The 1997 Plan amended the 1991 Plan to increase the number of shares of common stock subject to grants by 250,000 shares, expanded the types of awards available to be granted and replaced the current fixed formula grant by giving the Board discretionary authority to determine the amount and timing of awards under the Plan.

In 2002, 27,500 options were granted, with a weighted average option price of $27.97. Transactions during the last three years under the 1997 Plan are summarized as follows:

Stock Options - Director Equity Plans

	Option Shares (thousands)	*Weighted Avg. Option Price*
Balance at Dec. 31, 1999	273	$21.25
Granted	30	$23.49
Exercised	(33)	$18.57
Cancelled	(12)	$25.15
Balance at Dec. 31, 2000	258	$21.68
Granted	35	$31.26
Exercised	(91)	$19.12
Cancelled	—	—
Balance at Dec. 31, 2001	202	$24.49
Granted	28	$27.97
Exercised	(22)	$20.95
Cancelled	(2)	$27.56
Balance at Dec. 31, 2002	206	$25.31
Exercisable at Dec. 31, 2002	0	—
Available for future grant at Dec. 31, 2002	270	

As of Dec. 31, 2002, the 206,000 options outstanding under the 1997 Plan with option prices of $19.81-$31.575, had a weighted average option price of $25.31 and a weighted average remaining contractual life of six years.

TECO Energy has adopted the disclosure-only provisions of FAS 123, *Accounting for Stock-Based Compensation*, but applies Accounting Principles Board Opinion No. 25 and related interpretations in accounting for its plans. Therefore, since stock options are granted with an option price greater than or equal to the fair value on date of grant, no compensation expense has been recognized for stock options granted under the 1996 Plan and the 1997 Plan. If the company had elected to recognize compensation expense for stock options based on the fair value at grant date, consistent with the method prescribed by FAS 123, net income and earnings per share would have been reduced to the pro forma amounts as follows. These pro forma amounts were determined using the Black-Scholes valuation model with weighted average assumptions as follows.

Pro Forma Disclosure — Stock Options

	2002	2001	2000
Net income from continuing operations (millions)			
As reported	$ 298.2	$ 273.8	$ 227.5
Pro forma expense(1)	5.1	4.3	2.6
Pro forma	$ 293.1	$ 269.5	$ 224.9
Net income (millions)			
As reported	$ 330.1	$ 303.7	$ 250.9
Pro forma expense(1)	5.1	4.3	2.6
Pro forma	$ 325.0	$ 299.4	$ 248.3
Net income from continuing operations– EPS basic			
As reported	$ 1.95	$ 2.04	$ 1.81
Pro forma	$ 1.91	$ 2.00	$ 1.79
Net income – EPS basic			
As reported	$ 2.15	$ 2.26	$ 1.99
Pro forma	$ 2.12	$ 2.23	$ 1.97
Assumptions			
Risk-free interest rate	5.09%	4.86%	6.24%
Expected lives (in years)	6	6	6
Expected stock volatility	25.92%	27.45%	22.93%
Dividend yield	5.47%	5.46%	5.15%

(1) Compensation expense for stock options determined under fair-value based method, after-tax.

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan (DRP). TECO Energy raised $11.2 million, $8.6 million and $8.1 million of common equity from this plan in 2002, 2001 and 2000, respectively.

Common Stock and Treasury Stock

In September 1999, TECO Energy began a program to repurchase up to $150 million of its outstanding common stock. Shares acquired constituted treasury shares. In 1999 and 2000, the company acquired 7.0 million shares of its outstanding common stock at a cost of $144.7 million, or an average per share price of $20.55. The company's share repurchase program favorably impacted earnings in 2000 by approximately $0.06 per share.

On Mar. 12, 2001, the company completed a public offering of 8.625 million common shares at $27.75 per share, 7.0 million shares of which were reissued from treasury shares.

On Oct. 4, 2001, S&P announced the inclusion of TECO Energy shares in the S&P 500 Index effective as of the market close on Oct. 9, 2001. On Oct. 12, 2001, TECO Energy issued 3.5 million additional common shares at $26.72 per share. The sales of the common shares resulted in total net proceeds to TECO Energy of $325.5 million in 2001, which were used to fund capital expenditures, for working capital requirements, general corporate purposes and to repay short-term debt.

In June 2002, the company completed a public offering of 15.525 million common shares at a price to the public of $23.00 per share. The sale of these shares resulted in net proceeds to the company of approximately $346.4 million, which were used to repay short-term debt and for general corporate purposes. In October 2002, the company issued 19.385 million common shares at a price to the public of $11.00 per share. The sale of these shares resulted in net proceeds to the company of approximately $206.8 million, which were used to repay short-term debt.

Shareholder Rights Plan

In accordance with the company's Shareholder Rights Plan, a Right to purchase one additional share of the company's common stock at a price of $90 per share is attached to each outstanding share of the company's common stock. The Rights expire in May 2009, subject to extension. The Rights will become exercisable 10 business days after a person acquires 10 percent or more of the company's outstanding common stock or commences a tender offer that would result in such person owning 10 percent or more of such stock. If any person acquires 10 percent or more of the outstanding common stock, the rights of holders, other than the acquiring person, become rights to buy shares of common stock of the company (or of the acquiring company if the company is involved in a merger or other business combination and is not the surviving corporation) having a market value of twice the exercise price of each Right.

The company may redeem the Rights at a nominal price per Right until 10 business days after a person acquires 10 percent or more of the outstanding common stock.

Employee Stock Ownership Plan

Effective Jan. 1, 1990, TECO Energy amended the TECO Energy Group Retirement Savings Plan, a tax-qualified benefit plan available to substantially all employees, to include an employee stock ownership plan (ESOP). During 1990, the ESOP purchased 7 million shares of TECO Energy common stock on the open market for $100 million. The share purchase was financed through a loan from TECO Energy to the ESOP. This loan is at a fixed interest rate of 9.3% and will be repaid from dividends on ESOP shares and from TECO Energy's contributions to the ESOP.

TECO Energy's contributions to the ESOP were $13.6 million, $5.6 million and $6.8 million in 2002, 2001 and 2000, respectively. TECO Energy's annual contribution equals the interest accrued on the loan during the year plus additional principal payments needed to meet the matching allocation requirements under the plan, less dividends received on the ESOP shares. The components of net ESOP expense recognized for the past three years are as follows:

ESOP Expense

(millions)	*2002*	*2001*	*2000*
Interest expense	$ 4.3	$ 5.2	$ 6.0
Compensation expense	12.2	7.4	6.9
Dividends	(8.5)	(8.5)	(8.5)
Net ESOP expense	$ 8.0	$ 4.1	$ 4.4

Compensation expense was determined by the shares allocated method.

At Dec. 31, 2002, the ESOP had 4.0 million allocated shares, 0.3 million committed-to-be-released shares, and 1.7 million unallocated shares. Shares are released to provide employees with the company match in accordance with the terms of the TECO Energy Group Retirement Savings Plan and in lieu of dividends on allocated ESOP shares. The dividends received by the ESOP are used to pay debt service on the loan between TECO Energy and the ESOP.

For financial statement purposes, the unallocated shares of TECO Energy stock are reflected as a reduction of common equity, classified as unearned compensation. Dividends on all ESOP shares are recorded as a reduction of retained earnings, as are dividends on all TECO Energy common stock. The tax benefit related to the dividends paid to the ESOP for allocated shares is a reduction of income tax expense and for unallocated shares is an increase in retained earnings. All ESOP shares are considered outstanding for earnings per share computations.

J. Comprehensive Income

FAS 130, *Reporting Comprehensive Income*, requires that comprehensive income, which includes net income as well as certain changes in assets and liabilities recorded in common equity, be reported in the financial statements. TECO Energy reported the following comprehensive income (loss) in 2002, 2001 and 2000 related to changes in the fair value of cash flow hedges, foreign currency adjustments and adjustments to the minimum pension liability associated with the company's supplemental executive retirement plan:

Comprehensive Income (loss)

(millions)	*Gross*	*Tax*	*Net*
2002			
Unrealized (loss) gain on cash flow hedges	$ (8.7)	$ (4.0)	$ (4.7)
Less: Loss (gain) reclassified to net income	29.0	11.4	17.6
Gain (loss) on cash flow hedges	20.3	7.4	12.9
Portion of equity investee's loss on cash flow hedges	(42.5)	(16.4)	(26.1)
Foreign currency adjustments	(1.2)	—	(1.2)
Pension adjustments	(7.2)	(2.8)	(4.4)
Total other comprehensive income (loss)	$ (30.6)	$ (11.8)	$ (18.8)
2001			
Initial adoption of FAS 133	$ (19.0)	$ (7.3)	$ (11.7)
Unrealized (loss) gain on cash flow hedges	(13.9)	(5.5)	(8.4)
Less: Loss (gain) reclassified to net income	19.7	7.6	12.1
Gain (loss) on cash flow hedges	(13.2)	(5.2)	(8.0)
Portion of equity investee's loss on cash flow hedges	(18.2)	(7.0)	(11.2)
Pension adjustments	0.5	0.2	0.3
Total other comprehensive income (loss)	$ (30.9)	$ (12.0)	$ (18.9)
2000			
Pension adjustments	$ 3.3	$ 1.3	$ 2.0
Total other comprehensive income (loss)	$ 3.3	$ 1.3	$ 2.0

K. Employee Postretirement Benefits

Pension Benefits

TECO Energy has a non-contributory defined benefit retirement plan which covers substantially all employees. Benefits are based on employees' age, years of service and final average earnings. On April 1, 2000, the plan was amended to provide for benefits to be earned and payable substantially on a lump sum basis through an age and service credit schedule for eligible participants leaving the company on or after July 1, 2001. Other significant provisions of the plan, such as eligibility, definitions of credited service, final average earnings, etc., were largely unchanged. This amendment resulted in decreased pension expense of approximately $0.8 million and $2.0 million in 2001 and 2000, respectively, and a reduction of benefit obligation of $6.2 million and $14.4 million at Sept. 30, 2001 and Dec. 31, 2000, respectively.

The company's policy is to fund the plan within the guidelines set by ERISA for the minimum annual contribution and the maximum allowable as a tax deduction by the IRS. About 53 percent of plan assets were invested in common stock and 47 percent in fixed income investments at Sept. 30, 2002.

Amounts shown also include the unfunded obligations for the supplemental executive retirement plans, non-qualified, non-contributory defined benefit retirement plans available to certain senior management. TECO Energy reported other comprehensive loss of $4.4 million in 2002 and other comprehensive income of $0.3 million and $2.0 million in 2001 and 2000, respectively, related to adjustments to the minimum pension liability associated with the supplemental executive retirement plans.

In 2001, TECO Energy elected to change the measurement date for pension obligations and plan assets from Dec. 31 to Sept. 30. The effect of this accounting change was not material.

Other Postretirement Benefits

TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. The company contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and June 30, 2001, is limited to a defined dollar benefit based on years of service. On April 1, 2000, the company adopted changes to this program for participants retiring from the company on or after July 1, 2001. The company contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after July 1, 2001, is limited to a defined dollar benefit based on an age and service schedule. The impact of this amendment, including a change in the company's commitment for future retirees combined with a grandfathering provision for current retired participants, resulted in a reduction in the benefit obligation of $1.4 million in 2001. Postretirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify the plans in whole or in part at any time.

In 2001, TECO Energy elected to change the measurement date for benefit obligations from Dec. 31 to Sept. 30. The effect of this accounting change was not material.

The following charts summarize the income statement and balance sheet impact, as well as the benefit obligations, assets, funded status and rate assumptions associated with the pension and other postretirement benefits.

Benefit Expense

	Pension Benefits			*Other Postretirement Benefits*		
(millions)	*2002*	*2001*	*2000*	*2002*	*2001*	*2000*
Components of net periodic benefit expense						
Service cost (benefits earned during the period)	$ 11.8	$ 11.2	$ 10.7	$ 3.5	$ 3.4	$ 3.0
Interest cost on projected benefit obligations	28.7	27.9	27.5	11.2	10.9	8.9
Expected return on assets	(42.9)	(42.0)	(40.8)	—	—	—
Amortization of:						
Transition obligation (asset)	(1.1)	(1.1)	(1.0)	2.7	2.7	2.7
Prior service cost (benefit)	(0.5)	(0.5)	0.2	1.9	2.0	1.7
Actuarial (gain) loss	(3.7)	(4.4)	(5.6)	0.1	0.4	(0.2)
Pension expense (benefit)	(7.7)	(8.9)	(9.0)	19.4	19.4	16.1
Special termination benefit charge	2.7	—	1.1	0.6	—	0.2
Additional amounts recognized	—	—	—	—	—	0.9
Net pension expense (benefit) recognized in the Consolidated Statements of Income	$ (5.0)	$ (8.9)	$ (7.9)	$ 20.0	$ 19.4	$ 17.2

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for non-qualified pension plans with accumulated benefit obligations in excess of plan assets were $41.3 million, $32.8 million and $0, respectively, as of Sept. 30, 2002 and $27.3 million, $23.5 million and $0, respectively, as of Sept. 30, 2001.

Employee Postretirement Benefits

(millions)	Pension Benefits 2002	Pension Benefits 2001	Other Postretirement Benefits 2002	Other Postretirement Benefits 2001
Change in benefit obligation				
Net benefit obligation at prior measurement date	$ 382.3	$ 379.9	$ 150.2	$ 130.8
Service cost	11.8	11.2	3.5	3.4
Interest cost	28.7	27.9	11.2	10.9
Plan participants' contributions	—	—	1.0	0.9
Actuarial (gain) loss	58.3	(8.7)	25.6	11.6
Plan amendments	1.1	(6.2)	—	(1.4)
Special termination benefits	2.7	—	0.6	—
Gross benefits paid	(29.8)	(21.8)	(7.5)	(6.0)
Net benefit obligation at measurement date	$ 455.1	$ 382.3	$ 184.6	$ 150.2
Change in plan assets				
Fair value of plan assets at prior measurement date	$ 428.0	$ 493.8	$ —	$ —
Actual return on plan assets	(24.9)	(43.7)	—	—
Employer contributions	1.7	2.1	6.5	5.1
Plan participants' contributions	—	—	1.0	0.9
Gross benefits paid (including expenses)	(32.9)	(24.2)	(7.5)	(6.0)
Fair value of plan assets at measurement date	$ 371.9	$ 428.0	$ —	$ —
Funded status				
Funded status at measurement date	$ (83.2)	$ 45.7	$ (184.6)	$ (150.2)
Net contributions after measurement date	0.4	0.4	1.9	1.7
Unrecognized net actuarial (gain) loss	88.9	(44.0)	42.4	16.9
Unrecognized prior service cost (benefit)	(7.4)	(9.0)	22.4	24.3
Unrecognized net transition obligation (asset)	(2.5)	(3.6)	27.4	30.1
Accrued liability at end of year	$ (3.8)	$ (10.5)	$ (90.5)	$ (77.2)
Amounts recognized in the statement of financial position				
Prepaid benefit cost	$ 14.7	$ 6.3	$ —	$ —
Accrued benefit cost	(18.5)	(16.8)	(90.5)	(77.2)
Additional minimum liability	(13.8)	(6.2)	—	—
Intangible asset	1.5	1.1	—	—
Accumulated other comprehensive income	12.3	5.1	—	—
Net amount recognized at end of year	$ (3.8)	$ (10.5)	$ (90.5)	$ (77.2)
Assumptions used in determining actuarial valuations				
Discount rate to determine projected benefit obligation	6.75%	7.5%	6.75%	7.5%
Rate of increase in compensation levels	4.8%	4.7%		
Plan asset growth rate through time	9.0%	9.0%		

The assumed health care cost trend rate for medical costs was 12.5% in 2002 and decreases to 5.0% in 2013 and thereafter.

A 100 basis point increase in the medical trend rates would produce a 7 percent ($1.1 million) increase in the aggregate service and interest cost for 2002 and a 5 percent ($9.5 million) increase in the accumulated postretirement benefit obligation as of Sept. 30, 2002.

A 100 basis point decrease in the medical trend rates would produce a 3 percent ($0.5 million) decrease in the aggregate service and interest cost for 2002 and a 3 percent ($5.0 million) decrease in the accumulated postretirement benefit obligation as of Sept. 30, 2002.

L. Other Non-Operating Items Affecting Net Income

2002

In 2002, TECO Energy recorded $8.8 million of after-tax charges ($14.1 million pretax) to adjust asset valuations. The adjustments included a $5.8 million after-tax charge ($9.2 million pretax) related to the proposed sale of TPS' investment in the ECKG project, and a $3.0 million after-tax charge ($4.9 million pretax) at TECO Investments related to an aircraft leased to US Airways, which has filed for bankruptcy.

In November 2002, the proceeds from the issuance of TECO Energy notes were used, in part, to pay the $34.1 million option premium associated with the refinancing of $200 million of notes. The $34.1 million option premium ($20.9 million after-tax) was recognized as a charge in 2002.

2001

In the first quarter of 2001, TECO Energy recorded $7.2 million of after-tax charges ($11.1 million pretax) to adjust asset valuations. The adjustments included a $6.1 million after-tax charge ($9.3 million pretax) related to the sale of TPS' minority interests in Energia Global International, Ltd. (EGI) which owned smaller power generation projects in Central America, and a $1.1 million after-tax charge ($1.8 million pretax) to adjust the carrying value of leveraged leases at TECO Investments.

2000

In 2000, TECO Energy's results included an $8.3 million after-tax gain from the US Propane and Heritage Propane transactions offset by after-tax charges of $5.2 million to adjust the value of leveraged leases and $3.8 million to adjust property values at TECO Properties. Because of the offsetting nature of these items, there was no significant effect on earnings in 2000.

M. Income Tax Expense

Income tax expense consists of the following components:

Income Tax Expense

(millions)	*Federal*	*State*	*Total*
2002			
Currently payable	$ 41.1	$ 14.0	$ 55.1
Deferred	(81.7)	(7.0)	(88.7)
Amortization of investment tax credits	(4.8)	—	(4.8)
Income tax benefit from continuing operations	(45.4)	7.0	(38.4)
Currently payable	—	2.0	2.0
Deferred	(7.4)	(0.4)	(7.8)
Income tax benefit from discontinued operations	(7.4)	1.6	(5.8)
Total income tax expense (benefit)	$ (52.8)	$ 8.6	$ (44.2)
2001			
Currently payable	$ 85.7	$ 18.3	$ 104.0
Deferred	(94.1)	(7.1)	(101.2)
Amortization of investment tax credits	(4.9)	—	(4.9)
Income tax benefit from continuing operations	(13.3)	11.2	(2.1)
Currently payable	(7.9)	1.6	(6.3)
Deferred	(1.4)	(0.3)	(1.7)
Income tax benefit from discontinued operations	(9.3)	1.3	(8.0)
Total income tax expense (benefit)	$ (22.6)	$ 12.5	$ (10.1)
2000			
Currently payable	$ 103.3	$ 8.4	$ 111.7
Deferred	(79.5)	2.0	(77.5)
Amortization of investment tax credits	(4.9)	—	(4.9)
Income tax expense from continuing operations	18.9	10.4	29.3
Currently payable	(10.7)	—	(10.7)
Deferred	(1.6)	1.5	(0.1)
Income tax benefit from discontinued operations	(12.3)	1.5	(10.8)
Total income tax expense (benefit)	$ 6.6	$ 11.9	$ 18.5

Deferred taxes result from temporary differences in the recognition of certain liabilities or assets for tax and financial reporting purposes. The principal components of the company's deferred tax assets and liabilities recognized in the balance sheet are as follows:

Deferred Income Tax Assets and Liabilities

(millions) Dec. 31,	*2002*	*2001*
Deferred income tax assets (1)		
Property related	$ 86.8	$ 87.7
Basis differences in oil and gas producing properties	(0.1)	1.2
Alternative minimum tax credit carry forward	201.3	105.5
Other	52.2	47.6
Total deferred income tax assets	340.2	242.0
Deferred income tax liabilities (1)		
Property related	(565.3)	(522.8)
Basis differences in oil and gas producing properties	(13.9)	(8.9)
Other	84.2	33.0
Total deferred income tax liabilities	(495.0)	(498.7)
Accumulated deferred income taxes	$ (154.8)	$ (256.7)

(1) Certain property related assets and liabilities have been netted.

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes for the following reasons:

Effective Income Tax Rate

(millions)	*2002*	*2001*	*2000*
Net income from continuing operations	$ 298.2	$ 273.8	$ 227.5
Total income tax provision (benefit)	(38.4)	(2.1)	29.3
Income from continuing operations before income taxes	$ 259.8	$ 271.7	$ 256.8
Income taxes on above at federal statutory rate of 35%	$ 90.9	$ 95.1	$ 89.9
Increase (Decrease) due to			
State income tax, net of federal income tax	4.6	7.3	7.5
Amortization of investment tax credits	(4.8)	(4.9)	(4.9)
Non-conventional fuels tax credit	(107.3)	(86.2)	(52.1)
Permanent reinvestment-foreign income	(8.1)	(7.2)	(9.3)
AFUDC Equity	(8.7)	(2.3)	(0.6)
Other	(5.0)	(3.9)	(1.2)
Total income tax provision from continuing operations	$ (38.4)	$ (2.1)	$ 29.3
Provision for income taxes as a percent of income from continuing operations, before income taxes	-14.8%	-0.8%	11.4%

The provision for income taxes as a percent of income from discontinued operations was -22.4%, -36.5% and -46.1%, respectively, in 2002, 2001 and 2000. The total effective income tax rate differs from the federal statutory rate due to state income tax, net of federal income tax, the non-conventional fuels tax credit and other miscellaneous items. The actual cash paid for income taxes as required by the alternative minimum tax rules in 2002, 2001, and 2000 was $71.9 million, $52.4 million and $83.9 million, respectively.

N. Related Parties

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests. These transactions, primarily for legal services, were not material for 2002, 2001 and 2000. No material balances were payable as of Dec. 31, 2002 or 2001.

Tampa Electric and TECO-Panda Generating Company (TPGC) II entered into an assignment and assumption agreement whereby Tampa Electric obtained TPGC II's rights and interests to four combustion turbines being purchased from General Electric, and assumed the corresponding liabilities and obligations for such equipment. In accordance with the terms of the assignment and assumption agreement, Tampa Electric paid $62.5 million to TPGC II as reimbursement for amounts already paid to General Electric by TPGC II for such equipment.

TPS recognized income on the non-TPS portion of notes receivable from unconsolidated affiliates in which TPS holds joint venture interests and from credit support for the TPGC joint venture. The notes receivable from unconsolidated affiliates are as follows:

Notes Receivable From Related Parties

(millions) Dec. 31,	*Rate*	*2002*	*2001*
Panda Energy	14.00%	$ 137.0	$ 92.7
Energeticke Centrum Kladno	6.00%	1.4	—
Mosbacher Power Partners L.P.	12.00%	—	13.1
Mosbacher Power Partners L.P.	9.00%	13.7	21.1
Mosbacher Power Partners L.P.	12.00%	—	6.2
EEGSA	6.81%(1)	11.1	10.9
TPGC - Gila River	7.79%(1)	369.5	37.5
TPGC - Union Power	6.58%(1)	426.3	86.7

(1) Current rate at Dec. 31, 2002

Other Income (Expense) included pretax income from construction-related and loan agreements with Panda Energy, and interest income of $78.9 million and $32.8 million for 2002 and 2001, respectively from the other notes receivable shown on the preceeding table.

At Dec. 31, 2002, TPS' position in the Odessa and Guadalupe power stations in Texas was in the form of a $137 million loan to a Panda Energy International subsidiary, which is a partner in Texas Independent Energy (TIE). On Jan. 3, 2003 the loan converted to an ownership interest in these projects.

TPS Arkansas Operations Company and TPS Arizona Operations Company, both wholly-owned subsidiaries of TPS, have a combined receivable from TPGC of $0.8 million as of Dec. 31, 2002.

TPS has agreed to purchase the interests of Panda Energy in the TPGC projects in 2007 for $60 million, and TECO Energy has guaranteed payment of TPS' purchase obligation. This obligation may be accelerated if Panda Energy defaults on a bank loan for which the TPS purchase obligation is collateral or if TECO Energy permits its debt-to-capital ratio to exceed 65.0%, permits its EBITDA/interest ratio to fall below 1.5 times or defaults on the payment of indebtedness in excess of $50 million. TECO Energy's debt-to-capital ratio at Dec. 31, 2002, was 55.9% and its EBITDA/interest ratio was 3.6 times (See **Note R**). Panda Energy may cancel the purchase obligation at any time prior to 2007 by paying TPS a cancellation fee that ranges from $8 million to $20 million based on the time of such cancellation.

O. Discontinued Operations

TECO Coalbed Methane, a subsidiary of TECO Energy, had developed jointly the natural gas potential in a portion of Alabama's Black Warrior Basin. In September 2002, the company announced its intent to sell the TECO Coalbed Methane gas assets. On Dec. 20. 2002, TECO Energy sold substantially all of its coalbed methane assets in Alabama to the Municipal Gas Authority of Georgia. Proceeds from the sale were $140 million, $42 million paid in cash at closing, and a $98 million note receivable, which was paid in January 2003 (See **Note U**). TECO Coalbed Methane's results were accounted for as discontinued operations for all periods reported. The gas assets are included in Property held for sale net of accumulated depreciation on the Consolidated Balance Sheets as of Dec. 31, 2001. Operating revenues from TECO Coalbed Methane were $39.7 million, $55.0 million and $43.0 million, and pretax operating income was $14.9 million, $24.3 million and $12.6 million for the years ended Dec. 31, 2002, 2001 and 2000, respectively.

TECO Coalbed Methane utilized the successful efforts method to account for its gas operations, in which expenditures for unsuccessful exploration activities were expensed currently.

Capitalized costs were amortized on the unit-of-production method using estimates of proven reserves. Investments in unproven properties and major development projects were not amortized until proven reserves associated with the projects could be determined or until impairment occurred.

Aggregate capitalized costs related to producing wells at Dec. 31, 2001 were $220.8 million. Net proven reserves at Dec. 31, 2001 were as follows:

Net Proven Reserves - Coalbed Methane Gas

(billion cubic feet)	*2001*
Proven reserves, beginning of year	181.7
Production	(15.0)
Revisions of previous estimates	0.4
Proven reserves, end of year	167.1
Number of wells	682

P. Earnings Per Share

In 1997, the FASB issued FAS 128, Earnings per Share, which requires disclosure of basic and diluted earnings per share and a reconciliation (where different) of the numerator and denominator from basic to diluted earnings per share. The reconciliation of basic and diluted earnings per share is shown as follows:

Earnings Per Share

(millions, except per share amounts)	*2002*	*2001*	*2000*
Numerator			
Net Income from continuing operations, basic	$ 298.2	$ 273.8	$ 227.5
Effect of contingent performance shares	—	—	(1.9)
Net Income from continuing operations, diluted	$ 298.2	$ 273.8	$ 225.6
Net Income, basic	$ 330.1	$ 303.7	$ 250.9
Effect of contingent performance shares	—	—	(1.9)
Net Income, diluted	$ 330.1	$ 303.7	$ 249.0
Denominator			
Average number of shares outstanding - basic	153.2	134.5	125.9
Plus: incremental shares for assumed conversions: Stock options at end of period and contingent performance shares	2.1	4.2	3.3
Less: Treasury shares which could be purchased	(2.0)	(3.3)	(2.9)
Average number of shares outstanding - diluted	153.3	135.4	126.3
Earnings per share from continuing operations			
Basic	$ 1.95	$ 2.04	$ 1.81
Diluted	$ 1.95	$ 2.02	$ 1.79
Earnings per share			
Basic	$ 2.15	$ 2.26	$ 1.99
Diluted	$ 2.15	$ 2.24	$ 1.97

For the year ended Dec. 31, 2002, stock options for 4.5 million shares and 14.9 million common shares issuable under the purchase contract associated with the mandatorily convertible equity units issued in January 2002 were excluded from the computation of diluted earnings per share due to their antidilutive effect. For the year ended Dec. 31, 2001, stock options for 1.2 million shares were excluded from the computation of diluted earnings per share due to their antidilutive effect.

Q. Segment Information

TECO Energy is an electric and gas utility holding company with significant diversified activities. The management of TECO Energy determined its reportable segments based on each subsidiary's contribution of revenues, net income and total assets. All significant intercompany transactions are eliminated in the consolidated financial statements of TECO Energy but are included in determining reportable segments in accordance with FAS 131, Disclosures about Segments of an Enterprise and Related Information. In December 2002, TECO Energy sold the assets of TECO Coalbed Methane. Information presented here excludes TECO Coalbed Methane's results, which are reflected in the consolidated financial statements as discontinued operations.

Segment Information

(millions)		*Revenues(1)(2)*	*Net Income (1)(3)*	*Depreciation (1)*	*Assets at Dec. 31,*	*Capital Expenditures*
2002						
	Tampa Electric	$ 1,583.2 (4)	$ 171.8 (9)	$ 189.8	$ 3,737.0	$ 632.2
	Peoples Gas System	318.1	24.2 (10)	30.5	571.7	53.5
	TECO Power Services	309.8 (5)	34.1 (11)	28.1	2,875.0 (15)(16)	299.9
	TECO Transport	254.6 (6)	21.0 (12)	22.3	355.1	25.2
	TECO Coal	317.1 (7)	76.5 (13)	31.4	283.5	48.2
	Other unregulated businesses	122.1 (8)	6.8 (14)	1.3	312.4 (17)(18)	3.0
		2,904.9	334.4	303.4	8,134.7	1,062.0
	Other and eliminations	(229.1)	(36.2)	—	503.1 (19)	3.2 (19)
	TECO Energy consolidated	$ 2,675.8	$ 298.2	$ 303.4	$ 8,637.8	$1,065.2
2001						
	Tampa Electric	$ 1,412.7 (4)	$ 154.0 (9)	$ 173.4	$ 3,315.5	$ 426.3
	Peoples Gas System	352.9	23.1 (10)	27.9	528.9	73.0
	TECO Power Services	287.1 (5)	26.9 (11)	28.4	1,935.4 (15)(16)	397.5
	TECO Transport	274.9 (6)	27.6 (12)	24.1	333.1	38.8
	TECO Coal	303.4 (7)	59.0 (13)	28.3	258.5	25.8
	Other unregulated businesses	106.9 (8)	4.0 (14)	6.1	295.5 (17)(18)	(0.1)
		2,737.9	294.6	288.2	6,666.9	961.3
	Other and eliminations	(249.8)	(20.8)	—	96.5 (19)	4.6 (19)
	TECO Energy consolidated	$ 2,488.1	$ 273.8	$ 288.2	$ 6,763.4	$ 965.9
2000						
	Tampa Electric	$ 1,353.8 (4)	$ 144.5 (9)	$ 161.6	$ 2,997.1	$ 267.1
	Peoples Gas System	314.5	21.8 (10)	25.8	513.3	82.2
	TECO Power Services	199.1 (5)	22.8 (11)	18.5	1,350.6 (15)(16)	243.5
	TECO Transport	269.8 (6)	29.2 (12)	22.0	311.3	21.1
	TECO Coal	232.8 (7)	33.5 (13)	26.9	246.3	64.0
	Other unregulated businesses	81.8 (8)	1.2 (14)	3.2	213.3 (17)(18)	6.9
		2,451.8	253.0	258.0	5,631.9	684.8
	Other and eliminations	(228.7)	(25.5)	—	142.4 (19)	3.6 (19)
	TECO Energy consolidated	$ 2,223.1	$ 227.5	$ 258.0	$ 5,774.3	$ 688.4

(1) From continuing operations. Revenues, net income and depreciation for all periods have been adjusted to reflect the reclassification of TECO Coalbed Methane results as discontinued operations.

(2) Revenues for all periods have been adjusted to reflect the presentation of energy marketing related revenues on a net basis and the reclassification of earnings from equity investments from Revenues to Other income.

(3) Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated costs for 2002, 2001, and 2000 were at pretax rates of 7%, 7%, and 6.75%, respectively, based on the average investment in each subsidiary.

(4) Revenues from sales to affiliates were $ 34.4 million, $32.6 million and $32.4 million in 2002, 2001 and 2000, respectively.

(5) Revenues from sales to affiliates were $ 51.4 million, $65.0 million and $67.6 million in 2002, 2001 and 2000, respectively.

(6) Revenues from sales to affiliates were $110.7 million, $123.2 million and $118.0 million in 2002, 2001 and 2000, respectively.

(7) Revenues from sales to affiliates were $0.7 million, $5.1 million and $4.3 million in 2002, 2001 and 2000, respectively.

(8) Revenues from sales to affiliates were $31.9 million, $23.8 million and $6.5 million in 2002, 2001 and 2000, respectively.

(9) Net income includes net interest expense of $51.5 million, $60.8 million and $67.4 million in 2002, 2001 and 2000, respectively. Net income also includes provisions for income taxes of $85.7 million, $83.4 million and $82.5 million, respectively, for the same periods.

(10) Net income includes net interest expense of $14.7 million, $14.3 million and $12.6 million in 2002, 2001 and 2000, respectively. Net income also includes provisions for income taxes of $14.7 million, $14.2 million and $13.3 million, respectively, for the same periods.

(11) Net income includes net interest expense of $57.2 million, $51.8 million and $23.0 million for 2002, 2001 and 2000, respectively, of which $102.6 million, $54.1 million and $23.0 million for the same periods was internally allocated financing costs (see **Note A**). Net income also includes provisions for income taxes of $9.2 million and $0.7 million for 2002 and 2001, respectively, and an income tax benefit of $0.6 million for 2000.

(12) Net income includes net interest expense of $6.3 million, $8.9 million and $6.5 million for 2002, 2001 and 2000, respectively, of which $1.7 million, $0.7 million and $0.9 million for the same periods was internally allocated financing income. Net income also includes provisions for income taxes of $10.8 million, $14.2 million and $16.2 million, respectively for the same periods.

(13) Net income includes internally allocated financing costs of $8.1 million, $7.6 million and $6.5 million for 2002, 2001 and 2000, respectively. Net income also includes income tax benefits of $22.9 million, $19.0 million and $14.8 million, respectively, for the same periods.

(14) Net income includes internally allocated financing costs of $4.5 million, $4.4 million and $2.7 million for 2002, 2001 and 2000, respectively. Net income also includes provisions for income taxes of $0.3 million, $3.1 million and $0.9 million, respectively, for the same periods.

(15) Total assets include $97.4 million, $120.4 million and $145.5 million in investments in unconsolidated affiliates at Dec. 31, 2002, 2001 and 2000, respectively. Total assets also includes $972.6 million, $286.4 and $383.1 million in other non-current investments at Dec. 31, 2002, 2001 and 2000, respectively .

(16) Total assets include $154.5 million, $129.4 million and $65.7 million in goodwill net of amortization at Dec. 31, 2002, 2001 and 2000, respectively.

(17) Total assets include $51.8 million, $52.5 million and $50.4 million in investments in unconsolidated affiliates at Dec. 31, 2002, 2001 and 2000, respectively.

(18) Total assets include $39.1 million, $36.4 million and $27.4 million in goodwill net of amortization at Dec. 31, 2002, 2001 and 2000, respectively.

(19) Total assets and capital expenditures for all periods include amounts for the discontinued operations of TECO Coalbed Methane.

Tampa Electric Company provides retail electric utility services to almost 598,000 customers in West Central Florida. Its Peoples Gas System division is engaged in the purchase, distribution and marketing of natural gas for more than 281,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

TECO Transport, through its wholly-owned subsidiaries, transports, stores and transfers coal and other dry bulk commodities for third parties and Tampa Electric. TECO Transport's subsidiaries operate on the Mississippi, Ohio and Illinois rivers, in the Gulf of Mexico and worldwide.

TECO Coal, through its wholly-owned subsidiaries, owns mineral rights and owns or operates surface and underground mines and coal processing and loading facilities in Kentucky, Tennessee and Virginia. In 2000, these subsidiaries began operating two synthetic fuel processing facilities, whose production qualifies for the non-conventional fuels tax credit. With plans to continue growth in the production and sales of synfuel, TECO Coal has formed a new LLC and has transferred the synfuel units into this LLC effective Jan. 1, 2003. Selling partial interest in the LLC will facilitate efforts to maximize production as well as increase overall cash flow. TECO Coal's subsidiaries sell their coal production to third parties.

TPS has subsidiaries that have interests in independent power projects in Florida, Virginia, Texas, Arkansas, Mississippi, Arizona, Hawaii and Guatemala, and transmission and distribution facilities in Guatemala. TPS also has investments in unconsolidated affiliates that participate in independent power projects in other parts of the U.S. and the world.

TECO Energy's other diversified businesses are engaged in the marketing of natural gas, and energy services and engineering. Also included is the company's investment in the propane business.

Foreign Operations

TPS has independent power operations and investments in Guatemala.

TPS, through its subsidiaries, has a 96 percent ownership interest and operates a 78-megawatt power station that supplies energy to EEGSA, an electric utility in Guatemala, under a U.S. dollar-denominated power sales agreement.

At Dec. 31, 2002, TPS, through a wholly-owned subsidiary, had a 100 percent ownership interest in a 120-megawatt power station and in transmission facilities in Guatemala. The plant provides capacity under a U.S. dollar-denominated power sales agreement to EEGSA.

TPS, through a subsidiary, owns a 30 percent interest in a consortium that includes Iberdrola, an electric utility in Spain, and Electricidade de Portugal, an electric utility in Portugal. The consortium owns an 80.9 percent interest in EEGSA.

Total assets at Dec. 31, 2002, 2001 and 2000 included $415.9 million, $454.2 million and $442.6 million, respectively, related to these Guatemalan operations and investments. Revenues included $88.5 million, $79.9 million and $69.0 million for the years ended Dec. 31, 2002, 2001 and 2000, respectively, and operating income included $33.0 million, $38.0 million and $23.7 million for the same periods from these Guatemalan operations and investments.

R. Commitments and Contingencies

Capital Investments

TECO Energy has made certain commitments in connection with its continuing capital improvements program. At Dec. 31, 2002, these forecasted capital investments total approximately $2.0 billion for the years 2003 through 2007 and are summarized as follows.

Forecasted-Capital Investments

(millions)	*2003*	*2004*	*2005 – 2007*	*Total 2003-2007*
Florida operations	$ 272	$ 266	$ 725	$1,263
Independent power	424	25	75	524
Transportation	15	21	61	97
Other	16	23	55	94
	$ 727	$ 335	$ 916	$1,978

For 2003, Tampa Electric expects to spend $232 million, consisting of $78 million for the repowering project at the Gannon Station, and $154 million to support system growth and generation reliability. Tampa Electric's estimated capital expenditures over the 2004-2007 period are projected to be $841 million, including $67 for the Gannon repowering project. At the end of 2002, Tampa Electric had outstanding commitments of about $119 million for the Gannon repowering project.

Capital expenditures for PGS are expected to be about $40 million in 2003 and $160 million during the 2004-2007 period. Included in these amounts are approximately $25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing maintenance and system safety.

TPS expects to invest $424 million in 2003 for completion of the Union and Gila River power stations and $100 million in 2004 through 2006, mainly for the completion of the Dell and McAdams power stations. Estimates for TPS include net contributions to projects of unconsolidated affiliates and other investments of $393 million. TPS had outstanding commitments at Dec. 31, 2002 of approximately $384 million related to the Union and Gila River power stations.

The other unregulated companies expect to invest $31 million in 2003 and $160 million during 2004 through 2007, mainly for normal renewal and replacement capital.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2002, Tampa Electric Company has estimated its ultimate financial liability to be $20 million, and this amount has been accrued in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors, or Tampa Electric Company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other potentially responsible parties (PRPs) is based on each parties relative ownership interest in or usage of a site. Accordingly, Tampa Electric Company's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Long Term Operating Lease Commitments

TECO Energy has commitments under long-term operating leases, primarily for building space, office equipment and heavy equipment, marine assets at TECO Transport, and certain equipment at TPS' Hardee Power Station. On Dec. 30, 2002 TECO Transport completed a sales leaseback transaction to be accounted for as an operating lease covering one ocean-going tug and barge, five river towboats and 49 river barges. On Dec. 21, 2001, TECO Transport sold three ocean-going barges and one ocean-going tug boat in a sales leaseback transaction to be accounted for as an operating lease. Both lease terms are 12 years with early buyout options after 5 years. TPS completed a transaction on Dec. 29, 2000, where certain equipment at its Hardee Power Station was sold to a third party and leased back under a 12-year operating lease.

Total rental expense for these operating leases, included in the Consolidated Statements of Income for the years ended Dec. 31, 2002, 2001 and 2000 was $26.1 million, $20.4 million and $17.6 million, respectively. The following is a schedule of future minimum lease payments at Dec. 31, 2002 for all operating leases with noncancelable lease terms in excess of one year:

Future Minimum Lease Payments For Operating Leases

Year ended Dec. 31:	*Amount (millions)*
2003	$ 27.4
2004	26.5
2005	23.3
2006	20.7
2007	17.9
Later Years	107.1
Total minimum lease payments	$ 222.9

Guarantees and Letters of Credit

TECO Energy company has outstanding letters of credit of $185.0 million at Dec. 31, 2002, which guarantee performance to third parties related to debt service, major maintenance requirements and various trade activities. The company also has financial guarantees of $755.6 million at Dec. 31, 2002, primarily for fuel purchases, energy management and construction related debt for projects in which TPS is a participant. Most of the guarantees are renewable annually. In addition, TECO Energy has guaranteed a $375 million equity bridge loan and the $60 million construction undertaking related to the Gila River and Union power stations. A summary of TECO Energy's letters of credit and guarantees are as follows:

Letters of Credit and Guarantees

($ in millions) *Letters of Credit and Guarantees for the Benefit of*	*2003*	*2004*	*After 2005-2007*	*2007*	*Total*	*Liabilities Recognized at Dec. 31, 2002*
Tampa Electric						
Letters of credit	$ —	$ —	$ —	$ 0.9	$ 0.9	$ —
TECO Power Services						
Letters of credit	128.0	27.1		24.7	179.8	
Guarantees:						
Debt related				15.7	15.7	
Fuel purchase/energy management				443.9	443.9	10.0
Construction/Investment related	435.0		60.0	5.0	500.0	
	563.0	27.1	60.0	489.3	1,139.4	10.0
TECO Transport						
Letters of credit	—	—	—	1.5	1.5	—
TECO Coal						
Letters of credit				0.1	0.1	
Guarantees: Fuel purchase related				1.5	1.5	1.5
	—	—	—	1.6	1.6	1.5
Other unregulated subsidiaries						
Letters of credit				2.7	2.7	
Guarantees:						
Debt related				8.0	8.0	
Fuel purchase/energy management				221.5	221.5	46.4
	—	—	—	232.2	232.2	46.4
	$ 563.0	$ 27.1	$ 60.0	$ 725.5	$1,375.6	$ 57.9

Financial Covenants

A summary of TECO Energy's significant financial covenants is as follows:

TECO Energy Significant Financial Covenants

(millions) *Instrument*	*Financial Covenant(1)*	*Requirement/ Restriction*	*Calculation at Dec. 31, 2002*
Tampa Electric			
Mortgage bond indenture	Dividend restriction	Cumulative distributions cannot exceed cumulative net income plus $4	$189 unrestricted
PGS senior notes	EBIT/interest	Minimum of 2.0 times	3.7 times
	Restricted payments	Shareholder equity at least $500	$1,838
	Funded debt/capital	Cannot exceed 65%	44.8%
	Sale of assets	Less than 20% of total assets	0%
Credit facility	Debt/capital	Cannot exceed 60%	43.9%
	EBITDA/interest	Minimum of 2.5 times	7.8 times
TECO Energy			
Credit facilities	Debt/capital	Cannot exceed 65%	55.9%
$380 million note indenture(2)	Various	—	—
TECO/Panda guarantees(3)	Debt/capital	Cannot exceed 65%	55.9%
	EBITDA/interest	Minimum of 3.0 times	3.6 times
	Minimum ratings	BBB and Baa3, or BBB- and Baa2	BBB- and Baa2
TPS purchase obligation guarantee	Debt/capital	Cannot exceed 65%	55.9%
	EBITDA/interest	Minimum of 1.5 times	3.6 times
TECO Diversified			
Energy management services agreement guarantee	Consolidated tangible net worth	Minimum of $200	$575
	Consolidated funded debt	Cannot exceed 60%	19.1%
Coal supply agreement guarantee	Dividend restriction	Net worth not less than $200 or $446 (40% of tangible net assets)	$536

(1) As defined in applicable instrument.

(2) Indenture contains covenants which would apply only if either (a) Notes are rated below BBB- by S&P or below Baa3 by Moody's or (b) Notes are rated below Special Ratings Trigger (minimum of BBB- by S&P and Baa2 by Moody's or BBB by S&P and Baa3 by Moody's) if TECO Energy Construction Undertakings for the TECO/Panda projects are not substantially discharged. These covenants include Limitation on Restricted Payments, Limitations on Certain Liens and Limitation on Indebtedness.

(3) Includes Equity Bridge, Equity Contribution and Construction Undertaking Guarantees related to the TPGC projects.

Other Contingencies

In December 2001, Enron Corp., a large energy trading and services company, filed for protection under the U.S. Bankruptcy Code. TECO Energy announced it believed it had exposure in operations from trade payables and other trading positions due to the Enron bankruptcy of $3.5 million or less after-tax at its subsidiaries TPS, PGS and Prior Energy. TECO Energy has negotiated an agreement with Enron, pending approval of the Creditors Committee, to settle the previously reported $3.5 million of potential trade payables exposure as a result of the Enron bankruptcy. The net financial impact of the agreement is reflected in consolidated net income and no future financial impact is expected.

In addition to the financial and non-financial guarantees listed above, TECO Energy and its subsidiaries include indemnity clauses, in the normal course of business, in certain agreements with vendors and other third parties. Such clauses may provide indemnification to the counter-party for certain amounts such as legal fees, environmental remediation costs and other similar costs arising from potential future events or changes in laws or regulations. As these agreements cover a variety of goods and services, and have varying triggering events dependent on actions by third parties, TECO Energy is unable to estimate the maximum potential future exposure under these clauses. As claims are made or changes in laws or regulations indicate, an amount related to the indemnification is reflected in the financial statements.

S. Mergers and Acquisitions

In May 2002, TPS purchased Mosbacher Power Partners' interest in TM Power Ventures (TMPV) for $29.3 million. The majority of the purchase price was allocated to TMPV's investment in the 312-megawatt Commonwealth Chesapeake Power Station located on the Delmarva Peninsula in Virginia, and has been recorded as an increase in goodwill. The acquisition increased TPS' ownership interest in TMPV to 100 percent.

In November 2001, TECO Solutions acquired Prior Energy Corporation, a leading natural gas management company serving customers in Alabama, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee and Texas. Prior Energy handles all facets of natural gas energy management services, including natural gas purchasing and marketing. The company has an established market base in the Southeast and one of the top customer service reputations in the region. The acquisition was accounted for by the purchase method of accounting and, accordingly, the results of operations of Prior Energy are included as part of TECO Solutions' results beginning Nov. 1, 2001. The final working capital adjustment and purchase price allocation was completed in 2002. The total cost of the acquisition was $23.0 million plus a net working capital payment of $6.4 million. Goodwill of $9.6 million was recorded, representing the excess of purchase price over the fair market value of assets acquired. Under FAS 141, effective for all business combinations initiated after June 30, 2001, goodwill is no longer subject to amortization. Net intangible assets of $39.8 million were recorded, representing the value of customer backlog and supply agreements as well as the open cash flow hedges as of Nov. 1, 2001, which are being amortized over 2001 through 2004.

In March 2001, TPS acquired the Frontera Power Station located near McAllen, Texas, accounting for the transaction using the purchase method of accounting. This 477-megawatt, natural gas-fired combined-cycle plant, originally developed by CSW Energy (CSW), began commercial operation in May 2000. As a condition of the merger of Central & South West Corporation, CSW's parent company, with American Electric Power Company, Inc., the FERC required CSW to divest its ownership in this facility. The total cost of the acquisition was $265.3 million. Goodwill of $70.4 million, representing the excess of purchase price over the fair market value of assets acquired, was recorded, and was amortized on a straight-line basis over 40 years until the requirements of FAS 141 became effective on Jan. 1, 2002 (See **Note C**). The results of operations of Frontera Power Station are included as part of TPS' results beginning March 16, 2001.

The following pro forma disclosures include Prior Energy and the Frontera Power Station as if they had been included in TECO Energy's financial statements for the years ended Dec. 31, 2001 and 2000.

Pro Forma Disclosure — Mergers and Acquisitions

	Actual	*Pro Forma*	
Year ended Dec. 31,	*2002*	*2001*	*2000*
Revenues (millions)	$ 2,675.8	$ 2,557.4	$ 2,308.6
Net income from continuing operations(millions)	$ 298.2	$ 270.4	$ 230.5
Earnings per share from continuing operations – basic	$ 1.95	$ 2.01	$ 1.83

This pro forma information is not necessarily indicative of the operating results that would have occurred had the acquisitions been completed as of the dates indicated, nor are they indicative of future operating results.

In October 2001, TECO BGA, a unit of TECO Solutions, purchased a district cooling business from FPL Energy Services, a subsidiary of FPL Group. The acquisition includes a 12,000-ton design capacity cooling plant located in downtown Miami. This acquisition provides TECO BGA with a stronger presence in the growing South Florida energy market, long-term contract business, a franchise agreement with the city of Miami and the potential for expansion. The acquisition was accounted for by the purchase method of accounting and, accordingly, its results of operations are included as part of TECO BGA's results beginning Oct. 25, 2001. The total cost of the acquisition was $12.5 million. No goodwill was recorded for the acquisition. The acquisition was not material to the financial statements; no pro forma disclosures are presented.

On Nov. 1, 2000, TECO Coal acquired all of the outstanding stock of Perry County Coal for $14.9 million, comprised of $12.1 million in cash and $2.8 million in notes. Perry County Coal owns or controls more than 23 million tons of low-sulfur reserves, and operates both deep and surface contract mines. The acquisition was accounted for by the purchase method of accounting and, accordingly, the results of operations and assets of Perry County Coal are included as part of TECO Coal's results beginning Nov. 1, 2000. The acquisition was not material to the financial statements; no pro forma disclosures are presented.

In September 2000, TECO Energy acquired BCH Mechanical, Inc. and its affiliated companies ("BCH") accounting for the transaction using the purchase method of accounting. BCH is one of the leading mechanical contracting firms in Florida. TECO Energy purchased a combination of stock and assets of the BCH companies for $34.8 million, comprised of $26.1 million in cash, $2.9 million in notes, and 233,819 shares of TECO Energy common stock. Goodwill of $25.9 million representing the excess of purchase price over the fair market value of assets acquired was recorded, and was amortized on a straight-line basis over 20 years, until the requirements of FAS 141 became effective on Jan. 1, 2002 (See **Note C**). The results of operations of BCH are included as part of TECO Energy's results beginning Sept. 1, 2000. The acquisition was not material to the financial statements; no pro forma disclosures are presented.

In connection with this transaction. TECO Solutions was formed to support TECO Energy's strategy of offering customers a comprehensive and competitive package of energy services and products. Operating companies under TECO Solutions include TECO Energy Services (formerly TECO BGA and BCH Mechanical), TECO Partners, TPV, TECO Gas Services, Prior Energy and TECO Properties.

In February 2000, TECO Energy entered into an agreement to form US Propane, a joint venture to combine its Peoples Gas Company (PGC) propane operations with the propane operations of Atmos Energy Corporation, AGL Resources Inc. and Piedmont Natural Gas Company, Inc. Through a series of transactions completed Aug. 10, 2000, US Propane combined its propane operations with those of Heritage Propane Partners, L.P. US Propane now owns the general partner interest and 29 percent of the limited partnership interests of Heritage Propane Partners. TECO Energy through its wholly-owned subsidiary TPV, is accounting for its interest in US Propane under the equity method of accounting. As a result of these transactions, TPV also received $19.3 million in cash and recognized a pretax gain of $13.6 million ($8.3 million after-tax) on the sale of PGC assets and liabilities to the extent acquired by US Propane and Heritage Propane Partners.

T. New Accounting Pronouncements

Accounting for Asset Retirement Obligations

In July 2001, the FASB issued FAS 143, *Accounting for Asset Retirement Obligations*, which requires the recognition of a liability at fair value for an asset retirement obligation in the period in which it is incurred. Retirement obligations associated with long-lived assets included within the scope of FAS 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are included in the scope of the standard only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its future value. The corresponding amount capitalized at inception is depreciated over the useful life of the asset. The liability must be revalued each period based on current market prices. FAS 143 is effective for fiscal years beginning after June 15, 2002. The company estimates that the adoption of FAS 143 will result in a non-cash increase to net property, plant and equipment of approximately $8.0 million, a non-cash net increase to asset retirement obligation of approximately $10.0 million, and as a cumulative effect of change in accounting principle, a non-cash pretax charge of approximately $2.0 million.

Exit or Disposal Costs

In July 2002, the FASB issued FAS 146, *Accounting for Costs Associated with Exit or Disposal Activities*, which addresses the accounting for costs under certain circumstances, including costs to terminate a contract that is not a capital lease, costs to consolidate facilities or relocate employees, and termination benefits provided to employees that are involuntarily terminated under the terms of a one-time benefit arrangement that is not an ongoing benefit arrangement or an individual deferred compensation contract. FAS 146 is effective for disposal activities initiated after Dec. 31, 2002 with early adoption allowed.

TECO Energy opted to adopt early FAS 146 in 2002. Early retirements were accepted by 52 employees at Tampa Electric Company's electric division in mid-2002. Cost associated with this program were approximately $6.3 million and were recognized in operation expenses in the third quarter of 2003. In the fourth quarter of 2002, TECO Energy initiated an additional restructuring program that impacted approximately 200 employees. This program includes retirements, the elimination of positions and other cost control measures. The total costs associated with this program, including severance, salary continuance through the end of 2002 and other benefit costs, were approximately $13 million and were recognized in the fourth quarter.

Gains and Losses on Energy Trading Contracts

On Oct. 25, 2002, the Emerging Issues Task Force released EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, which 1) precludes mark-to-market accounting for energy trading contracts that are not derivatives pursuant to FAS 133, 2) requires that gains and losses on all derivative instruments within the scope of FAS 133 be presented on a net basis in the income statement if held for trading purposes, and 3) limits the circumstances in which a reporting entity may recognize a "day one" gain or loss on a derivative contract. The measurement provisions of the issue are effective for all fiscal periods beginning after Dec. 15, 2002. The net presentation provisions are effective for all financial statements issued after Dec. 15, 2002. In accordance with the recommended transition provisions, TECO Energy reclassified certain amounts in prior periods to present gains and losses on a net basis (see **Note A**). The adoption of the measurement provisions is not anticipated to have a material impact.

Guarantees

In November 2002, the FASB issued Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of others (an interpretation of FAS No. 5, 57, and 107 and rescission of FAS Interpretation No. 34)*, which modifies the accounting and enhances the disclosure of certain types of guarantees. FIN 45 requires that upon issuance of certain guarantees, the guarantor must recognize a liability for the fair value of the obligation it assumes under the guarantee. FIN 45's provisions for the initial recognition and measurement are to be applied to guarantees issued or modified after Dec. 31, 2002. The disclosure requirements are effective for financial statements of annual periods that end after Dec. 15, 2002 (see Note R).

Stock-Based Compensation

In December 2002, the FASB issued FAS 148, *Accounting for Stock-Based Compensation – Transition and Disclosure, an amendment of FASB Statement No. 123*. This standard amends FAS 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for companies that voluntarily change to the fair value based method of accounting for stock-based employee compensation. It also requires prominent disclosure about the effects on reported net income of the company's accounting policy decisions with respect to stock-based employee compensation in both annual and interim financial statements. The transition provisions and annual disclosure requirements are effective for all fiscal years ending after Dec. 15, 2002, while the interim period disclosure requirements are effective for all interim periods beginning after Dec. 15, 2002. The adoption of the disclosure provisions of this standard does not have a material impact.

Consolidation of Variable Interest Entities

The equity method of accounting is used to account for investments in partnership arrangements in which TECO Energy or its subsidiary companies do not have a majority ownership or exercise control. On Jan. 17, 2003, the FASB issued FASB Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*, which imposes a new approach in determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as variable interest entities or VIEs. A legal entity is considered a VIE if it does not have sufficient equity at risk to finance its own activities without relying on financial support from other parties. Additional criteria must be applied to determine if this condition is met or if the equity holders, as a group, lack any one of three stipulated characteristics of a controlling financial interest. If the legal entity is a VIE, then the reporting entity determined to be the primary beneficiary must consolidate it. Even if a reporting entity is not obligated to consolidate a VIE, then certain disclosures must be made about the VIE if the reporting entity has a significant variable interest. Certain transition disclosures are required for all financial statements issued after Jan. 31, 2003. The on-going disclosure and consolidation requirements are effective for all interim financial periods beginning after June 15, 2003.

Based on a preliminary review, TECO Energy believes it is reasonably possible that FIN 46 may impact the accounting for certain unconsolidated affiliates. Management is continuing to assess the extent of the relationships and obtain adequate information upon which to base appropriate conclusions. Below is a discussion of the legal entities existing as of Dec. 31, 2002 that TECO Energy considers to be possibly subject to either 1) additional disclosure requirements or 2) consolidation by the company, in accordance with FIN 46.

TPS entered into a joint venture, TPGC, to build, own and operate the Union and Gila River power stations. As of Dec. 31, 2002, TPGC is a development stage partnership that may meet the definition of a VIE in accordance with FIN 46. The third-party debt financing at TPGC is non-recourse and does not create an estimated loss exposure to TECO Energy. The estimated maximum loss exposure is approximately the current and guaranteed equity investment in the partnership. (See Notes A, N and R.)

TPS completed a transaction whereby certain equipment at the Hardee Power Station was sold to a third party (the Lessor) and leased back under an operating lease agreement with an initial term of 12 years. The original cost of the equipment was $46.6 million. The sole purpose of the Lessor is to own and lease back the equipment to Hardee Power. The Lessor may be a VIE in accordance with FIN 46. The lease financing arrangement includes $41.6 million of subordinated debt and $1.4 million of equity contributed by an unrelated third party. If the Lessor were to be consolidated, TPS estimates that it would incur after-tax incremental expenses of approximately $9.5 million over the 12 year term of the lease. (See Note R.)

TECO Properties formed two limited liability companies with project developers which may meet the definition of a VIE. Hernando Oaks, LLC was formed by TECO Properties with the Pensacola Group to buy and develop 627 acres of land in Hernando County, Florida into a residential golf community comprised of an 18-hole golf course and 975 single-family lots for sale to homebuilders. Hernando Oaks, LLC had total assets at Dec. 31, 2002 of $18.9 million. TECO Properties' estimated maximum loss exposure in this project is approximately $9.7 million.

B-T One, LLC is a limited liability company formed by TECO Properties with Boyd Development Co., the project developer, to buy 592 acres of land in Ocala, Florida and to develop and sell 585 single-family lots to homebuilders. B-T One, LLC had total assets at Dec. 31, 2002 of $13.1 million. TECO Properties' estimated maximum loss exposure in this project is approximately $7.5 million.

TECO Propane Ventures (TPV) has an investment in a partnership formed to combine propane operations with the propane operations of three third-party entities. The partnership may meet the definition of a VIE as established in FIN 46. At Dec. 31, 2002, the estimated maximum loss exposure faced by TPV is approximately $44.6 million. (See **Note S.**)

TECO Transport entered into two separate sale-leaseback transactions for certain vessels which were recognized as sales at the time of each transaction, and are currently recognized as operating leases for the assets. The sale-leaseback transactions were entered into with a third party that may meet the definition of a VIE. TECO Transport currently leases two ocean-going tugboats, four ocean-going barges, five river towboats and 49 river barges. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable equipment to meet contractual obligations. (See **Note R.**)

TECO Energy Services (formerly TECO BGA) formed a partnership to construct, own and operate a water cooling plant to produce and distribute chilled water to customers via a local distribution loop for use, primarily, in air conditioning systems. The partnership may meet the definition of a VIE in accordance FIN 46. The estimated maximum loss exposure associated with this partnership is approximately $3.6 million as of Dec. 31, 2002.

In November 2000, TECO Energy established TECO Capital Trust I (Trust I) for the sole purpose of issuing Trust Preferred Securities (TRuPS) and using the proceeds to purchase company preferred securities from TECO Funding Company I, LLC. Trust I may be a VIE in accordance with FIN 46. TECO Energy has guaranteed the payments to the holders of the company preferred securities and indirectly, the payments to the holders of the TRuPS, as a result of their beneficial interest in the company preferred securities.

Subsequently, in January 2002, TECO Energy sold 17.965 million units of mandatorily convertible equity units in the form of 9.5% equity units at $25 per unit. Each equity unit consisted of $25 in principal amount of a trust preferred security of TECO Capital Trust II (Trust II), a Delaware business trust formed for the purpose of issuing these securities. Trust II may meet the definition of a VIE in accordance with FIN 46. The estimated maximum loss exposure is not expected to be incrementally significant to obligations currently recognized by TECO Energy for the activities of either Trust I or Trust II. (See **Note G.**)

As a result of the conversion of a loan to a Panda Energy International subsidiary on Jan. 3, 2003, TPS has an equity interest in the TIE partnership (See **Note N**). The TIE partnership owns and operates the Odessa and Guadalupe power stations in Texas. The partnership may be a VIE in accordance with FIN 46. The estimated maximum loss exposure is approximately $137 million, representing TPS' equity investment as of Jan. 3, 2003.

U. Subsequent Event

On Jan. 30, 2003, TECO Energy received $98.1 million in cash for the repayment of a note receivable from the Municipal Gas Authority of Georgia, related to the sale of its coalbed methane assets on Dec. 20, 2002.

V. Quarterly Data (unaudited)

Financial data by quarter is as follows: *Quarter ended*	*March 31*	*June 30*	*Sept. 30*	*Dec. 31*
2002				
Revenues(1)	$ 606.6	$ 677.7	$ 731.0	$ 660.5
Income from operations(1)	$ 89.2	$ 97.8	$ 142.5	$ 59.5
Net income(1)				
Net income from continuing operations	$ 69.9	$ 80.9	$ 112.8	$ 34.6
Net income	$ 75.4	$ 85.7	$ 118.9	$ 50.1
Earnings per share (EPS)- basic				
EPS from continuing operations	$ 0.50	$ 0.56	$ 0.72	$ 0.20
EPS	$ 0.54	$ 0.59	$ 0.76	$ 0.29
Earnings per share (EPS) - diluted				
EPS from continuing operations	$ 0.50	$ 0.56	$ 0.72	$ 0.20
EPS	$ 0.54	$ 0.59	$ 0.76	$ 0.29
Dividends paid per common share(2)	$ 0.345	$ 0.355	$ 0.355	$ 0.355
Stock price per common share(3)				
High	$ 28.940	$ 29.050	$ 24.710	$ 16.480
Low	$ 23.400	$ 22.700	$ 14.200	$ 10.020
Close	$ 28.630	$ 24.750	$ 15.880	$ 15.470
2001				
Revenues(1)	$ 641.3	$ 613.2	$ 659.6	$ 574.0
Income from operations(1)	$ 103.0	$ 95.4	$ 131.7	$ 68.1
Net income(1)				
Net income from continuing operations	$ 62.1	$ 61.8	$ 90.8	$ 59.1
Net income	$ 69.7	$ 71.9	$ 97.3	$ 64.8
Earnings per share (EPS)- basic				
EPS from continuing operations	$ 0.48	$ 0.46	$ 0.67	$ 0.43
EPS	$ 0.54	$ 0.53	$ 0.72	$ 0.47
Earnings per share (EPS) - diluted				
EPS from continuing operations	$ 0.47	$ 0.44	$ 0.66	$ 0.42
EPS	$ 0.53	$ 0.52	$ 0.71	$ 0.47
Dividends paid per common share(2)	$ 0.335	$ 0.345	$ 0.345	$ 0.345
Stock price per common share(3)				
High	$ 32.125	$ 32.970	$ 31.650	$ 28.300
Low	$ 26.100	$ 28.780	$ 25.530	$ 24.750
Close	$ 29.960	$ 30.500	$ 27.100	$ 26.240

(1) Millions.
(2) Dividend paid on TECO Energy common stock.
(3) Trading prices for common shares.

TAMPA ELECTRIC COMPANY
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All other financial statement schedules have been omitted since they are not required, are inapplicable or the required information is presented in the financial statements or notes thereto.

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

To the Board of Directors and Shareholder of Tampa Electric Company

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Tampa Electric Company and its subsidiaries, (a wholly owned subsidiary of TECO Energy, Inc.) at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers, LLP

Tampa, Florida
January 22, 2003

TAMPA ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

Assets (millions) *Dec. 31,*	*2002*	*2001*
Property, Plant and Equipment		
Utility plant in service		
Electric	$ 4,310.8	$ 4,112.3
Gas	746.7	699.4
Construction work in progress	768.5	404.4
Property, plant and equipment, at original costs	5,826.0	5,216.1
Accumulated depreciation	(2,161.0)	(2,014.8)
	3,665.0	3,201.3
Other property	7.9	8.2
Total property, plant and equipment	3,672.9	3,209.5
Current Assets		
Cash and cash equivalents	6.9	15.4
Receivables, less allowance for uncollectibles of $1.1 million and $1.6 million at Dec. 31, 2002 and 2001, respectively	186.5	166.8
Inventories		
Fuel, at average cost	79.1	69.0
Materials and supplies	48.1	51.0
Prepayments and other	18.4	12.5
Total current assets	339.0	314.7
Deferred Debits		
Unamortized debt expense	23.7	8.0
Deferred income taxes	133.3	136.2
Regulatory assets	163.2	198.3
Other	5.6	12.5
Total deferred debits	325.8	355.0
Total Assets	$ 4,337.7	$ 3,879.2

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

Liabilities and Capital (millions) *Dec. 31,*	*2002*	*2001*
Capital		
Common stock	$ 1,535.1	$ 1,318.1
Retained earnings	302.9	304.4
Accumulated other comprehensive loss	--	(0.1)
Total capital	1,838.0	1,622.4
Long-term debt, less amount due within one year	1,345.6	880.9
Total capitalization	3,183.6	2,503.3
Current Liabilities		
Long-term debt due within one year	81.0	156.1
Notes payable	10.5	249.0
Accounts payable	178.8	135.8
Customer deposits	94.6	86.3
Interest accrued	18.3	16.1
Taxes accrued	46.9	57.3
Total current liabilities	430.1	700.6
Deferred Credits		
Deferred income taxes	483.1	441.6
Investment tax credits	27.1	31.6
Regulatory liabilities	98.1	106.2
Other	115.7	95.9
Total deferred credits	724.0	675.3
Total liabilities and capital	$ 4,337.7	$ 3,879.2

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME

(millions) *Year Ended Dec. 31,*	*2002*	*2001*	*2000*
Revenues			
Electric (includes franchise fees and gross receipts taxes of $63.5 million in 2002, $56.0 million in 2001, and $47.5 million in 2000)	$ 1,582.5	$ 1,411.8	$ 1,352.9
Gas (includes franchise fees and gross receipts taxes of $10.3 million in 2002, $15.1 million in 2001, and $12.2 million in 2000)	318.1	352.9	314.5
Total revenues	1,900.6	1,764.7	1,667.4
Expenses			
Operation			
Fuel	424.1	346.5	323.3
Purchased power	253.7	209.7	192.1
Cost of natural gas sold	148.9	186.4	157.0
Other	273.0	249.1	246.3
Maintenance	112.0	103.2	99.9
Depreciation	220.1	201.3	187.4
Taxes, federal and state income	100.3	97.7	95.8
Taxes, other than income	132.6	129.3	120.8
Total expenses	1,664.7	1,523.2	1,422.6
Income from operations	235.9	241.5	244.8
Other income			
Allowance for other funds used during construction	24.9	6.6	1.6
Other income, net	1.5	4.1	--
Total other income	26.4	10.7	1.6
Interest charges			
Interest on long-term debt	77.5	62.5	52.4
Other interest	(1.6)	15.2	28.4
Allowance for borrowed funds used during construction	(9.6)	(2.6)	(0.7)
Total interest charges	66.3	75.1	80.1
Net income	$ 196.0	$ 177.1	$ 166.3

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions) *Year Ended Dec. 31,*	*2002*	*2001*	*2000*
Net income	$ 196.0	$ 177.1	$ 166.3
Other comprehensive (loss) income, net of tax			
Net unrealized losses on cash flow hedges	0.1	(0.1)	—
Other comprehensive (loss) income, net of tax	0.1	(0.1)	—
Comprehensive income	$ 196.1	$ 177.0	$ 166.3

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions) *Year Ended Dec. 31,*	*2002*	*2001*	*2000*
Cash flows from operating activities			
Net income	$ 196.0	$ 177.1	$ 166.3
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation	220.1	201.3	187.4
Deferred income taxes	23.7	(1.9)	(39.4)
Investment tax credits, net	(4.4)	(4.5)	(4.4)
Allowance for funds used during construction	(34.5)	(9.2)	(2.3)
Deferred recovery clause	72.2	(19.0)	(68.7)
Refund to customers	(6.4)	–	(13.2)
Receivables, less allowance for uncollectibles	(19.8)	24.1	(33.3)
Inventories	(7.2)	(10.8)	13.0
Taxes accrued	(10.4)	(14.3)	40.7
Interest accrued	2.3	(18.1)	21.3
Accounts payable	43.1	(52.4)	24.3
Other	–	20.9	45.7
Cash flows from operating activities	474.7	293.2	337.4
Cash flows from investing activities			
Capital expenditures	(685.7)	(499.3)	(349.3)
Allowance for funds used during construction	34.5	9.2	2.3
Cash flows from investing activities	(651.2)	(490.1)	(347.0)
Cash flows from financing activities			
Proceeds from contributed capital from parent	217.0	170.0	105.0
Proceeds from long-term debt	689.3	250.0	154.5
Repayment of long-term debt	(302.4)	(54.4)	(84.1)
Net increase (decrease) in short-term debt	(238.5)	17.8	(40.0)
Payment of dividends	(197.4)	(171.8)	(151.2)
Cash flows from financing activities	168.0	211.6	(15.8)
Net (decrease) increase in cash and cash equivalents	(8.5)	14.7	(25.4)
Cash and cash equivalents at beginning of year	15.4	0.7	26.1
Cash and cash equivalents at end of year	$ 6.9	$ 15.4	$ 0.7
Supplemental Disclosure of Cash Flow Information			
Cash paid during the year for:			
Interest	$ 74.0	$ 85.3	$ 66.7
Income taxes	$ 143.9	$ 119.9	$ 98.4

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(millions) *Year Ended Dec. 31,*	*2002*	*2001*	*2000*
Balance, Beginning of Year	$ 304.3	$ 299.0	$ 283.9
Add-Net income	196.0	177.1	166.3
	500.3	476.1	450.2
Deduct-Cash dividends on capital stock			
Common	197.4	171.8	151.2
	197.4	171.8	151.2
Balance, End of Year	$ 302.9	$ 304.3	$ 299.0

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(millions, except share amounts)	*Current* Redemption *Price*	*Capital Stock Outstanding Dec. 31,* *Shares*	*Amount*	*Cash dividends paid (1)* Per *Share*	*Amount*
Common stock-Without par value					
25 million shares authorized					
2002	N/A	10	$ 1,535.1	N/A	$ 197.4
2001	N/A	10	$ 1,318.1	NA	$ 171.8
Preferred Stock-$100 Par Value					
1.5 million shares authorized, none outstanding.					
Preferred Stock - no Par					
2.5 million shares authorized, none outstanding.					
Preference Stock - no Par					
2.5 million shares authorized, none outstanding.					

(1) Quarterly dividends paid on Feb. 15, May 15, Aug. 15 and Nov. 15.

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)

(millions) *Long-Term Debt*	*Outstanding at Dec. 31,*	*Due*	*2002*	*2001*
Tampa Electric				
First mortgage bonds (issuable in series):				
7.75% (effective rate of 7.96%)		2022	$ 75.0	$ 75.0
6.125% (effective rate of 6.61%)		2003	75.0	75.0
Installment contracts payable (3):				
5.75%		2002	--	22.5
7.875% Refunding bonds (4)		2002	--	25.0
8% Refunding bonds (4)		2002	--	100.0
6.25% Refunding bonds (effective rate of 6.81%) (5)		2034	86.0	86.0
5.85% (effective rate of 5.88%)		2030	75.0	75.0
5.1% Refunding bonds (effective rate of 5.78%) (6)		2013	60.7	--
5.5% Refunding bonds (effective rate of 6.35%) (6)		2023	86.4	--
4% for 2002 (effective rate of 4.21%) and variable rate of 1.45% for 2001 (1) (7)		2025	51.6	51.6
4% for 2002 (effective rate of 4.16%) and variable rate of 1.47% for 2001 (1) (7)		2018	54.2	54.2
4.25% for 2002 (effective rate of 4.43%) and variable rate of 1.52% for 2001 (1) (7)		2020	20.0	20.0
Notes: 5.86% (1)		2002	--	100.0
Notes: 6.875% (effective rate of 6.98%) (2)		2012	210.0	210.0
Notes: 6.375% (effective rate of 7.34%) (2)		2012	330.0	--
Notes: 5.375% (effective rate of 5.58%) (2)		2007	125.0	--
			1,248.9	894.3
Peoples Gas System				
Senior Notes (8)				
10.35%		2007	4.2	5.0
10.33%		2008	5.6	6.4
10.3%		2009	7.2	7.8
9.93%		2010	7.4	8.0
8.0%		2012	25.4	27.5
Notes: 5.86% (1)		2002	--	50.0
Notes: 6.875% (effective rate of 6.98%) (2)		2012	40.0	40.0
Notes: 6.375% (effective rate of 7.34%) (2)		2012	70.0	--
Notes: 5.375% (effective rate of 5.58%) (2)		2007	25.0	--
			184.8	144.7
			1,433.7	1,039.0
Unamortized debt premium (discount), net			(7.1)	(2.0)
			1,426.6	1,037.0
Less amount due within one year (9)			81.0	156.1
Total long-term debt			$ 1,345.6	$ 880.9

(1) Composite year-end interest rate.
(2) These notes are subject to redemption in whole or in part, at any time, at the option of the company.
(3) Tax exempt securities.
(4) Proceeds of these bonds were used to refund bonds with interest rates of 11.625% - 12.625%. For accounting purposes, interest expense has been recorded using blended rates of 8.28% - 8.66% on the original and refunding bonds, consistent with regulatory treatment.
(5) Proceeds of these bonds were used to refund bonds with an interest rate of 9.9% in February 1995. For accounting purposes, interest expense has been recorded using a blended rate of 6.52% on the original and refunding bonds, consistent with regulatory treatment.
(6) Proceeds on these bonds were used to refund bonds with interest rates of 5.75% - 8%.
(7) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002.
(8) These long-term debt agreements contain various restrictive covenants, including provisions related to interest coverage, maximum levels of debt to total capitalization and limitations on dividends.
(9) Of the amount due in 2003, $0.8 million may be satisfied by the substitution of property in lieu of cash payments.

Substantially all of the property, plant and equipment of the company is pledged as collateral to secure its first mortgage bonds and certain pollution control equipment is pledged to secure installment contracts payable. Maturities and annual sinking fund requirements of long-term debt for the years 2004, 2005, 2006 and 2007 are $5.3 million, $5.5 million, $5.9 million and $156.1 million, respectively. Of these amounts $0.8 million per year for 2003 through 2006 may be satisfied by the substitution of property in lieu of cash payments.

At Dec. 31, 2002, total long-term debt had a carrying amount of $1,352.6 million and an estimated fair market value of $1,440.8 million. The estimated fair market value of long-term debt was based on quoted market prices for the same or similar issues, on the current rates offered for debt of the same remaining maturities, or for long-term debt issues with variable rates that approximate market rates, at carrying amounts. The carrying amount of long-term debt due within one year approximated fair market value because of the short maturity of these instruments.

The accompanying notes are an integral part of the consolidated financial statements.

A. Summary of Significant Accounting Policies

The significant accounting policies are as follows:

Principles of Consolidation

Tampa Electric Company (the "company") is a wholly-owned subsidiary of TECO Energy, Inc. The company is comprised of the Electric division, generally referred to as Tampa Electric, and the Natural Gas division, generally referred to as Peoples Gas System (PGS).

All significant intercompany balances and intercompany transactions have been eliminated in consolidation.

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles.

Deferred Credits and Other Liabilities

Other deferred credits primarily include the accrued post-retirement benefit liability and pension liability.

Revenue Recognition

Tampa Electric Company recognizes revenues in accordance with the Securities and Exchange Commission's Staff Accounting Bulletin (SAB) 101, *Revenue Recognition in Financial Statements*. The criteria outlined in SAB 101 are that a) there is persuasive evidence that an arrangement exists; b) delivery has occurred or services have been rendered; c) the fee is fixed and determinable; and d) collectibility is reasonably assured. Except as discussed below, the company recognizes revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer.

The regulated utilities' (Tampa Electric and Peoples Gas System) retail businesses and the prices charged to customers are regulated by the Florida Public Service Commission (FPSC). Tampa Electric's wholesale business is regulated by the Federal Energy Regulatory Commission (FERC). As a result, the regulated utilities qualify for the application of Financial Accounting Standard No. (FAS) 71, *Accounting for the Effects of Certain Types of Regulation*. See **Note D** for a discussion of the applicability of FAS 71 to the company.

Revenues and Fuel Costs

Revenues include amounts resulting from cost recovery clauses which provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs for Tampa Electric and purchased gas, interstate pipeline capacity and conservation costs for PGS. These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over-recovery or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. Over-recoveries of costs are recorded as deferred credits, and under-recoveries of costs are recorded as deferred charges.

In 1994, Tampa Electric bought out a long-term coal supply contract which would have expired in 2004 for a lump sum payment of $25.5 million. In February 1995, the FPSC authorized the recovery of this buy-out amount plus carrying costs through the Fuel and Purchased Power Cost Recovery Clause over the 10-year period beginning April 1, 1995. In each of the years 2002, 2001 and 2000, $2.7 million of buy-out costs were amortized to expense.

Certain other costs incurred by the regulated utilities are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed.

The regulated utilities accrue base revenues for services rendered but unbilled to provide a closer matching of revenues and expenses.

Tampa Electric's objectives of stabilizing prices from 1996 through 1999 and securing fair earnings opportunities during this period were accomplished through a series of agreements entered into in 1996 with Florida's Office of Public Counsel (OPC) and the Florida Industrial Power Users Group which were approved by the FPSC. Prior to these agreements, the FPSC approved a plan submitted by Tampa Electric to defer certain 1995 revenues.

In general, under these agreements Tampa Electric was allowed to defer revenues in 1995 and 1996 during the construction of Polk Unit 1 and recognize these revenues in 1997 and 1998 after commercial operation of the unit. Other components of the agreements were a base rate freeze through 1999 and refunds to customers totaling $50 million during the period October 1996 through December 1998 while Tampa Electric was allowed recovery of the capital costs incurred for the Polk Unit 1 project.

In October 2000, the FPSC staff recommended a refund of $6.1 million for the final year of the agreements. OPC objected to certain interest expenses recognized in 1999 that were associated with prior years' tax positions and used to calculate the amount to be refunded. Following a review by the FPSC staff, the FPSC agreed in December 2000 that the original $6.1

million was to be refunded to customers. In February 2001, OPC protested the FPSC's decision. The FPSC held hearings on the issue in August 2001 and upheld its original decision. In January 2002, the OPC filed a motion with the FPSC asking for reconsideration of its decision, alleging the FPSC relied on erroneous information. This was not granted and Tampa Electric made refunds associated with 1999 earnings in 2002. Over the terms of the agreements, the company refunded in total about $69 million.

Since the expiration of the agreements, Tampa Electric is not under a new stipulation. Therefore, its rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue earning within its allowed ROE range.

On June 27, 2002, PGS filed a petition with the FPSC to increase its service rates. The requested rates would have resulted in a $22.6 million annual base revenue increase, reflecting a ROE midpoint of 11.75 percent.

On the date of the FPSC hearing, PGS agreed to a settlement with all parties involved, and a final FPSC order was granted on Dec. 17, 2002. PGS received authorization to increase annual base revenues by $12.05 million. The new rates allow for an ROE range of 10.25 to 12.25 percent with an 11.25 percent midpoint ROE and a capital structure with 57.43 percent equity. The increase went into effect on Jan. 16, 2003.

Purchased Power

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. For the years ended Dec. 31, 2002, 2001 and 2000, Tampa Electric purchased power of $253.7 million, $209.7 million and $192.1 million, respectively. These purchased power costs are recoverable through an FPSC-approved cost recovery clause.

Planned Major Maintenance

Tampa Electric expenses major maintenance costs as incurred. Concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with FPSC and FERC regulations.

Depreciation

Tampa Electric Company provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage, of depreciable property over its estimated service life. The provision for utility plant in service, expressed as a percentage of the original cost of depreciable property, was 4.2% for 2002 and 2001, and 4.1% for 2000.

The original cost of utility plant retired or otherwise disposed of and the cost of removal less salvage are charged to accumulated depreciation. The implementation of FAS 143, *Accounting for Asset Retirement Obligations* in 2003 will result in the carrying amount of long-lived assets being increased, and this adjusted capitalized amount depreciated over the useful life of the asset. **(See Note N – Accounting for Asset Retirement Obligations.)**

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

Tampa Electric Company is allowed to recover certain costs incurred from customers through prices approved by the regulatory process. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statement of Income. These amounts totaled $73.8 million, $71.1 million and $59.7 million, respectively, for 2002, 2001 and 2000. Franchise fees and gross receipt taxes payable by the company are included as an expense on the Consolidated Statement of Income in Taxes, other than income. For 2002, 2001 and 2000 these totaled $73.7 million, $71.0 million and $59.8 million, respectively.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant, which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2002, 2001, and 2000. Total AFUDC for 2002, 2001 and 2000 was $34.5 million, $9.2 million and $2.3 million, respectively. The base on which AFUDC is calculated excludes construction work in progress, which has been included in rate base.

Deferred Income Taxes

The company utilizes the liability method in the measurement of deferred income taxes. Under the liability method, the temporary differences between the financial statement and tax bases of assets and liabilities are reported as deferred taxes measured at current tax rates. Tampa Electric and PGS are regulated, and their books and records reflect approved regulatory treatment, including certain adjustments to accumulated deferred income taxes and the establishment of a corresponding regulatory tax liability reflecting the amount payable to customers through future rates.

Investment Tax Credits

Investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property.

Asset Impairments

Effective Jan. 1, 2002, Tampa Electric Company adopted FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which supersedes FAS 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of.* FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a segment of a business.

The company periodically assesses whether there has been a permanent impairment of its long-lived assets and certain intangibles held and used by the company, in accordance with FAS 144, and prior to 2002 with FAS 121. Tampa Electric Company has not recorded any impairment adjustments.

Restrictions on Dividend Payments and Transfer of Assets

Tampa Electric's first mortgage bonds and certain of PGS' long-term debt issues contain provisions that limit the dividend payment on Tampa Electric Company's common stock. At Dec. 31, 2002, substantially all of the company's retained earnings were available for dividends on its common stock.

Lease Accounting Amendment

In April 2002, the Financial Accounting Standards Board (FASB) issued FAS 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* In addition to rescinding the aforementioned statements, FAS 145 amends FAS 13, *Accounting for Leases*, to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The implementation of FAS 145 has not had a significant impact on Tampa Electric Company's results.

Reclassifications

Certain prior year amounts were reclassified to conform with current year presentation.

B. Derivatives and Hedging

From time to time, Tampa Electric Company enters into futures, forwards, swaps and option contracts to limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric and PGS.

The company uses derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers.

The risk management policies adopted by the company provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operating companies.

Effective Jan. 1, 2001, the company adopted FAS 133, *Accounting for Derivative Instruments and Hedging Activities.* The new standard requires companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of other comprehensive income (OCI) or in net income, depending on the designation of those instruments. The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or the loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of its reclassification. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the amount paid or received on the underlying physical transaction. Additionally, amounts defined in OCI related to an effective designated cash flow hedge must be reclassified to current earnings if the anticipated hedged transaction is no longer probable of occurring.

At Dec. 31, 2002, the company had derivative assets totaling $3.4 million. At Dec. 31, 2001, the company had derivative liabilities totaling $0.1 million. At Dec. 31, 2001, accumulated OCI included $0.1 million of unrealized after-tax losses, representing the fair value of cash flow hedges whose transactions will occur in the future. There were no amounts recorded in OCI as of Dec. 31, 2002. Amounts recorded in OCI reflect the value of derivative instruments designated as hedges, based on market prices as of the balance sheet date. These amounts are expected to fluctuate with movements in market prices and may or may not be realized as a loss upon future reclassification from OCI.

As of Dec. 31, 2002, the company had transactions in place to hedge commodity price that qualify for cash flow hedge accounting treatment under FAS 133. During 2002, the company reclassified net pretax gains of $0.2 million to earnings for cash flow hedges, compared to pretax losses of $0.7 million in 2001. Amounts reclassified from OCI were primarily related to cash flow hedges of physical purchases of natural gas. For these types of hedge relationships, the loss on the derivative, reclassified from OCI to earnings, is offset by the reduced expense arising from lower prices paid for spot purchases of natural gas. Conversely, reclassification of a gain from OCI to earnings is offset by the increased cost of spot purchases of natural gas.

Based on the fair values at Dec. 31, 2002, pretax gains of $3.4 million are expected to be reversed from OCI to the Consolidated Statement of Income within the next twelve months. However, these gains and other future reclassifications from OCI will fluctuate with movements in the underlying market price of the derivative instruments. The company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2003.

C. Goodwill and Other Intangible Assets

Effective Jan. 1, 2002, Tampa Electric Company adopted FAS 141, *Business Combinations*, and FAS 142, *Goodwill and Other Intangible Assets*. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting. With the adoption of FAS 142, goodwill is no longer subject to amortization. Rather, goodwill is subject to an annual assessment for impairment by applying a fair-value-based test. Under the new rules, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented, or exchanged, regardless of the acquiror's intent to do so. These intangible assets are required to be amortized over their useful lives. The company has no recorded goodwill.

D. Regulatory Assets and Liabilities

Tampa Electric and PGS maintain their accounts in accordance with recognized policies of the FPSC. In addition, Tampa Electric maintains its accounts in accordance with recognized policies prescribed or permitted by the FERC. These policies conform with generally accepted accounting principles in all material respects.

Tampa Electric and PGS apply the accounting treatment permitted by FAS 71, *Accounting for the Effects of Certain Types of Regulation*. Areas of applicability include: deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel; purchased power, conservation and environmental costs; and deferral of costs as regulatory assets when cost recovery is ordered over a period longer than a fiscal year, to the period that the regulatory agency recognizes them. Details of the regulatory assets and liabilities as of Dec. 31, 2002 and 2001 are presented in the following table:

Regulatory Assets and Liabilities

(millions) Dec. 31,	*2002*	*2001*
Regulatory assets:		
Regulatory tax asset (1)	$ 54.9	$ 41.3
Other:		
Cost recovery clauses	34.7	105.2
Coal contract buy-out (2)	5.4	8.1
Unamortized refinancing costs (3)	35.9	13.7
Environmental remediation	20.3	22.3
Competitive rate adjustment	7.4	5.9
Other	4.6	1.8
	108.3	157.0
Total regulatory assets	$ 163.2	$ 198.3
Regulatory liabilities:		
Regulatory tax liability (1)	$ 36.6	$ 43.1
Other:		
Deferred allowance auction credits	2.1	1.1
Cost recovery clauses	2.2	0.5
Revenue refund	—	6.3
Environmental remediation	20.3	22.3
Transmission and distribution storm reserve	36.0	32.0
Deferred gain on property sales(4)	0.9	0.9
	61.5	63.1
Total regulatory liabilities	$ 98.1	$ 106.2

(1) Related primarily to plant life. Includes excess deferred taxes of $20.9 million and $24.6 million as of Dec. 31, 2002 and 2001, respectively.

(2) Amortized over a 10-year period ending December 2004.

(3) Unamortized refinancing costs:

Related to debt transactions as follows (millions):	Amortized until:
$ 155.0	2003
$ 51.6	2005
$ 22.1	2007
$ 25.0	2011
$ 50.0	2011
$ 150.0	2012
$ 150.0	2012
$ 85.9	2014
$ 25.0	2021
$ 100.0	2022

(4) Amortized over a 5-year period with various ending dates.

E. Short-term Debt

Notes payable consisted primarily of commercial paper with weighted average interest rates of 1.86% and 1.99% at Dec. 31, 2002 and 2001, respectively. The carrying amount of notes payable approximated fair market value because of the short maturity of these instruments. Tampa Electric has a bank credit facility of $300 million with a maturity date of November 2003. None of the credit facility was drawn at Dec. 31, 2002. The credit facility requires commitment fees of 15 basis points and drawn amounts are charged interest at LIBOR plus 87–97.5 basis points at current ratings.

F. Common Stock

Tampa Electric Company is a wholly owned subsidiary of TECO Energy, Inc.

(millions, except per share amounts)	*Common Stock Shares*	*Common Stock Amount*	*Issue Expense*	*Total*
Balance Dec. 31, 1999	10	$ 1,043.8	$ (0.7)	$ 1,043.1
Contributed capital from parent	--	105.0	--	105.0
Balance Dec. 31, 2000	10	1,148.8	(0.7)	1,148.1
Contributed capital from parent	--	170.0	--	170.0
Balance Dec. 31, 2001	10	1,318.8	(0.7)	1,318.1
Contributed capital from parent	--	217.0	--	217.0
Balance Dec. 31, 2002	10	$ 1,535.8	$ (0.7)	$ 1,535.1

G. Comprehensive Income

FAS 130, *Reporting Comprehensive Income*, requires that comprehensive income, which includes net income as well as certain changes in assets and liabilities recorded in common equity, be reported in the financial statements. Tampa Electric Company reported the following comprehensive income (loss) in 2002 and 2001 related to changes in the fair value of cash flow hedges. There was no comprehensive income (loss) for 2000.

Comprehensive Income (loss)

(millions)	*Gross*	*Tax*	*Net*
2002			
Unrealized (loss) gain on cash flow hedges	$ 0.3	$ 0.1	$ 0.2
Less: Loss (gain) reclassified to net income	(0.2)	(0.1)	(0.1)
Total other comprehensive income (loss)	$ 0.1	$ --	$ 0.1
2001			
Unrealized (loss) gain on cash flow hedges	$ (0.8)	$ (0.3)	$ (0.5)
Less: Loss (gain) reclassified to net income	0.7	0.3	0.4
Total other comprehensive income (loss)	$ (0.1)	$ --	$ (0.1)

H. Employee Postretirement Benefits

Pension Benefits

Tampa Electric Company is a participant in the comprehensive retirement plans of TECO Energy, including a non-contributory defined benefit retirement plan which covers substantially all employees. On April 1, 2000, the plan was amended to provide for benefits to be earned and payable substantially on a lump sum basis through an age and service credit schedule for eligible participants leaving the company on or after July 1, 2001. Other significant provisions of the plan, such as eligibility, definitions of credited service, final average earnings, etc., were largely unchanged. This amendment resulted in decreased pension expense at TECO Energy of approximately $0.8 million and $2.0 million in 2001 and 2000, respectively, and a reduction of benefit obligation of $6.2 million and $14.4 million at Sept. 30, 2001 and 2000, respectively.

TECO Energy's policy is to fund the plan within the guidelines set by ERISA for the minimum annual contribution and the maximum allowable as a tax deduction by the IRS. About 53 percent of plan assets were invested in common stocks and 47 percent in fixed income investments at Sept. 30, 2002.

Amounts shown also include the unfunded obligations for the supplemental executive retirement plan, non-qualified, non-contributory defined benefit retirement plans available to certain senior management. TECO Energy reported other comprehensive loss of $4.4 million in 2002 and other comprehensive income of $0.3 million and $2.0 million in 2001 and 2000, respectively, related to adjustments to the minimum pension liability associated with the supplemental executive retirement plan.

In 2001, TECO Energy elected to change the measurement date for pension obligations and plan assets from Dec. 31 to Sept. 30. The effect of this accounting change is not material.

Components of net pension expense, reconciliation of the funded status and the accrued pension liability are presented below for TECO Energy consolidated.

Components of net periodic pension benefit expense

(millions)	*2002*	*2001*	*2000*
Service cost (benefits earned during the period)	$ 11.8	$ 11.2	$ 10.7
Interest cost on projected benefit obligations	28.7	27.9	27.5
Expected return on assets	(42.9)	(42.0)	(40.8)
Amortization of:			
Transition obligation (asset)	(1.1)	(1.1)	(1.0)
Prior service cost (benefit)	(0.5)	(0.5)	0.2
Actuarial (gain) loss	(3.7)	(4.4)	(5.6)
Pension expense (benefit)	(7.7)	(8.9)	(9.0)
Special termination benefit charge	2.7	—	1.1
Additional amounts recognized	—	—	—
Net pension expense (benefit) recognized in the Consolidated Statements of Income (1)	$ (5.0)	$ (8.9)	$ (7.9)

(1) Tampa Electric Company's portion was ($7.8) million, ($10.4) million and ($9.4) million for 2002, 2001 and 2000, respectively.

Reconciliation of the funded status of the retirement plan and the accrued pension prepayment/(liability)

(millions)	*2002*	*2001*
Change in benefit obligation		
Net benefit obligation at prior measurement date	$ 382.3	$ 379.9
Service cost	11.8	11.2
Interest cost	28.7	27.9
Actuarial (gain) loss	58.3	(8.7)
Plan amendments	1.1	(6.2)
Special termination benefits	2.7	—
Gross benefits paid	(29.8)	(21.8)
Net benefit obligation at measurement date	$ 455.1	$ 382.3
Change in plan assets		
Fair value of plan assets at prior measurement date	$ 428.0	$ 493.8
Actual return on plan assets	(24.9)	(43.7)
Employer contributions	1.7	2.1
Gross benefits paid (including expenses)	(32.9)	(24.2)
Fair value of plan assets at measurement date	$ 371.9	$ 428.0
Funded status		
Funded status at measurement date	$ (83.2)	$ 45.7
Net contributions after measurement date	0.4	0.4
Unrecognized net actuarial (gain) loss	88.9	(44.0)
Unrecognized prior service cost (benefit)	(7.4)	(9.0)
Unrecognized net transition obligation (asset)	(2.5)	(3.6)
Accrued liability at end of year	$ (3.8)	$ (10.5)
Amounts recognized in the statement of financial position		
Prepaid benefit cost	$ 14.7	$ 6.3
Accrued benefit cost	(18.5)	(16.8)
Additional minimum liability	(13.8)	(6.2)
Intangible asset	1.5	1.1
Accumulated other comprehensive income	12.3	5.1
Net amount recognized at end of year	$ (3.8)	$ (10.5)
Assumptions used in determining actuarial valuations		
Discount rate to determine projected benefit obligation	6.75%	7.5%
Rate of increase in compensation levels	4.8%	4.7%
Plan asset growth rate through time	9.0%	9.0%

Other Postretirement Benefits

Tampa Electric provides certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. The company contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and June 30, 2001, is limited to a defined dollar benefit based on years of service. On April 1, 2000, the company adopted changes to this program for participants retiring from the company on or after July 1, 2001. The company contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after July 1, 2001 is limited to a defined dollar benefit based on an age and service schedule. The impact of this amendment, including a change in the company's commitment for future retirees combined with a grandfathering provision for current retired participants, resulted in a reduction in the benefit obligation of $1.4 million in 2001. Postretirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify the plans in whole or in part at any time.

In 2001, the company elected to change the measurement date for benefit obligations from Dec. 31 to Sept. 30. The effect of this accounting change was not material.

Components of postretirement benefit cost

(millions)	*2002*	*2001*	*2000*
Service cost (benefits earned during the period)	$ 2.4	$ 2.3	$ 2.0
Interest cost on projected benefit obligations	8.6	8.4	7.0
Amortization of:			
Transition obligation (straight line over 20 years)	2.1	2.1	2.1
Prior service cost	1.7	1.7	1.5
Actuarial loss/(gain)	0.1	0.3	(0.2)
Pension expense	14.9	14.8	12.4
Special termination benefits	0.6	--	0.2
Additional amounts recognized	(0.1)	--	(0.2)
Net periodic postretirement benefit expense	$ 15.4	$ 14.8	$ 12.4

Reconciliation of the funded status of the postretirement benefit plan and the accrued liability

(millions)	*2002*	*2001*
Change in benefit obligation		
Net benefit obligation at prior measurement date	$ 114.8	$ 103.9
Service cost	2.4	2.3
Interest cost	8.6	8.4
Plan participants' contributions	0.8	0.7
Actuarial loss	17.3	5.8
Plan amendments	--	(1.4)
Special termination benefits	0.6	--
Gross benefits paid	(5.7)	(4.9)
Net benefit obligation at measurement date	$ 138.8	$ 114.8
Change in plan assets		
Fair value of plan assets at prior measurement date	--	--
Employer contributions	4.9	4.2
Plan participants' contributions	0.8	0.7
Gross benefits paid (including expenses)	(5.7)	(4.9)
Fair value of plan assets at measurement date	$ --	$ --
Funded status		
Funded status at measurement date	$ (138.8)	$ (114.8)
Net contributions after measurement date	1.5	1.2
Unrecognized net actuarial loss	29.5	12.2
Unrecognized prior service cost	20.3	22.0
Unrecognized net transition obligation	21.1	23.2
Accrued liability at end of year	$ (66.4)	$ (56.2)
Assumptions Used in Determining Actuarial Valuations		
Discount rate to determine projected benefit obligation	6.75%	7.5%

The assumed health care cost trend rate for medical costs was 12.5% in 2002 and decreases to 5.0% in 2013 and thereafter.

A 100 basis point increase in the medical trend rates would produce a 7 percent ($0.8 million) increase in the aggregate service and interest cost for 2002, and a 5 percent ($7.2 million) increase in the accumulated postretirement benefit obligation as of Sept. 30, 2002.

A 100 basis point decrease in the medical trend rates would produce a 3 percent ($0.4 million) decrease in the aggregate service and interest cost for 2001 and a 3 percent ($3.8 million) decrease in the accumulated postretirement benefit obligation as of Sept. 30, 2001.

I. Income Tax Expense

Tampa Electric Company is included in the filing of a consolidated federal income tax return with TECO Energy and its affiliates. Tampa Electric Company's income tax expense is based upon a separate return computation. Income tax expense consists of the following:

Income Tax Expense

(millions)	*Federal*	*State*	*Total*
2002			
Currently payable	$ 66.7	$ 14.9	$ 81.6
Deferred	23.2	0.4	23.6
Amortization of investment tax credits	(4.4)	--	(4.4)
Total income tax expense	$ 85.5	$ 15.3	100.8
Included in other income, net			0.5
Included in operating expenses			$ 100.3
2001			
Currently payable	$ 88.6	$ 15.7	$ 104.3
Deferred	(1.3)	(0.7)	(2.0)
Amortization of investment tax credits	(4.4)	--	(4.4)
Total income tax expense	$ 82.9	$ 15.0	97.9
Included in other income, net			0.2
Included in operating expenses			$ 97.7
2000			
Currently payable	$ 128.3	$ 11.4	$ 139.7
Deferred	(42.5)	3.1	(39.4)
Amortization of investment tax credits	(4.4)	--	(4.4)
Total income tax expense	$ 81.4	$ 14.5	95.9
Included in other income, net			0.1
Included in operating expenses			$ 95.8

Deferred taxes result from temporary differences in the recognition of certain liabilities or assets for tax and financial reporting purposes. The principal components of the company's deferred tax assets and liabilities recognized in the balance sheet are as follows:

Deferred Income Tax Assets and Liabilities

(millions) Dec. 31,	*2002*	*2001*
Deferred tax assets (1)		
Property related	$ 90.3	$ 106.1
Leases	3.5	3.9
Insurance reserves	17.7	16.5
Early capacity payments	6.0	6.5
Other	–	3.2
Total deferred income tax assets	117.5	136.2
Deferred income tax liabilities (1)		
Property related	(499.5)	(461.2)
Other	32.2	19.6
Total deferred income tax liabilities	(467.3)	(441.6)
Accumulated deferred income taxes	$ (349.8)	$ (305.4)

(1) Certain property related assets and liabilities have been netted.

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes for the following reasons:

Effective Income Tax Rate

(millions)	*2002*	*2001*	*2000*
Net income	$ 196.0	$ 177.1	$ 166.3
Total income tax provision	100.8	97.9	95.9
Income before income taxes	$ 296.8	$ 275.0	$ 262.2
Income taxes on above at federal statutory rate of 35%	$ 103.8	$ 96.2	$ 91.7
Increase (decrease) due to			
State income tax, net of federal income tax	10.0	9.8	9.5
Amortization of investment tax credits	(4.4)	(4.5)	(4.4)
Equity portion of AFUDC	(8.7)	(2.3)	(0.5)
Other	0.1	(1.3)	(0.4)
Total income tax provision	$ 100.8	$ 97.9	$ 95.9
Provision for income taxes as a percent of income before income taxes	34.0%	35.6%	36.6%

J. Related Party Transactions

Tampa Electric and TECO-Panda Generating Company (TPGC) II, an affiliate of TECO Power Services, Inc., entered into an assignment and assumption agreement whereby Tampa Electric obtained TPGC II's rights and interests to four combustion turbines being purchased from General Electric, and assumed the corresponding liabilities and obligations for such equipment. In accordance with the terms of the assignment and assumption agreement, Tampa Electric paid $62.5 million to TPGC II as reimbursement for amounts already paid to General Electric by TPGC II for such equipment.

A summary of activities between Tampa Electric Company and its affiliates follows:

Net transactions with affiliates:

(millions)	*2002*	*2001*	*2000*
Fuel and interchange related, net	$ 144.9	$ 162.0	$ 155.7
Administrative and general, net	$ 10.7	$ 22.1	$ 24.7

Amounts due from or to affiliates of the company at Dec. 31,

(millions)	*2002*	*2001*
Accounts receivable (1)	$ 6.6	$ 7.5
Accounts payable (1)	$ 23.6	$ 13.0

(1) Accounts receivable and accounts payable were incurred in the ordinary course of business and do not bear interest.

K. Segment Information

Tampa Electric Company is a public utility operating within the state of Florida. Through its Tampa Electric division, it is engaged in the generation, purchase, transmission, distribution and sale of electric energy to almost 598,000 customers in West Central Florida. Its Peoples Gas System division is engaged in the purchase, distribution and marketing of natural gas for more than 281,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

Segment Information

(millions)		*Revenues*	*Net Income*	*Depreciation*	*Assets at Dec. 31.*	*Capital Expenditures*
2002						
	Tampa Electric	$ 1,583.2 (1)	$ 171.8	$ 189.8	$ 3,745.8	$ 632.2
	Peoples Gas System	318.1	24.2	30.5	592.0 (2)	53.5
	Other and eliminations	(0.7)	--	--	--	--
	Tampa Electric Company	$ 1,900.6	$ 196.0	$ 220.3	$ 4,337.8	$ 685.7
2001						
	Tampa Electric	$ 1,412.7 (1)	$ 154.0	$ 173.4	$ 3,328.0	$ 426.3
	Peoples Gas System	352.9	23.1	27.9	551.2 (2)	73.0
	Other and eliminations	(0.9)	--	--	--	--
	Tampa Electric Company	$ 1,764.7	$ 177.1	$ 201.3	$ 3,879.2	$ 499.3
2000						
	Tampa Electric	$ 1,353.8 (1)	$ 144.5	$ 161.6	$ 3,014.2	$ 267.1
	Peoples Gas System	314.5	21.8	25.8	535.6 (2)	82.2
	Other and eliminations	(0.9)	--	--	--	--
	Tampa Electric Company	$ 1,667.4	$ 166.3	$ 187.4	$ 3,549.8	$ 349.3

(1) Revenues from sales to affiliates were $34.4 million, $32.6 million and $32.4 million in 2002, 2001 and 2000, respectively.

(2) Includes a regulatory asset for estimated environmental remediation of $20.3 million at Dec. 31, in 2002 and $22.3 million at Dec. 31, 2001 and 2000.

L. Commitments and Contingencies

Capital Investments

For 2003, Tampa Electric expects to spend $232 million, consisting of $78 million for the repowering project at the Gannon Station, and $154 million to support system growth and generation reliability. Tampa Electric's estimated capital expenditures over the 2004-2007 period are projected to be $841 million, including $67 for the Gannon repowering project. At the end of 2002, Tampa Electric had outstanding commitments of about $119 million for the Gannon repowering project.

Capital expenditures for PGS are expected to be about $40 million in 2003 and $160 million during the 2004-2007 period. Included in these amounts are approximately $25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing maintenance and system safety.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company is a potentially responsible party for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2002, Tampa Electric Company has estimated its ultimate financial liability to be $20 million, and this amount has been accrued in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors, or Tampa Electric Company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric and other potentially responsible parties (PRPs) is based on each parties relative ownership interest in or usage of a site. Accordingly, Tampa Electric's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Guarantees and Letters of Credit

Tampa Electric Company has outstanding letters of credit of $0.9 million at Dec. 31, 2002, which guarantee performance to third parties related to debt service.

In addition, Tampa Electric Company includes indemnity clauses, in the normal course of business, in certain agreements with vendors and other third parties. Such clauses may provide indemnification to the counter-party for certain amounts such as legal fees, environmental remediation costs and other similar costs arising from potential future events or changes in laws or regulations. As these agreements cover a variety of goods and services, and have varying triggering events dependent on actions by third parties, Tampa Electric Company is unable to estimate the maximum potential future exposure under these clauses. As claims are made or changes in laws or regulations indicate, an amount related to the indemnification is reflected in the financial statements.

Financial Covenants

A summary of Tampa Electric's significant financial covenants is as follows:

Tampa Electric Significant Financial Covenants

(millions) *Instrument*	*Financial Covenant (1)*	*Requirement/ Restriction*	*Calculation at Dec. 31, 2002*
Tampa Electric			
Mortgage bond indenture	Dividend restriction	Cumulative distributions cannot exceed cumulative net income plus $4	$189 unrestricted
PGS senior notes	EBIT/interest	Minimum of 2.0 times	3.7 times
	Restricted payments	Shareholder equity at least $500	$1,838
	Funded debt/capital	Cannot exceed 65%	44.8%
	Sale of assets	Less than 20% of total assets	0%
Credit facility	Debt/capital	Cannot exceed 60%	43.9%
	EBITDA/interest	Minimum of 2.5 times	7.8 times

(1) As defined in applicable instrument.

N. New Accounting Pronouncements

Accounting for Asset Retirement Obligations

In July 2001, the FASB issued FAS 143, *Accounting for Asset Retirement Obligations*, which requires the recognition of a liability at fair value for an asset retirement obligation in the period in which it is incurred. Retirement obligations associated with long-lived assets included within the scope of FAS 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are included in the scope of the standard only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its future value. The corresponding amount capitalized at inception is depreciated over the useful life of the asset. The liability must be revalued each period based on current market prices. FAS 143 is effective for fiscal years beginning after June 15, 2002. The adoption of FAS 143 is not anticipated to have a material impact on Tampa Electric's results.

Exit or Disposal Costs

In July 2002, the FASB issued FAS 146, *Accounting for Costs Associated with Exit or Disposal Activities*, which addresses the accounting for costs under certain circumstances, including costs to terminate a contract that is not a capital lease, costs to consolidate facilities or relocate employees, and termination benefits provided to employees that are involuntarily terminated under the terms of a one-time benefit arrangement that is not an ongoing benefit arrangement or an individual deferred compensation contract. FAS 146 is effective for disposal activities initiated after Dec. 31, 2002 with early adoption allowed.

Tampa Electric Company opted to adopt early FAS 146 in 2002. Early retirements were accepted by 52 employees at Tampa Electric's electric division in mid-2002. Costs associated with this program were approximately $6.3 million and were recognized in operation expenses in the third quarter of 2002. In the fourth quarter of 2002, Tampa Electric Company initiated an additional restructuring program that impacted approximately 130 employees. This program includes retirements, the elimination of positions and other cost control measures. The total costs associated with this program, including severance, salary continuance through the end of 2002 and other benefit costs, were approximately $12 million and were recognized in the fourth quarter of 2002.

Guarantees

In November 2002, the FASB issued Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of others (an interpretation of FAS Nos. 5, 57, and 107 and rescission of FAS Interpretation No. 34)*, which modifies the accounting and enhances the disclosure of certain types of guarantees. FIN 45 requires that upon issuance of certain guarantees, the guarantor must recognize a liability for the fair value of the obligation it assumes under the guarantee. FIN 45's provisions for the initial recognition and measurement are to be applied to guarantees issued or modified after Dec. 31, 2002. The disclosure requirements are effective for financial statements of annual periods that end after Dec. 15, 2002 (see **Note L**).

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

During the period Jan. 1, 2001 to the date of this report, neither TECO Energy nor Tampa Electric Company has had or has filed with the Commission a report as to any changes in or disagreements with accountants on accounting principles or practices, financial statement disclosure, or auditing scope or procedure.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

(a) The information required by Item 10 with respect to the directors of the registrant is included under the caption "Election of Directors" on pages 1 through 3 of TECO Energy's definitive proxy statement, dated March 7, 2003, for its Annual Meeting of Shareholders to be held on April 22, 2003 (Proxy Statement) and is incorporated herein by reference.

(b) The information required by Item 10 concerning executive officers of the registrant is included under the caption "Executive Officers of the Registrant" on page 19 of this report.

(c) The information required by Item 10 concerning Section 16(a) Beneficial Ownership Reporting Compliance is included under that caption on page 18 of the Proxy Statement and is incorporated herein by reference.

(d) TECO Energy has had a code of ethics applicable to all of its employees and officers for many years. It was expanded to apply to the Board of Directors in 2002. The text of the *Standards of Integrity* is available on the company's website at www.tecoenergy.com under Investor Relations. Any amendments to or waivers of the *Standards of Integrity* for the benefit of any executive officer or director will also be posted on the website.

(e) Information regarding TECO Energy's Audit Committee is included on pages 4 and 17 of the Proxy Statement. The Board of Directors has determined that at least one of the independent directors serving on the Audit Committee, Mr. Sherrill Hudson, is an audit committee financial expert, as that term has been defined by the SEC.

Item 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is included in the Proxy Statement beginning on page 6 under the caption "Shareholder Return Performance Graph" and ending on page 13 just above the caption "Shareholder Proposals", and under the caption "Compensation of Directors" on page 4, and is incorporated herein by reference.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

The information required by Item 12 is included under the caption "Share Ownership" on pages 5 and 6 of the Proxy Statement and is incorporated herein by reference.

Equity Compensation Plan Information

(thousands, except per share price)	(a)	(b)	(c)
Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans/arrangements approved by the stockholders			
1996 Equity Incentive Plan	6,416	$ 25.94	4,288
1997 Director Equity Plan	206	$ 25.31	270
	6,622	$ 25.92	4,558
Equity compensation plans/arrangements not approved by the stockholders			
None	--	--	--
Total	6,622	$ 25.92	4,558

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

The information required by Item 13 is included under the caption "Certain Relationships and Related Transactions" on pages 5 and 6 of the Proxy Statement and is incorporated herein by reference.

Item 14. CONTROLS AND PROCEDURES

TECO Energy, Inc.

(a) **Evaluation of Disclosure Controls and Procedures**. TECO Energy's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of TECO Energy's disclosure controls and procedures (as such term is defined in Rules 13a-14(c) and 15d-14(c) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, TECO Energy's disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to TECO Energy (including its consolidated subsidiaries) required to be included in TECO Energy's reports filed or submitted under the Exchange Act.

(b) **Changes in Internal Controls**. Since the Evaluation Date, there have not been any significant changes in TECO Energy's internal controls or in other factors that could significantly affect such controls.

Tampa Electric Company

(a) **Evaluation of Disclosure Controls and Procedures**. Tampa Electric Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of Tampa Electric's disclosure controls and procedures (as such term is defined in Rules 13a-14(c) and 15d-14(c) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, Tampa Electric's disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to Tampa Electric (including its consolidated subsidiaries) required to be included in Tampa Electric's reports filed or submitted under the Exchange Act.

(b) **Changes in Internal Controls**. Since the Evaluation Date, there have not been any significant changes in Tampa Electric's internal controls or in other factors that could significantly affect such controls.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(a)
1. TECO Energy, Inc. Financial Statements - See index on page 64
2. Tampa Electric Company Financial Statements - See index on page 104
3. TECO Energy, Inc. Financial Statement Schedules - See index on page 64
4. Tampa Electric Company Financial Statement Schedules - See index on page 104
5. Exhibits - See index beginning on page 139

(b) **Reports on Form 8-K**

TECO Energy, Inc. filed the following reports on Form 8-K during the last quarter of 2002.

1. The registrant filed a Current Report on Form 8-K on Oct. 8, 2002 under "Item 5. Other Events" and "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", reporting on TECO Energy's preliminary third quarter results and announcing its plan to conduct a public offering of its common stock.

2. The registrant filed a Current Report on Form 8-K on Oct. 11, 2002 under "Item 5. Other Events" and "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", furnishing certain exhibits for incorporation by reference into the Registration Statement on Form S-3 previously filed with the Securities and Exchange Commission (File No. 333-83958).

3. The registrant filed a Current Report on Form 8-K on Nov. 5, 2002 under "Item 9. Regulation FD Disclosure", reporting that the press release for the third quarter earnings, along with additional third quarter financial information, including unaudited financial statements and other financial data, could be found on the registrant's website.

4. The registrant filed a Current Report on Form 8-K on Nov. 12, 2002 under "Item 5. Other Events" and "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", reporting TECO Energy's progress on its business plan, credit facilities and bond exchange and responding to investor concerns.

5. The registrant filed a Current Report on Form 8-K on Nov. 15, 2002 under "Item 5. Other Events", and "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", announcing that TECO Energy agreed to sell a new series of five-year notes to refinance an earlier series of notes.

6. The registrant filed a Current Report on Form 8-K on Nov. 15, 2002 under "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", furnishing the Credit Agreement among Tampa Electric Company, as borrower, Citibank, N.A., as Administrative Agent, Salomon Smith Barney, Inc., as Lead Arranger, Morgan Stanley Senior Funding, Inc., and The Bank of New York, as Co-Syndication Agents, and Bank of America, N.A., as Documentation Agent.

7. The registrant filed a Current Report on Form 8-K on Nov. 20, 2002 under "Item 5. Other Events", and "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", to furnish certain exhibits including the Purchase Agreement, Eighth Supplemental Indenture, and Registration Rights Agreements for the sales of Notes in private transactions in conformance with Rule 144A under the Securities Act of 1933, as amended.

8. The registrant filed a Current Report on Form 8-K/A on Nov. 21, 2002 under "Item 5. Other Events", and "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", to furnish, due to a printer error in submitting the Current Report on Nov. 20, 2002, a complete copy of the Purchase Agreement for the sales of notes in private transactions in conformance with Rule 144A under the Securities Act of 1933, as amended.

9. The registrant filed a Current Report on Form 8-K on Dec. 18, 2002 under "Item 5. Other Events", and "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", reporting that Peoples Gas System had received Florida Public Service Commission authorization to increase the annual gross revenues of the company.

10. The registrant filed a Current Report on form 8-K on Dec. 19, 2002 under "Item 5. Other Events" and "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", filing audited historical financial statements for the years ended Dec. 31, 2001, 2002 and 1999 in connection with (1) the adoption of Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets", (2) the adoption of the consensus reached through the deliberations of Emerging Issues Task Force No. 02-03, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities" and (3) its announced intent to sell the TECO Coalbed Methane gas assets, requiring its reclassification as discontinued operations.

11. The registrant filed a Current Report on Form 8-K on Dec. 20, 2002 under "Item 5. Other Events" and "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", reporting that TECO Energy, Inc.'s TECO Coalbed Methane subsidiary had completed the sale of substantially all of its assets in Alabama to the Municipal Gas Authority of Georgia.

TECO Energy, Inc. filed the following reports on Form 8-K subsequent to Dec. 31, 2002.

1. The registrant filed a Current Report on Form 8-K dated Jan. 22, 2003, under "Item 5. Other Events" and "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", reporting on TECO Energy's full-year 2002 financial results.

Tampa Electric Company filed the following report on Form 8-K during the last quarter of 2002.

1. The registrant filed a Current Report on Form 8-K on Nov. 15, 2002 under "Item 7. Financial Statements, Pro Forma Financial Statements and Exhibits", furnishing the Credit Agreement among Tampa Electric Company, as borrower, Citibank, N.A., as Administrative Agent, Salomon Smith Barney, Inc., as Lead Arranger, Morgan Stanley Senior Funding, Inc., and The Bank of New York, as Co-Syndication Agents, and Bank of America, N.A., as Documentation Agent.

(c) The exhibits filed as part of this Form 10-K are listed on the Exhibit Index immediately preceding such Exhibits. The Exhibit Index is incorporated herein by reference.

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended Dec. 31, 2002, 2001 and 2000
(millions)

TECO Energy, Inc.

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Other Charges	Deductions(1)	Balance at End of Period
Allowance for Uncollectible Accounts:					
2002	$ 7.1	$ 9.4	$ 0.3	$ 10.2	$ 6.6
2001	$ 8.7	$ 8.1	$ (0.3)	$ 9.4	$ 7.1
2000	$ 3.5	$ 10.2	$ 0.2	$ 5.2	$ 8.7

(1) Write-off of individual bad debt accounts

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended Dec. 31, 2002, 2001 and 2000
(millions)

Tampa Electric Company

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Other Charges	Deductions(1)	Balance at End of Period
Allowance for Uncollectible Accounts:					
2002	$ 1.6	$ 7.7	$ --	$ 8.2	$ 1.1
2001	$ 2.0	$ 7.2	$ --	$ 7.6	$ 1.6
2000	$ 1.1	$ 5.6	$ --	$ 4.7	$ 2.0

---

(1) Write-off of individual bad debt accounts

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 7th day of March, 2003.

TECO ENERGY, INC.

By: /s/ R. D. FAGAN
R. D. FAGAN, Chairman of the Board,
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on March 7, 2003:

Signature	Title
/s/ R. D. FAGAN R. D. FAGAN	Chairman of the Board, President, Director and Chief Executive Officer (Principal Executive Officer)
/s/ G. L. GILLETTE G. L. GILLETTE	Senior Vice President-Finance and Chief Financial Officer (Principal Financial Officer)
/s/ S. A. MYERS S. A. MYERS	Vice President-Corporate Accounting and Tax (Principal Accounting Officer)

Signature	Title	Signature	Title
C. D. AUSLEY* C. D. AUSLEY	Director	T. L. RANKIN* T. L. RANKIN	Director
S. L. BALDWIN* S. L. BALDWIN	Director	W. D. ROCKFORD* W. D. ROCKFORD	Director
J. L. FERMAN, JR.* J. L. FERMAN, JR.	Director	W. P. SOVEY* W. P. SOVEY	Director
L. GUINOT, JR.* L. GUINOT, JR.	Director	J. T. TOUCHTON* J. T. TOUCHTON	Director
I. D. HALL* I.D. HALL	Director	J. A. URQUHART* J. A. URQUHART	Director
S. W. HUDSON* S. W. HUDSON	Director	J. O. WELCH, JR. * J. O. WELCH, JR.	Director

*By: /s/ G. L. GILLETTE
G. L. GILLETTE, Attorney-in-fact

CERTIFICATIONS

I, Robert D. Fagan, certify that:

1. I have reviewed this annual report on Form 10-K of TECO Energy, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 7, 2003

/s/ R. D. FAGAN
R. D. FAGAN
Chairman of the Board, President,
Director and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATIONS

I, Gordon L. Gillette, certify that:

1. I have reviewed this annual report on Form 10-K of TECO Energy, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 7, 2003

/s/ G. L. GILLETTE
G. L. GILLETTE
Senior Vice President - Finance
and Chief Financial Officer
(Principal Financial Officer)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 7th day of March, 2003.

TAMPA ELECTRIC COMPANY

By: /s/ R. D. FAGAN
R. D. FAGAN, Chairman of the Board,
Director and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on March 7, 2003:

Signature	Title
/s/ R. D. FAGAN R. D. FAGAN	Chairman of the Board, Director and Chief Executive Officer (Principal Executive Officer)
/s/ G. L. GILLETTE G. L. GILLETTE	Senior Vice President-Finance and Chief Financial Officer (Principal Financial Officer)
/s/ P. L. BARRINGER P. L. BARRINGER	Vice President-Controller (Principal Accounting Officer)

Signature	Title	Signature	Title
C. D. AUSLEY* C. D. AUSLEY	Director	T. L. RANKIN* T. L. RANKIN	Director
S. L. BALDWIN* S. L. BALDWIN	Director	W. D. ROCKFORD* W. D. ROCKFORD	Director
J. L. FERMAN, JR.* J. L. FERMAN, JR.	Director	W. P. SOVEY* W. P. SOVEY	Director
L. GUINOT, JR.* L. GUINOT, JR.	Director	J. T. TOUCHTON* J. T. TOUCHTON	Director
I. D. HALL* I. D. HALL.	Director	J. A. URQUHART* J. A. URQUHART	Director
S. W. HUDSON* S. W. HUDSON	Director	J. O. WELCH, JR.* J. O. WELCH, JR.	Director

*By: /s/ G. L. GILLETTE
G. L. GILLETTE, Attorney-in-fact

CERTIFICATIONS

I, Robert D. Fagan, certify that:

1. I have reviewed this annual report on Form 10-K of Tampa Electric Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 7, 2003

/s/ R. D. FAGAN
R. D. FAGAN
Chairman of the Board, President,
Director and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATIONS

I, Gordon L. Gillette, certify that:

1. I have reviewed this annual report on Form 10-K of Tampa Electric Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 7, 2003

/s/ G. L. GILLETTE
G. L. GILLETTE
Senior Vice President - Finance
and Chief Financial Officer
(Principal Financial Officer)

Supplemental Information to Be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act

No annual report or proxy material has been sent to Tampa Electric Company's security holders because all of its equity securities are held by TECO Energy, Inc.

INDEX TO EXHIBITS

Exhibit No.	Description	Page No.
3.1	Articles of Incorporation of TECO Energy, Inc., as amended on April 20, 1993 (Exhibit 3, Form 10-Q for the quarter ended March 31, 1993 of TECO Energy, Inc.).	*
3.2	Bylaws of TECO Energy, Inc., as amended effective Jan. 18, 2001 (Exhibit 3.2, Form 10-K 2000 of TECO Energy, Inc.).	*
3.3	Articles of Incorporation of Tampa Electric Company (Exhibit 3, to Registration Statement No. 2-70653).	*
3.2	Bylaws of Tampa Electric Company, as amended effective Apr. 16, 1997 (Exhibit 3 Form 10-Q for the quarter ended June 30, 1997 of Tampa Electric Company).	*
4.1	Indenture of Mortgage among Tampa Electric Company, State Street Trust Company and First Savings & Trust Company of Tampa, dated as of Aug. 1, 1946 (Exhibit 7-A to Registration Statement No. 2-6693).	*
4.2	Thirteenth Supplemental Indenture, dated as of Jan. 1, 1974, to Exhibit 4.1 (Exhibit 2-g-1, Registration Statement No. 2-51204).	*
4.3	Sixteenth Supplemental Indenture, dated as of Oct. 30, 1992, to Exhibit 4.1 (Exhibit 4.1, Form 10-Q for the quarter ended Sept. 30, 1992 of TECO Energy, Inc.).	*
4.4	Eighteenth Supplemental Indenture, dated as of May 1, 1993, to Exhibit 4.1 (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 1993 of TECO Energy, Inc.).	*
4.5	Installment Purchase Contract between the Hillsborough County Industrial Development Authority and Tampa Electric Company, dated as of Jan. 31, 1984 (Exhibit 4.13, Form 10-K for 1993 of TECO Energy, Inc.).	*
4.6	First Supplemental Installment Purchase Contract, dated as of Aug. 2, 1984 (Exhibit 4.14, Form 10-K for 1994 of TECO Energy, Inc.).	*
4.7	Second Supplemental Installment Purchase Contract, dated as of July 1, 1993 (Exhibit 4.3, Form 10-Q for the quarter ended June 30, 1993 of TECO Energy, Inc.).	*
4.8	Loan and Trust Agreement among the Hillsborough County Industrial Development Authority, Tampa Electric Company and NCNB National Bank of Florida, as trustee, dated as of Sept. 24, 1990 (Exhibit 4.1, Form 10-Q for the quarter ended Sept. 30, 1990 for TECO Energy, Inc.).	*
4.9	Loan and Trust Agreement among the Hillsborough County Industrial Development Authority, Tampa Electric Company and NationsBank of Florida, N.A., as trustee, dated as of Oct. 26, 1992 (Exhibit 4.2, Form 10-Q for the quarter ended Sept. 30, 1992 of TECO Energy, Inc.).	*
4.10	Loan and Trust Agreement among the Hillsborough County Industrial Development Authority, Tampa Electric Company and NationsBank of Florida, N.A., as trustee, dated as of June 23, 1993 (Exhibit 4.2, Form 10-Q for the quarter ended June 30, 1993 of TECO Energy, Inc.).	*
4.11	Loan and Trust Agreement among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company of Florida, as trustee, dated as of June 1, 2002. (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2002 of TECO Energy, Inc.).	*
4.12	Loan and Trust Agreement, dated as of Dec. 1, 1996, among the Polk County Industrial Development Authority, Tampa Electric Company and The Bank of New York, as trustee (Exhibit 4.22, Form 10-K for 1996 of TECO Energy, Inc.).	*
4.13	Installment Sales Agreement between the Plaquemines Port, Harbor and Terminal District (Louisiana) and Electro-Coal Transfer Corporation, dated as of Sept. 1, 1985 (Exhibit 4.19, Form 10-K for 1986 of TECO Energy, Inc.).	*
4.14	First Supplemental Installment Sales Agreement, between Plaquemines Port, Harbor, and Terminal District (Louisiana) and Electro-Coal Transfer Corporation, dated Dec. 20, 2000 (Exhibit 4.20, Form 10-K for 2000 of TECO Energy, Inc.).	*
4.15	Amended and Restated Reimbursement Agreement between TECO Energy, Inc. and Electro-Coal Transfer LLC, dated as of Apr. 5, 2001 (Exhibit 4.1, Form 8-K date Apr. 5, 2001 of TECO Energy, Inc.).	*
4.16	Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of July 1, 1998 (Exhibit 4.1, Registration Statement No. 333-55873)	*

4.17	Third Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of June 15, 2001 (Exhibit 4.2, Form 8-K dated June 25, 2001 of Tampa Electric Company).	*
4.18	Fourth Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Aug. 15, 2002. (Exhibit 4.2, Form 8-K dated Aug. 26, 2002 of Tampa Electric Company).	*
4.19	Credit Agreement dated as of Nov. 13, 2002, among Tampa Electric Company as Borrower, Citibank, N.A., as Administrative Agent, Salomon Smith Barney Inc. and The Bank of New York, As Co-Lead Arrangers, Morgan Stanley Senior Funding, Inc., and The Bank of New York, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent and the lenders parties Thereto as Lenders (Exhibit 4.1, Form 8-K dated Nov. 13, 2002 for TECO Energy, Inc.).	*
4.20	Indenture between TECO Energy, Inc. and The Bank of New York, as trustee, dated as of Aug. 17, 1998 (Exhibit 4.1, Form 8-K dated Sept. 20, 2000 of TECO Energy, Inc.).	*
4.21	Second Supplemental Indenture dated as of Aug. 15, 2000 between TECO Energy, Inc. and The Bank of New York (Exhibit 4.1, Form 8-K dated Sept. 28, 2000 of TECO Energy, Inc.).	*
4.22	Third Supplemental Indenture dated as of Dec. 1, 2000 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.21, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.23	Amended and Restated Limited Liability Company Agreement of TECO Funding Company I, LLC dated as of Dec. 1, 2000 (Exhibit 4.24, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.24	Amended and Restated Trust Agreement of TECO Capital Trust I among TECO Funding Company I, LLC, The Bank of New York and The Bank of New York (Delaware) dated as of Dec. 1, 2000 (Exhibit 4.22, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.25	Guaranty Agreement between TECO Energy, Inc. and The Bank of New York, as trustee, dated as of Dec. 1, 2000 (Exhibit 4.25, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.26	Fourth Supplemental Indenture dated as of Apr. 30, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.28, Form 8-K dated May 1, 2001 of TECO Energy, Inc.).	*
4.27	Fifth Supplemental Indenture dated as of Sept. 10, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.16, Form 8-K dated Sept. 26, 2001 of TECO Energy, Inc.).	*
4.28	Sixth Supplemental Indenture dated as of Jan. 15, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.28, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.29	Purchase Contract Agreement between TECO Energy, Inc. and The Bank of New York, as Purchase Contract Agent, dated as of Jan. 15, 2002 (Exhibit 4.29, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.30	Amended and Restated Trust Agreement of TECO Capital Trust II among TECO Funding Company II, LLC, The Bank of New York and The Bank of New York (Delaware), dated as of Jan. 15, 2002 (Exhibit 4.31, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.31	Amended and Restated Limited Liability Agreement of TECO Funding Company II, LLC, dated as of Jan. 15, 2002 (Exhibit 4.33, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.32	Guarantee Agreement by and between TECO Energy, Inc., as Guarantor and The Bank of New York, dated as of Jan. 15, 2002 (Exhibit 4.35, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.33	Form of Remarketing Agreement by and between TECO Energy, Inc. and the Remarketing Agent (Exhibit 4.37, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.34	Pledge Agreement among TECO Energy, Inc., The Bank of New York, as Collateral Agent, Custodial Agent and Securities Intermediary and The Bank of New York, as Purchase Contract Agent dated as of Jan. 15, 2002 (Exhibit 4.38, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.35	Seventh Supplemental Indenture dated as of May 1, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.15, Form 8-K dated May 13, 2002 of TECO Energy, Inc.).	*
4.36	Eighth Supplemental Indenture dated as of Nov. 20, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.1, Form 8-K dated Nov. 20, 2002 for TECO Energy, Inc.).	*

4.37	Credit Agreement dated as of Nov. 14, 2001, among TECO Energy, Inc., as Borrower, Citibank. N.A., as Administrative Agent, Salomon Smith Barney Inc. and Banc of America Securities, LLC, as Co-Lead Arrangers, Banc of America, as Syndication Agent, the Bank of Nova Scotia, BNP Paribas and SunTrust Bank, as Co-Documentation Agents, JP Morgan Chase Bank, LC Issuing Bank, and the lenders parties thereto as Lenders (Exhibit 4.41, Form 10-K for 2001 of TECO Energy, Inc.).	*
4.38	Renewed Rights Agreement between TECO Energy, Inc. and BankBoston, N.A., as Rights Agent, dated as of Oct. 21, 1998 (Exhibit 4, Form 8-K, dated as of Oct. 21, 1998 of TECO Energy, Inc.).	*
10.1	TECO Energy Group Supplemental Executive Retirement Plan, as amended and restated as of July 1, 1998, as further amended as of July 15, 1998. (Exhibit 10.1, Form 10-K for 2001 of TECO Energy, Inc.).	*
10.2	TECO Energy Group Supplemental Retirement Benefits Trust Agreement, as amended and restated as of Jan. 1, 1998, as further amended as of July 15, 1998. (Exhibit 10.2, Form 10-K for 2001 of TECO Energy, Inc.).	*
10.3	Annual Incentive Compensation Plan for TECO Energy and subsidiaries, revised as of April 17, 2002. (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2002 for TECO Energy, Inc.).	*
10.4	TECO Energy Group Supplemental Disability Income Plan, dated as of March 20, 1998 (Exhibit 10.22, Form 10-K for 1988 of TECO Energy, Inc.).	*
10.5	Forms of Severance Agreement between TECO Energy, Inc. and certain officers, as amended and restated as of Oct. 22, 1999 (Exhibit 10.7, Form 10-K for 1999 of TECO Energy, Inc.).	*
10.6	Loan and Stock Purchase Agreement between TECO Energy, Inc. and Barnett Banks Trust Company, N.A., as trustee of the TECO Energy Group Savings Plan Trust Agreement (Exhibit 10.3, Form 10-Q for the quarter ended March 31, 1990 for TECO Energy, Inc.).	*
10.7	TECO Energy Directors' Deferred Compensation Plan, as amended and restated effective as of April 1, 1994 (Exhibit 10.1, Form 10-Q for the quarter ended March 31, 1994 for TECO Energy, Inc.).	*
10.8	TECO Energy Group Deferred Compensation Plan (previously the TECO Energy Group Retirement Savings Excess Benefit Plan), as amended and restated effective as of Oct. 17, 2001. (Exhibit 10.8, Form 10-K for 2001 of TECO Energy, Inc.).	*
10.9	Compensation Committee's Determinations Regarding Credit Rates for the TECO Energy Group Deferred Compensation Plan. (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2002 of TECO Energy, Inc.).	*
10.10	TECO Energy, Inc. 1996 Equity Incentive Plan as amended Apr. 18, 2001 (Exhibit 10.1, Form 10-Q for the quarter ended March 31, 2001 of TECO Energy, Inc.).	*
10.11	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1996 Equity Incentive Plan (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 1996 of TECO Energy, Inc.).	*
10.12	Form of Amendment to Nonstatutory Stock Option, dated as of July 15, 1998, under the TECO Energy, Inc. 1996 Equity Incentive Plan (Exhibit 10.3, Form 10-Q for the quarter ended Sept. 30, 1998 of TECO Energy, Inc.).	*
10.13	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1996 Equity Incentive Plan (Exhibit 10.5, Form 10-Q for the quarter ended June 30, 1999 of TECO Energy, Inc.).	*
10.14	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 1996 Equity Incentive Plan (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 1998 of TECO Energy, Inc.).	*
10.15	Form of Amendment to Restricted Stock Agreements, dated as of July 15, 1998, TECO Energy, Inc. and certain officers under the TECO Energy, Inc. between 1996 Equity Incentive Plan (Exhibit 10.2, Form 10-Q for the quarter ended Sept. 30, 1998 of TECO Energy, Inc.).	*
10.16	TECO Energy, Inc. 1997 Director Equity Plan (Exhibit 10.1, Form 8-K dated April 16, 1997 of TECO Energy, Inc.).	*
10.17	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1997 Director Equity Plan (Exhibit 10, Form 10-Q for the quarter ended June 30, 1997 of TECO Energy, Inc.).	*
10.18	Supplemental Executive Retirement Plan for R. K. Eustace as of Jan. 15, 1997 (Exhibit 10.24, Form 10-K for 1997 of TECO Energy, Inc.).	*
10.19	Supplemental Executive Retirement Plan for R. D. Fagan as amended (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2001 of TECO Energy, Inc.).	*
10.20	Nonstatutory Stock Option granted to R. D. Fagan, dated as of May 24, 1999, under the TECO Energy, Inc. 1996 Equity Incentive Plan (Exhibit 10.3, Form 10-Q for the quarter ended June 30, 1999 of TECO Energy, Inc.).	*

10.21	Restricted Stock Agreement between TECO Energy, Inc. and R. D. Fagan, dated as of May 24, 1999 (Exhibit 10.4, Form 10-Q for the quarter ended June 30, 1999 of TECO Energy, Inc.).	*
10.22	Severance Agreement between TECO Energy, Inc. and R.D. Fagan, as amended (Exhibit 10.2, form 10-Q for the quarter ended June 30, 2001 of TECO Energy, Inc.).	*
10.23	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 1996 Equity Incentive Plan. (Exhibit 10.7, Form 10-Q for the quarter ended June 30, 2000 of TECO Energy, Inc.).	*
10.24	Form of 2002 Amendment to TECO Performance Shares Agreements between TECO Energy, Inc., and certain officers under the TECO Energy Inc. 1996 Equity Incentive Plan. (Exhibit 10.25, Form 10-K for 2001 of TECO Energy, Inc.).	*
10.25	Form of Performance Shares Agreement between TECO Energy, Inc. and certain TECO Power Services Corporation officers under the TECO Energy, Inc. 1996 Equity Incentive Plan. (Exhibit 10.3, Form 10-Q for the quarter ended June 30, 2000 of TECO Energy, Inc.).	*
10.26	Supplemental Executive Retirement Plan for R. Lehfeldt as of Apr. 17, 2002. (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2002 of TECO Energy, Inc.).	*
10.27	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 1996 Equity Incentive Plan, dated as of Jan. 28, 2003.	[ ]
10.28	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1997 Director Equity Plan, dated as of Jan. 29, 2003.	[ ]
10.29	Equity Contribution Guaranty Agreement between TECO Energy, Inc., and Citibank, N.A., as Administrative Agent under the Union Power Project Credit Agreement (Exhibit 10.4, Form 10-Q for the quarter ended June 30, 2001 of TECO Energy, Inc.).	*
10.30	Equity Bridge Guaranty Agreement between TECO Energy, Inc., and Citibank, N.A., as Administrative Agent under the Union Power Project Bridge Loan Agreement (Exhibit 10.5, form 10-Q for the quarter ended June 30, 2001 of TECO Energy, Inc.).	*
10.31	Contingent Equity Contribution Guaranty Agreement between TECO Energy, Inc., and Citibank, N.A., as Administrative Agent under the Gila River Project Credit Agreement (Exhibit 10.6, Form 10-Q for the quarter ended June 30, 2001 of TECO Energy, Inc.).	*
10.32	Equity Contribution Guaranty Agreement between TECO Energy, Inc., and Citibank, N.A., as Administrative Agent under the Gila River Project Credit Agreement (Exhibit 10.7, Form 10-Q for the quarter ended June 30, 2001 of TECO Energy, Inc.).	*
10.33	Equity Bridge Guaranty Agreement between TECO Energy, Inc., and Citibank, N.A., as Administrative Agent under the Gila River Bridge Loan Agreement (Exhibit 10.8, Form 10-Q for the quarter ended June 30, 2001 of TECO Energy, Inc.).	*
10.34	Omnibus Amendment to TECO guarantees related to the Union Power Project, dates as of Oct. 31, 2001, by and among TECO Energy, Inc., Guarantor, and Administrative Agent (Exhibit 10.4, Form 10-Q for the quarter ended June 30, 2002 of TECO Energy, Inc.).	*
10.35	Omnibus Amendment to TECO Guarantees related to the Gila River Project, dated as of Oct. 31, 2001, by and among TECO Energy, Inc., Guarantor, and Administrative Agent. (Exhibit 10.3, Form 10-Q for the quarter ended June 30, 2002 of TECO Energy, Inc.).	*
10.36	Amended and Restated Construction Contract Undertaking by TECO Energy, Inc. in favor of Union Power Partners, L.P., as Borrower, and Citibank, N.A., as Administrative Agent under the Union Power Project Credit Agreement, dated as of May 14, 2002 (Exhibit 99.5 to Registration Statement No. 333-102019.	*
10.37	Amended and Restated Construction Contract Undertaking by TECO Energy, Inc. in favor of Panda Gila River, L.P., as Borrower, and Citibank. N.A., as Administrative Agent under the Gila River Project Credit Agreement, dated as of May 14, 2002 (Exhibit 99.4 to Registration Statement No. 333-102019).	*
10.38	Consent and Acceleration Agreement dated as of Feb. 7, 2002 by and among TECO Power Services Corporation, TECO Energy, Inc., TPS GP, Inc., TPS LP, Inc., Panda GS V, LLC, Panda GS VI, LLC, Panda Energy International, Inc. and Bayerische Hypo-Und Vereinsbank AG, New York Branch.	[ ]
12.1	Ratio of Earnings to Fixed Charges – TECO Energy, Inc.	[ ]
12.2	Ratio of Earnings to Fixed Charges – Tampa Electric Company.	[ ]
21.	Subsidiaries of the Registrant.	[ ]
23.1	Consent of Independent Certified Public Accountants – TECO Energy, Inc.	[ ]
23.2	Consent of Independent Certified Public Accountants – Tampa Electric Company.	[ ]

24.1.1	Power of Attorney – TECO Energy, Inc.	[ ]
24.1.2	Power of Attorney – Tampa Electric Company.	[ ]
24.2.1	Certified copy of resolution authorizing Power of Attorney – TECO Energy, Inc.	[ ]
24.2.2	Certified copy of resolution authorizing Power of Attorney – Tampa Electric Company.	[ ]

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* Indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. Exhibits filed with periodic reports of TECO Energy, Inc. and Tampa Electric Company were filed under Commission File Nos. 1-8180 and 1-5007, respectively.

Certain instruments defining the rights of holders of long-term debt of TECO Energy, Inc. and its consolidated subsidiaries authorizing in each case a total amount of securities not exceeding 10 percent of total assets on a consolidated basis are not filed herewith. TECO Energy, Inc. will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Certain instruments defining the rights of holders of long-term debt of Tampa Electric Company authorizing in each case a total amount of securities not exceeding 10 percent of total assets on a consolidated basis are not filed herewith. Tampa Electric Company will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Executive Compensation Plans and Arrangements

Exhibits 10.1 through 10.5 and 10.7 through 10.28 above are management contracts or compensatory plans or arrangements in which executive officers or directors of TECO Energy, Inc. participate.

TECO ENERGY, INC.

RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth the company's ratio of earnings to fixed charges for the periods indicated.

$ millions	Year Ended December 31, (1)				
	2002	2001	2000	1999	1998
Income before income tax	$ 259.8	$ 271.7	$ 256.8	$ 280.5	$ 277.7
Interest expense (6)	196.9	190.0	174.9	130.7	108.9
Preferred stock dividends	--	--	--	--	--
Less: (Income) loss from equity investments	6.0	(6.7)	(7.7)	(3.2)	(3.4)
Earnings before taxes and fixed charges	$ 462.7	$ 455.0	$ 424.0	$ 408.0	$ 383.2
Interest expense (6)	$ 196.9	$ 190.0	$ 174.9	$ 130.7	$ 108.9
Interest on refunding bonds	(0.9)	(1.0)	(1.0)	(1.0)	(1.0)
Preferred stock dividends	--	--	--	--	--
Total fixed charges	$ 196.0	$ 189.0	$ 173.9	$ 129.7	$ 107.9
Ratio of earnings to fixed charges	2.36x (2)	2.41x (3)	2.44x	3.15x (4)	3.55x (5)

For the purposes of calculating these ratios, earnings consist of income from continuing operations before income taxes, income or loss from equity investments and fixed charges. Fixed charges consist of interest on indebtedness, amortization of debt premium, the interest component of rentals and preferred stock dividend requirements.

(1) All prior periods presented reflect the reclassifications of TECO Coalbed Methane's results from continuing operations to discontinued operations. In December 2002, TECO Energy sold substantially all of its coalbed methane assets to the Municipal Gas Authority of Georgia.

(2) Includes the effect of other non-operating pretax items totaling $48.2 million, including $34.1 million at TECO Energy related to a debt refinancing, and asset valuations of $9.2 million and $4.9 million at TECO Power Services and TECO Investments, respectively. The effect of these items was to reduce the ratio of earnings to fixed charges. Had these items been excluded from the calculation, the ratio of earnings to fixed charges would have been 2.61x for the year ended Dec. 31, 2002.

(3) Includes the effect of other non-operating pretax items totaling $11.1 million for asset valuations recorded at TECO Power Services and TECO Investments. The effect of these items was to reduce the ration of earnings to fixed charges. Had these items been excluded from the calculation, the ratio of earnings to fixed charges would have been 2.47x for the year ended Dec. 31, 2001.

(4) Includes the effect of other non-operating pretax items totaling $21.0 million recorded at Tampa Electric, TECO Investments and TECO Energy. The effect of these items was to reduce the ratio of earnings to fixed charges. Had these items been excluded from the calculation, the ratio of earnings to fixed charges would have been 3.49x for the year ended Dec. 31, 1999.

(5) Includes the effect of other non-operating pretax items totaling $30.5 million associated with write-offs at TECO Coal and Tampa Electric, and $.6 million pretax of merger-related costs. The effect of these items was to reduce the ratio of earnings to fixed charges. Had these items been excluded from the calculation, the ratio of earnings to fixed charges would have been 3.84x for the year ended Dec. 31, 1998.

(6) Interest expense includes total interest expense, excluding AFUDC, and an estimate of the interest component of rentals.

Exhibit 12.2

TAMPA ELECTRIC COMPANY

RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth the company's ratio of earnings to fixed charges for the periods indicated.

$ millions	Year Ended December 31,				
	2002	2001	2000	1999	1998
Income before income tax	$ 296.3	$ 274.7	$ 261.8	$ 226.3	$ 232.3
Interest expense (3)	80.4	81.8	84.7	81.7	67.4
Preferred stock dividends	--	--	--	--	--
Earnings before taxes and fixed charges	$ 376.7	$ 356.5	$ 346.5	$ 308.0	$ 299.7
Interest expense (3)	$ 80.4	$ 81.8	$ 84.7	$ 81.7	$ 67.4
Interest on refunding bonds	(0.9)	(1.0)	(1.0)	(1.0)	(1.0)
Preferred stock dividends	--	--	--	--	--
Total fixed charges	$ 79.5	$ 80.8	$ 83.7	$ 80.7	$ 66.4
Ratio of earnings to fixed charges	4.74x	4.41x	4.14x	3.82x (1)	4.51x (2)

For the purposes of calculating these ratios, earnings consist of income from continuing operations before income taxes, income or loss from equity investments and fixed charges. Fixed charges consist of interest on indebtedness, amortization of debt premium, the interest component of rentals and preferred stock dividend requirements.

(1) Includes the effect of other non-operating pretax items totaling $18.3 million recorded in the third and fourth quarters of 1999. Charges consisted of the following: $10.5 million recorded based on Florida Public Service Commission audits of Tampa Electric's 1997 and 1998 earnings, which limited Tampa Electric's equity ratio to 58.7 percent; $3.5 million to resolve litigation filed by the U.S. Environmental Protection Agency; and $4.3 million for corporate income tax settlements related to prior years' tax returns. The effect of these items was to reduce the ratio of earnings to fixed charges. Had these items been excluded from the calculation, the ratio of earnings to fixed charges would have been 4.61 for the year ended Dec. 31, 1999.

(2) Includes the effect of other non-operating pretax items totaling $16.9 million, as more fully explained in Note I to Item 8, Financial Statements and Supplementary Data of the Company's Annual Report on Form 10-K for the 1998 fiscal year. The effect of these charges was to reduce the ratio of earnings to fixed charges. Had these items been excluded from the calculation, the ratio of earnings to fixed charges would have been 4.66 for the year ended Dec. 31, 1998.

(3) Interest expense includes total interest expense, excluding AFUDC, and an estimate of the interest component of rentals.

SUBSIDIARIES OF THE REGISTRANT

All of the following subsidiaries of TECO Energy, Inc., are organized under the laws of Florida except as indicated. The following list omits certain subsidiaries pursuant to paragraph (b)(21)(ii) of Regulation S-K Item 601.

- Tampa Electric Company
- TECO Diversified, Inc.
  - TECO Transport Corporation
    - TECO Bulk Terminal, LLC (formerly Electro-Coal Transfer, LLC a Louisiana limited liability company)
    - TECO Ocean Shipping, Inc. (formerly Gulfcoast Transit Company)
    - TECO Barge Line, Inc. (formerly Mid-South Towing Company)
    - TECO Towing Company
  - TECO Coal Corporation (a Kentucky corporation)
    - Gatliff Coal Company (a Kentucky corporation)
    - Bear Branch Coal Company (a Kentucky Corporation
    - Rich Mountain Coal Company (a Tennessee corporation)
    - Clintwood Elkhorn Mining Company (a Kentucky corporation)
    - Pike-Letcher Land Company (a Kentucky corporation)
    - Premier Elkhorn Coal Company (a Kentucky corporation)
    - Perry County Coal Corporation (a Kentucky corporation)
  - TECO Solutions, Inc.
    - TECO Energy Services, Inc. (formerly TECO BGA, Inc.)
      - BCH Mechanical, Inc.
    - TECO Gas Services, Inc.
    - Prior Energy Corporation (a Delaware Corporation)
    - TECO Properties Corporation
    - TECO Partners, Inc.
    - TECO Propane Ventures, LLC (a Delaware limited liability company)
  - TECO Coalbed Methane Florida, Inc. (formerly TECO Coalbed Methane, Inc. an Alabama corporation)
- TECO Stevedoring Services, Inc. (formerly GC Services Company, Inc.)
- TECO Finance, Inc.
- TECO Investments, Inc.
- TECO Funding Company I, LLC (a Delaware limited liability company)
- TECO Funding Company II, LLC (a Delaware limited liability company)
- TECO Power Services Corporation
  - Hardee Power I, Inc.
  - Hardee Power II, Inc.
  - TPS Guatemala One, Inc.
  - TPS Hamakua, Inc.
  - TPS Hawaii, Inc.
  - TM Power Ventures, LLC (a Delaware limited liability company)
    - TM Delmarva Power LLC (a Delaware limited liability company)
  - TECO Power Ventures, Inc.
    - TPS TriCo., LLC (a Delaware limited liability company)
      - TPS Dell, LLC (a Delaware limited liability company)
      - TPS McAdams, LLC (a Delaware limited liability company)
      - TPS Tejas GP, LLC (a Delaware limited liability company)
      - TPS Tejas LP, LLC (a Delaware limited liability company)
  - TPS LP, Inc.
  - TPS GP, Inc.
    - TECO-Panda Generating Company, L.P. (a Delaware partnership)
      - Union Power I, LLC (a Delaware limited liability company)
      - Union Power II, LLC (a Delaware limited liability company)
      - Panda Gila River I, LLC (a Delaware limited liability company)
      - Panda Gila River II, LLC (a Delaware limited liability company)
      - Trans-Union Interstate I, LLC (a Delaware limited liability company)
      - Trans-Union Interstate II, LLC (a Delaware limited liability company)
  - TPS International Power, Inc. (a Cayman Islands limited liability company)
    - TPS de Ultramar, Ltd. (a Cayman Islands company)
    - TPS San Jose International, Inc. (a Cayman Islands company)
    - TPS San Jose, LDC (a Cayman Islands company)
  - TECO EnergySource, Inc.

CONSENT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (File Nos. 33-43512, and 333-83958) and on Form S-8 (File Nos. 333-02563, 333-25563, 333-60776 and 333-72542) of TECO Energy, Inc. of our report dated January 22, 2003, except for the information in Note U as to which the date is January 30, 2003, relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Tampa, Florida
March 6, 2003

CONSENT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (File Nos. 33-61636, 333-55090 and 333-91602) of Tampa Electric Company of our report dated January 22, 2003, relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Tampa, Florida
March 6, 2003

TECO ENERGY, INC.
POWER OF ATTORNEY

Each of the undersigned in his capacity as a Director or officer or both, as the case may be, of said Corporation, does hereby appoint R. D. Fagan, G. L. Gillette and D. E. Schwartz, and each of them, severally, his true and lawful attorneys or attorney to execute in his name, place and stead, in his capacity as Director or officer or both, as the case may be, of said Corporation, the Annual Report on Form 10-K for year ended December 31, 2002, and any and all amendments thereto and all instruments necessary or incidental in connection therewith, and to file the same with the Securities and Exchange Commission. Each of said attorneys has the power to act hereunder with or without the other of said attorneys and shall have full power of substitution and resubstitution.

IN TESTIMONY WHEREOF, the undersigned have executed this instrument on the dates set forth below.

/s/ R. D. Fagan **R. D. Fagan, Chairman of the Board, President, Director and Chief Executive Officer (Principal Executive Officer)**	January 28, 2003
/s/ G. L. Gillette **G. L. Gillette, Senior Vice President-Finance and Chief Financial Officer (Principal Financial Officer)**	February 25, 2003
/s/ S. A. Myers **S. A. Myers, Vice President-Corporate Accounting and Tax (Principal Accounting Officer)**	February 25, 2003
/s/ C. D. Ausley **C. D. Ausley, Director**	January 30, 2003
/s/ S. L. Baldwin **S. L. Baldwin, Director**	January 28, 2003
/s/ J. L. Ferman, Jr. **J. L. Ferman, Jr., Director**	January 28, 2003
/s/ L. Guinot, Jr. **L. Guinot, Jr., Director**	January 30, 2003
/s/ I. D. Hall **I. D. Hall Director**	January 28, 2003
/s/ T. L. Rankin **T. L. Rankin, Director**	January 28, 2003
/s/ W. D. Rockford **W. D. Rockford, Director**	January 30, 2003

/s/ W. P. Sovey **W. P. Sovey, Director**	January 28, 2003
/s/ J. T. Touchton **J. T. Touchton, Director**	January 28, 2003
/s/ J. A. Urquhart **J. A. Urquhart, Director**	January 28, 2003
/s/ J. O. Welch, Jr. **J. O. Welch, Jr., Director**	January 28, 2003
/s/ S. W. Hudson **S. W. Hudson, Director**	January 30, 2003

Exhibit 24.1.2

TAMPA ELECTRIC COMPANY
POWER OF ATTORNEY

Each of the undersigned in his capacity as a Director or officer or both, as the case may be, of said Company, does hereby appoint R. D. Fagan, G. L. Gillette and D. E. Schwartz, and each of them, severally, his true and lawful attorneys or attorney to execute in his name, place and stead, in his capacity as Director or officer or both, as the case may be, of said Company, the Annual Report on Form 10-K for year ended December 31, 2002, and any and all amendments thereto and all instruments necessary or incidental in connection therewith, and to file the same with the Securities and Exchange Commission. Each of said attorneys has the power to act hereunder with or without the other of said attorneys and shall have full power of substitution and resubstitution.

IN TESTIMONY WHEREOF, the undersigned have executed this instrument on the dates set forth below.

/s/ R. D. Fagan **R. D. Fagan, Chairman of the Board, President, Director and Chief Executive Officer (Principal Executive Officer)**	January 28, 2003
/s/ G. L. Gillette **G. L. Gillette, Senior Vice President-Finance and Chief Financial Officer (Principal Financial Officer)**	February 25, 2003
/s/ P. L. Barringer **P. L. Barringer, Vice President-Controller and Assistant Secretary (Principal Accounting Officer)**	February 26, 2003
/s/ C. D. Ausley **C. D. Ausley, Director**	January 30, 2003
/s/ S. L. Baldwin **S. L. Baldwin, Director**	January 28, 2003
/s/ J. L. Ferman, Jr. **J. L. Ferman, Jr., Director**	January 28, 2003
/s/ L. Guinot, Jr. **L. Guinot, Jr., Director**	January 30, 2003
/s/ I. D. Hall **I. D. Hall Director**	January 28, 2003
/s/ T. L. Rankin **T. L. Rankin, Director**	January 28, 2003
/s/ W. D. Rockford **W. D. Rockford, Director**	January 30, 2003

/s/ W. P. Sovey **W. P. Sovey, Director**	January 28, 2003
/s/ J. T. Touchton **J. T. Touchton, Director**	January 28, 2003
/s/ J. A. Urquhart **J. A. Urquhart, Director**	January 28, 2003
/s/ J. O. Welch, Jr. **J. O. Welch, Jr., Director**	January 28, 2003
/s/ S. W. Hudson **S. W. Hudson, Director**	January 30, 2003

Exhibit 24.2.1

TECO ENERGY, INC.

Transcript from Records of Board of Directors

January 28, 2003

****

RESOLVED, that the preparation and filing with the Securities and Exchange Commission of the Annual Report on Form 10-K for the year ended December 31, 2002 pursuant to the Securities Exchange Act of 1934, as amended, including any amendments thereto and containing the information required by such form and any additional information as the officers of the Corporation, with the advice of counsel, deem necessary, advisable or appropriate (the "10-K"), are hereby authorized and approved; that the Chief Executive Officer, the President and any Vice President of the Corporation be, and each of them acting singly hereby is, authorized for and in the name and on behalf of the Corporation to execute the 10-K and cause it to be filed with the Securities and Exchange Commission; and that the officers referred to above be, and each of them hereby is, authorized to execute the 10-K through or by R. D. Fagan, G. L. Gillette or D. E. Schwartz, or any of them, as duly authorized attorneys pursuant to a Power of Attorney in such form as shall be approved by the Corporation's general counsel.

****

I, D. E. Schwartz, hereby certify that I am Secretary of TECO Energy, Inc., a Florida corporation (the "Corporation"), and set forth above is a true and correct copy of certain resolutions from the minutes of the meeting of the Board of Directors of the Corporation convened and held on January 28, 2003, at which meeting a quorum for the transaction of business was present and acting throughout.

I further certify that the resolutions set forth above have not been altered, amended or rescinded and the same are now in full force and effect.

EXECUTED this 25th day of February, 2003.

/s/ D. E. Schwartz
Secretary
TECO ENERGY, INC.

Corporate Seal

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TAMPA ELECTRIC COMPANY
Transcript from Records of Board of Directors

January 28, 2003

****

RESOLVED, that the preparation and filing with the Securities and Exchange Commission of the Annual Report on Form 10-K for the year ended December 31, 2002 pursuant to the Securities Exchange Act of 1934, as amended, including any amendments thereto and containing the information required by such form and any additional information as the officers of the Company, with the advice of counsel, deem necessary, advisable or appropriate (the "10-K"), are hereby authorized and approved; that the Chief Executive Officer, the President and any Vice President of the Company be, and each of them acting singly hereby is, authorized for and in the name and on behalf of the Company to execute the 10-K and cause it to be filed with the Securities and Exchange Commission; and that the officers referred to above be, and each of them hereby is, authorized to execute the 10-K through or by R. D. Fagan, G. L. Gillette or D. E. Schwartz, or any of them, as duly authorized attorneys pursuant to a Power of Attorney in such form as shall be approved by the Company's general counsel.

****

I, D. E. Schwartz, hereby certify that I am Secretary of Tampa Electric Company, a Florida corporation (the "Company"), and set forth above is a true and correct copy of certain resolutions from the minutes of the meeting of the Board of Directors of the Company convened and held on January 28, 2003, at which meeting a quorum for the transaction of business was present and acting throughout.

I further certify that the resolutions set forth above have not been altered, amended or rescinded and that the same are now in full force and effect.

EXECUTED this 25th day of February, 2003.

/s/ D. E. Schwartz
Secretary
TAMPA ELECTRIC COMPANY

Corporate Seal

TAMPA ELECTRIC COMPANY

Certification of Periodic Financial Report Pursuant to 18 U.S.C. Section 1350

Each of the undersigned officers of Tampa Electric Company (the "Company") certifies, under the standards set forth in and solely for the purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Annual Report on Form 10-K of the Company for the year ended Dec. 31, 2002 fully, to his knowledge, complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in that Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 7, 2003

/s/ Robert D. Fagan
Robert D. Fagan
Chief Executive Officer

Dated: March 7, 2003

/s/ Gordon L. Gillette
Gordon L. Gillette
Chief Financial Officer

TECO ENERGY, INC

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

Each of the undersigned officers of TECO Energy, Inc. (the "Company") certifies, under the standards set forth in and solely for the purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge, the Annual Report on Form 10-K of the Company for the year ended Dec. 31, 2002 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in that Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 7, 2003

/s/ Robert D. Fagan
Robert D. Fagan
Chief Executive Officer

Dated: March 7, 2003

/s/ Gordon L. Gillette
Gordon L. Gillette
Chief Financial Officer

18. Referring to POD 36, please state the amount of total tonnage of Petcoke purchased by Tampa Electric in 2001, 2002 and 2003 from Texas, and the total tonnage that was handled by the terminal in Davant.

A. Tampa Electric understands that this question refers only to pet coke that is purchased from Texas and therefore answers as such. All tons of pet coke from Texas were delivered directly to Big Bend Station. The table below shows the tons of pet coke purchased from Texas each year and the tons of pet coke handled by the terminal in Davant, Louisiana.

Pet Coke Purchased from Texas

	2001	2002	2003
Tons Purchased	142,936	153,591	89,730
Tons Handled by Terminal in Davant	0	0	0

23. Please state the percentage and tons of coal that were directly transferred from river barge and ocean transport to Gulf barges in 2001, 2002 and 2003 and the projected amount for 2004, and state whether or not the lower rates for this service were reflected in the rates passed on to ratepayers under the fuel clause.

A. Ratepayers pay the actual costs incurred by Tampa Electric for waterborne transportation services. Under the previous contracts, tons that were directly transferred from river barge to an ocean-going barge were tracked and billed at a different rate than tons that were moved to ground storage prior to ocean shipment, and ratepayer costs reflected these rates. The following table shows the percent and tons of coal that were directly transferred to an ocean barge.

Terminal Transfers

To Ground	2001	2002	2003	2004 Proj. [1]
Tons	4,170,174	4,837,452	4,321,707	NA
Percent	61	75	83	NA

To Barge	2001	2002	2003	2004 Proj. [1]
Tons	2,646,709	1,639,726	914,279	NA
Percent	39	25	17	NA

[1] Tampa Electric does not project tons that will be placed in ground storage versus transfer to barge.

24. Please state the percentage and tons of coal that required storage and blending at the terminal in 2001, 2002 and 2003 and the projected amount for 2004.

A. The following table shows the percentage and tons of coal that required storage and blending at the terminal.

Coal Stored or Blended at the Terminal

Storage	2001	2002	2003	2004 Proj.
Tons	4,170,174	4,837,452	4,321,707	NA[1]
Percent	59	72	78	NA[1]

Blending	2001	2002	2003	2004 Proj.
Tons	2,006,095	2,949,549	1,166,750	714,000
Percent	30	44	20	14

[1] The amount of coal to be stored at the terminal is not projected.

33. Has Tampa Electric or Mr. Dibner inquired as to why Ingram did not bid on TECO's solicitation? If so, what was the result of the inquiry?

A. No, neither Tampa Electric nor Mr. Dibner has contacted Ingram or any other recipient of Tampa Electric's 2003 RFP for waterborne transportation services to ask why the companies did not submit a bid in response to the RFP.

24. How, when and by whom did TECo communicate the "market prices" to TECO Transport. To whom at TECo Transport were the prices communicated? Describe any written communications as to the proffered "market prices."

A. Tampa Electric communicated the market prices to TECO Transport in writing. The letter was from William Cantrell, President of Tampa Electric, to Jeffrey Rankin, President of TECO Transport, dated September 25, 2003. A copy of the letter is provided in the response to FIPUG's First Request for Production of Documents, No. 23.

5. What has been the largest total amount of coal tons stored at Big Bend's coal storage yard, silos, and day bins since 1990? Show or describe the location at that time of the coal piles and storage and the tonnages in each by coal quality type, if more than one type of coal was in storage.

A. The largest total amount of coal stored at Big Bend Station's coal yard since 1990 was 1,041,730 tons in April 1999. A description of the coal tons by type and diagram of the coal piles and storage is provided in Tampa Electric's response to CSXT's Fifth Request for Production of Documents, No. 21, filed March 22, 2004.

6. When the April-June 2003 blend test with South American coal was conducted (see TECO response to Staff's 1st Set of Interrogatories No. 1), where was the coal blended? If it was blended at Big Bend, provide a flow sheet/diagram of the facilities used to do the blending and their mode of operation when blending occurred.

A. The fuel used in the aforementioned test bum of blended South American coal was blended at Big Bend Station, primarily into Unit 4. A diagram and description of the blending process at Big Bend Station are provided in Tampa Electric's response to CSXT's Fifth Request for Production of Documents, No. 20, filed March 22, 2004.

7. According to TECO's response the Citizens' (Public Counsel's) 2nd Set of Interrogatories No. 24, TECO plans to blend 14% of the coal it transfers at Devant (Electro-Coal) in 2004. Identify the fuels and tons of such fuel projected to be blended and whether they are destined for Polk or Big Bend.

A. Tampa Electric plans to blend 14 percent of the coal it transfers at the terminal in Davant, Louisiana in 2004. The fuel that will be blended represents 100 percent of Polk Station's fuel requirements. The tons and types of fuel expected to be blended are shown in the table below.

Fuel for Polk Station
2004 Projection

Fuel	Tons
Pet Coke	428,400
Illinois Basin coal	71,400
South American coal	214,000

The blending performed at the terminal in 2004 is expected to be exclusively for Polk Station.

8. What is the current status of the coal handling and storage equipment at Gannon Station and the rail and barge delivery equipment at Gannon Station?

A. The current status of the coal handling and storage equipment at Gannon Station and the rail and barge delivery equipment at Gannon Station is the following:

- Rail Delivery
  - A large portion of the track was required to be removed for the construction of Bayside Station.
  - The locomotive was leased; therefore, it was returned to the owner.
  - All other rail equipment is in place.
- Barge Delivery
  - All mobile equipment was transferred to Big Bend Station or sold at auction.
  - The dust suppression system was removed.
  - All other barge equipment is in place.
- Coal Handling and Storage
  - All structures and equipment remain in place.

Tampa Electric does not currently maintain the equipment that remains in place, and it will continue to deteriorate. The company has a five-year dismantlement plan and is pursuing the sale of all equipment.

9. For each of the types of equipment listed below, identify any coal handling and storage equipment, and any barge and rail equipment formerly used for coal delivery, that is still in place at Gannon Station, and its status and planned disposition, if any.

a. storage silos and bins
b. bucket elevators
c. transfer hoppers
d. dumpers and unloaders
e. conveyors (feet of length and width and whether covered or enclosed)
f. rails (feet and weight)
g. scales (truck, rail, or belt)
h. coal sampling equipment
i. mobile equipment including dozers, scrapers, loaders, and locomotives
j. stacker reclaimers
k. foundations
l. buildings
m. other (itemize)

A. A list of the equipment that remains in place is provided in the attached table. Tampa Electric does not currently maintain this equipment, and it will continue to deteriorate. The company has a five-year dismantlement plan and is pursuing the sale of all equipment.

Type of Equipment	Specific Equipment	Description
"C" Conveyor	Conveyor Structure Incl. Foundation	Foundations, Supports, Box Beam, 89 Idlers, 10 Pulleys, Conveyor B
"C" Conveyor	Conveyor Mechanical Components	Misc. Mechanical Components Including Belt Cleaners.
"C" Conveyor	Conveyor Drive	Westinghouse 150 Hp, 1780 Rpm Motor. Also One 5kv Motor Starter - Class I, Type B
"C" Conveyor	Drive Reduction Gear	Gear Reducer, Bedplate, Couplings, Completely Assembled And Mounted.
"C" Conveyor	Weighing Device	Belt Scale Po# 90095.
"C" Conveyor	Sampling System	Tema Inc. Hammer Sampler, Enclosed Belt Feeder, Crusher, Disc Divider
"C" Conveyor	Magnetic Separator	Magnetic Separator, Stearns Model 61-A Inline Suspended Explosion Proof Box W/ 5 Hp Explo-
"C" Conveyor	Sampling System	Spill Over Costs: Housing, Shaft Assy, Roll Crusher Assy, Clutch, Sheet Guiding, Comb,
"C" Conveyor	Conveyor Structure Incl. Foundation	Mechanical Components Jervis B. Webb. New Equipm
"C" Conveyor	Weighing Device	Coal Yard Veyor "C" - 1 Ea, Merrick Weightometer, Model #E-310
"C" Conveyor	Sampling System	Gannon Station Coal Yard - Mfg By Tema In C. Motor Components Include: (1) Ha
"C" Conveyor	Sampling System Structure	Ure - Overall Dimensions Are 41 Ft 1-7/8 In. In Height, 24 Ft By10 Ft
"C" Conveyor	Conveyor Mechanical Components	Blade Belt Cleaning System Arch Environmental Equipment, Inc.
"D" Conveyor	Weighing Device	Power Switch, Recorder
"D" Conveyor	Weighing Device	Additional Charges for Upgrade
"D" Conveyor	Weighing Device	Weightometer, Merrick E310-15276
"D" Conveyor	Conveyor Structure Incl. Foundation	Conveyor Assembly
"D" Conveyor	Conveyor Mechanical Components	S Veco Belt Cleaner Mod Bbld 440 V Motor For 42' Belt
"D" Conveyor	Conveyor Mechanical Components	Ratchet Bar Tensioner For 42" Belt
"D" Conveyor	Conveyor Drive	Ge 100/50 Hp 440v Meter 8131435
"D" Conveyor	Conveyor Structure Incl. Foundation	Nd Pulley By Steel Tail End Frame
"D" Conveyor	Conveyor Mechanical Components	Gannon Station Coal Yard Rd, Mfg By Jervis B.Webb 48" W,1500
"D" Conveyor	Conveyor Drive	Drive Motors S - Gannon Station Coal Yard - Westinghouse Squirrel Cage Induct
"D" Conveyor	Drive Reduction Gear	Drive Reduction Gears - Gannon Station Coal Yard Rd D.O. James Parallel Shaft Reduce
"E" Conveyor	Conveyor Structure Incl. Foundation	Conveyor Assembly
"E" Conveyor	Conveyor Structure Incl. Foundation	Tie Down For Tower
"E" Conveyor	Weighing Device	Master Totalizer Weightometer

Type of Equipment	Specific Equipment	Description
"E" Conveyor	Conveyor Structure Incl. Foundation	Located In Transfer Tower 2; E1 And E2 Radial Stackers Convey Coal F
"E" Conveyor	Conveyor Mechanical Components	Mech Components - Gannon Station Coal Yard Stacking Conveyor - Mfg By Jervis
"E" Conveyor	Conveyor Drive	Drive Motor S - Gannon Station Coal Yard - Squirrel Cage Induction Motors, Foot M
"E" Conveyor	Drive Reduction Gear	Drive Reduction Gears - Gannon Station Coal Yard Rd D.O. James Parallel Shaft Reduce
"E" Conveyor	Belt	Belts Non Station Coal Yard - Mfg By Tokai Rubber Industries. Belt Width
"E" Conveyor	Stacker Slewing Machinery	Stacker Sle, Wing Machinery Mechanical Components Gannon Station Coal Yard - Mfg By
"E" Conveyor	Stacker Slewing Machinery Drives	Stacker Sle, Wing Drive Motors - Gannon Station Coal Yard - Westinghouse 2-Spee
"E" Conveyor	Stacker Slewing Mach. Speed Reducer	Stacker Sle, Wing Drive Reduction Gear -- Gannon Station Coal Yard - Each Assemb
"E" Conveyor	Stacker Boom Retaining Mechanism	Stacker Boo M Retaining Mechanism - Gannon Station Coal Yard - Mfg By Jervisb. Web
"E" Conveyor	Belt	Conveyor Belt At Gannon 09/01/95 Tgc
"E" Conveyor	Conveyor Mechanical Components	Installed 2 Belt Cleaners For Gn Coalfield For E-1 & E-2
"F" Conveyor	Conveyor Structure Incl. Foundation	L End Pulley By Steel Tail End Fr
"F" Conveyor	Conveyor Mechanical Components	Gannon Station Coal Yard - Mfg By Jervis B.W Ebb, 48"W,1600tph Nom.Ca
"F" Conveyor	Conveyor Drive	Drive Motors S - Gannon Station Coal Yard - Westinghouse Squirrel Cage Induct
"F" Conveyor	Drive Reduction Gear	Drive Reduction Gears - Gannon Station Coal Yard Rd D.O. James Parallel Shaft Reduce
"F" Conveyor	Belt	Gannon Station Coal Yard - Mfg By Tokai Rubber Industries, Belt Width
"F" Conveyor	Hopper	Gannon Station Coal Yard - 2 Hoppers Each Conveyor. Overall Inside
"F" Conveyor	Dribble Scraper Conveyor	Belt Scales - Gannon Station Coal Yard - 48 In Belt Size Merrick Model 460-Ds
"F" Conveyor	Dribble Scraper Conveyor Drive	Variable Feeders, Mark Nos. R1a,R1b,R4a And R4 B Gannon Station Coal Yard - 2 Vari
"F" Conveyor	Belt	Conveyor Belt Replacement Po 02209 Vo 402564 02/20/96 Tgc
"F" Conveyor	Hopper	Reclaim Hopper Liner With High Density Polyethylene. 04/28/97 Tgc
"F" Conveyor	Belt	Belt Installation 05/16/97 Tgc
"F" Conveyor	Conveyor Structure Incl. Foundation	Structure In Conjunctions With The Gannon Reclaim Addition Project.
"F" Conveyor	Conveyor Mechanical Components	Mechanical Components Installed In Conjunction With The Reclaim Addition Project.
"F" Conveyor	Conveyor Drive	Associated With The F2 Conveyor Installed In The Reclaim Addition

Type of Equipment	Specific Equipment	Description
"F" Conveyor	Drive Reduction Gear	Reduction Gear Installed Along With The F2 Drive. Installed In Conjunction
"F" Conveyor	Belt	Belt Installed In Conjunction With The Gannon Reclaim Addition
"F" Conveyor	Hopper	Hopper Installed In Conjunction With The F2 Mid West Conveyor
"G" Conveyor	Magnetic Separator	4000 V Cross Belt Magnetic Separator
"G" Conveyor	Magnetic Separator	Conveyor & Drive Assembly Magnetic Separator
"G" Conveyor	Magnetic Separator	Dust Tight Enclosure
"G" Conveyor	Magnetic Separator	Full Wave Selenium Rectifier Assembly
"G" Conveyor	Conveyor Structure Incl. Foundation	Steel Framing
"G" Conveyor	Conveyor Structure Incl. Foundation	Lower Structural Steel Providing A Negative Slope On Tail Pully End Of G1 & G2 Conveyors. Structural Steel
"G" Conveyor	Conveyor Structure Incl. Foundation	Asbestos Siding & Roof, Corrugated
"G" Conveyor	Conveyor Structure Incl. Foundation	6x12 Legs At T/Concrete El 9 Ft In
"G" Conveyor	Conveyor Mechanical Components	Mechanical Components - Gannon Station Coal Yard Rd - Mfg By Jervis B. Webb, 36" Wi
"G" Conveyor	Conveyor Drive	Drive Motor S - Gannon Station Coal Yard - Westinghouse Squirrel Cage Induct
"G" Conveyor	Drive Reduction Gear	Reduction Gears - Gannon Station Coal Yard D D.O. James Parallel Shaft Reduce
"G" Conveyor	Magnetic Separator	Magnetic Separators, Mark Nos. Msg1 And Msg2 - Gannon Station Coal Yard - Eriez
"G" Conveyor	Conveyor Mechanical Components	Belt Slider Bed Modification. Roller System. 07/01/98 Rjb
"H" Conveyor	Conveyor Structure Incl. Foundation	Conveyor Assembly Foundation
"H" Conveyor	Belt	Tripper Conveyor Assembly Extension
"H" Conveyor	Conveyor Structure Incl. Foundation	Foundations And Structural Supports At 60' And 100' Towers, Replacement
"H" Conveyor	Conveyor Mechanical Components	Modifications To Conveyors H1&H2. All Equipment Furnished By Continental Convey
"H" Conveyor	Conveyor Mechanical Components	Belt Scales For Conveyors H1&H2. Mfg By Merrick Corp. Model No. 460 Ds. Designed For Calibr
"H" Conveyor	Conveyor Drive	Drive Motors For Conveyors H1 & H2. Westinghouse , 200 Hp, 1800 Rpm, Frame No.447,t
"H" Conveyor	Drive Reduction Gear	Reduction Gear For Conveyors H1 & H2. Furnished By Chicago Gear Mfg. Co. D.O. J
"H" Conveyor	Belt	Belting For Conveyors H1 & H2. 36" Wide, Approx. 1400 L.F. Long Each. Manufa
"H" Conveyor	Belt	H-2 Conveyor Belt - 36" Wide - 1,271 Ft.
"H" Conveyor	Conveyor Mechanical Components	Mechanical Components Modified Two Large Chutes (One Chute Per Conveyor) Four Scraper's,

Type of Equipment	Specific Equipment	Description
"H" Conveyor	Conveyor Structure Incl. Foundation	Gn Station As-Fired Scale Controls In The Coalfields To Improve Operat
"H" Conveyor	Conveyor Mechanical Components	Gn H1 Conveyor Skirt Board 5/13/97 Tgc
"H" Conveyor	Conveyor Mechanical Components	Gn H2 Conveyor Skirt Board 5/13/97 Tgc
"H" Conveyor	Belt	Gn H-2 Conveyor Belt 5/16/97 Tgc
"J" Conveyor	Conveyor Mechanical Components	Trigger Conveyor Assembly Extension
"J" Conveyor	Conveyor Drive	Ge Motor 40hp 440v 8291421
"J" Conveyor	Conveyor Drive	Ge 40hp 440v Motor Zr525007
"J" Conveyor	Drive Reduction Gear	Ge Motor 40hp 440v Zr525007
"J" Conveyor	Drive Reduction Gear	Speed Reducer
"J" Conveyor	Conveyor Structure Incl. Foundation	Conveyor Assembly
"J" Conveyor	Conveyor Structure Incl. Foundation	Conveyor Assembly
"J" Conveyor	Conveyor Structure Incl. Foundation	Extension Of Bunker Tripper Conveyor
"J" Conveyor	Conveyor Mechanical Components	Conveyor Assembly Extension Exc. Belt
"J" Conveyor	Conveyor Mechanical Components	Conveyor Assembly
"J" Conveyor	Conveyor Mechanical Components	Conveyor Assembly
"J" Conveyor	Belt	36" Conveyor Belt
"J" Conveyor	Conveyor Mechanical Components	Conveyors J1&J2. All Equipment Furnished By Continental Conveyor Corp.
"J" Conveyor	Conveyor Drive	Drive Motors For Conveyors J1 & J2. Westinghouse 50 Hp, 1800 Rpm, Frame No. 326t
"J" Conveyor	Drive Reduction Gear	Reduction Gear For Conveyors J1&J2. Furnished By Chicago Gear Mfg. Co. D.O. James
"J" Conveyor	Belt	Belting For Conveyors J1&J2. 36" Wide, Approx. 800 L.F. Long Each. Mfg By B.
"J" Conveyor	Tripper Assembly	Modifications To "J" Conveyor Tripper Assemblies. All Equipment Furnished By Contin
"J" Conveyor	Tripper Assembly	Coal Bunker Seal Belts (At Discharge Of Conveyors J1 & J2 From Unit 1 Thru Unit 6 At Elev. 148'). Each S
"J" Conveyor	Belt	J-2 Conveyor Belt 36" Wide - 1302 Ft
"J" Conveyor	Conveyor Mechanical Components	Modified Two Large Chutes (One Chute Per Conveyor) Four Scraper's
"J" Conveyor	Conveyor Structure Incl. Foundation	Install New Tripper Rails To The "J-1" Conveyor System

Type of Equipment	Specific Equipment	Description
"J" Conveyor	Belt	Gn J-1 Install J-1 Conveyor Belt Provide Greater Reliability
"J" Conveyor	Conveyor Mechanical Components	Gn J2 Conveyor Skirt Board Installation 05/16/97 Tgc
"J" Conveyor	Conveyor Mechanical Components	Install 2 Belt Cleaners For J-1 & J-2 Conveyor sat Gn Coalfield
"K" Conveyor	Conveyor Mechanical Components	Arch Environmental Equipment Co. Gordon Saber Primary Belt Cleaners Po 48739 Vo 819780
"L" Conveyor	Conveyor Structure Incl. Foundation	Conveyor Assembly
"L" Conveyor	Conveyor Mechanical Components	Ratchet Bar Tensioner For 48" Belt Cleaner Switch
"L" Conveyor	Conveyor Drive	Westinghouse 100hp 440v Motor
"L" Conveyor	Conveyor Structure Incl. Foundation	Upgrade Work Performed Included Structural Steel Modification Of The Conveyor L Scale
"L" Conveyor	Conveyor Structure Incl. Foundation	Sampling System Structure - Overall Dimensions Are 40 Ft- 3/8 In. In Height, 21 Ft 3 In.
"L" Conveyor	Conveyor Mechanical Components	Jervis B. Webb - New Equipment
"L" Conveyor	Weighing Device	Shelter For Existing Conveyor "L" Scale - Overall Dimensions Of Scale Shelter Are 20' X 16'. Support
"L" Conveyor	Sampling System	Sampling System - Gannon Station Coal Yard - Mfg By Tema Inc. Major Components
"M" Conveyor	Conveyor Structure Incl. Foundation	Yors D1 And D2 Via Splitter Gates
"M" Conveyor	Conveyor Mechanical Components	Components - Gannon Station Coal Yard Rd - Mfg By Jervis B. Webb, 48" Wi
"M" Conveyor	Conveyor Drive	Drive Motor S - Gannon Station Coal Yard - Westinghouse Squirrel Cage Induct
"M" Conveyor	Drive Reduction Gear	Reduction Gears - Gannon Station Coal Yard D.O James Parallel Shaft Herrin
"M" Conveyor	Belt	Gannon Station Coal Yard - Mfg By Tokai Rubber Industries. Belt Width
"M" Conveyor	Belt	48 In Belt Stores Iss 7-15698-95
"M" Conveyor	Belt	Install 1 48 In Conveyor Belt At Gn Stock #600312 11/04/96 Tgc
Coal Area Yard Lighting System	Lighting System N/I Xfr Or Pnl	Coal Yard Lighting - Contains A Total Of (370) Lighting Fixtures Of Which There Are (326) Ge 70 Watt H
Coal Barge Unloader	Bearings	
Coal Barge Unloader - Ladder Type	Travel Tower Structure	Traveling Crane Mead-Morrison Unloader
Coal Barge Unloader - Ladder Type	Travel Tower Structure	Crane Accessories Mead-Morrison Unloader

Type of Equipment	Specific Equipment	Description
Coal Barge Unloader - Ladder Type	Travel Tower Structure	Unloading Tower Mead-Morrison Unloader
Coal Barge Unloader - Ladder Type	Conveyor A - Complete	Conveyor & Belt Mead-Morrison Unloader
Coal Barge Unloader - Ladder Type	Conveyor B - Complete	Upgrade Incl. Additional Structural Steel Supports And Foundations, New 100 Hp Drive Motor
Coal Barge Unloader - Ladder Type	Travel Tower Structure	Coal Barge Unloader Gnc Bucket Unloader - H3077
Coal Barge Unloader - Ladder Type	Travel Tower Structure	Spare Equipment For Coal Barge Unloader (H3081). Needs To Be
Coal Barge Unloader - Ladder Type	Travel Tower Structure	Drive Systems With Plc Control, 480 Volt Transformer, And Motor Control
Coal Barge Unloader - Ladder Type	Main Power Cable Reel Assembly	Motor Driven Cable Reel, This Reel To Be Gleason Reel Corp. Model #E440-13-602e112-30-15-K1
Coal Barge Unloader - Ladder Type	Conveyor B - Complete	851 Ft Long 48in Wide, 4 Ply 440 Piw W/1/4 In Top Cover & 1/16
Coal Barge Unloader - Ladder Type	Digging Ladder Assembly	Replace The Existing Conveyor Belt On The Continuous Ship Unloader. Belt Has Steel Mesh.
Coal Crushers	Fine Crusher	Ocyh-Crh-1a&B, 2a&B - Fine Crushers. Mfg By Pennsylvania Crusher, Model # Sxcag119,400 Tph Capacity,15" X
Coal Crushers	Fine Crusher Drive	Ocyh-M1a&B, M2a&B - Fine Crusher Drives. Mfg By Siemens-Allis, Type Az S, 1000 Hp, Frame 3030s6, 142amps
Coal Crushers	Fine Crusher - Inlet Chutes	Ocyh-Crh-1a&B & 2a&B - Inlet Chutes For Fine Crushers. Furnished By Continental Conveyor And Equipment
Coal Crushers	Fine Crusher - Outlet Chutes	Ocyh-Crh-1a&B, 2a&B - Fine Crusher Outlet Chutes. Mfg By Continental Conveyor Corp. Outlet Chutes Extend
Coal Crushers	Fine Crusher - Tramp Iron Chutes	Ocyh-Crh-1a&B, 2a&B - Tramp Iron Chutes. Chutes Are Located At The Fine Crusher House And Is Flange
Coal Crushers	Lube Oil System	Ocyh-Crh-1a&B, 2a&B - Lubricating Oil Systems For Fine Crushers. Mfg B Y T. H. Paris, Inc. Each System
Coal Crushers	Fine Crusher	Miscellaneous Parts For Fine Crusher - Lubricating Oil Systems - Serial No. 4976, (Model Sxcag-119) Consis
Coal Crushers	Rotor	Gnc Coalfield 1a Crusher Rotor Replacement. 12/04/98 Rjb

Type of Equipment	Specific Equipment	Description
Coal Crushers	2 600 Tph Coal Crushers	With 2500 Hp Motors. Installed In Conjunction With The Gannon Coalfield Crusher
Coal Crushers	Gannon 2c Crusher Actuator	Replaces Actuator In The Coal Crusher. 12/10/02 Rjb
Coal Crushers/ Feeders	Complete Control System For	Coal Crushers In The Gannon Coalfield. Installed In Conjunction With The Gannon
Coal Crushers/Feeders	Chute/Downspout	Inlet Chutes With Dispersion Devices. Installed In Conjunction With The Gannon
Coal Crushers/Feeders	Chute/Downspout	Discharge Chutes - Qty 2 Installed In Conjunction With The Gannon
Coal Crushers/Feeders	Hoists	27.5 Ton Hoists. Installed In Conjunction With The Gannon
Coal Crushers/Feeders	Structural Support Steel	Coalfield Crusher. Installed In Conjunction With The Gannon
Coal Field Mobile Equipment	Portable Conveyor	Portable Conveyor
Coal Field Mobile Equipment	Portable Conveyor	Portable Reclaimer To Be Used As A Backup. 05/13/98 Rjb
Coal Handling	Fire Detection	Protector wire Fire Protection/Detection System. On G1 And G2 Coal Conveyors.
Coal Handling	Diverter/Gate	Ga9 T-2 Tower Splitter Gates 3,4,6, And 7 05/10/00 Rjb
Coal Handling	Fire Detection	
Coal Handling & Blending Structures	Crusher House	Ohvy-Fn1 - Vane Axial Fan For Fine Crusher House Electrical Equipment Room. Mfg By Chicago Blower Corp
Coal Handling & Blending Structures	Crusher House	Ohvy-Flt1 - Inertial Separation Air Filter For Fine Crusher House Electrical Equipment Room. Mfg By pneuma
Coal Handling & Blending Structures	Crusher House	Ohvy-Duct1 - Ductwork For Fine Crusher House Electrical Equipment Room All Interior Ductwork 24 Gauge
Coal Handling Structures	Coarse Crusher House	Coarse Crusher House W/Roof, Vent Fan
Coal Handling Structures	Car Shaker House	Car Shaker, House, Structural Steel With Lighting
Coal Handling Structures	Fine Crusher House	Incandescent Fixtures F/Fine Crusher House
Coal Handling Structures	Fine Crusher House	Structure-Including Substructure (38 Cu Yd Concrete) Superstructure Steel & Concrete

Type of Equipment	Specific Equipment	Description
Coal Handling Structures	Fine Crusher House	Johnson-Marsh Dust Control Equip Consisting Of Proportioners, Pump, Motor, & Controllers
Coal Handling Structures	Car Shaker House	Additional Control Equipment
Coal Handling Structures	Car Shaker House	High Pressure Hose & Fittings
Coal Handling Structures	Car Shaker House	Adam Jic Power Unit With 10 Gpm Pump
Coal Handling Structures	Car Shaker House	Installation Labor
Coal Handling Structures	Car Shaker House	Miscellaneous Material & Teco Labor
Coal Handling Structures	Car Shaker House	Booth For Operator
Coal Handling Structures	Car Shaker House	Materials And Installation Costs For 10'x12' Extension On East And West End Of Gannon Shaker
Coal Handling Structures	Car Shaker House	Additional Charges For Car Shaker House Extension, Carried Over From 1983
Coal Handling Structures	Fine Crusher House Substructure	Common - Fine Crusher House Foundation - Consists Of: 44 Ea, 50 Ton Load Bearing Capacity Concrete Piles
Coal Handling Structures	Fine Crusher House Structural Steel	Common - Fine Crusher House Steel Work - Consists Of 236 Tons Of Structural Steel That Supports Fine C
Coal Handling Structures	Fine Crusher House Electrical Bldg	Common - Fine Crusher House - Electrical Building Is Located Between Columns Cl-4,Cn-4,Cl-2.1 And Cn-2.1
Coal Handling Structures	Fine Crusher House Mechanical Room	Common - Fine Crusher House - Mechanical Room - Located Between Column S Ck-4, Ch-4,Ck-2.1 And Ch-2.1
Coal Handling Structures	Fine Crusher House Roof	Common - Fine Crusher House - Roof 63'-10". Covers Mechanical Room A
Coal Handling Structures	Transfer Tower No. 1	Structure - Overall Dimensions Are 37 Ft 11-3/4 Inches In Height, 36 Ft By 27 Ft 6 I
Coal Handling Structures	Transfer Tower No. 2	Structure Overall Dimensions: 90 Ft High, 108 Ft By 46 Ft. Fdn Consists Of: 144, 1
Coal Handling Structures	Transfer Tower No. 2	Coal Yard - Central Control Room - Fire Protection - Halon System - 1 Ea Halon System Consists Of: 2 Ea 1
Coal Handling Structures	Reclaim Hopper	Reclaim Hopper Foundation - F1 And F4 Each Have (57) 12 Inch Square Precast, Prestressed Concre
Coal Handling Structures	Reclaim Pit / Tunnel	Reclaim Tunnel Foundation - F1 And F4 Each Have (64) 12 Inch Square Precast, Prestressed Concre
Coal Handling Structures	Reclaim Pit / Tunnel	Coal Reclaim Tunnel & F-4) Ventilation Systems – Gannon Station Coal Yard – Centri.
Coal Handling Structures	Reclaim Pit / Tunnel	Ventilation System - Gannon Station Coal Yard - Consists Of 2 Units

Type of Equipment	Specific Equipment	Description
Coal Handling Structures	Transfer Tower No. 1	Coalfield Bathroom Install 15 Linear Wall, New Water Basin And Toilet
Coal Handling Structures	Car Shaker House	Materials And Installation Costs To Expand The Concrete Structure Feeding The Hopper By Two (2) Feet
Coal Handling Structures	Transfer Tower No. 1	Gn Coalfield Grounding Upgrade Install Grounding System At Coal Field Fine Crusher House, T-2
Coal Handling Structures	Transfer Tower No. 2	Structure Addition Installed In Conjunction The Gannon Reclaim Addition
Coal Handling Structures	Reclaim Pit / Tunnel	Reclaim Tunnel Installed In Conjunction With The Gannon Reclaim Addition.
Coal Handling Structures	Ventilation System	T-2 Tunnel Ventilation System Installed In Conjunction With The Gannon Reclaim Addition Project
Coal Handling Structures	Sump Pump W/Drive	7.5 Hp Motor Manufactured By Reliance. Goulds Pump With Coupling. Installed Within
Coal Handling System	Control Panels	Sampling System Control Panel. Po# 85162
Coal Handling System	Control System	Coal Handling Yard - Consisting Of (8) Flow Indicating Switches, (8) Vibrat
Coal Handling System	Control Panel	(Ocyh-Pnlbtm) Fine Crushers Bearing Temperature Monitor Panel. Consists Of A Wall Mounted Nema 4 Stainl
Coal Handling System	Control Panel	(Ocyh-Pnl21, Ocyh-Pnl22) Fine Crusher 1 & 2 Lube Oil System Control Panels. Consists Of A Wall Mounted
Coal Handling System	Control Panel	Magnetic Separator Rectifier #1 & 2 Mfg By Eriez Magnetic Control Equipment, Model N4x-50c41, Style#84692
Conveyor	Detector	Ga9 L Conveyor Metal Detector Addition. 10/15/01 Rjb
Conveyor	Gate	T1 Splitter gate
Conveyor	Gate	T2 Splitter gate
Conveyor - Coal Handling	Mechanical Components	Replace Existing Cable Reel Add Some New Cable For Conveyor System
Conveyor - Coal Handling	Retaining Wall	Gannon Coalfield Upgrade Retaining Wall.
Conveyor/Coal Handling	Belt	Gannon H-1 Conveyor Belt Replacement. 1250 Ft. 09/20/99 Rjb
Conveyor/Coal Handling	Belt	Ga9 G-2 Conveyor Belt 1050 Lf 12/13/99 Rjb
Conveyor/Coal Handling	Belt	Ga9 E-1 Conveyor Belt Repl. 275 Ft Of 48" 3 Ply 04/19/00 Rjb
Conveyor/Coal Handling	Belt	Ga9 E-2 Conveyor Belt 275 Linear Feet 48" Wide 05/26/00 Rjb
Conveyor/Coal Handling	Belt	Ga9 - L Conveyor Belt Replacement 580 Ft Of 48" 3ply

Type of Equipment	Specific Equipment	Description
Conveyor/Coal Handling	Belt	Gannon D-2 Conveyor Belt Replacement. 440'long 48" Wide
Conveyor/Coal Handling	Belt	Gannon D-2 Conveyor Belt Replacement. 440'long 48" Wide
Conveyor/Coal Handling	Belt	Gannon "G-1" Conveyor Belt 02/18/02 Rjb
Conveyor/Coal Handling	Belt	H-2 conveyor belt
Conveyor/Coal Handling	Belt	F-2 conveyor belt
Conveyor/Coal Handling	Hydraulic Unit	E-1 conveyor hydraulic brake
Rail Car Unloading System	Car Shaker	Car Shaker, Allis-Chalmers W/ 2 Speed Motor
Rail Car Unloading System	Concrete Tunnel	Track Hopper Tunnel, 239 Cy Concrete
Rail Car Unloading System	Sump Pump W/Drive	Nagle Vertical Cantilirer Shaft Pump With 10 Hp Motor Np 75 1514
Rail Car Unloading System	Track Hopper	Track Hopper, 2 Compartment
Rail Car Unloading System	Track Hopper	Substructure And Foundation (395 Cy Concrete)
Transport Bridge & Trench	Bridge	Common - Waste Water Pipe Bridge Foundation - Consists Of Bridge Foundation F1 Thru F17, Anchors A1thru A
Transport Bridge & Trench	Bridge	Common - Waste Water Pipe Bridge Is To Support Waste Water Piping - From Waste Water Transfer Sumpsto Was
Transport Bridge & Trench	Bridge	Common - Fly Ash Pipe Bridge - This Consists Of Pipe Bridge And Walkway Ys Along Fly Ash Conveying Pipes
Unloader	Bucket	Ga9 14 Ton Unloader Bucket For Clamshell Unloader 06/20/00 Rjb

10. If any of the coal handling, storage, and rail and barge delivery equipment and facilities at Gannon Station have been demolished, sold, or removed, provide a time line showing when demolition, sale, or removal, occurred and any scrap or re-sale values realized by line item of equipment or facility, for the following categories of equipment:

a. storage silos and bins
b. bucket elevators
c. transfer hoppers
d. dumpers and unloaders
e. conveyors (feet of length and width and whether covered or enclosed)
f. rails (feet and weight)
g. scales (truck, rail, or belt)
h. coal sampling equipment
i. mobile equipment including dozers, scrapers, loaders, and locomotives
j. stacker reclaimers
k. foundations
l. buildings
m. other (itemize)

A. The following items in the aforementioned categories were removed from Gannon Station:

- The locomotive was removed in 2001. The equipment was leased; therefore, no salvage value was realized.
- The rail track was removed in 2001 by a contractor, and the contractor kept the scrap to offset the cost of removal.
- Bulldozer D8N was transferred to Big Bend Station in 2003. No salvage value was realized.
- Bulldozer D9R was transferred to Big Bend Station in 2003. No salvage value was realized.
- Bulldozer D9L was transferred to Big Bend Station in 2003. No salvage value was realized.
- A pay loader was removed in 2003 and sold at auction. The salvage value was $21,350.
- The dust suppression system was removed in 2003. The equipment was leased; therefore, no salvage value was realized.

11. With respect to any coal yard equipment of the types identified in items 10.a. through 10.m. above, what was the depreciated book value of the coal yard equipment when it was demolished, sold, or removed?

A. All coal yard equipment of the types identified in Interrogatory No. 10, parts "a" through "m," were fully depreciated as of December 31, 2003, and all equipment had a depreciated book value of $0.00.

4. Identify all customers to whom CSXT transports coal or synthetic fuels to destinations in Florida.

CSXT'S RESPONSE

Since 2001, CSXT has transported in excess of 50 million total tons of coal to Florida for the following customers: Progress Fuels Corp.; JEA; Seminole Electric Cooperative, Inc.; Gainesville Regional Utilities; Lakeland Electric; Orlando Utilities Commission; Cedar Bay Cogeneration, L.P.; Indiantown Cogeneration, L.P.; Gulf Power Company; Florida Rock Industries; CEMEX; Central Power and Lime; International Paper Company; Jefferson Smurfit Corp.; Rinker Materials; Tarmac Americas.

Since 2001, CSXT has transported synfuel in excess of 1 million total tons to the following customers: Cedar Bay Generating; City of Lakeland; JEA; Orlando Utilities; Seminole Electric Cooperative.

5. Identify all customers to whom CSXT transports petroleum coke to destinations in Florida.

CSXT'S RESPONSE

Since 2001, CSXT has transported in excess of 1 million total tons to the following:

Seminole Electric Cooperative, Inc.

Grand Eagle

Royal Oak Enterprises

6. Did CSXT's Bids A and B include a provision that the bid price be adjusted by CSXT's fuel surcharge per Tariff CSXT 8200 for all shipments of coal to Tampa Electric's Big Bend Station?

CSXT'S RESPONSE

CSXT has objected to this interrogatory on the ground that it seeks confidential, proprietary business information. Subject to this objection, CSXT provides the following confidential answer subject to a non-disclosure agreement executed by CSX and TECO.

[redacted]

20. Provide the assumptions used regarding the permitting of the construction of the rail receiving facilities at Big Bend Station.

CSXT'S RESPONSE

CSXT assumed Tampa Electric would acquire and manage permits with NSPS standards.

21. Provide the assumptions used regarding the permitting of the construction of the rail receiving facilities at Polk Station.

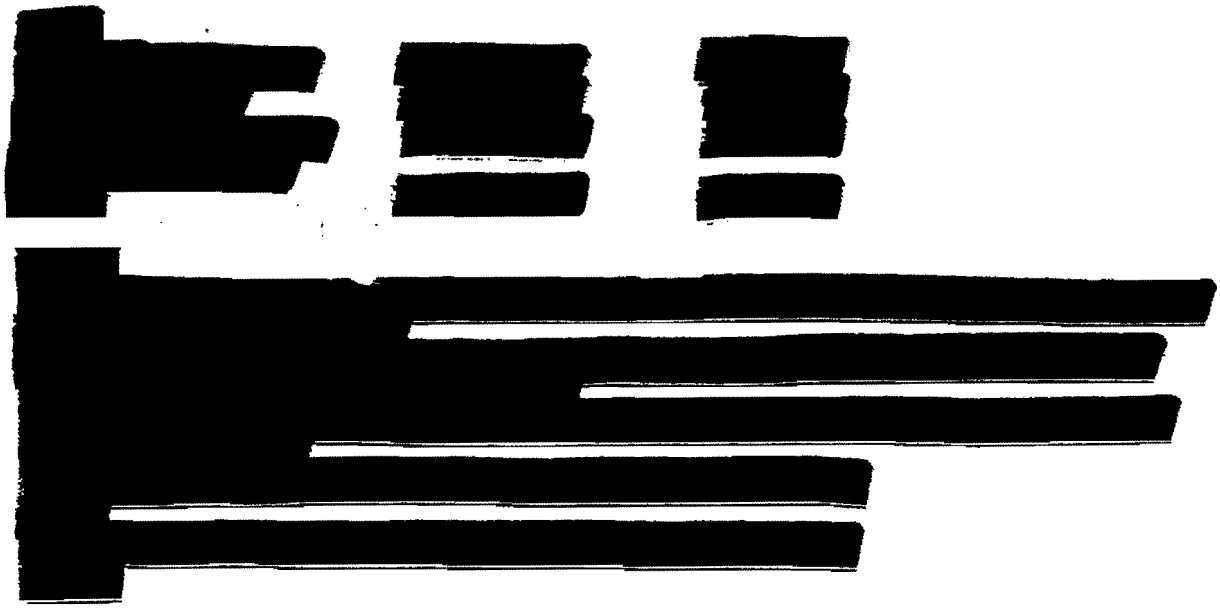
CSXT'S RESPONSE

CSXT assumed Tampa Electric would acquire and manage permits with NSPS standards.

22. Please describe the rail facilities at origin for the following mines: Galatia, Liberty, Zeigler and Somerville.

CSXT'S RESPONSE

Mine	Size	Train Loadout	Route
Galatia	90	4-hour fast-load	IC/Paducah/CSXT
Liberty	100	4-hour fast-load	IC/Paducah/CSXT
Zeigler	100	4-hour fast-load	UP/Memphis/CSXT
Somerville	100	4-hour fast-load	ISRR/Evansville/CSXT



24. How many crew districts and crew changes would be required for the movement of solid fuel between Big Bend Station and Polk Station, pursuant to CSXT's Bids A and B submitted to Tampa Electric on July 30, 2003?

CSXT'S RESPONSE

One crew district; one crew change including loading at Big Bend.

12. Please provide all requests for proposals for provision of coal transportation that Tampa Electric has issued over the last 10 years.

A. See attached.

TECO
TAMPA ELECTRIC

August 11, 1997

«Name»
«JobTitle»
«Company»
«Address1»
«Address2»
«City», «State» «PostalCode»

Dear «Salutation»:

RE: Request for Waterborne Transportation Services Proposals WB - 0199

The Fuels Department of Tampa Electric Company is requesting proposals to provide integrated waterborne transportation services for the movement of coal from mid-west coal supply sources for final delivery to Tampa Electric's generating stations near Tampa, Florida. Terminal facilities should be accessible to Mississippi River barge traffic and capable of receiving and discharging inland river barges from domestic suppliers and Panamax sized vessels from offshore suppliers.

The enclosed sheets provide pertinent information on the preparation and submittal of your proposal. Should you require additional information or clarification, please contact me at (813) 641-5055.

We invite you to participate in this bidding process. Please review this Request for Proposal and send your formal reply by October 15, 1997, 1:00 p.m. (EDST), as specified under the section "Bidding Procedures". If you do not wish to respond to this request, please send us a formal written declination for recording purposes.

We look forward to your response.

Sincerely,

C. Carey McBride
Sr. Consulting Engineer

Enclosure

TAMPA ELECTRIC COMPANY

P.O. BOX 111

TAMPA, FL 33601-0111

HILLSBOROUGH COUNTY 223-0800

OUTSIDE OF HILLSBOROUGH COUNTY 1-888-223-0800

HTTP://WWW.TECOENERGY.COM

AN EQUAL OPPORTUNITY COMPANY

BID SOLICITATION WB-0199

Coal Transportation and Terminal Services

GENERAL

The Fuels Department of Tampa Electric is inviting proposals to provide integrated waterborne transportation services for the movement of coal from mid-west supply sources for final delivery to Tampa Electric's generating stations near Tampa, Florida. Terminal facilities should be accessible to Mississippi River barge traffic and capable of receiving and discharging inland river barges from domestic suppliers and Panamax sized vessels for offshore coal. Proposals should represent the entire stated requirements of Tampa Electric's waterborne coal and petroleum coke transportation services. The specifics of this request and the bidding procedures to be followed are outlined below.

QUANTITY AND TERM

Tampa Electric anticipates that the volume of required river transportation services will range from 4.0 to 6.0 million tons per year. The volume of Terminal and Gulf Transportation services is expected to range between 7.5 and 8.5 million tons annually including approximately 1.0 million tons of international deliveries and 1.3 million tons of domestic deliveries currently delivered to the port of New Orleans that will remain under an existing river barge supply agreement. Notice of annual tonnage declarations by Tampa Electric shall be given in July of each contract year for the following calendar year. Monthly shipment variances of plus or minus 20% from the ratable annual tonnage declaration shall be allowable. The term is from January 1, 1999 through December 31, 2003.

PRICING

Pricing shall be composed of an annual capacity charge (invoiced monthly), and is divided into fixed and variable components and incremental rates, divided into fuel and variable components. Proposals should include capacity charges and incremental rates for both river shipments and gulf/terminal shipments. Proposals should include bidder's preferred escalation methodology to be applied to the fuel and variable components. The fuel and variable components shall be subject to quarterly adjustment with the fourth quarter of 1998 serving as the base period. Pricing should be stated in January 1999 dollars. Payment terms are thirty (30) days net from receipt of proper invoice based on receipt at destination. Pricing should include a minimum of four (4) free days allowed to load river barges and forty-eight (48) free hours to unload ocean barges. Barge demurrage shall be calculated on a quarterly credit / debit system.

CONTRACT PROVISIONS

The Winning bidder will be expected to enter into a contract which will among other things include the following provisions.

REQUIRED RIVER TRANSPORTATION SERVICES

The incremental rate and capacity charge must include port charges, fleeting charges, switching fees, emergency vessel services, existing taxes and any other charges associated with the transportation of coal. Carrier shall bear the risk of cargo loss. Tampa Electric will reserve the right to expedite coal shipments at no additional cost in critically low inventory situations. Carrier shall be required to report shipment information and tonnage reconciliation by coal type on a weekly and monthly basis. Carrier shall be responsible for meeting all regulatory requirements i.e. Coast Guard, Responsible Carrier Program, environmental and others.

REQUIRED TERMINAL AND GULF TRANSPORTATION SERVICES

The incremental rate and capacity charge must include port charges, fleeting and constructive placement charges, switching fees, emergency vessel services, wharfage services, docking/undocking services, trimming services, launch boat services, maintenance crane services, tractor cleaning services, stockpile storage fees, existing taxes, and any other charges associated with the unloading, loading, storage and transportation of coal and petroleum coke. Historically, ground storage facilities have been utilized to provide surge capacity such that Tampa Electric's local inventories can be maintained at acceptable levels. Stockpile maintenance, compaction, and inventory accounting (physical inventories) should be considered routine terminal services, and include prevention and control of spontaneous combustion within stockpiles as part of routine stockpile maintenance. Sampling and weighing services should be provided for both inbound and outbound shiprnents. Precise blending services of multiple coal types is required to meet performance and environmental requirements at Tampa Electric's generating stations. Application of dust suppressant is required for all outbound shipments. The average discharge rate for unloading Panamax sized vessels of imported coal should be 750 tons per hour. The terminal/carrier shall bear the risk of cargo loss. Cargoes of multiple coal types will be required. The terminal /carrier shall be responsible for maintaining local (Tampa) inventories at acceptable ranges as determined by Tampa Electric. The terminal/carrier shall provide daily inventory and position reports. The terminal/carrier shall be responsible for meeting all regulatory requirements i.e. Coast Guard, environmental, and others. Tampa Electric will reserve the right to switch or change the composition of previously scheduled cargoes on short notice in critical situations. Attachment C lists the unloading port's capabilities and limitations.

MISCELLANEOUS PROVISIONS

The contract will contain other commercially reasonable terms and conditions customarily found in contracts for similar services, including but not limited to, provisions dealing with standards of performance, risk allocation, force majeure, events of default, remedies, and others.

BIDDING PROCEDURES

In order to ensure that proposals are responsive to Buyer's needs and provide a uniform basis for evaluation, bidders are requested to provide the information on the attached Transportation Proposal Form, complete rate quotes on Attachments A & B and send Sealed Bid Packages to:

Carey McBride, Fuels Department
Bid Proposal WB-0199
Tampa Electric Company
Production Service Center
6944 US Hwy. 41 North
Apollo Beach, Florida 33572

Failure to properly mark bid reference number WB-0199 on the exterior of the sealed envelope could result in non-consideration of the bid.

Bid packages must be received at the Fuels Department no later than 1:00 p.m. (EDST) on October 15, 1997. Bids received after this date will not be evaluated or considered. The bidder shall be responsible for the completeness and accuracy of all information contained in and used in preparation of it's proposal and for having supplied all necessary information. Bid packages which are incomplete may not be evaluated. Revised proposals, if any, must be received before the closing deadline for evaluation.

Any award will be based on Tampa Electric Company's evaluation process and not on price alone. The evaluation will include price, ability to supply sufficient barge, towing and storage capacity, financial stability and other pertinent factors. Field inspections and audits by Tampa Electric personnel or Tampa Electric's designated representative(s) may be required to verify the accuracy of information provided in proposals. Tampa Electric reserves the right to reject any and all proposals which in Tampa Electric's sole judgment are determined to not be in its best interest.

Bid proposals shall remain open for a period of six months beyond the closing date of this solicitation. Proposals represent a firm offer to supply Transportation and Terminal services at the prices and under the terms provided in your proposal, subject to the execution and delivery of a contract, the first draft of which will be provided by Tampa Electric Company. Those suppliers who feel that a personal presentation of their proposal is warranted due to the complexity of the proposal will be allowed to do so before the closing deadline. Should you have questions or desire to schedule a presentation, please call Carey McBride at 813-641-5055.

Waterborne Transportation Proposal Form

TECO

Fuels and Environmental Services

PART 1

Company Name:_____

Mailing Address:_____

_____

_____

_____

Authorized Representative:_____

Phone Number:_____ Fax Number:_____

Corporate Affiliations (Include parent, subsidiary and affiliated companies):

_____

_____

_____

_____

_____

Facility Locations:

_____

_____

_____

_____

_____

RIVER TRANSPORTATION
PART 2

Towing Equipment Description (Include name, age, rated horsepower, towing capability, and other pertinent information):

Barge Fleet Description (Include design, configuration, type, size, style ownership, number of barges and other pertinent information):

Insurance Coverage Description (types of coverage, insureds coverage limits, carrier, policy numbers and expiration dates, etc.):

Major Customer Listing (Include company name, tonnage lifted in 1995 and 1996, Contact and Phone number):

Subcontractors (Include company name, contact, phone number, and description of services rendered):

Financial Information (provide last five years of audited financial statements and other relevant information):

TERMINAL FACILITIES
PART 3

Terminal Equipment Description (Include unloading and loading equipment, reclaim equipment, mobile equipment, rated capacities, average performance capabilities and other pertinent information):

Terminal Ground Storage Description (Include schematic or diagram of storage capacity):

Sampling Equipment (Include a description of inbound and outbound capabilities):

WATERBORNE TRANSPORTATION PROPOSAL FORM - Part 3 (Continued)

Weighing Equipment (Include a description of belt scale capabilities inbound and outbound):

Fleeting Equipment (Include a description of harbor boats and other fleeting equipment):

Insurance Coverage Description (types of coverage, insureds coverage limits, carrier, policy numbers and expiration dates, etc.):

WATERBORNE TRANSPORTATION PROPOSAL FORM - Part 3 (Continued)

Major Customer Listing (Including company name, tonnage lifted in 1995 and 1996, Contact and Phone number):

Subcontractors (Include company name, contact, phone number, and description of services rendered):

Financial Information (provide last five years of audited financial statements and other relevant information):

GULF TRANSPORTATION
PART 4

Ship or Ocean Barge Fleet Description (Include design, configuration, type, size, style, cargo capacity and other pertinent information):

Insurance Coverage Description (types of coverage, insureds coverage limits, carrier, policy numbers and expiration dates, etc.):

Major Customer Listing (Including company name, tonnage lifted in 1995 and 1996, Contact and Phone number):

Subcontractors (Include company name, contact, phone number, and description of services rendered):

_____

_____

_____

_____

_____

Financial Information (provide last five years of audited financial statements and other relevant information):

_____

_____

_____

_____

_____

Signature:

_____
(Signature of person having proper authority to legally obligate the Transportation Company)

Title:

_____

Date:

_____

Attachment A

ANNUAL RIVER TRANSPORTATION CAPACITY CHARGE

	FIXED	VARIABLE	TOTAL

INCREMENTAL BARGE RATE/TON

LOCK 53 POOL OHIO RIVER	FUEL	VARIABLE	TOTAL
Cook Coal Terminal - MP 948 OH			
Mound City - MP 976 OH			
TENNESSEE RIVER			
BRT - MP 23 TR			
Kentucky Lakes Dock - MP 24 TR			
SMITH LAND POOL OHIO RIVER			
Empire Dock - MP 896 OH			
Rigsby & Barnard - MP 881 OH			
Kanipe Enterprises - MP 872 OH			
Caseyville - MP 872 OH			
Hamilton - MP 852 OH			
UNIONTOWN POOL OHIO RIVER			
Overland Terminal - MP 842 OH			
Mount Vernon - MP 828 OH			
Southern Indiana - MP 794 OH			

ATTACHMENT A (Continued)

GREEN RIVER	FUEL	VARIABLE	TOTAL
Green Coal - MP 11 GR			
Patriot - MP 32 GR			
Sebree - MP 43 GR			
Pyramid - MP 94 GR			
Ken Mine - MP 98 GR			
NEWBURGH POOL OHIO RIVER			
Yankeetown - MP 773 OH			
Owensboro - MP 750 OH			
New Hope - MP 734 OH			
CANNELTON POOL OHIO RIVER			
Jefferson River Port - MP 618 OH			
MELDAHL POOL OHIO RIVER			
Transcontinental Terminals - MP 406 OH			
GREENUP POOL OHIO RIVER			
Big Sandy - MP (1-8)			
Huntington - MP 306 OH			
UPPER MISSISSIPPI RIVER			
Cora - MP 99 UMR			
Kellogg - MP 125 UMR			
Cahokia - MP 178 UMR			

PROPOSED ESCALATION METHODOLOGY:

FUEL

VARIABLE

PROPOSED DAILY DEMURRAGE RATE:

Attachment B

ANNUAL GULF AND TERMINAL CAPACITY CHARGE

FIXED	VARIABLE	TOTAL

INCREMENTAL GULF AND TERMINAL RATE/TON

FUEL	VARIABLE	TOTAL

PROPOSED ESCALATION METHODOLOGY:

FUEL

VARIABLE

PROPOSED HOURLY DEMURRAGE RATE:

Attachment C

UNLOADING PORT FACILITIES - CAPABILITIES AND LIMITATIONS

A. Tampa Electric's Gannon Station at Black Point Dock, Tampa, Florida.

1. Draft Limitations: 28 feet except for some shoaling to 25 feet near the dock which may require the unloading vessel to stand off until partially unloaded.
2. Maximum Vessel Limitations: 650 feet length. (Note: vessels longer than 500 feet must be shifted in order to facilitate unloading.) 85 ft. beam.
3. Airdraft: Maximum airdraft is 45 ft. Vessel may have to be ballasted to maintain this maximum.
4. Minimum Hatch Size: 30' width x 50' length; greater size highly desirable.
5. Discharging Equipment: One traveling clamshell crane and one Dravo continuous ship unloader.
6. Expected Average Unloading Rate: 1200 net tons per hour excluding delays caused by vertical interference's from vessel booms, masts and superstructures.
7. Draft Surveying: If it is necessary to make a draft survey of the delivering vessel in loaded conditions, such survey is to be made while the vessel is standing in deep water before she comes into the dock. This may require that the vessel anchor in a protected deep water area nearby while the survey is performed.

B. Tampa Electric's Big Bend Station on Hillsborough Bay, Tampa, Florida.

1. Draft Limitation: 33 feet.
2. Maximum Vessel Dimensions: 650 feet length; and vessels over 600 feet must be shifted at the dock during unloading. 85 feet beam.
3. Airdraft: Maximum airdraft is 47 feet. Vessel may have to be ballasted during unloading to maintain this maximum.
4. Minimum Hatch Size: 38' width x 50' length; greater size highly desirable.
5. Discharging Equipment: Dravo ladder bucket machine and Traveling Clamshell Crane.
6. Expected Average Unloading Rate: 2000 net tons per hour, excluding delays caused by vertical interference from vessel booms, masts and superstructures.
7. Draft Surveying: If it is necessary to make a draft survey of the delivering vessel in loaded conditions, such survey is to be made while the vessel is standing in deep water before she comes into the dock.

C. EXCEPTIONS: Vessel of slightly different maximum dimensions may be accommodated provided that mutual agreement has been reached between the Seller and Tampa Electric and/or Tampa Electric's unloading contractor prior to loading and also prior to any commitments on the part of the Seller to utilize such vessels.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

October 31,1996

Mr. Robert E. Krause
President
Railmark Americas
8068 - 12th Avenue South
St. Petersburg, FL 33707

Dear Mr. Krause:

RE: Request for Rail Car Lease Proposals RCL - 0197

The Fuels Department of Tampa Electric Company is requesting proposals for the lease of steel, lightweight steel, steel/aluminum or aluminum rail cars to be used for the transportation of coal from the Eastern United States to Tampa Electric's Francis J. Gannon Generating Station. Leasing firms wishing to submit proposals may cover all or part of this requirement.

The enclosed sheets provide pertinent information on the preparation and submittal of your proposal. Should you require additional information or clarification, please contact me at (813) 641-5055.

We invite you to participate in this bidding process. Please review this Request for Proposal and send your formal reply by November 20, 1996, 4:00 p.m., Eastern Standard Time, as specified under the section "Bidding Procedures". If you do not wish to respond to this request, please send us a formal written declination for recording purposes.

We look forward to your response.

Sincerely,

Carey M Bride

C. Carey McBride
Sr. Consulting Engineer

Enclosure

REQUEST FOR RAIL CAR LEASE PROPOSALS RCL - 0197

General

The Fuels Department of Tampa Electric seeks to lease rail cars. These cars will be used for the transportation of coal from the coal fields of the Eastern United States to Tampa Electric's Francis J. Gannon Generating Facility in Tampa, Florida. The equipment will be required for a twenty four (24) to thirty six (36) month period beginning in January of 1997 and extending through December of 1998 with an optional one-year extension. The specifics of this request and the bidding procedures to be followed are outlined below.

Equipment Requirements

Tampa Electric requests bids for 200 rail cars. Bids should be submitted for bottom dump, rapid-discharge, open-top hopper cars. Respondents may submit bids for all or part of Tampa Electric's requirements as stated in this solicitation. All cars should be designed to yield a fully-loaded gross weight on rail (GWR) of at least 270,000 pounds. Cars yielding less than 270,000 GWR will be assigned a penalty based in part on the additional costs incurred by Tampa Electric in utilizing the lower capacity cars.

The coal to be transported has an approximate density of 52 lbs./cu. ft. Any car design submitted in response to this solicitation should therefore meet the minimum GWR based on a coal of this density. In addition, all cars proposed in response to this solicitation should be of a standardized proposal and should be constructed to all applicable Association of American Railroads (AAR) and Federal Railroad Administration requirements.

Equipment Delivery

Any cars leased as a result of this solicitation will be tendered to Tampa Electric at a location acceptable to Tampa Electric or its transportation contractor. All proposals should include a December 31, 1996, delivery date for all cars supplied to Tampa Electric.

Bid information

All participants in this solicitation are required to submit detailed information regarding the equipment represented in their bid. This information should include, but not be limited to, the following:

- detailed specifications covering the equipment
- age of the cars
- pricing information
- disposition of tax credits, if any
- options to purchase
- warranties and warranty period with regard to operating performance and condition

Tampa Electric will accept full service lease and/or financial lease terms. A full service lease can be quoted on a time or revenue-ton-mile basis.

If a financial lease is offered, maintenance and repair cost history data should be provided, and pricing information should be expressed on a dollars per car per month basis.

In addition, all participants should include company information including, but not limited to, annual reports, company literature, and relevant financial information which would provide the Fuels Department with an overview of your firm and its ability to meet the requirements of this solicitation should your firm be awarded a contract.

Bidding Procedures

Upon completion of all information in this Bid Solicitation, send the sealed bid to:

Mr. C. Carey McBride
Fuels Department
Bid Proposal RCL - 0197
Tampa Electric Company/ Prod. Engr.
6944 US 41 North
Apollo Beach, FL. 33572

Please indicate "Bid Proposal RCL - 0197" on the envelope.

Bid proposals must be received at the Fuels Department no later than November 20, 1996, 4:00 p.m., Eastern Standard time, for evaluation. Bids received after this date will not be evaluated or considered. Bid proposals that are incomplete may not be evaluated. Revised proposals, if any, must be received before the deadline.

The Fuels Department reserves the right to provide the bid information received from you to our consultants for evaluation, subject to confidentiality agreement terms that exist between the respondent and Tampa Electric.

All proposals should remain in effect for a minimum of 60 days after the closing bid date. Each respondent must stipulate any and all other proposed standard terms and conditions.

The Fuels Department reserves the right to award all, part, or none of this intended lease to any one or several qualified bidders. The Fuels Department also reserves the right to disqualify any bid proposal that does not conform to the procedures set forth in this Bid Solicitation. Any respondent desiring to make a personal presentation of its proposal will be allowed to do so before the closing deadline of this bid solicitation, by contacting the Fuels Department before November 12, 1996, to schedule the presentation.

Any award will be based upon Tampa Electric Company's overall evaluation of bid proposals and not on price alone.

Each respondent will be notified at the conclusion of the evaluation whether or not its bid response will be awarded any portion of Tampa Electric Company's requirements. We anticipate providing such notification by December 3,1996. No information will be released to any respondent concerning proposals of other respondents. Final contractual details for the purchase commitment will be negotiated between the successful bidder(s) and the Fuels Department.

If you have questions, please contact Carey McBride at (813) 641-5055 for further information.

H:\FUELS\RAIL-CAR.LSE\RCL-0197\BID

TAMPA ELECTRIC
A TECO ENERGY COMPANY

December 29, 1994

AAA Cooper Transportation
Attn: Sales
10109 Ceder Run Road
Tampa, FL 33619

Dear Sir:

RE: Request for Coal Trucking Proposals CT - 0295

The Fuels Department of Tampa Electric is requesting proposals for the truck transporation of coal from Big Bend Station in Tampa, Florida, to the new Polk Power Station in Polk County Florida. We seek term agreement(s) that provide this transfer in a reliable, professional and cost efficient manner.

The enclosed sheets provide pertinent information on preparation and submittal requirements for your proposal. Should additional information or clarification be required, please contact either me at (813) 228-1615, or in the alternative, Mark Senior at (813) 228-1652.

We invite you to participate in this bidding process. Please review this Request for Proposal and send your formal reply by February 15, 1995, 4:00 p.m., Eastern Standard Time, as specified under the section "Bidding Procedures". If you do not wish to respond to this request, please send us a formal written declination for recording purposes, and mark "No Bid" on the envelope.

We look forward to your response.

Sincerely,

Rod Burkhardt
Manager, Fuels Transportation and Planning

Enclosure

GENFILE:MAS:CT-0295.LTR

Request for Coal Trucking Proposals CT-0295

General

The Fuels Department of Tampa Electric is requesting proposals for term agreements to provide for the trucking of coal from Big Bend Station in Tampa, Florida, to the new Polk Power Station in Polk County, Florida. The specifics of this request and the procedures to be followed are outlined below.

Expectations

Tampa Electric expects the bid proposals to provide for the full trucking requirements with a seven days a week operation. The trucking firm is to establish a close and tightly coordinated working relationship with power plant operations. The limited storage capacity at Polk Power Station makes the reliability of the coal transportation critical to power plant operation.

Origin Point

The coal will be loaded into trucks at Big Bend Station using flood loading equipment owned and operated by Tampa Electric Company. Loaded coal weight will be determined by the weigh bin incorporated into the loading system. Loading time will be a maximum of five minutes per trailer.

A drawing of the loading facilities is included in this bid solicitation package to provide major dimensions of the loading facilities.

Truck Trailer Type

The coal will be delivered in top loading, bottom dump, dual trailers with an approximate payload capacity of 14 tons per trailer. Both the bottom gates and top covers are to be pneumatically or hydraulically actuated. Side slopes within the trailers shall be of sufficient angle to dump fine, wet coal or petroleum coke without vibratory assistance.

Required Haul Route

Tampa Electric's power plant site permit requires that trucks enter Big Bend Road from the south truck entrance gate at Big Bend Station. They then proceed east on Big Bend Road to U.S. Hwy 301.
Turn south on U.S. Hwy 301 and proceed to State Road 672.
Turn east on State Road 672 and proceed to State Road 39.
Turn south on State Road 39 and proceed to State Road 674.
Turn east on State Road 674 and proceed to State Road 37.
Turn north on State Road 37 and proceed to the Polk Power Station Entrance on State Road 37.

The total distance is 34 miles one way more or less. All roads are believed (but not warranted) to be currently in excellent condition and posted with 55 mile per hour speed limits. The

bidder assumes all risks of road, rail crossings and bridge conditions.

Destination

Polk Power Station will have a maximum storage capacity of 10,000 tons. This quantity equates to about 5 days maximum supply for the station. Delivery schedules will have to accommodate the limited on-site storage. Unloading times will be a maximum of five minutes.

The unloading facilities consist of a drive over hopper enclosed in a steel building with dust control equipment. Coal will be conveyed directly from the unloading hopper to the storage silo.

Back Haul Operations

The Polk Power Station is located near to many phosphate mining operations that currently transport product to terminals near Big Bend Station. Tampa Electric encourages the back hauling of these products as a method of reducing the transport cost of coal.

Tampa Electric will require a cleaning of the trucks after carrying a commodity other than coal or petroleum coke.

Hours of Operation

Bids should be based on the loading and unloading facilities being open from 7:00 AM to 11:00 PM. Proposals based on 24 hour operation of the facilities may be proposed as an option to the base proposal.

Emergency delivery of coal around the clock must be available and will be assumed to be at the normal rate unless any additional charges for this type of operation are stated in the proposal.

Quantities

Quantities to be delivered to the Polk Power Station can vary annually based on the heat content of the fuel and plant maintenance schedules. Deliveries will be halted upon request of the loading or unloading facilities for reasons of plant maintenance, inventory or other reason deemed appropriate by the buyer. The following quantities are projections of annual movements and are to be used for estimation purposes only.

Time Period	Tons
Apr - Dec 1996	120,000
1997	440,000
1998	580,000
1999	670,000

Term

Tampa Electric desires to structure the term of this proposed trucking agreement to coincide with the economic life of the trucking equipment to be used. Bidders shall propose a term for the agreement and state how it ties into equipment life. Tampa Electric has expectations of a three to six year term. Shipments under the proposed transportation agreement would begin in April, 1996. After the initial term, an extension term of equal duration should be provided for in your proposal, with the extension offered at Tampa Electric's sole option.

Transportation Operation Description

Please provide information in the following areas on the planned trucking operation:

- Total number of tractors and trailers for this contract and total company. (State whether tractor/trailers can be separated for maintenance)
- Tractor specifications, including make, model, engine, transmission, axles, suspension, tire model and size, cab type, whether air conditioned, other accessories.
- Trailer specifications including load and dump mechanisms, tire model and size, and tread type.
- Planned life cycle (replacement interval) of tractors and trailers.
- Age and condition of equipment at the beginning of the contract period.
- Applicable manufacturer's warranties or extended service plans in effect.
- Vehicle downtime expectations and standards.
- Vehicle appearance and condition expectations/standards.
- Personnel requirements
- Expected trip cycle time broken down by sequence
- Location and description of support facilities
- Identify tractors/trailers held as spare
- Scheduled maintenance plan (prevention and repairs)
- Safety program
- Ownership of Equipment (leased, rented or owned)
- Source of labor supply (contract, employee, union/non-union)
- Demonstrated safety record over the last 5 years.

Price Adjustments

Respondents are welcome to suggest any method of price adjustment. Tampa Electric has a preference for a fixed (non-indexed) price.

If cost escalations are proposed, cost adjustments for productivity improvements are also requested.

Capital Improvements

If a capital investment is required by the bidder to service the proposed agreement, please provide the following information:

1). Detailed description of investment.
2). Proposed financial backing for project.
3). Anticipated performance and capacity resulting from investment.

Company Information

Please provide information on the bidder's operating company, corporate structure, financial statements and banking references.

Bidding Procedures

Upon completion of a proposal, send it to:

Mr. Rod Burkhardt, Manager, Fuels Transportation and Planning
Bid Proposal CT - 02935
Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

Please indicate "Bid Proposal CT - 0295" on the envelope.

Bid proposals must be received at the Fuels Department no later than February 15, 1995, 4:00 p.m., Eastern Standard time, for evaluation. Bids received after this date will not be evaluated or considered. Bid proposals that are incomplete may not be evaluated. Revised proposals, if any, must be received before the foregoing deadline. If you do not wish to bid, please send a formal reply to that effect, and mark "no Bid" on the envelope.

The Fuels Department reserves the right to provide the bid information received from you to our consultants for evaluation, subject to confidentiality agreement terms that exist between the respondent and Tampa Electric.

The Fuels Department reserves the right to disqualify any bid proposal that does not conform to the procedures set forth in this Bid Solicitation. Any respondent desiring to make a personal presentation of its proposal will be allowed to do so before the closing deadline of this bid solicitation, by contacting the Fuels Department before January 16, 1995, to schedule the presentation.

All proposals should remain in effect for a minimum of 180 days after the closing bid date. Each respondent must stipulate any and all other proposed special terms and conditions.

Any award will be based upon Tampa Electric Company's determination of the bidder's qualifications and an overall evaluation of bid proposals and not on price alone. The overall evaluation will include, but not be limited to: current and projected delivered price per ton

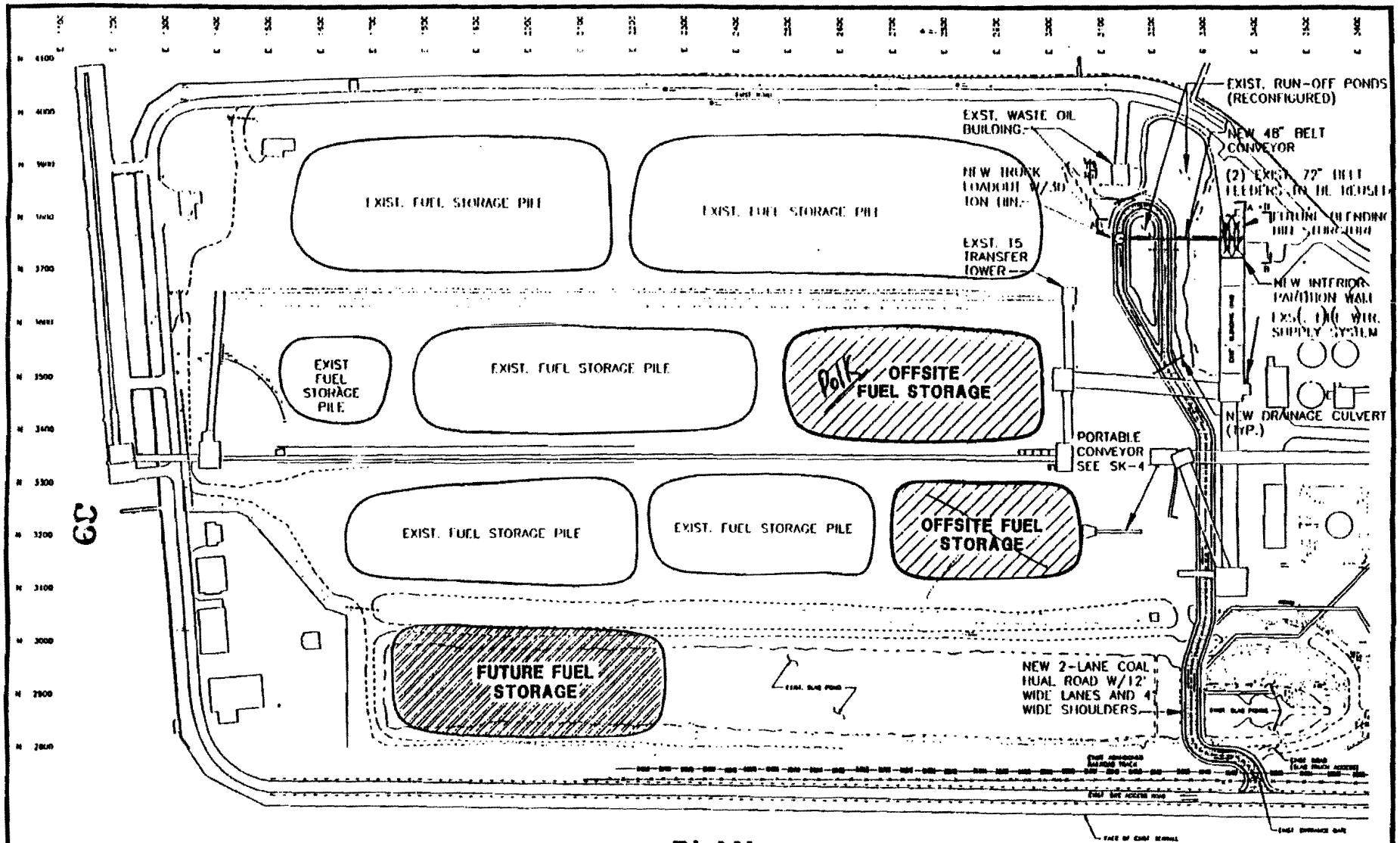
during the initial term and for any optional periods, performance guarantees, physical capability to perform by all parties on a given route, demonstrated safety performance, financial viability of all parties involved in service on a given route, and other pertinent factors.

Each respondent will be notified at the conclusion of the evaluation whether or not its bid response will be awarded Tampa Electric Company's requirements. We anticipate providing such notification by March 1, 1995. No information will be released to any respondent concerning proposals of other respondents.

Contractual Requirements

Final contractual details for the purchase commitment will be negotiated between the successful bidder(s) and the Fuels Department. This Contract of Affreightment shall require the successful bidder, among other things, to provide minimum General Liability insurance in the amount of one million dollars, Works Compensation at statutory limits, broad form indemnification of Tampa Electric for all claims arising from the bidder's performance under the contract and comply with all of the applicable requirements of the Department of Energy. The requirements placed on this contract by the Department of Energy are enclosed as Supplement A.

If you have questions, please feel free to contact Rod Burkhardt at (813) 228-1615, or in the alternative, Mark Senior at (813) 228-1652 for further clarification.



PLAN

N.T.S.

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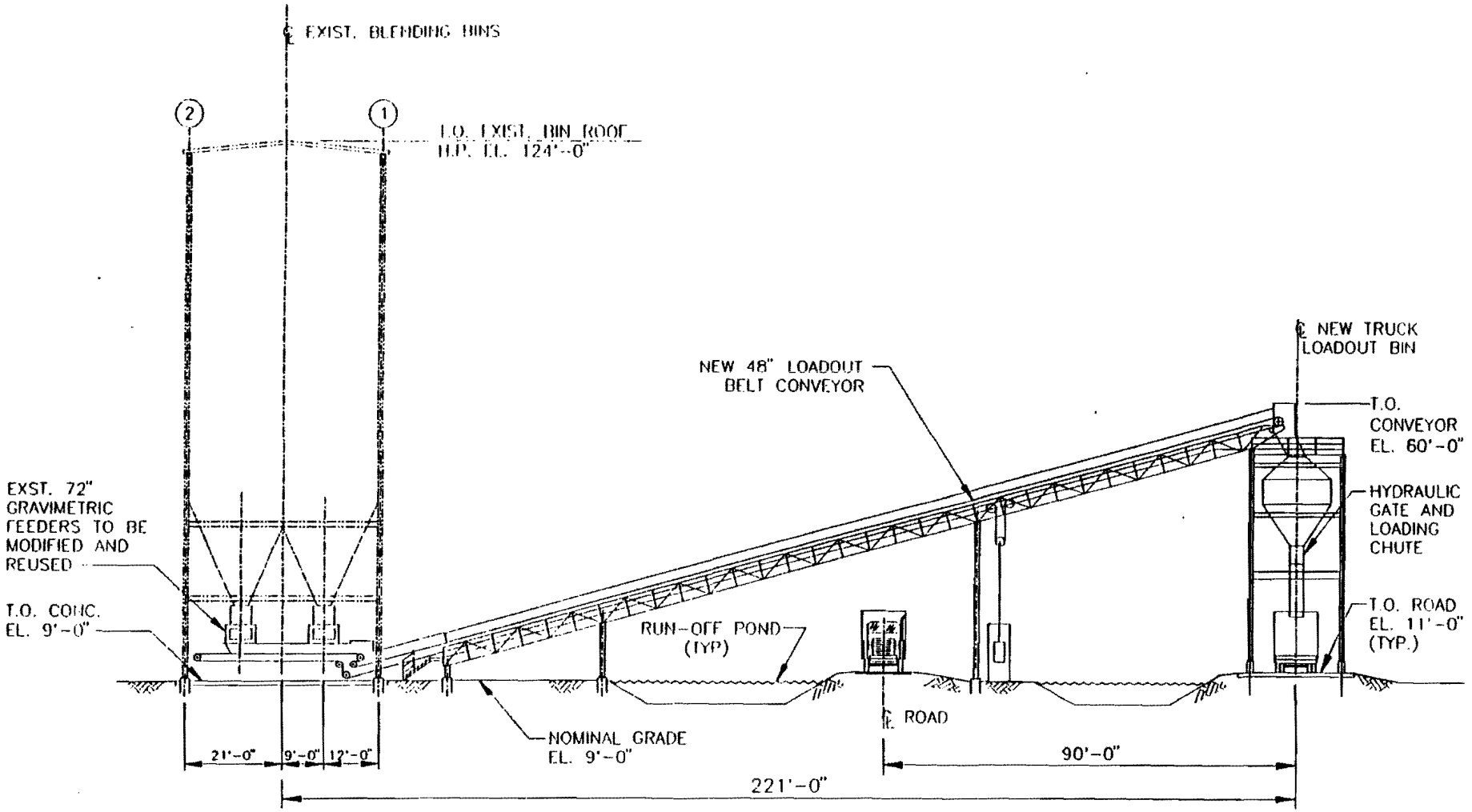
TAMPA ELECTRIC
A TECO ENERGY COMPANY

BIG BEND STATION
COAL TRANSLOADING FACILITY
FOR FUTURE BLENDING BIN

DESIGNED BY	CHECKED BY	APPROVED BY
RMG	WWS	TW
DATE: 12/94	JOB NO.: 183-26	
FILE NAME: PLANBLIN		DWG. NO.: BB1

TAMPA ELECTRIC COMPANY
PAGE 31 OF 99



SECTION A - A

(LOOKING SOUTH)(N.T.S.)

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TAMPA ELECTRIC
A TECO ENERGY COMPANY

BIG BEND STATION
COAL TRANSLOADING FACILITY

DESIGNED BY	CHECKED BY	APPROVED BY
RMG	WWS	TW
DATE 11/94	JOB NO. 183-26	
FILE NAME SEC-A		DWG. NO SK-2

TAMPA ELECTRIC COMPANY
PAGE 22 OF 49

SUPPLEMENT A

DOE RELATED PROVISIONS

Tampa Electric Company ("Owner") and the United States Department of Energy ("DOE") have entered into a Cooperative Agreement, effective as of March 5, 1992 (the "Cooperative Agreement"). The Cooperative Agreement provides for certain financial assistance to be given to Owner by the DOE in connection with Owner's proposed Polk Power Station Unit 1 (the "Facility"). The Cooperative Agreement also imposes certain requirements on Owner and all parties with whom Owner contracts in connection with the Facility, and such requirements are included in this Supplement A. The agreement (or purchase order or other set of terms and conditions) to which these DOE Related Provisions are attached is referred to herein as "this Agreement," and the party with whom Owner is contracting with in this Agreement is referred to herein as the "Seller." To the extent that any of the provisions of this Supplement A conflict with any of the other provisions of this Agreement, the provisions of this Supplement A shall govern.

I. AUDIT AND RECORDS REQUIREMENTS

1.1 Books and Records Maintenance

During the period of this Agreement and in connection with charges under this Agreement based on Seller's actual costs due or which may be due by Owner hereunder relating to the performance and operation of the Facility, Seller shall maintain a set of accounts and records including all financial documents, correspondence, data, files, record layouts and codes, and any other financial evidence which shows and supports the aforesaid charges, including the costs incurred or anticipated, and any applicable credits and Facility operating and performance data which is not proprietary (collectively, the "Books and Records"). Owner shall have the full right of access to the Books and Records in order to verify any amounts that are payable to Seller hereunder. The system of accounts to be used by Seller shall be in accordance with generally accepted accounting principles. Seller shall preserve these records for a period of five years after final payment pursuant to this Agreement. If an audit, litigation, or other action involving any of the Books and Records is commenced before the end of the five-year retention period, the Books and Records shall be retained until all issues arising out of the action are resolved, or until the end of the five-year period, whichever is later.

1.2 Access to Records

Seller acknowledges and agrees that the DOE and the Comptroller General of the United States, or any of their duly authorized representatives, shall have the right of access to any books, documents, papers, or other records (including those on electronic media) which are pertinent to the Cooperative Agreement, for the purpose of making audits, examinations, excerpts, and transcripts, for as long as Seller retains the records which are pertinent to the Cooperative Agreement.

1.3 Subcontractor Requirements

Seller shall require all subcontractors to maintain a set of Books and Records in the same manner required of Seller as set out in this Agreement and shall cause its subcontractors' records to be subject to access by Owner, the DOE and the Comptroller General of the United States or their duly authorized representatives during the same time periods and under the same conditions as Seller's records are available. Payment of any invoice, in whole or in part, shall not bar Owner's rights to take later exception thereto.

1.4 Reporting Requirements

Seller shall furnish such information within its possession or control that Owner may reasonably require in order to comply with the Owner's reporting requirements under the Cooperative Agreement, so long as such information is protected as may be appropriate for the type of information provided.

II. CERTIFICATE OF COMPLIANCE AND OTHER CERTIFICATIONS

2.1 E.O. 11246, as amended by E.O. 11375 (Race, Color, Religion, Sex and National Origin).

2.1.1 Seller agrees to comply with the provisions of Section 202 of such Order (the "Equal Opportunity Clause") which clause is incorporated herein by reference pursuant to regulations promulgated under such Order (41 C.F.R. 60-1.4(d)).

2.1.2 Seller certifies that it does not maintain or provide, nor will it maintain or provide, for its employees any segregated facilities at any of its establishments, and that it does not permit, nor will it permit, its employees to perform their services at any location under its control where segregated facilities are maintained. As used herein, the term "segregated facilities" means any waiting rooms, work areas, rest rooms and wash rooms, restaurants and other eating areas, time clocks, locker rooms and other storage or dressing areas, parking lots, drinking fountains, recreation or entertainment areas, transportation and housing facilities provided for employees which are segregated by explicit directive or are in fact segregated on the basis of race, creed, color or national origin because of habit, local custom or otherwise. Seller agrees that a breach of this certification is a violation of the Equal Opportunity Clause of Executive Order 11246. Seller further agrees that (except where it has obtained identical certifications from proposed subcontractors for specific time periods) it will obtain identical certifications from proposed subcontractors exceeding $10,000 which are not exempt from the provisions of the Equal Opportunity Clause, that it will retain such certifications in its files and that it will forward the prescribed notice to such proposed subcontractors (except where the proposed subcontractors have submitted identical certifications for specific time periods). The form of the prescribed notice is as follows: "NOTICE TO PROSPECTIVE SUBCONTRACTORS OF REQUIREMENT FOR CERTIFICATION OF NONSEGREGATED FACILITIES. A Certificate of Nonsegregated Facilities

as required by the May 9, 1967, order on Elimination of Segregated Facilities by the Secretary of Labor (32 Fed. Reg. 7439, May 19, 1967) must be submitted prior to the award of a subcontract exceeding $10,000 which is not exempt from the provisions of the Equal Opportunity Clause. The certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semi-annually or annually). Note: The penalty for making false statements is prescribed in 18 U.S.C. 1001."

2.1.3 Seller agrees (a) to file annually, by September 30 of each year, (or within 30 days after the award of the Contract if not filed within 12 months preceding the date of the award), complete and accurate reports on standard Form 100 (EEO-1) with the appropriate governmental agency, in accordance with the regulations issued by the Secretary of Labor (41 C.F.R. 60-1.7), and (b) to develop a written affirmative - action compliance program for each of its establishments in accordance with the regulations issued by the Secretary of Labor (41 C.F.R. 60-1.40).

2.2 E.O 11701 (Section 402 - Veterans Readjustment Act of 1974). Seller agrees to comply with the affirmative action clause and regulations promulgated under such Order (41 C.F.R. Part 60-250) which clause is incorporated herein by reference pursuant to Section 60-250.22 of such regulations.

2.3 E.O. 11758 (Section 503 - Rehabilitation Act of 1973). Seller agrees to comply with the affirmative action clause and the regulations promulgated under such Order (41 C.F.R. Part 60-741), which clause is incorporated herein by reference pursuant to Section 60-741.22 of such regulations.

2.4 The Americans with Disabilities Act of 1990. Seller certifies that discrimination will not be made against individuals with disabilities in any manner, including employment and participation in contractual or bargaining agreements.

2.5 Procurement Goals. Seller agrees to use positive efforts to utilize small business, local business and minority-owned business sources of supplies and services. Such efforts shall allow these sources the maximum feasibility to compete for contracts utilizing Federal funds.

2.6 E.O. 12138, as amended by E.O. 12608 (Women's Business Enterprises Program). Seller agrees to use its best efforts to provide women-owned businesses with the maximum practicable opportunity to participate in the performance of the work under this Agreement ("Work") to the fullest extent consistent with the efficient performance thereof in accordance with the executive order and any regulations promulgated thereunder, which are incorporated herein by reference.

2.7 Environment and Other Legal Compliance

Seller shall comply with all requirements of the Clean Air Act, as amended (CAA), 42 U.S.C. SS7041, et seq., and the Clean Water Act, as amended CWA), 33 U.S.C. SS1251, et seq., including the requirements of Section 114 of the CAA and Section 508

of the CWA, and all applicable clean air standards and clean water standards and Environmental Protection Agency regulations (40 C.F.R. Part 15). See Federal Acquisition Regulation, 48 C.F.R. SS52.223-1 and 52.223.2. Seller shall also comply in performing the Work hereunder, as applicable, with the following: the Safe Drinking Water Act, as amended; the Resource Conservation and Recovery Act of 1976, as amended; the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended; the Toxic Substances Control Act, as amended; the Noise Control Act, as amended; the Endangered Species Act; the National Historic Preservation Act; the Marine Protection, Research, and Sanctuaries Act of 1972, as amended; the Fish and Wildlife Coordination Act; the Coastal Zone Management Act of 1972, as amended; the Coastal Barrier Resource Act of 1982, the Federal Insecticide, Fungicide, and Rodenticide Act, as amended; the Occupational Safety and Health Act; and other federal and non-federal environmental protection laws, codes, ordinances and regulations, if identified in writing by the DOE's authorized official (the "Contracting Officer"), and any and all other federal, state or local laws, ordinances, rules, and regulations relating to protection of the environment.

Failure to list a law above, or to identify a requirement having the force and effect of law, shall not be construed as waiving a requirement for the Seller to comply with such law or requirement.

For the period ending three years after the termination of this Agreement, the Contracting Officer or his authorized representative shall have access to and the right to examine the Seller's records with respect to environmental protection related to the Work performed hereunder upon request.

During performance of the Work under this Agreement, Seller agrees to comply with all applicable mandatory standards and policies relating to energy efficiency contained in the applicable state's energy conservation plan issued pursuant to the Energy Policy and Conservation Act (42 U.S.C. 6201, et seq.). Seller further agrees to comply with the Copeland Anti-Kickback Act (18 U.S.C. 874) as supplemented in U.S. Department of Labor regulations (29 C.F.R. Part 3) and with Sections 103 and 107 of the Contract Work Hours and Safety Standards Act (40 U.S.C. 327-330) as supplemented by U.S. Department of Labor regulations (29 C.F.R. Part 5).

2.8 Subcontractor Flowdown Clauses. Seller shall cause each subcontract or bid or solicitation to contain the applicable contract clauses set out in Exhibit A. Seller shall provide, and shall cause all of its solicitations, bidders and subcontractors to contain or provide, as applicable, (i) a "Certification Regarding Debarment, Suspension, Ineligibility and Voluntary Exclusion - Lower Tier Covered Transactions," as set forth in Exhibit B, (ii) a "Certificate Regarding Lobbying," as set forth in Exhibit C, and (iii) a "Certification Regarding Drug-Free Workplace Requirements," as set forth in Exhibit D.

2.9 Special Surveillance Subcontracts

Seller acknowledges that the DOE has the authority to designate certain contracts as Surveillance Contracts under the Cooperative Agreement, which are subject to the DOE's review and approval. Seller agrees that, upon receiving notice that a contract

has been designated by the Contracting Officer as requiring the Contracting Officer's review and approval, Seller will not execute such contract without first obtaining such review and approval.

III. PATENTS

3.1 Indemnification and Defense of Infringement Claims. Seller shall indemnify, defend and hold harmless Owner and its Affiliates and their respective officers, agents and employees (each, an "Indemnitee") against any liability, including costs and expenses, directly relating to or arising out of any suit or proceeding brought against an Indemnitee, so far as based on a claim that the product being sold to Owner under this Agreement, or any part thereof designed, engineered, or manufactured by Seller, or technology, material, equipment or services, as the case may be, furnished by Seller under this Agreement (collectively, the "Product"), constitutes an infringement of any patent of the United States. Owner shall notify Seller promptly in writing and Owner shall give Seller control, exclusive authority, information and assistance for the defense of any such claim, suit or proceeding. Seller shall pay all damages and court or other tribunal-awarded costs of Owner in connection therewith; provided, however, that Seller shall not be responsible for any settlement of any such claim, suit or proceeding made by Owner without its written consent. In case the Product is in such claim, suit or proceeding held to constitute infringement or the use of the Product is enjoined, Seller shall, at its own expense and at its option, either procure for Owner the right to continue using the Product, replace the Product with non-infringing equipment or modify the Product so that it becomes non-infringing in a manner consistent with Seller's obligations hereunder. This Section 3.1 shall not apply to any Products manufactured to Owner's detailed design, and Seller shall have no liability for infringement with respect to such Products.

3.2 Patent Claim Notice.

3.2.1 Seller shall report to Owner and to the DOE promptly and in reasonable written detail, each notice of claim of patent or copyright infringement based on the performance of this Agreement of which Seller has knowledge.

3.2.2 In the event of any claim or suit against the United States Government (the "Government") on account of any alleged patent or copyright infringement arising out of the performance of this Agreement or out of the use of any supplies furnished or work or services performed hereunder, Seller shall furnish to the Government when requested by Owner or the DOE's designated Contracting Officer all evidence and information in possession of Seller pertaining to such suit or claim. Such evidence and information shall be furnished at the expense of the Government except where Seller has agreed to indemnify the Government.

3.2.3 Seller agrees to flow down the above two clauses in all contracts and subcontracts relating to the goods or services to be furnished hereunder.

3.3 Patent Liability.

3.3.1 The Seller shall indemnify the Government and its officers, agents, and employees against liability, including costs, for infringement of U.S. Letters Patent (except U.S. Letters Patent issued upon an application which is now or may hereafter be kept secret or otherwise withheld from issue by order of the

Government) resulting from the Seller's (a) furnishing or supplying standard parts or components which have been sold or offered for sale to public on the commercial open market; (b) utilizing its normal practices or methods which normally are or have been used in providing goods and services in the commercial open market in the performance of the Cooperative Agreement; or (c) utilizing any parts, components, practices, or methods to the extent to which the Seller has secured indemnification from liability. The foregoing indemnity shall not apply unless the Seller shall have been informed as soon as practicable by the Government of the suit or action alleging such infringement and shall have been given such opportunity as is afforded by applicable laws, rules, or regulations to participate in the defense thereof; and further, such indemnity shall not apply to a claimed infringement which is settled without the consent of the Seller unless required by final decree of a court of competent jurisdiction or to an infringement resulting from addition to or change in such supplies or components furnished or construction work performed for which addition or change was made subsequent to delivery or performance by the Seller.

3.3.2 Seller shall indemnify and save and hold harmless the Government, its officers, agents, and employees acting within the scope of their official duties against any liability, including costs and expenses, for violation by Seller of proprietary rights or copyrights, arising out of delivery or use of any data furnished or utilized by Seller in the course of its performance of its obligations or otherwise under this Agreement.

3.3.3 Seller shall flow down the above two clauses to any of its subcontractors or licensees hereunder.

3.4 DOE Intellectual Property Requirements. Seller hereby represents that the Product is a Commercial Product as defined in clause 9(m) of Attachment B to the Cooperative Agreement.

3.4.1 Rights in intellectual property (including Subject Inventions and Technical Data as defined in Attachment B to the Cooperative Agreement ("Attachment B") included in the request for proposal previously delivered to Seller by Owner) made or conceived by Seller, its affiliates or any of its or their subcontractors in connection with this Agreement that are not directly related to the Product shall be subject to the terms and conditions of Attachment B, which is incorporated herein by reference. As set forth in Attachment B, Seller maintains all rights in Technical Data associated with the Product.

3.4.2 Owner has received an Advance Patent Waiver ("Advance Waiver") and has elected to retain rights in the Subject Inventions as part of the Advance Waiver, which includes a provision that authorizes Owner to flow down the terms of the Advance Waiver to Seller in a manner consistent with this Agreement (including Section 3.4.3 below). Owner does hereby flow down for the benefit of Seller the terms of the Advance Waiver, allowing Seller to retain rights in Subject Inventions directly related to the Product. Owner and Seller further acknowledge

and agree that Seller reserves the right to elect to apply to DOE directly for an Advance Waiver in its own right with respect to patents, inventions or discoveries which would be covered by Section 3.4.1 above.

3.4.3 To the extent that patented and unpatented information, data, engineering and other design data, including without limitation, the engineering, design and know-how necessary to integrate the Product with the other components of the Facility and which constitutes the IGCC Technology (as defined below) is developed for and provided to Owner in connection with the IGCC Project (as defined below) (collectively, "IGCC Data"), such IGCC Data shall be owned by Seller and may be used by Owner or its Affiliates on a non-exclusive, royalty-free basis. IGCC Technology which directly modifies Seller's commercially available Product shall be and remain the exclusive property of Seller; provided, however, that the same may be used by Owner on a royalty-free basis solely in connection with the IGCC Project so long as Owner operates the Product.

IV. OTHER PROVISIONS

4.1 Demonstration Period. The Seller acknowledges that participation by the Seller may be required during the two year demonstration testing period after written notification of acceptance of the Work by Owner to Seller. Seller's participation shall be when reasonably requested as necessary to support DOE requirements.

4.2 Commercial Availability of the Product. Seller agrees to make the Product available in support of other projects using the IGCC Technology throughout the world to responsible customers under reasonable terms and conditions in accordance with its then current business practice.

V. CERTAIN DEFINITIONS

5.1 "IGCC Project" means the fully permitted and operational nominal net 260 MW integrated gasification combined cycle electric power generating facility, utilizing IGCC Technology, including the simple cycle phase, to be located on Owner's site in Polk County, Florida (including all ancillary equipment and site development activities necessary to support such operation), part of which is a Clean Coal Technology Demonstration Project for which the DOE is providing funding in the amount of approximately $120,000,000 pursuant to the Cooperative Agreement.

5.2 "IGCC Technology" means all of the patented and/or unpatented technical data and know-how required to design, procure, construct, and operate an integrated coal gasification combined cycle system comprised of the following basic elements and process(es): a pressurized, oxygen-blown, entrained-flow gasifier, capable of utilizing caking coal which is gasified in the presence of oxygen to produce a hot product gas mixture composed substantially of hydrogen and carbon monoxide; a commercially available cold gas cleanup system and/or a metal oxide hot gas conditioning system for removing sulfur compounds, particulates, and other contaminants as necessary to meet environmental and combustion turbine fuel requirements; a combined cycle power generation system wherein the cleaned produce gas is combusted in an advanced combustion turbine generator to make electrical power and wherein steam, produced

from a heat-recovery steam generator in the combustion turbine exhaust, is used in part to feed a steam turbine-generator to generate a second source of electrical power; an integrated air separation process for removing oxygen and nitrogen from ambient air and supplying oxygen to the gasification unit as an oxidant while simultaneously supplying nitrogen to the combustion turbine for NO_x control and power augmentation; and the control system and algorithms necessary to integrate and control the overall system as required by the operator, as demonstrated under the Cooperative Agreement, including any improvements or modification embodied during commercialization by/or through Owner which is incorporated into the system.

specify that the right of access shall last as long as the contractor retains records which are directly pertinent to that specific contract.

9. For contracts and subcontracts over $100,000: a clause requiring the contractor or subcontractor to comply with all applicable standards, orders, or requirements issued under section 306 of the Clean Air Act (42 U.S.C. 1857(h)), section 508 of the Clean Water Act (33 U.S.C. 1368), Executive Order 11738, and Environmental Protection Agency regulations (40 C.F.R. Part 15) or otherwise relating to protection of the environment.

10. For all contracts and subcontracts: a clause requiring compliance with all applicable mandatory standards and policies relating to energy efficiency contained in the state energy conservation plan issued pursuant to the Energy Policy and Conservation Act (42 U.S.C. 6201, et seq.)

11. In solicitations: the Instructions for and Certification Regarding Debarment, Suspension, Ineligibility and Voluntary Exclusion - Lower Tier Covered Transactions contained in Exhibit B, the Certificate Regarding Lobbying attached as Exhibit C, and the Certification Regarding Drug-Free Workplace Requirements attached as Exhibit D.

12. For all contracts and subcontracts: the applicable "flow-down" clauses contained in the sections entitled "Certificate of Compliance and Other Certifications" and "Patents" set forth above.

EXHIBIT B

DEPARTMENT OF ENERGY REQUIREMENTS REGARDING LOWER-TIER TRANSACTIONS

The United States Department of Energy ("DOE") requires lower tier participants in certain government-funded transactions to follow the instructions and to certify as to the matters set forth herein. As a prerequisite to performing any work for Tampa Electric Company relating to the Cooperative Agreement, Seller and any of its bidders or subcontractors must comply with the following instructions and execute and deliver the certificate included as part of this Exhibit B, the certificate attached as Exhibit C, and the certificate attached as Exhibit D.

Instructions for Certification:

1. By signing and submitting this proposal, the prospective lower tier Participant is providing the certification set out below.

2. The certification contained herein is a material representation of fact upon which reliance was placed when this transaction was entered into. If it is later determined that the prospective lower tier Participant knowingly rendered an erroneous certification, in addition to other remedies available to the Federal Government, the DOE may pursue available remedies, including suspension and/or debarment.

3. The prospective lower tier Participant shall provide immediate written notice to the person to which this proposal is submitted if at any time the prospective lower tier Participant learns that its certification was erroneous when submitted or has become erroneous by reason of changed circumstances.

4. The terms "covered transaction," "debarred," "suspended," "ineligible," "lower tier covered transaction," "Nonprocurement List," "DOE List," "Participant," "person," "primary covered transaction," "principal," "proposal," and "voluntarily excluded," as used in this clause, have the meanings set out in the Definitions and Coverage sections of the DOE rules implementing Executive Order 12549. See, 10 CFR Part 1036 [53 F.R. 19204 (May 26, 1988)]. You may contact the person to which the proposal is to be submitted for assistance in obtaining a copy of these rules.

5. The prospective lower tier Participant agrees by submitting this proposal that, should the proposed covered transaction be entered into, it shall not knowingly enter into any lower tier covered transaction with a person who is barred, suspended, declared ineligible, or voluntarily excluded from participation in this covered transaction, unless authorized by the DOE.

6. The prospective lower tier Participant further agrees by submitting this proposal that it will include the document titled "Certification Regarding Debarment, Suspension, Ineligibility and Voluntary Exclusion-Lower Tier Covered

Transactions," without modification, in all lower tier covered transactions and in all solicitations for lower tier covered transactions.

7. A Participant in a covered transaction may rely upon a certification of a prospective Participant in a lower tier covered transaction that it is not debarred, suspended, ineligible, or voluntarily excluded from the covered transaction, unless it knows that the certification is erroneous. A Participant may decide the method and frequency by which it determines the eligibility of its principals. Each Participant may, but is not required to, check the Nonprocurement List.

8. Nothing contained in the foregoing shall be construed to require establishment of a system of records in order to render in good faith the certification required by this document. The knowledge and information of a Participant is not required to exceed that which is normally possessed by a prudent person in the ordinary course of business dealings.

9. Except for transactions authorized under paragraph 5 of these instructions, if a Participant in a covered transaction knowingly enters into a lower tier covered transaction with a person who is suspended, debarred, ineligible, or voluntarily excluded from participation in this transaction, in addition to other remedies available to the Government, the DOE may pursue available remedies, including suspension and/or debarment.

Certification Regarding Debarment, Suspension, Ineligibility and Voluntary Exclusion-Lower Tier Covered Transactions:

The prospective lower tier Participant certifies, by submission of this proposal, that neither it nor its principals is presently debarred, suspended, proposed for debarment, declared ineligible, or voluntarily excluded from participation in this transaction by any Federal department or agency.

Where the prospective lower tier Participant is unable to certify to any of the statements in this certification, such prospective Participant shall attach an explanation to this proposal.

_____
Date

_____
Participant

By: _____

Name: _____

Title: _____

EXHIBIT C

CERTIFICATE REGARDING LOBBYING

The undersigned certifies, to the best of its knowledge and belief, that:

(1) No Federal appropriated funds have been paid, by or on behalf of the undersigned, to any person for influencing or attempting to influence an officer or employee of an agency, a Member of Congress, an officer or employee of Congress, or an employee of a Member of Congress in connection with the awarding of any Federal contract, the making of any Federal grant, the making of any Federal loan, the entering into of any cooperative agreement, and the extension, continuation, renewal, amendment, or modification of any Federal contract, grant, loan, or cooperative agreement.

(2) If any funds other than Federal appropriated funds have been paid or will be paid to any person for influencing or attempting to influence an officer or employee of any agency, a Member of Congress, an officer or employee of Congress, or an employee of a Member of Congress in connection with this Federal contract, grant, loan, or cooperative agreement, the undersigned shall complete and submit Standard Form-LLL, "Disclosure Form to Report Lobbying," in accordance with its instructions.

(3) The undersigned shall require that the language of this certification be included in the award documents for all subawards at all tiers (including subcontracts, subgrants, and contracts under grants, loans, and cooperative agreements) and that all subrecipients shall certify and disclose accordingly.

This certification is a material representation of fact upon which reliance was placed when this transaction was made or entered into. Submission of this certification is a prerequisite for making or entering into this transaction imposed by section 1352, title 31, U.S. Code. Any person who fails to file the required certification shall be subject to a civil penalty of not less than $10,000 and not more than $100,000 for each such failure.

_____ _____

Date Participant

By: _____

Name: _____

Title: _____

EXHIBIT D

CERTIFICATION REGARDING DRUG-FREE WORKPLACE REQUIREMENTS

This certification is required by the Drug-Free Workplace Act of 1988 (Pub. L. 100-690, Title V, Subtitle D) and is implemented through additions to the Debarment and Suspension regulations, published in the Federal Register on January 31, 1989.

An organizational applicant certifies that it will provide a drug-free workplace by:

(a) Publishing a statement notifying employees that the unlawful manufacture, distribution, dispensing, possession, or use of a controlled substance is prohibited in the grantee's workplace and specifying the actions that will be taken against employees for violation of such prohibition;

(b) Establishing a drug-free awareness program to inform employees about:

(1) the dangers of drug abuse in the workplace;

(2) the grantee's policy of maintaining a drug-free workplace;

(3) any available drug counseling, rehabilitation, and employee assistance programs; and

(4) the penalties that may be imposed upon employees for drug abuse violations occurring in the workplace;

(c) Making it a requirement that each employee to be engaged in the performance of the grant be given a copy of the statement required by paragraph (a);

(d) Notifying the employee in the statement required by paragraph (a) that, as a condition of employment under the grant, the employee will:

(1) abide by the terms of the statement; and

(2) notify the employer of any criminal drug statute conviction for a violation occurring in the workplace not later than five days after such conviction;

(e) Notifying the agency within ten days after receiving notice under subparagraph (d)(2) from an employee or otherwise receiving actual notice of such conviction;

(f) Taking one of the following actions, within 30 days of receiving notice under subparagraph (d)(2), with respect to any employee who is so convicted:

(1) taking appropriate personnel action against such an employee, up to and including termination; or

(2) requiring such employee to participate satisfactorily in a drug abuse assistance or rehabilitation program approved for such purposes by a federal, state, or local health, law enforcement, or other appropriate agency;

(g) Making a good faith effort to continue to maintain a drug-free workplace through implementation of paragraphs (a), (b), (c), (d), (e) and (f).

PLACE OF PERFORMANCE. The applicant shall insert in the space provided below the site(s) for the performance of work done in connection with the specific grant: (street address, city, county, state, zip code)

_____

_____

An applicant who is an individual certifies that, as a condition of the grant, he or she will not engage in the unlawful manufacture, distribution, dispensing, possession, or use of a controlled substance in conducting any activity with the grant.

This assurance is given in connection with any and all financial assistance from the Department of Energy after the date this form is signed. This includes payments after such date for financial assistance approved before such date. The applicant recognizes and agrees that any such assistance will be extended in reliance on the representations and agreements made in this assurance, and the United States shall have the right to seek judicial enforcement of this assurance. This assurance is binding on the applicant, its successors, transferees, and assignees, and on the authorized official (or individual applicant, as appropriate) whose signature appears below.

Organization Name _____ Award Number

Name and Title of Authorized Representative

Signature _____ Date

1. Please provide the results of Tampa Electric's most recent test burn of South American coal at the Big Bend Station. In your response, please identify the fusion temperature of the South American coal test burned.

A. Attached are the results from Tampa Electric's most recent test burn of South American coal at Big Bend Station. The fusion temperature of the coal tested was 2,663° Fahrenheit, H=W, in a reducing atmosphere.

Big Bend Station Colombian Coal Test Burn Final Report

Summary

During the period April through June 2003, Big Bend Units 1-4 consumed approx. 80K tons of Colombian Coal. The bulk of the coal (68K tons) was consumed by BB4 at blends of up to 60 percent. BB Units 1-3 consumed the remaining 22K tons at 20-30 percent blends. No significant operational issues were observed throughout the tests. This includes slag tapping, fouling, slagging, LOI, opacity, and NOx.

The Colombian coal tested was a high BTU coal with low ash. The chlorides were also very low (0.03%) which is a benefit for the FGD system and the station chloride balance. One limitation is the percentage of Colombian in BB1-3 should be held to 30 percent or less because of slag tank freezing concerns due to the high ash fusion temperatures.

In conclusion, the Colombian coal appears to be an acceptable alternative coal. The test burn confirmed it could be consumed at up to 60% in BB4 and up to a 30% in units BB1-3.

Discussion

Coal Analysis Parameters

As seen in the analysis below, the Colombian coal is similar to Big Bend's normally consumed coals. (An ash mineral analysis was not available) The notable exceptions include the Chlorine, SO2, and the ash fusion temperatures.

A very beneficial component is the 0.03 percent chlorine level, which is only 15-30 percent of our typical coals. Since currently over 80% of the chlorides entering the station come from the coal, the use of Colombian coal would significantly reduce the risk associated with FGD chloride levels and also proportionately reduce the blowdown requirements and O&M. (Reduced lime, dibasic acid, defoamer, filter cake disposal)

The second parameter, the sulfur content, is only 1.1 lbs SO2/MBTU which approx. 75 percent of our typical fuels for FGD use. Normally, the low Sulfur content adversely affects fly ash resistivity, which results in precipitator performance issues. However, we experienced no significantly precipitator performance issues throughout the test.

The final parameter, the ash fusion temperatures, is 300-400 deg-F higher than our highest typical coal. This could result in slag tapping issues in the BB Units 1-3. For this reason, the Colombian was limited to 30 percent in these units. This is not an issue in BB4, a dry bottom unit.

The coal analysis was received from a Colombian lab: Inspectorate Colombia LTDA Cert. # 01-8677 from Duke Energy Merchants, LLC. An ash mineral analysis was not available.

Property, units	Value	Comparisons to BB Typical Coals
BTU/lb, as-fired	12,400	similar to STD-H
lbs SO2/MBTU	1.1	very low, (4.5 typical for BB)
Ash, %	6.0	little low
Moisture, %	9.0	normal
Volatiles, %	36	normal
Chlorine, %	0.03	low (0.10 more typical) ; help control chlorides
Fluorine, ppm	20	normal / low
HGI	46	slightly lower (50's more typical) ; harder to grind
Ash Fusion Temps		300-400 deg-F higher than ZGLR; thickens slag in wet bottom units

Colombian Coal Test Burn Report
Page Two

Chronology of Test Burns

Below are the test burn start/stop times and percentages during the evaluated periods:

BB1&2:	Start 6/4 @ 20 %	BB3: Start 6/15 @ 30 %	BB4: Start 4/22 @ 20 %
	End 6/6 @ 20 %	End 6/22 @ 30 %	Start 4/28 @ 50 %
			End 5/08 @ 50 %
Tons Consumed	4,153	7,476	67,830

Total Consumed BB1-4: 79,459

Test Observations

As seen in the test chronology, BB4 consumed the majority of the Colombian Coal because of slag tap issues in the wet bottom BB1-3. Comments regarding slag tapping, fouling, slagging, LOI, Opacity, and NOx are as follows:

Slag Tapping
We did not expect or experience any slag tapping issues in BB1-3 because we deliberately held the Colombian coal fraction to no more than 30%. This effectively raised the ash fusion temperatures only 100 deg-F.

Fouling & Slagging
As evidenced by PI system steam temperature charts, there was no evidence of fouling or slagging in the boiler areas.

LOI
Because of the volatile nature of the LOIs, no significant trends were detectable in the routine W&Fs LOI tabulations during the test burns in any of the units

Opacity
The PI system did not indicate any significant variations in opacity in any of the test burns. The Colombian coal content was held to 50% (3 lb SO2/MBTU) to avoid possible fly ash resistivity / opacity issues.

NOx
The PI system indicated no significant NOx variations in any of the test burns

2. Please identify all coals that have been test burned at the Polk Station and all coals that have been found to be operationally suitable for use at that facility.

A. The following is a complete list of the types of coal and petcoke that have been burned at Polk Power Station. All were successfully burned. However, some types are suitable alone while others must be blended because one or more specifications falls outside the capabilities of the equipment or outside the specification range permitted by the Florida Department of Environmental Protection.

Seam	Mine
Individual Coals	
Pittsburgh #8	Humphrey
Pittsburgh #8	Williams #4
Pittsburgh #8	Loveridge
Pittsburgh #8	Cumberland
Pittsburgh #8	Blacksville
Illinois #6	Old Ben No 11 mines
Illinois #6	Wildcat
West Kentucky #11	Ohio No 11
Kentucky #9	Camp
Kentucky #9	Patriot
Indiana #5 & #6	Somerville
Blended Fuels	
Petroleum Coke	Chalmette
Petroleum Coke	Orion
Petroleum Coke	Baton Rouge
Petroleum Coke	Garyville
Petroleum Coke	Valero
Indonesia	Paringin/Tutpan
Guasare Basin	Mina Norte
Pittsburgh #8	Powhatan #6
Powder River Basin	Jacobs Ranch
Biomass (Eucalyptus)	N/A
Kentucky #9	Patriot
Pittsburgh #8	Maple Creek
Indiana #5 & #6	Black Beauty
Guasare Basin	Paso Diablo

3. Please indicate whether Pittsburgh Number 8 Seam coal is compatible with the coal needs at Tampa Electric's Big Bend Station or Polk Station. If such coal is not compatible with the needs at either facility, please explain.

A. Pittsburgh Number 8 seam coals are compatible with the coal needs at Tampa Electric's Big Bend Station and Polk Station. Although Big Bend Station units were designed to burn Illinois Basin coal, the station has burned Pittsburgh Number 8 seam coal when the coal was available and its price, including transportation, was a cost-effective choice. Polk Station has conducted test burns for a number of different Pittsburgh 8 seam coals. Polk Station currently burns a blend of 55 percent petroleum coke, 35 percent South American and 10 percent Illinois Basin because it is substantially less expensive than Pittsburgh Number 8 seam coal, as identified in the *Coal Daily*, Vol. 7, No. 245. The following table shows the price differential.

Coal Type	Quality	Commodity Price ($/Ton)	Difference ($/Ton)	Price Source
Pittsburgh 8	13,000 Btu 3.0-4.0 Lbs SO_2/mmBtu	$33.00	-	*Coal Daily*
South American	11,300 Btu 1% Sulfur	$44.25	NA	*Coal Daily*
Illinois Basin	11,200 Btu 4.5 Lbs SO_2/mmBtu	$26.00	NA	*Coal Daily*
Petroleum Coke	High Sulfur Green Coke Gulf Coast > 50 Hardgrove Grindability Index	$9.00-$16.00 per metric ton	NA	*Pace Petroleum Coke Quarterly*
Petroleum Coke South American Illinois Basin Blend	13,000 Btu 5.2 Lbs. SO_2/mmBtu	$24.68	($8.32)	Weighted average

4. Please identify all coals from U.S. Bureau of Mines Regions 2 through 8 that are compatible with Big Bend or Polk Station coal specifications.

A. For informational purposes, the U.S. Bureau of Mines has ceased operations and those functions are now handled by the Department of Interior. There are many different mines and seams in Regions 2 through 8. Tampa Electric does not have access to the quality analysis of all these coals in order to make a determination whether or not the company can burn all of the coals from Regions 2 through 8. With that said, the Big Bend units were designed to burn Illinois Basin Coal. Each of the four Big Bend boilers has unique constraints. Polk Station was designed to burn Pittsburgh Number 8 seam coal and has its own constraints. Below is a table of key properties and their typical ranges for Big Bend and Polk Stations' fuel blends. Since both Big Bend and Polk Stations typically burn fuel blends to improve operability, to comply with permit requirements or to lower fuel cost, some properties of one or more constituents of a blend may fall outside these ranges.

Big Bend Station	Typical Range
Fusion Temp. Range (°F) [1]	2,050 – 2,475
Lb Ash / MMBtu	6.0 – 8.5
Chlorine Percent	0.1 – 0.25
Lb SO_2 / MMBtu	4.0 – 5.5
Moisture Percent	5 – 11
Hardgrove Grindability Index	50 – 60
Btu / Lb	11,500 – 12,600

[1] Ash softening, (Hemispherical = Width, Reducing)

Polk Station	Typical Range
Ash Fusion Characteristics - T_{250} [2]	2,400 – 2,700(°F)
Lb Ash / MMBtu	<9.0
Chlorine Percent	<0.10
Lb SO_2 / MMBtu	<5.5
Moisture Percent	<10
Hardgrove Grindability Index	50 – 60
Btu / Lb (dry basis)	<12,500

[2] T-250 is the temperature at which the melted ash will exhibit 250 centipoises of viscosity. Viscosity determines the stickiness of the melted ash. It also determines the rate and ease at which the ash will flow out of the boiler.

19. Does all of the Petcoke coal handled by the terminal in Davant require off-loading, storage and loading to ocean barges under the terminal contracts? Why is it no [sic] possible to ship Petcoke directly from Texas to Tampa?

A. The pet coke handled by the terminal is purchased on the river and used at Polk Power Station. This pet coke must be off-loaded and blended with other coals before it is loaded on an ocean-going vessel destined for Tampa. As previously stated, all pet coke purchased from Texas is shipped directly to Big Bend Station in Tampa.

20. Are the amounts charged to ratepayers for waterborne transport under the existing Tampa Electric procedures equal to the detailed billing under the TECO Transport/Tampa Electric contracts that apply for transport, loading, unloading, storage, demurrage and other miscellaneous charges as specified under those contracts? If not, what differences exist?

A. Yes, the amounts charged to ratepayers for waterborne transportation are equal to the detailed billing under the TECO Transport/Tampa Electric contracts that apply for transport, loading, unloading, storage, demurrage and other miscellaneous charges.

21. Referring to OPC POD 10, please demonstrate what specific charges, if any, as specified in the company's FPSC 423 reports must be added in order to arrive at the amount of inland river transportation expense that is included in the fuel surcharge. Please provide similar information for terminal services and cross-Gulf transport.

A. There are no charges added to the contract rates in order to arrive at the amounts of inland river transportation or terminal services expense that are recovered through the fuel and purchased power cost recovery clause ("fuel clause"). Trucking expense for deliveries to Polk Station and harbor maintenance fees that are paid to U.S. Customs are costs incurred that are added to ocean transportation expenses, reported on the company's FPSC 423 reports and recovered through the fuel clause.

22. In reference to POD 37, please discuss the costs of foreign coal terminal expense as compared to the terminal expense for domestic coal and explain the reasons for the different rates that will apply under the TECO Transport contract for services that essentially appear to be the same.

A. Throughout the waterborne transportation industry, it is widely understood that terminal services for deliveries of foreign coal are more expensive than domestic river coal deliveries. The vessels that deliver foreign coal differ greatly in size, draft and capacity from the open hopper river barges that transport domestic coal on the river system, and there are different requirements for unloading each type of vessel.

Ocean vessels that deliver foreign coal for Tampa Electric have a capacity between 50,000 to 80,000 tons while domestic coal transported to the terminal is carried on open hopper river barges with capacity of approximately 1,500 tons. The river barges are unloaded by continuous bucket unloaders, and this equipment operates at rates that are significantly faster than the unloading rates that can be achieved for ocean vessels. This is reflected in the bid received for terminal services in response to Tampa Electric's 2003 RFP, which included a higher rate for handling foreign coal deliveries.

23. Please state the percentage and tons of coal that were directly transferred from river barge and ocean transport to Gulf barges in 2001, 2002 and 2003 and the projected amount for 2004, and state whether or not the lower rates for this service were reflected in the rates passed on to ratepayers under the fuel clause.

A. Ratepayers pay the actual costs incurred by Tampa Electric for waterborne transportation services. Under the previous contracts, tons that were directly transferred from river barge to an ocean-going barge were tracked and billed at a different rate than tons that were moved to ground storage prior to ocean shipment, and ratepayer costs reflected these rates. The following table shows the percent and tons of coal that were directly transferred to an ocean barge.

Terminal Transfers

To Ground	2001	2002	2003	2004 Proj. [1]
Tons	4,170,174	4,837,452	4,321,707	NA
Percent	61	75	83	NA

To Barge	2001	2002	2003	2004 Proj. [1]
Tons	2,646,709	1,639,726	914,279	NA
Percent	39	25	17	NA

[1] Tampa Electric does not project tons that will be placed in ground storage versus transfer to barge.

24. Please state the percentage and tons of coal that required storage and blending at the terminal in 2001, 2002 and 2003 and the projected amount for 2004.

A. The following table shows the percentage and tons of coal that required storage and blending at the terminal.

Coal Stored or Blended at the Terminal

Storage	2001	2002	2003	2004 Proj.
Tons	4,170,174	4,837,452	4,321,707	NA[1]
Percent	59	72	78	NA[1]

Blending	2001	2002	2003	2004 Proj.
Tons	2,006,095	2,949,549	1,166,750	714,000
Percent	30	44	20	14

[1] The amount of coal to be stored at the terminal is not projected.

29. With reference to page 47 of Mr. Dibner's confidential exhibit, are there any aspects of the (confidential) terminal that would render it unsuitable to handle TECO's coal traffic? In what aspects is TECO's Davant terminal superior and what aspects is it inferior?

A. The bidder's terminal would be suitable to handle Tampa Electric's coal traffic. However, TECO Transport had a contractual right of first refusal for Tampa Electric's business and chose to exercise its right to provide services at the bidder's proposed rates. Page 47 of Mr. Dibner's exhibit provides a comparison of the two terminal facilities.

53. For each month during the term of Tampa Electric's 1998-2003 contract with TECO Transport ("1998 contract"), please provide the end-of-month inventory levels for Tampa Electric's solid fuel located at TECO Bulk Terminal in Davant, LA.

A. The chart below reflects end-of-month inventory levels for Tampa Electric's solid fuel located at TECO Bulk Terminal in Davant, Louisiana

1998	Tons	1999	Tons	2000	Tons
January	1,081,275	January	1,310,679	January	1,065,086
February	1,126,735	February	1,372,560	February	984,500
March	1,430,060	March	1,539,149	March	941,947
April	1,555,027	April	1,382,264	April	1,011,138
May	1,274,246	May	1,490,993	May	1,292,407
June	1,364,559	June	1,627,511	June	1,151,198
July	1,289,679	July	1,608,695	July	995,015
August	1,204,062	August	1,174,865	August	681,555
September	1,273,635	September	993,394	September	686,720
October	835,790	October	890,088	October	735,179
November	907,637	November	1,104,511	November	797,601
December	1,119,228	December	1,021,816	December	801,023
2001	**Tons**	**2002**	**Tons**	**2003**	**Tons**
January	687,053	January	1,275,558	January	1,512,102
February	810,616	February	1,403,741	February	1,443,889
March	862,369	March	1,307,153	March	1,326,226
April	847,386	April	1,200,007	April	1,323,953
May	889,139	May	1,197,071	May	1,322,221
June	998,197	June	1,144,761	June	1,258,864
July	1,000,489	July	1,203,062	July	1,307,082
August	800,891	August	1,247,772	August	1,174,249
September	725,185	September	1,238,976	September	1,112,160
October	983,284	October	1,245,593	October	1,020,370
November	1,071,904	November	1,431,171	November	1,081,705
December	1,001,189	December	1,534,268	December	961,764

61. For each year during the term of the 1998 contract, please provide the amount of demurrage incurred for inland river barges.

A. Tampa Electric did not incur demurrage charges for inland river barges during the term of the 1998 contract.

62. For each year during the term of the 1998 contract, please provide the amount of demurrage incurred for ocean barges.

A. Tampa Electric did not incur demurrage charges for ocean barges[1] during the term of the 1998 contract.

[1] Ocean barges transport shipments between TECO Bulk Terminal and Tampa Electric's generating stations. Therefore, this response does not include shipments of foreign coal.

64. Please explain the basis for inclusion of the sentence at the end of the second paragraph of Section 5.1.10 of the 2003 contract as an addition to the corresponding provision from the 1998 contract.

A. The basis for inclusion of the sentence at the end of the second paragraph of Section 5.1.10 of the 2003 contract as an addition to the corresponding provision from the 1998 contract was to ensure the contract conformed to the terms listed in Tampa Electric's RFP, in anticipation of receiving bid responses for one or more segments of the requested waterborne transportation services. Tampa Electric's contract specifies that the company will not be responsible for inland river barge or ocean barge demurrage charges at TECO Bulk Terminal because TECO Transport is responsible for coordinating all segments of the shipping once the fuel is loaded on TECO Barge Line's barges.[1] Therefore, the RFP and the contract were updated to specify that Tampa Electric would not be responsible for demurrage costs at the terminal for inland river or ocean barges to protect Tampa Electric from the additional risk of demurrage charges that could be incurred at the terminal facility if transportation services were segmented.

[1] The company may incur demurrage charges to TECO Barge Line at upriver loading terminals.

65. Refer to Tampa Electric's response to Staff's Second Set of Interrogatories, No. 28, in this docket. If the 2003 contract had the same throughput requirements as the 1998 contract, would TECO Bulk Terminal have sufficient space to meet Tampa Electric's storage needs? Please show all calculations made in responding to this interrogatory.

A. If the 2003 contract had the same throughput requirements as the 1998 contract, TECO Bulk Terminal would have sufficient space to meet Tampa Electric's storage needs. Changing the throughput assumption, or the required annual tons, will result in no change to the calculations used to establish the maximum storage for the 2003 contract because the 2003 calculation was based on the potential for supply disruptions and potential terror alert levels, not strictly on expected use. The throughput decline in the 2003 contract compared to the 1998 contract is due to repowering coal-fired Gannon Station to Bayside Power Station which burns natural gas.

66. Has Tampa Electric invoked the provisions of Section 5 of the 1998 contract or any substantially similar provisions found in earlier contracts between Tampa Electric and TECO Transport? Please describe the circumstances of each instance in detail.

A. Tampa Electric is not aware of any invocation of the provisions of Section 5 of the 1998 contract or any substantially similar provisions found in earlier contracts between Tampa Electric and TECO Transport.

67. Has Tampa Electric or TECO Transport invoked the provisions of Section 10 of the 1998 contract or any substantially similar provisions found in earlier contracts between Tampa Electric and TECO Transport? Please describe the circumstances of each instance in detail.

A. Tampa Electric is not aware of any invocation of the provisions of Section 10 of the 1998 contract or any substantially similar provisions found in earlier contracts between Tampa Electric and TECO Transport.

72. For Tampa Electric witness Brent Dibner's computer model to calculate the market price for inland river barge service, please provide the basis for the assumptions regarding tow size and speed for the following rivers:

A) Ohio;
B) Green;
C) Tennessee;
D) Middle Mississippi; and
E) Lower Mississippi.

A. Tow size and speeds on the inland waterways specified in this question are based on DMA knowledge and observations of actual performance of commercial carriers. The factors that influence tow size are the following:

- lock chamber sizes (length, width, sill height);
- river, channel and traffic factors;
- the patterns and range of average weather; and
- river gage conditions.

In addition, tow geometry was considered to create a neat maneuverable tow. Consequently Mr. Dibner used judgment and experience, based on data regarding year-round actual operating performance of towboats, which he has collected over many years of working in this industry.

The assumed tow size on the Ohio River is 15, which is based on a tow that is five barges long (1,000-foot length) and three barges wide (105 foot width), which, when combined with an appropriate towboat of less than 200 feet in length, fully uses the 1,200-foot long by 110-foot wide lock chambers on the lower Ohio River.

The assumed tow size on the lower Mississippi River is 30 barges, which is based on a tow that is six barges wide and five barges long, which is the maximum practical length of loaded and empty tows that can be consistently planned for, given the variations in water levels and traffic conditions that will occur during the contract period.

The assumed tow size on the middle Mississippi River is 20 barges, which is based on a tow that is four barges wide and five barges long, and reflects typical conditions and sizes of tows on this segment of the Mississippi. While this segment of the Mississippi River does not have locks, some channel configuration factors exist that lead to maximum tows of this size.

The assumed tow size on the Green River is four barges, which is based on a tow that is two barges wide and two barges long as well as observed practices on the Green River. The tow size is governed by the size of the lock chambers, which are 600 feet long and 84 feet wide, allowing only for the four barges and length of the towboat.

The assumed tow size on the Tennessee River is 12 barges, which reflects the practices on the river and the size of the lock chambers on the lower Tennessee River, which are 600 feet long and 110 feet wide, as well as practical operating and scheduling conditions.

With respect to tow speed, data gained from confidential commercial sources was used, and the assumed speeds are clearly shown in Mr. Dibner's model.

73. For Tampa Electric witness Brent Dibner's computer model to calculate the market price for inland river barge service, please provide the basis for the assumptions regarding lock delays and load and discharge times.

A. The lock delay time was set at zero, which means that none was assumed. Lock processing times (the actual time that a tow is in the lock chamber) were drawn from the U.S. Army Corps of Engineers Lock Performance Monitoring System, at the Internet site http://www.iwr.usace.army.mil/ndc/lpms/pdf/s2011299.pdf, using the most recent data available. With respect to load and discharge times, the model was set at four days for all loading and 3.5 days for all discharge. This was based on the specified time in Tampa Electric's RFP of 3 days loading and 3 free days discharging, plus 1.5 days for demurrage due to average actual experiences in the industry. However, no demurrage costs were charged in the contract rates because the demurrage and dispatch times were assumed to be countervailing at year end.

Schedule 5

History and Forecast of Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2001	Actual 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	6,962	6,556	5,849	4,831	4,824	4,652	4,813	4,792	4,825	4,832	4,855	4,801
(3)	Residual	Total	1000 BBL	144	138	151	48	77	194	291	331	349	353	361	370
(4)		Steam	1000 BBL	4	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	140	138	151	48	77	194	291	331	349	353	361	370
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	408	319	294	240	306	401	496	613	615	743	852	960
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	224	214	176	192	192	189	194	193	190	193	195	183
(11)		CT	1000 BBL	184	105	118	48	114	212	303	419	425	550	658	777
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	3,349	5,151	24,116	34,100	48,715	58,798	56,382	58,345	65,546	70,805	73,091	74,779
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	0	0	22,163	34,010	48,325	58,128	54,895	56,643	63,333	67,775	69,710	69,148
(16)		CT	1000 MCF	3,349	5,151	1,953	90	390	670	1,487	1,702	2,213	3,030	3,381	5,631
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	327	545	243	221	221	212	220	219	221	221	222	221

85. For each month during the term of Tampa Electric's 1998 contract, please provide the end-of-month inventory levels for its solid fuels located at its Big Bend and Polk Stations, separately.

A. The end-of-month inventory levels for solid fuels located at Big Bend and Polk stations during the term of Tampa Electric's 1998 contract are detailed below. The Big Bend/Polk table shows inventory for Polk that is being stored at Big Bend.

Big Bend	1999	2000	2001	2002	2003
January	834,658	557,429	377,910	323,566	267,407
February	882,247	746,559	313,031	490,071	351,091
March	901,645	859,083	527,815	693,559	357,233
April	984,497	858,250	680,666	839,123	455,794
May	807,661	715,580	849,175	806,643	561,102
June	628,174	672,886	702,957	829,196	575,495
July	404,860	680,351	791,334	738,671	512,956
August	485,316	702,851	822,857	616,158	423,873
September	529,859	581,906	791,593	538,037	372,384
October	469,986	512,964	616,526	468,600	440,010
November	429,187	442,863	500,872	432,016	452,146
December	593,268	377,957	444,418	336,403	598,426

Polk	1999	2000	2001	2002	2003
January	4,312	7,673	3,500	5,200	7,100
February	7,445	8,256	7,300	4,500	5,650
March	9,506	7,942	2,100	5,720	4,961
April	9,312	1,606	3,700	7,600	7,150
May	8,149	8,190	7,332	5,950	5,720
June	7,788	9,636	5,007	4,350	6,000
July	7,474	5,491	2,873	6,720	4,265
August	6,795	10,000	6,920	4,000	3,310
September	5,867	8,500	6,500	6,100	7,700
October	4,050	4,800	3,350	5,000	6,535
November	9,583	6,250	1,150	4,998	4,300
December	8,365	5,650	5,350	4,005	5,568

Big Bend / Polk	1999	2000	2001	2002	2003
January	38,582	58,286	50,554	21,241	24,124
February	59,460	44,958	39,220	54,784	14,345
March	64,229	97,537	7,280	48,216	8,428
April	47,921	79,723	48,710	53,142	31,507
May	38,192	78,825	43,685	54,200	5,063
June	49,468	63,729	56,001	57,662	29,540
July	46,225	51,164	24,835	40,263	7,765
August	43,990	70,769	39,296	41,853	20,463
September	43,886	13,422	39,643	56,737	36,828
October	46,328	34,405	39,096	42,173	36,828
November	36,998	56,555	44,127	25,249	34,249
December	52,236	57,239	84,350	36,455	35,280

1. The volume of coal consumption for Tampa Electric's Big Bend Units 1 through 4 for the period January 2001 through December 2003 is accurately reflected in the chart attached hereto as Attachment A.

A. Denied, with respect to the value listed for Big Bend Unit 3 for December 2002, which should be 97,929 tons, not 97,473 tons. The total for December 2002 should therefore be 392,089 tons. Admitted, with respect to all other values for Big Bend Units 1 through 4 included in the table Attachment A.

2. The volume of coal consumption for Tampa Electric's Polk Unit 1 for the period January 2001 through December 2003 is accurately reflected in the chart attached hereto as Attachment A.

A. Admitted.

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIRST REQUEST FOR ADMISSIONS
ATTACHMENT A
PAGE 1 OF 1
FILED: MARCH 18, 2004

Coal-fired and -Gasified Consumption at Selected Tampa Electric Generating Units (Tons)

January, 2001 - December, 2003

		Big Bend				Polk	
Month	Year	Unit 1	Unit 2	Unit 3	Unit 4	Unit 1	Total
January	2001	91,061	91,195	81,511	124,235	55,755	443,757
February	2001	84,777	35,622	83,827	94,459	61,185	359,870
March	2001	32,135	46,095	103,406	126,696	31,122	339,454
April	2001	-	85,681	85,729	123,038	32,661	327,109
May	2001	74,447	102,116	84,587	5,075	56,601	322,826
June	2001	87,070	91,006	90,245	112,718	14,466	395,505
July	2001	94,529	95,766	78,239	126,600	68,604	463,738
August	2001	103,506	102,932	98,602	112,805	52,990	470,835
September	2001	82,519	87,299	68,806	95,593	44,841	379,058
October	2001	71,177	88,393	79,302	119,345	51,795	410,012
November	2001	79,842	81,472	91,433	93,516	39,886	386,149
December	2001	79,135	83,331	75,070	78,090	59,801	375,427
January	2002	78,744	96,725	70,360	116,973	62,631	425,433
February	2002	47,043	39,069	81,526	117,504	48,381	333,523
March	2002	93,895	76,491	2,951	135,503	42,171	351,011
April	2002	90,717	45,359	1,194	131,149	44,334	312,753
May	2002	81,260	109,912	71,298	121,741	35,958	420,169
June	2002	75,140	88,412	59,195	123,663	59,233	405,643
July	2002	96,666	82,611	48,211	125,167	56,782	409,437
August	2002	72,873	97,276	65,412	125,413	62,074	423,048
September	2002	103,307	76,415	86,478	29,315	51,757	347,272
October	2002	87,465	0	111,012	111,893	68,834	379,204
November	2002	77,521	0	85,201	104,984	62,836	330,542
December	2002	102,004	21,657	97,473	120,473	50,026	391,633
January	2003	89,811	54,770	96,662	106,491	50,701	398,435
February	2003	81,064	31,100	98,908	93,138	47,412	351,622
March	2003	85,820	91,862	82,662	119,863	15,801	396,008
April	2003	97,089	99,085	91,020	99,782	9,003	395,979
May	2003	68,372	99,708	72,715	120,634	61,677	423,106
June	2003	74,759	87,730	85,348	109,842	47,899	405,578
July	2003	77,772	94,584	84,993	89,739	66,338	413,426
August	2003	76,741	64,637	89,154	133,240	60,922	424,694
September	2003	89,245	63,202	55,445	126,870	13,738	348,500
October	2003	65,391	99,910	71,713	115,022	1,165	353,201
November	2003	91,962	60,829	48,924	0	61,311	263,026
December	2003	84,997	54,663	25,194	71,523	60,285	296,662

10. Please list the name of each TECO Transport vessel that delivered coal or fuel to Tampa Electric in the past three years.

a. For each vessel, provide the following information, year built, cost new, depreciated value.

A. Listed below is the name and date built of each TECO Transport vessel that delivered coal or fuel to Tampa Electric in the past three years as made available in public records. Tampa Electric does not have vessel information such as new costs or depreciated value.

Vessel	Date Built
Barbara Vaught	1966
Diana T.	1975
Diane Ludwig	1967
Doris Guenther	1985
Gayle Eustace	1977
Judy Litrico	1973
Marie Flood	1972
Mary Turner	1982
Pat Cantrell	1984
Peggy Palmer	1981
Sheila McDevitt	1980
Wanda Wheelock	1966
Louise Kilpatrick	1964

EXHIBIT NO. 3

DOCKET NO: 031033-EI

WITNESS: VARIOUS

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT OF STIPULATED CONFIDENTIAL DOCUMENTS:

DOCKET NO. 031033-EI

1. Tampa Electric Company's response to staff's 2nd set of interrogatories (Nos. 28, 30, 35, and 36)
2. Tampa Electric Company's response to staff's 3rd set of interrogatories (Nos. 43-45)
3. Tampa Electric's responses to Office of Public Counsel's 2nd set of interrogatories (Nos. 25, 37, 39, and 41)
4. Tampa Electric's responses to Office of Public Counsel's 3rd set of interrogatories (Nos. 57-58).
5. Tampa Electric's responses to Florida Industrial Power Users Group 1st set of interrogatories (Nos. 5, 14, 16, and 20)
6. CSX Transportation's responses to Tampa Electric Company's 1st set of interrogatories (No. 11)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 3
COMPANY/ FPSC Staff
WITNESS: Confidential Stip-1
DATE: 05/27-28/04

DOCKET NO. 030001-EI

1. Tampa Electric's response to staff's 6th set of interrogatories (No. 55)
2. Tampa Electric's response to staff's 7th set of interrogatories (Nos. 81, 83, 84, 86-87, 96-97, 111, 115-117, and 119)
3. Late-filed deposition Exhibit No. 1 of Joann Wehle

DOCKET NO. 020001-EI

1. Tampa Electric Company's response to staff's 2nd set of interrogatories (No. 43)

PROFERRED BY: STAFF

CONFIDENTIAL

(BD-1)	**CONFIDENTIAL,** Exhibit to the Direct Testimony of Brent Dibner

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 4
COMPANY/ TECO
WITNESS: BD-1
DATE: 05/27-28/04

CONFIDENTIAL

(BD-2)	**CONFIDENTIAL,** Exhibit to the Rebuttal Testimony of Brent Dibner (Rebuttal)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 5
COMPANY/ TECO
WITNESS: BD-2
DATE: 05/27-28/04

CONFIDENTIAL

(JTW-1)	**CONFIDENTIAL,** Exhibit to the Direct Testimony of Joann T. Wehle

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 6
COMPANY/ TECO
WITNESS: JTW-1
DATE: 05/27-28/04

CONFIDENTIAL

(JTW-2)	**CONFIDENTIAL,** Exhibit to the Rebuttal Testimony of Joann T. Wehle (Rebuttal)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 7
COMPANY/ TECO
WITNESS: JTW-2
DATE: 05/27-28/04

Resume of H. G. (Pat) Wells

H. G. (Pat) Wells is a consultant to clients on energy matters including electric rates, power supply contracts, fuels and other related matters. He has served in this capacity since 1987.
Prior to then he was President of Electric Fuels Corporation, originally a subsidiary of Florida Power Corporation, and later a subsidiary of Florida Progress Corporation, covering a period of about 12 years.
Prior to this assignment, he was Assistant Vice President of Corporate Planning at Florida Power Corporation for a number of years, having worked in the past as head of System Planning, head of Transmission Engineering and a number of more junior positions, his first assignment being as Transmission Engineer when Florida Power was building its Crystal River power plant facility. As head of Corporate Planning, he was responsible for the planning and electric rate departments and computer services. His total service at Florida Power was about 12 years. During this time he was a delegate of Florida Power on the Florida Operating Committee, a coordinating group formed of representatives from all operating electric companies, both public and private, in Florida. He served as Chairman of this committee until he was appointed as President of Electric Fuels Corporation. The Florida Operating Committee was a predecessor of the electric reliability councils now so important to the electric industry.
During this time at the Florida Progress/Florida Power group of companies, he testified before the Florida Public Service Commission on a number of occasions and a number of subjects, including planning, electric rates and related matters.
Since his retirement in 1987 he has been an independent energy consultant. He has been consultant to Public Utility Commissions in Illinois and Kentucky, consultant to independent industrial companies on electric rate and contract matters and to a number of city and county governments and school boards in Florida. Some of these assignments required filing of testimony, and in some cases testifying, in legal proceedings.
He is a graduate of Louisiana Tech University in Ruston, Louisiana in 1950 with a B.S. in Electrical Engineering. He briefly did graduate work in electrical engineering at the University of Texas in Austin before the Korean conflict broke out, at which time he joined the U.S. Navy, attended their Officer Candidate School, and was assigned to the San Francisco Naval Shipyard at Hunter's Point in San Francisco, where he served as a Ship's Repair Superintendent for four years, working on repairs, overhaul and re-conditioning of naval vessels of all kinds, from submarines to aircraft carriers and battleships. After leaving the Navy he worked at a number of industrial and engineering firms in Texas before moving to Florida in late 1962.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 031033-EI EXHIBIT NO. 8
COMPANY/ OPC/FIPUG
WITNESS: HGW-1
DATE: 05-27-28-04

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 031033-EI EXHIBIT NO. 9
COMPANY/ OPC/FIPUG
WITNESS. HGW-2
DATE 05/27-28/04

STATE OF FLORIDA

COMMISSIONERS:
LILA A. JABER, CHAIRMAN
J. TERRY DEASON
BRAULIO L. BAEZ
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

TIMOTHY DEVLIN, DIRECTOR
DIVISION OF ECONOMIC REGULATION
(850) 413-6900

Public Service Commission

July 11, 2003

Joann T. Wehle, Director
Department of Wholesale Marketing and Fuels
Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

VIA FAX (813) 228-1545

RE: Docket No. 030001-EI - Fuel and Purchased Power Cost Recovery Clause and GPIF

Dear Ms. Wehle:

As you know, on June 19, 2003, staff requested a meeting with Tampa Electric to discuss formulating a request for proposals for waterborne coal transportation (RFP), and such a meeting was arranged for July 1, 2003. However, staff was surprised and disappointed that Tampa Electric not only formulated but also issued the RFP to prospective bidders prior to the meeting with staff. Upon staff inquiry, the utility informed staff that the necessary utility personnel could not meet with staff and parties during the week of June 23, 2003, thus, the delay in the meeting date until the following week. However, Tampa Electric never indicated to staff that it would also issue the RFP prior to the meeting.

As a result of the events described above, staff agreed at the conclusion of the July 1, 2003, meeting to prepare and forward to all parties a minimum set of clarifying statements to Tampa Electric's RFP. Such clarifying statements are enclosed with this letter. In staff's opinion, such statements are necessary to clarify certain ambiguous aspects of the RFP which may otherwise limit the number and type of bids that Tampa Electric receives in response to the RFP as issued. These clarifications will have little impact in addressing this concern unless Tampa Electric distributes these clarifications to current and prospective bidders immediately, given Tampa Electric's August 1, 2003 bid deadline. While Tampa Electric has recently indicated that it will not provide staff's RFP clarifications to current and prospective bidders, trade publications, and newspapers, staff believes it would be prudent for the utility to do so in order for staff's concern to be adequately addressed.

If you have any questions, please contact Todd Bohrmann at (850) 413-6445.

Sincerely,

Timothy J. Devlin, Director

TJD:kb
Enclosures (2)
cc: Mary Bane
Harold McLean
Jim Beasley
Parties of Record
Division of Commission Clerk & Administrative Services

TECO RFP MINIMUM CLARIFICATIONS SHEET

1. TENTATIVE TIMETABLE: Attached is the timetable that Tampa Electric has established for solicitating, evaluating, and awarding bids for coal transportation for the period 2004 through 2008.

2. TRANSPORTATION SEGMENT BIDS: Bids for transportation segments will be matched to form a complete transportation system. For purposes of bid evaluation and selection, Tampa Electric will combine segments to achieve the best combination of price and non-price factors.

3. ALTERNATIVE TO MISSISSIPPI RIVER TERMINALS: Alternative terminals, such as Pascagoula, Mississippi; Mobile, Alabama; and Tampa, Florida; are acceptable locations and will be subject to the provisions of clarification 2 above.

4. INTERNATIONAL SHIPMENT TERMINALS: Tampa Electric will evaluate bids for international shipments separately from domestic shipments. International shipments may be received at Pascagoula, Mississippi; Mobile, Alabama; Tampa, Florida; or elsewhere.

5. MISPRINT: The first sentence under the "Required Terminal Transportation Services" paragraph should be deleted. Thus, Tampa Electric would strike the passage: "The fixed and variable component charges must represent all charges other than fuel."

6. TERMINAL VESSEL SIZE: Terminals which can not accept Panamax-sized vessels will also be evaluated.

7. TECO TRANSPORT: TECO Transport can/can not (circle one) match the lowest bid with all non-price factors considered.

Transportation Services Solicitation Schedule

Step	Tasks to Establish Transportation Contract	Estimated Time to Complete Task
1.	Mail RFP to bid list of waterborne coal transportation providers and notify industry publications of pending RFP	Week of June 23, 2003
2.	Deadline to submit sealed proposals	August 1, 2003
3.	Complete evaluation of proposals	Week of August 11, 2003
4.	Notify transportation provider that submitted the winning proposal and begin contract negotiations	Week of August 18, 2003
5.	Complete transportation contract negotiations	Week of October 6, 2003
6.	Execute new transportation contract	Week of October 6, 2003
7.	Notify unsuccessful bidders that contract has been awarded	Week of October 13, 2003

TECO seeks barge bids; industry skeptical/Platts News

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
OPC'S 1st REQUEST FOR POD

TECO seeks barge bids; industry skeptical

Pennsylvania solicits bituminous and anthracite coal offers

NRP buys reserves, Pinnacle and Oak Grove mines from PinnOak

IRS widens review of chemical change processes at synfuel facilities

Kospo tenders for 300,000 mt

print :
e-mail a friend :
close window :

Knoxville (Platts Coal Outlook) 7 July 2003

Tampa Electric is taking bids to transport solid fuels — including coal, coal-based synfuel and petroleum coke — to the Big Bend station, but some in the industry are skeptical about the offer. Bids are due Aug. 1, and the utility expects to award a five-year contract, beginning in 2004 and running through 2008. TECO is seeking bids to move the fuels from midwestern supply sources convenient to the Mississippi and Ohio river systems. Minimum annual tonnage requirements for 2004-2006 range from 3.25 million tons on the inland river system to 4 million tons on the Gulf.

The tonnage will decrease in 2007-2008 "if a consent decree trigger event occurs," TECO said. Such an event would be if Tampa Electric "decided to comply with the [Environmental Protection Agency's] Consent Decree by either shutting down Big Bend or repowering Big Bend to natural gas," it explained. Industry sources, however, downplayed the solicitation as "an exercise in futility." "We went through this same process six years ago," said one industry executive. "They'll take bids and then award the contract to their sister company, TECO Transport. It's all a game to keep the Public Service Commission happy." TECO solicited in 1997 for a five-year contract and awarded it to TECO Transport. For details, contact Martin Duff at 813-228-1596.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 10
COMPANY/OPC/FIPUG
WITNESS. HGW-3
DATE 05/27-28/04

CONFIDENTIAL

(HGW-4)	**CONFIDENTIAL,** Letter from barge company to TECO

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 11
COMPANY/ OPC/FIPUG
WITNESS: HGW-4
DATE: 05/27-28/04

Docket No. 031033-EI
Wells Exhibit No. 11
(HGW-4)
Letter from [redacted] to TECO

ENTIRE DOCUMENT IS CONFIDENTIAL

CONFIDENTIAL

(HGW-5)	**CONFIDENTIAL,** Letter from barge company to TECO

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 12
COMPANY/ OPC/FIPUG
WITNESS: HGW-5
DATE: 05/27-28/04

Docket No. 031033-EI
Wells Exhibit No. 12
(HGW-5)
Letter from [redacted] to TECO

ENTIRE DOCUMENT IS CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 031033-EI EXHIBIT NO. 13
COMPANY/ OPC/FIPUG - Appdx. A
WITNESS. MAJAROS Resume
DATE: 05/27-28/04

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. Mr. Majoros has appeared before Federal and state agencies. His testimony has encompassed a wide variety of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice.

Mr. Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice. He has also developed the firm's capabilities in the management audit area.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros performed various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company). In addition, he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.
Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

Michael J. Majoros, Jr.

Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RR79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.

State Regulatory Agencies

1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Electric Power Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.

Michael J. Majoros, Jr.

1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa

Michael J. Majoros, Jr.

1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia

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2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 38/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company

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PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

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PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia2/	93-1165-E-D	Potomac Edison
West Virginia2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

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Clients

1/ New Jersey Rate Counsel/Advocate	33/ Michigan Attorney General
2/ West Virginia Consumer Advocate	34/ New Mexico Attorney General
3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D.C. People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U.S. Dept. of Defense	43/ Nevada Bureau of Consumer Protection
12/ N.M. State Corporation Comm.	44/ GCI
13/ City of Philadelphia	45/ Wisc. Citizens' Utility Rate Board
14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
16/ Illinois Attorney General	48/ National Association of Utility Consumer Advocates
17/ Mass Coalition of Municipalities	49/ Nova Scotia Utility and Review Board
18/ U.S. Department of Energy	50/ Florida Office of Public Counsel
19/ Arizona Electric Power Corp.	51/ Maryland Public Service Commission
20/ Kansas Corporation Commission	52/ MCI
21/ Public Service Comm. – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept. of Consumer Affairs	
23/ Georgia Public Service Comm.	
24/ Delaware Public Service Comm.	
25/ Conn. Ofc. Of Consumer Counsel	
26/ Arizona Corp. Commission	
27/ AT&T	
28/ AT&T/MCI	
29/ IN Office of Utility Consumer Counselor	
30/ Unitel (AT&T – Canada)	
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	

APPENDIX A

FLORIDA PUBLIC SERVICE
COMMISSION FUEL PROCUREMENT POLICY

I. General

A. The Public Service Commission requires that all expense associated with the procurement of fuel, fuel related handling services and fuel transportation which are recovered through the Fuel Adjustment Clause be prudently incurred, result from competitive procurement procedures, be reasonably competitive in cost or value relative to what other buyers are paying under similar terms and conditions for fuel or services of comparable quality or specifications and result from sound administration of fuel supply agreements.

B. To accomplish the objectives expressed in (A), the Commission establishes the following guidelines that it recommends to electric utilities seeking fuel expense recovery through the Fuel Adjustment Clause. The Commission fully recognizes that differing fuel mixes and plant locations will necessarily result in vastly different fuel procurement strategies. However, the Commission also believes that there are certain fundamental, common procedures which, when employed, will result in the lowest, long run overall fuel expense to the companies and their ratepayers.

C. While the Commission believes that compliance with the guidelines expressed in this policy will achieve the lowest system fuel cost, the utility's management has sole responsibility to procure fuel in the most cost efficient manner possible and therefore it should have the flexibility to employ any means to achieve this result. In consideration of the above, departures from Commission policy are authorized when such departures can be justified and shown to be in the best interest of the utility and its ratepayers.

D. Departures from Commission policy which through Commission audit, investigation and hearing can be shown to have resulted in unjustified additional fuel expense are inappropriate for recovery through the Fuel Adjustment Clause and such expense will be disallowed.

E. If the Commission determines, based upon Staff audit and/or investigation, that a utility's unjustified departure from recommended Commission policy has resulted in unnecessary fuel expense, then the utility shall be required to apply credits against the clause or to make refunds to its customers.

F. The Commission's guidelines are intentionally broad to allow utility management the flexibility to tailor procurement procedures to fit a broad range of contingencies and adapt to changes in fuel markets.

G. The burden of proof rests solely with the utility to ument the reasonableness of its procurement practices and the ltant expenses from such practices.

General overall compliance with Commission policy in no oves the responsibility of a utility to justify andy ar transaction the Commission may require be specifically t.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
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WITNESS: MJM-1
DATE: 05/27-28/04

II. Long-Term Agreements for Fuel, Fuel Handling Services, Fuel Transportation, Spot Purchases and Affiliate Transaction.

A. The Commission recommends that the majority of a utility's requirements for fuel, fuel handling services and/or transportation be procured under the terms of a long-term contract. Primary reliance upon long-term contracts will ensure that fuel or services will be available when required at reasonable, stable costs to the utility and its ratepayers.

B. The Commission recommends that, to the extent practicable, such long-term contracts be negotiated in a competitive environment. It is recommended that the primary method employed should be an open competitive bidding process or some comparable alternative which produces the same result.

C. All aspects of the procurement process employed in acquiring a long-term fuel or services supply contract should be documented and available to the Commission upon request.

D. Vendors should be selected on the basis of a formal evaluation system which is neutral in its application and capable of producing quantifiable ratings of individual suppliers. Considerations other than delivered price, fuel quality and vendor performance should be thoroughly documented.

E. The Commission recommends that all fuel agreements incorporate clear specification for the fuel or service to be provided and bonus/penalty provisions to ensure that the fuel or services contracted for are provided in accordance with contract terms.

F. The Commission recommends that the utility arrange for adequate fuel sampling techniques and equipment to be deployed at the point of receipt from the fuel supplier and the point of delivery, if different. Such a procedure will ensure that the quality of the fuel received at the unloading facility is consistent with that of the fuel as loaded, the invoiced priced and the contract specifications. To the extent possible, all such arrangements should be clearly written in the contract.

G. Utilities subject to the Commission's jurisdiction should not pay for or agree to pay for fuel or services at prices in excess of that dictated by the negotiated price terms of executed contracts existing between such utilities and providers of such fuel or services.

H. The Commission recommends that long term fuel or service contracts be based upon a base price plus well defined escalators, public tariffs or public postings unless a benefit to the ratepayer can be demonstrated by using some other pricing arrangement.

I. The Commission recommends that all utilities seek to incorporate a "right to audit" clause in any contract which utilizes escalators. The right to audit clause should give the utility the authority to audit specific records of the supplier.

J. The Commission recommends that all utilities enforce the right to audit through the annual use of its own audit staff or an independent accounting firm. Any refunds or adjustments due, as identified by audit, should be promptly resolved and credited to fuel expense.

K. The Commission recommends that any escalation methodology to be employed in a long-term contract be tied as closely as possible to actual changes in a suppliers verifiable costs.

L. The Commission recommends that all utilities seek to incorporate adequate well defined remedies in all long-term contracts for substandard quality performance unreliable volume or quality performance and unacceptable high price over protracted periods of time.

M. It is recommended that all contracts and the individual terms of each contract be reviewed and approved by the legal office of the utility.

O. All utility personnel having any interest in a particular firm seeking a long term fuel or services contract with a utility should be removed from any selection process, contract negotiation or administration of a contract with the firm. All personnel having any potential conflict of interest should be prevented from having any impact upon the contracting process.

P. All utility transaction with affiliated companies which provide fuel or fuel related services should be based on costs which are consistent with or lower than the costs a utility would incur if the utility received the fuel or services from an independent supplier in the competitive market obtained through competitive bidding.

Q. All spot transactions should be priced at, or below, the market price at the time of purchase and should not exceed the normal contract price for similar fuel or fuel related services unless required for reliability purposes.

R. The Commission expects, to the extent possible, that each utility utilize the terms of their long-term contracts relating to minimum and maximum volumes of fuel required to be delivered in order to take advantage of lower prices in the spot market when they exist.

S. The Commission expects that any utility which has a contract with an affiliated organization shall administer that contract in a manner identical to the administration of a contract with an independent organization.

T. Any fuel or fuel related transaction which does not meet the above criteria shall be denied recovery through the fuel clause by the Commission, unless the utility, which has the full burden of proof, can demonstrate that the transaction is in the best interest of the ratepayer.

Full Text
Available
Upon Request

TECO Transport Cross-Gulf Vessels

Summary of Backhaul By Trip

	10/01/01 to 9/30/03		
	Trips		Backhaul
	LA to TPA	TPA to LA	Ratio
Doris Guenther	39	15 1/	38.46%
Peggy Palmer	43	22	51.16%
Gayle Eustace	68	60 2/	88.24%
Diane Ludwig	34	9	26.47%
Diana T	63	61 3/	96.83%
Mary Turner	66	61 1/	92.42%
Barbara Vaught	36 4/	14	38.89%
Average	349	242	69.34%

1/ Includes 1 trip to LA that does not have an associated trip to Tampa.
2/ Includes 1 trip to LA that does not have an associated trip to Tampa, probably due to 10/1/01 start date of file.
3/ Includes 4 trips to LA that do not have an associated trip to Tampa.
4/ Includes 9 trips that included a load of grain in addition to the coal/coke.

Source: Data from Port of Tampa
Vessels with TECO as Agent
October 1, 2001 - September 30, 2003
Does not include all Tugs (Tugs listed took on bunkers)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 15
COMPANY/ OPC/FIPUG
WITNESS: MJM-2
DATE: 05/27-28/04

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF HILLSBOROUGH

BEFORE ME, the undersigned authority, personally appeared Debra Davis, who deposed and stated that he/she provided the attached copy of all Tampa Port Authority documents that show all port activities for vessels that show TECO as the agent between October 1, 2001 and September 30, 2003, including the vessel name, schedule number, activity date, commodity in tons, import or export classification, load or unload status, berth destination, DF, origin and terminal, and are true and correct to the best of his/her information and belief.

DATED at Tampa, FL, this 22ND day of March, 2004.

Sworn and subscribed before me this 22ND day of March, 2004.

ANGELA A. CANDIS
MY COMMISSION # DD 117538
EXPIRES: June 29, 2006
Bonded Thru Notary Public Underwriters

Angela A. Candis
NOTARY PUBLIC

State of Florida at Large

My Commission Expires: June 29, 2006

Vessels with TECO as Agent
October 1, 2001 - September 30, 2003
Does not include all Tugs (Tugs listed took on bunkers)

Vessel Name	Schedule No	Activity	Date	Commodity Description	Tons	Import/Export	Load/Unload	Berth	Destination	D	Origin	Terminal
SHEILA McDEVITT	13066	10/1/2001	PHOSPHAT CHEMICAL, BULK	18275	E	L	4110	LA	D	TPA	GARD
GAYLE EUSTACE	13069	10/1/2001	PHOSPHATE, ROCK, BULK	31594	E	L	4103	LA	D	TPA	AGRI
PAT CANTRELL	13112	10/2/2001	COAL	13874	I	U	4144	TPA	D	LA	TEGA
PAT CANTRELL	13112	10/3/2001	PHOSPHAT CHEMICAL, BULK	25525	E	L	4146	LA	D	TPA	ROCK
PAT CANTRELL	13112	10/4/2001	PHOSPHAT CHEMICAL, BULK	9014	E	L	204	LA	D	TPA	CFI
DIANA T	13125	10/2/2001	COAL	15603	I	U	4101	TPA	D	LA	TEBB
DIANA T	13125	10/4/2001	PHOSPHATE, ROCK, BULK	28149	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	13151	10/7/2001	COAL	27473	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	13151	10/8/2001	PHOSPHATE, ROCK, BULK	37621	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	13171	10/12/2001	COAL	35385	I	U	4101	TPA	D	LA	TEBB
SHEILA McDEVITT	13171	10/13/2001	PHOSPHAT CHEMICAL, BULK	36007	E	L	204	LA	D	TPA	CFI
BARBARA KESSEL	13176	10/10/2001	COAL	29366	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	13177	10/10/2001	COAL	30114	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	13177	10/12/2001	PHOSPHATE, ROCK, BULK	30644	E	L	4103	LA	D	TPA	AGRI
LOUISE KIRKPATRI	13220	10/15/2001	GRAINS, NOS, BULK	9520	I	U	256	TPA	D	LA	CARG
LOUISE KIRKPATRI	13220	10/17/2001	POTASH, BULK	7665	I	U	23	TPA	D	TX	PS
LOUISE KIRKPATRI	13220	10/18/2001	SCRAP METAL	18390	E	L	219	LA	D	TPA	KT
DIANA T	13234	10/16/2001	COAL	16096	I	U	4144	TPA	D	LA	TEGA
DIANA T	13234	10/17/2001	PHOSPHATE, ROCK, BULK	27083	E	L	4103	LA	D	TPA	AGRI
WANDA WHEELOC	13246	10/18/2001	COAL	18081	I	U	4144	TPA	D	LA	TEGA
WANDA WHEELOC	13246	10/19/2001	PHOSPHAT CHEMICAL, BULK	14998	E	L	4110	LA	D	TPA	GARD
MARY TURNER	13278	10/20/2001	SEAWATER, BULK	1063	I	U	271	TPA	D	LA	GARR
MARY TURNER	13278	10/22/2001	COAL	29123	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	13278	10/23/2001	PHOSPHATE, ROCK, BULK	38449	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	13281	10/20/2001	COAL	9614	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	13281	10/21/2001	COAL	19602	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	13281	10/22/2001	PHOSPHATE, ROCK, BULK	30565	E	L	4103	LA	D	TPA	AGRI
DIANA T	13302	10/24/2001	COAL	15187	I	U	4144	TPA	D	LA	TEGA
DIANA T	13302	10/25/2001	PHOSPHATE, ROCK, BULK	28316	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	13336	10/25/2001	COAL	34189	I	U	4101	TPA	D	LA	TEBB
DANA DUNN	13343	10/25/2001	PHOSPHATE, ROCK, BULK	24252	E	L	4103	LA	D	TPA	AGRI
LOUISE KIRKPATRI	13353	10/29/2001	COKE	17245	I	U	219	TPA	D	LA	KT
GAYLE EUSTACE	13381	11/1/2001	COAL	15196	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	13381	11/1/2001	COAL	14577	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	13381	11/2/2001	PHOSPHATE, ROCK, BULK	31461	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	13385	11/2/2001	COAL	21606	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	13385	11/3/2001	PHOSPHAT CHEMICAL, BULK	7510	E	L	4148	LA	D	TPA	EAT
WANDA WHEELOC	13392	11/3/2001	COAL	15982	I	U	4101	TPA	D	LA	TEBB
WANDA WHEELOC	13392	11/4/2001	PHOSPHAT CHEMICAL, BULK	15471	E	L	4148	LA	D	TPA	EAT
MARY TURNER	13396	11/1/2001	COAL	27623	I	U	4101	TPA	D	LA	TEBB

MARY TURNER	13396	11/2/2001	PHOSPHATE, ROCK, BULK	38204	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	13435	11/7/2001	PHOSPHATE, ROCK, BULK	24121	E	L	4103	LA	D	TPA	AGRI
DIANA T	13450	11/7/2001	COAL	15933	I	U	4144	TPA	D	LA	TEGA
DIANA T	13450	11/8/2001	PHOSPHATE, ROCK, BULK	28507	E	L	4103	LA	D	TPA	AGRI
LOUISE KIRKPATRI	13464	11/9/2001	COAL	18530	I	U	4144	TPA	D	LA	TEGA
SHEILA McDEVITT	13469	11/10/2001	PHOSPHAT CHEMICAL, BULK	36001	E	L	204	LA	D	TPA	CFI
GAYLE EUSTACE	13475	11/11/2001	COAL	29590	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	13475	11/11/2001	PHOSPHATE, ROCK, BULK	32264	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	13504	11/12/2001	COAL	28037	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	13504	11/13/2001	PHOSPHATE, ROCK, BULK	38116	E	L	4103	LA	D	TPA	AGRI
WANDA WHEELOC	13514	11/15/2001	COAL	18188	I	U	4144	TPA	D	LA	TEGA
DANA DUNN	13516	11/15/2001	PHOSPHATE, ROCK, BULK	24833	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	13534	11/17/2001	COAL	33665	I	U	4101	TPA	D	LA	TEBB
LOUISE KIRKPATRI	13559	11/17/2001	COAL	8545	I	U	4144	TPA	D	LA	TEGA
LOUISE KIRKPATRI	13559	11/19/2001	GRAINS, NOS, BULK	9603	I	U	256	TPA	D	LA	CARG
LOUISE KIRKPATRI	13559	11/21/2001	PHOSPHAT CHEMICAL, BULK	9035	E	L	4103	LA	D	TPA	AGRI
LOUISE KIRKPATRI	13559	11/22/2001	PHOSPHAT CHEMICAL, BULK	9079	E	L	4146	LA	D	TPA	ROCK
DIANE LUDWIG	13572	11/19/2001	COAL	20971	I	U	4144	TPA	D	LA	TEGA
WANDA WHEELOC	13586	11/21/2001	COAL	18134	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	13588	11/22/2001	COAL	28139	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	13588	11/23/2001	PHOSPHATE, ROCK, BULK	37763	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	13595	11/23/2001	PHOSPHATE, ROCK, BULK	24613	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	13617	11/21/2001	COAL	32967	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	13619	11/23/2001	COAL	27993	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	13619	11/24/2001	PHOSPHATE, ROCK, BULK	31487	E	L	4103	LA	D	TPA	AGRI
DIANA T	13623	11/24/2001	COAL	16211	I	U	4144	TPA	D	LA	TEGA
DIANA T	13623	11/25/2001	PHOSPHATE, ROCK, BULK	28037	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	13653	11/27/2001	COAL	22409	I	U	4144	TPA	D	LA	TEGA
DIANE LUDWIG	13653	11/28/2001	PHOSPHAT CHEMICAL, BULK	7610	E	L	4148	LA	D	TPA	EAT
DIANE LUDWIG	13653	11/29/2001	PHOSPHAT CHEMICAL, BULK	10497	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	13662	11/29/2001	COAL	33935	I	U	4101	TPA	D	LA	TEBB
WANDA WHEELOC	13669	12/1/2001	COAL	18316	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	13687	12/2/2001	COAL	28408	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	13687	12/3/2001	PHOSPHAT CHEMICAL, BULK	38178	E	L	4103	LA	D	TPA	AGRI
LOUISE KIRKPATRI	13694	12/3/2001	COAL	18184	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	13696	11/9/2001	COAL	21038	I	U	4144	TPA	D	LA	TEGA
SHEILA McDEVITT	13721	12/4/2001	COAL	34434	I	U	4101	TPA	D	LA	TEBB
DANA DUNN	13730	12/5/2001	PHOSPHAT CHEMICAL, BULK	24605	E	L	4103	LA	D	TPA	AGRI
DIANA T	13738	12/2/2001	COAL	15990	I	U	4144	TPA	D	LA	TEGA
DIANA T	13738	12/3/2001	PHOSPHAT CHEMICAL, BULK	28000	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	13752	12/5/2001	COAL	31889	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	13752	12/6/2001	PHOSPHAT CHEMICAL, BULK	31891	E	L	4103	LA	D	TPA	AGRI
WANDA WHEELOC	13764	12/8/2001	COAL	18061	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	13830	12/11/2001	COAL	28733	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	13830	12/12/2001	PHOSPHAT CHEMICAL, BULK	37177	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	13843	12/12/2001	COAL	21475	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	13843	12/13/2001	PHOSPHAT CHEMICAL, BULK	11881	E	L	4103	LA	D	TPA	AGRI

LOUISE KIRKPATRI	13844	12/12/2001	GRAINS, NOS, BULK	9534	I	U	256	TPA	D	LA	CARG
LOUISE KIRKPATRI	13844	12/14/2001	COAL	9430	I	U	4144	TPA	D	LA	TEGA
DIANA T	13847	12/12/2001	COAL	16803	I	U	4144	TPA	D	LA	TEGA
DIANA T	13847	12/13/2001	PHOSPHAT CHEMICAL, BULK	28029	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	13861	12/15/2001	COAL	10898	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	13861	12/16/2001	COAL	19295	I	U	4144	TPA	D	LA	TEGA
WANDA WHEELOC	13863	12/15/2001	COAL	17950	I	U	4144	TPA	D	LA	TEGA
DANA DUNN	13867	12/16/2001	PHOSPHAT CHEMICAL, BULK	24522	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	13872	12/6/2001	COAL	8207	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	13872	12/6/2001	COKE	8647	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	13928	12/21/2001	SEAWATER, BULK	1063	I	U	271	TPA	D	LA	GARR
MARY TURNER	13928	12/22/2001	COAL	29191	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	13928	12/22/2001	PHOSPHAT CHEMICAL, BULK	37016	E	L	4103	LA	D	TPA	AGRI
LOUISE KIRKPATRI	13934	12/20/2001	COAL	18144	I	U	4144	TPA	D	LA	TEGA
LOUISE KIRKPATRI	13934	12/23/2001	PHOSPHAT CHEMICAL, BULK	7510	E	L	4110	LA	F	TPA	GARD
GAYLE EUSTACE	13944	12/22/2001	COAL	29089	I	U	4101	TPA	D	LA	TEBB
DIANA T	13946	12/22/2001	COAL	15448	I	U	4144	TPA	D	LA	TEGA
DIANA T	13946	12/23/2001	PHOSPHAT CHEMICAL, BULK	28174	E	L	4103	LA	D	TPA	AGRI
WANDA WHEELOC	13948	12/22/2001	COAL	18757	I	U	4144	TPA	D	LA	TEGA
SHEILA McDEVITT	13953	12/23/2001	COAL	33130	I	U	4101	TPA	D	LA	TEBB
ELLENA HICKS	13964	12/22/2001	PETROLEUM, BKRS, ALL OTHS	59.4	E	R	024B	FL	D	FL	PS
BARBARA VAUGHT	13965	12/21/2001	COKE	15551	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	13965	12/22/2001	PHOSPHAT CHEMICAL, BULK	4578	E	L	4146	LA	D	TPA	ROCK
BARBARA VAUGHT	13965	12/24/2001	PHOSPHAT CHEMICAL, BULK	13497	E	L	4110	LA	D	TPA	GARD
DANA DUNN	13969	12/26/2001	PHOSPHAT CHEMICAL, BULK	23833	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	14006	12/27/2001	COAL	31285	I	U	4101	TPA	D	LA	TEBB
SHEILA McDEVITT	14008	12/28/2001	COAL	33416	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	20012	1/1/2002	COAL	30549	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	20012	1/2/2002	PHOSPHATE, ROCK, BULK	32501	E	L	4103	LA	D	TPA	AGRI
LOUISE KIRKPATRI	20034	1/1/2002	COAL	18787	I	U	4144	TPA	D	LA	TEGA
LOUISE KIRKPATRI	20034	1/2/2002	PHOSPHAT CHEMICAL, BULK	12115	E	L	4148	LA	D	TPA	EAT
SHEILA McDEVITT	20043	1/2/2002	COAL	34289	I	U	4101	TPA	D	LA	TEBB
PAULA G	20065	1/6/2002	PHOSPHATE, ROCK, BULK	24462	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	20066	1/6/2002	PHOSPHAT CHEMICAL, BULK	24462	E	L	4103	LA	F	TPA	AGRI
MARY TURNER	20072	1/6/2002	COAL	29389	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	20072	1/6/2002	PHOSPHATE, ROCK, BULK	37248	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	20133	1/10/2002	COAL	14829	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	20133	1/11/2002	COAL	15935	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	20133	1/12/2002	PHOSPHATE, ROCK, BULK	31980	E	L	4103	LA	F	TPA	AGRI
DIANA T	20139	1/15/2002	PHOSPHATE, ROCK, BULK	28009	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	20143	1/10/2002	COAL	23709	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	20143	1/12/2002	PHOSPHAT CHEMICAL, BULK	16500	E	L	4110	LA	D	TPA	GARD
DORIS GUENTHER	20143	12/11/2002	PHOSPHAT CHEMICAL, BULK	4544	E	L	4148	LA	D	TPA	EAT
DANA DUNN	20163	1/15/2002	PHOSPHATE, ROCK, BULK	24490	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	20211	1/16/2002	COAL	15099	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	20211	1/17/2002	COAL	13308	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	20211	1/18/2002	PHOSPHATE, ROCK, BULK	37835	E	L	4103	LA	D	TPA	AGRI

DIANE LUDWIG	20223	1/18/2002	COAL	11318	I	U	4144	TPA	D	LA	TEGA
DIANE LUDWIG	20223	1/19/2002	COAL	10842	I	U	4101	TPA	D	LA	TEBB
DIANE LUDWIG	20223	1/20/2002	PHOSPHAT CHEMICAL, BULK	10504	E	L	4103	LA	D	TPA	AGRI
LOUISE KIRKPATRI	20234	1/15/2002	GRAINS, NOS, BULK	9500	I	U	256	TPA	D	LA	CARG
LOUISE KIRKPATRI	20234	1/17/2002	COAL	8946	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	20235	1/21/2002	COAL	22175	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	20263	1/22/2002	COKE	8793	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	20263	1/23/2002	COAL	19695	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	20263	1/24/2002	PHOSPHAT CHEMICAL, BULK	30822	E	L	204	LA	D	TPA	CFI
SHEILA McDEVITT	20278	1/23/2002	COAL	34606	I	U	4101	TPA	D	LA	TEBB
DIANA T	20283	1/24/2002	COAL	16338	I	U	4144	TPA	D	LA	TEGA
DIANA T	20283	1/25/2002	PHOSPHATE, ROCK, BULK	28259	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	20292	1/25/2002	PHOSPHATE, ROCK, BULK	24512	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	20311	1/27/2002	COAL	27847	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	20311	1/28/2002	PHOSPHATE, ROCK, BULK	37070	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	20327	1/27/2002	COAL	22859	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	20327	1/29/2002	PHOSPHAT CHEMICAL, BULK	7652	E	L	4148	LA	D	TPA	EAT
DORIS GUENTHER	20327	1/29/2002	PHOSPHAT CHEMICAL, BULK	10499	E	L	4103	LA	D	TPA	AGRI
LOUISE KIRKPATRI	20329	1/28/2002	COAL	18535	I	U	4144	TPA	D	LA	TEGA
SHEILA McDEVITT	20330	1/28/2002	COAL	34541	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	20373	1/31/2002	COAL	30397	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	20373	2/1/2002	PHOSPHAT CHEMICAL, BULK	30997	E	L	204	LA	D	TPA	CFI
BARBARA VAUGHT	20375	2/1/2002	COKE	9062	I	U	4101	TPA	D	TX	TEBB
BARBARA VAUGHT	20375	2/2/2002	COKE	8249	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	20375	2/2/2002	PHOSPHAT CHEMICAL, BULK	14491	E	L	4110	LA	D	TPA	GARD
DANA DUNN	20386	2/3/2002	PHOSPHATE, ROCK, BULK	24679	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	20418	2/5/2002	COAL	21949	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	20418	2/6/2002	PHOSPHAT CHEMICAL, BULK	10478	E	L	4103	LA	D	TPA	AGRI
PAT CANTRELL	20426	2/2/2002	COAL	32516	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	20426	2/4/2002	PHOSPHAT CHEMICAL, BULK	27898	E	L	4110	LA	D	TPA	GARD
DIANA T	20428	2/3/2002	COAL	15241	I	U	4144	TPA	D	LA	TEGA
DIANA T	20428	2/4/2002	PHOSPHATE, ROCK, BULK	28222	E	L	4103	LA	D	TPA	AGRI
AMERICAN FREEDO	20455	2/8/2002	COAL	34503	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	20469	2/9/2002	COAL	31064	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	20480	2/10/2002	COAL	28832	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	20480	2/11/2002	PHOSPHATE, ROCK, BULK	38543	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	20492	2/11/2002	PHOSPHATE, ROCK, BULK	24457	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	20494	2/12/2002	COAL	18754	I	U	4144	TPA	D	LA	TEGA
LOUISE KIRKPATRI	20501	2/10/2002	GRAINS, NOS, BULK	14157	I	U	256	TPA	D	LA	CARG
LOUISE KIRKPATRI	20501	2/13/2002	COAL	4115	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	20508	2/12/2002	COAL	21111	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	20508	2/13/2002	PHOSPHAT CHEMICAL, BULK	9155	E	L	4148	LA	D	TPA	EAT
AMERICAN FREEDO	20516	2/13/2002	COAL	34503	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	20540	2/14/2002	COAL	32925	I	U	4101	TPA	D	LA	TEBB
DIANA T	20542	2/14/2002	COAL	15982	I	U	4144	TPA	D	LA	TEGA
DIANA T	20542	2/15/2002	PHOSPHATE, ROCK, BULK	28024	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	20568	2/18/2002	COAL	27824	I	U	4101	TPA	D	LA	TEBB

LOUISE KIRKPATRI	20596	2/19/2002	COAL	18382	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	20598	2/19/2002	COAL	28236	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	20598	2/20/2002	PHOSPHATE, ROCK, BULK	39274	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	20600	2/19/2002	PHOSPHATE, ROCK, BULK	24323	E	L	4103	LA	D	TPA	AGRI
PAT CANTRELL	20613	2/20/2002	COAL	33637	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	20618	2/21/2002	COAL	21274	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	20625	2/22/2002	COAL	31318	I	U	4101	TPA	D	LA	TEBB
DIANA T	20627	2/23/2002	COAL	15363	I	U	4144	TPA	D	LA	TEGA
DIANA T	20627	2/24/2002	PHOSPHATE, ROCK, BULK	28178	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	20645	2/23/2002	COAL	29480	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	20645	2/24/2002	PHOSPHAT CHEMICAL, BULK	30578	E	L	204	LA	D	TPA	CFI
AMERICAN FREEDC	20662	2/26/2002	COAL	34741	I	U	4101	TPA	D	LA	TEBB
DIANE LUDWIG	20679	2/23/2002	COAL	22093	I	U	4144	TPA	D	LA	TEGA
DANA DUNN	20692	2/26/2002	PHOSPHATE, ROCK, BULK	24255	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	20703	2/27/2002	COAL	21239	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	20703	2/28/2002	PHOSPHAT CHEMICAL, BULK	9290	E	L	4148	LA	D	TPA	EAT
DIANE LUDWIG	20717	3/2/2002	COAL	22167	I	U	4101	TPA	D	LA	TEBB
LOUISE KIRKPATRI	20730	3/1/2002	GRAINS, NOS, BULK	9388	I	U	256	TPA	D	LA	CARG
LOUISE KIRKPATRI	20730	3/1/2002	COAL	6132	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	20751	3/1/2002	COAL	27723	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	20751	3/2/2002	PHOSPHATE, ROCK, BULK	37211	E	L	4103	LA	D	TPA	AGRI
BEVERLY ANDERS(	20752	3/1/2002	COAL	27723	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	20753	3/1/2002	COAL	33246	I	U	4101	TPA	D	LA	TEBB
AMERICAN FREEDC	20756	2/19/2002	COAL	35403	I	U	4101	TPA	D	LA	TEBB
DIANA T	20767	3/6/2002	COAL	16410	I	U	4144	TPA	D	LA	TEGA
DIANA T	20767	3/7/2002	PHOSPHATE, ROCK, BULK	28030	E	L	4103	LA	D	TPA	AGRI
AMERICAN FREEDC	20769	3/6/2002	COAL	34739	I	U	4101	TPA	D	LA	TEBB
DANA DUNN	20783	3/8/2002	PHOSPHATE, ROCK, BULK	24872	E	L	4103	LA	D	TPA	AGRI
PAT CANTRELL	20787	3/8/2002	COAL	33435	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	20787	3/9/2002	PHOSPHAT CHEMICAL, BULK	18000	E	L	4148	LA	D	TPA	EAT
PAT CANTRELL	20787	3/9/2002	PHOSPHAT CHEMICAL, BULK	6015	E	L	4146	LA	D	TPA	ROCK
GAYLE EUSTACE	20802	3/9/2002	COAL	29265	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	20802	3/10/2002	PHOSPHAT CHEMICAL, BULK	30699	E	L	204	LA	D	TPA	CFI
DIANE LUDWIG	20811	3/10/2002	COAL	22203	I	U	4144	TPA	D	LA	TEGA
LOUISE KIRKPATRI	21143	3/11/2002	COAL	18208	I	U	4144	TPA	D	LA	TEGA
LOUISE KIRKPATRI	21143	3/12/2002	PHOSPHAT CHEMICAL, BULK	6964	E	L	4146	LA	D	TPA	ROCK
LOUISE KIRKPATRI	21143	3/13/2002	PHOSPHAT CHEMICAL, BULK	8049	E	L	4110	LA	D	TPA	GARD
PEGGY PALMER	21156	3/12/2002	COAL	34140	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	21163	3/13/2002	COAL	28443	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	21163	3/14/2002	PHOSPHATE, ROCK, BULK	38373	E	L	4103	LA	D	TPA	AGRI
AMERICAN FREEDC	21168	3/13/2002	COAL	34479	I	U	4101	TPA	D	LA	TEBB
DIANA T	21188	3/15/2002	COAL	15546	I	U	4144	TPA	D	LA	TEGA
DIANA T	21188	3/15/2002	PHOSPHATE, ROCK, BULK	28126	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	21192	3/15/2002	PHOSPHATE, ROCK, BULK	24557	E	L	4103	LA	D	TPA	AGRI
PAT CANTRELL	21196	3/16/2002	COAL	33852	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	21198	3/16/2002	COAL	17917	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	21224	3/18/2002	COAL	30403	I	U	4101	TPA	D	LA	TEBB

SHEILA McDEVITT	21230	3/19/2002	COAL	34630	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	21248	3/11/2002	COAL	21651	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	21255	3/19/2002	COKE	14232	I	U	4101	TPA	D	LA	AGRI
PEGGY PALMER	21255	3/22/2002	COAL	17258	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	21255	3/22/2002	PHOSPHAT CHEMICAL, BULK	15150	E	L	4110	LA	D	TPA	GARD
PEGGY PALMER	21255	3/22/2002	PHOSPHAT CHEMICAL, BULK	10598	E	L	4103	LA	D	TPA	AGRI
AMERICAN FREED(	21289	3/21/2002	COAL	9746	I	U	4101	TPA	D	LA	TEBB
AMERICAN FREED(	21289	3/22/2002	COAL	25014	I	U	4144	TPA	D	LA	TEGA
AMERICAN FREED(	21289	3/24/2002	PHOSPHAT CHEMICAL, BULK	33545	E	L	204	LA	D	TPA	CFI
GAYLE EUSTACE	21295	3/23/2002	COAL	29994	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	21295	3/26/2002	PHOSPHAT CHEMICAL, BULK	23496	E	L	4148	LA	D	TPA	EAT
JUDY LITRICO	21296	3/25/2002	COAL	29393	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	21299	3/23/2002	COAL	28110	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	21299	3/23/2002	PHOSPHATE, ROCK, BULK	38557	E	L	4103	LA	D	TPA	AGRI
DIANA T	21301	3/24/2002	COAL	15929	I	U	4144	TPA	D	LA	TEGA
DIANA T	21301	3/25/2002	PHOSPHATE, ROCK, BULK	28247	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	21309	3/26/2002	PHOSPHATE, ROCK, BULK	24857	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	21326	3/26/2002	COAL	21962	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	21357	3/29/2002	GRAINS, NOS, BULK	13399	I	U	256	TPA	D	LA	CARG
BARBARA VAUGHT	21357	3/30/2002	COAL	3959	I	U	4144	TPA	D	LA	TEGA
JUDY LITRICO	21376	3/30/2002	COAL	31095	I	U	4101	TPA	D	LA	TEBB
LOUISE KIRKPATRI	21391	3/31/2002	COAL	13470	I	U	4144	TPA	D	LA	TEGA
LOUISE KIRKPATRI	21391	4/1/2002	POTASH, BULK	4843	I	U	23	TPA	D	LA	PS
PEGGY PALMER	21393	3/31/2002	COAL	33788	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	21407	4/1/2002	COAL	21979	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	21407	4/2/2002	PHOSPHAT CHEMICAL, BULK	10483	E	L	4103	LA	D	TPA	AGRI
DIANA T	21412	4/2/2002	COAL	15166	I	U	4144	TPA	D	LA	TEGA
DIANA T	21412	4/4/2002	PHOSPHATE, ROCK, BULK	28337	I	L	4103	LA	D	TPA	AGRI
DANA DUNN	21426	4/3/2002	PHOSPHATE, ROCK, BULK	24802	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	21442	4/5/2002	COAL	21442	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	21442	4/6/2002	PHOSPHATE, ROCK, BULK	29458	E	L	4103	LA	D	TPA	AGRI
AMERICAN FREED(	21453	4/3/2002	COAL	33836	I	U	4144	TPA	D	LA	TEGA
AMERICAN FREED(	21453	4/4/2002	PHOSPHAT CHEMICAL, BULK	33577	E	L	204	LA	D	TPA	CFI
MARY TURNER	21455	4/3/2002	SEAWATER, BULK	1063	I	U	271	TPA	D	LA	GARR
MARY TURNER	21455	4/3/2002	COAL	28140	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	21455	5/27/2002	PHOSPHATE, ROCK, BULK	34854	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	21465	4/6/2002	COAL	18479	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	21465	4/8/2002	SCRAP METAL	6097	E	L	219	LA	F	TPA	KT
BARBARA VAUGHT	21465	4/8/2002	SCRAP METAL	6796	E	L	219	LA	F	TPA	KT
PEGGY PALMER	21468	4/6/2002	COKE	6523	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	21468	4/8/2002	COAL	25507	I	U	4101	TPA	D	LA	TEBB
DIANE LUDWIG	21476	4/7/2002	COAL	22285	I	U	4144	TPA	D	LA	TEGA
JUDY LITRICO	21484	4/8/2002	COAL	29700	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	21496	4/9/2002	COAL	22202	I	U	4144	TPA	D	LA	TEGA
DIANA T	21532	4/12/2002	COAL	16945	I	U	4144	TPA	D	LA	TEGA
DIANA T	21532	4/13/2002	PHOSPHATE, ROCK, BULK	24471	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	21542	4/13/2002	PHOSPHATE, ROCK, BULK	24600	E	L	4103	LA	D	TPA	AGRI

PEGGY PALMER	21556	4/14/2002	COAL	24689	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	21556	4/14/2002	COKE	9171	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	21563	4/15/2002	COAL	23067	I	U	4101	TPA	D	LA	TEBB
DIANE LUDWIG	21587	4/14/2002	COAL	22327	I	U	4144	TPA	D	LA	TEGA
DIANE LUDWIG	21587	4/16/2002	PHOSPHAT CHEMICAL, BULK	10575	E	L	4101	LA	D	TPA	TEBB
GAYLE EUSTACE	21596	4/16/2002	COAL	27350	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	21596	4/17/2002	PHOSPHATE, ROCK, BULK	31204	E	L	4103	LA	D	TPA	AGRI
PAT CANTRELL	21600	4/17/2002	COAL	33441	I	U	4101	TPA	D	LA	TEBB
JUDY LITRICO	21624	4/18/2002	COAL	29657	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	21628	4/19/2002	COAL	18090	I	U	4144	TPA	D	LA	TEGA
DIANA T	21653	4/20/2002	PHOSPHATE, ROCK, BULK	26044	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	21655	4/20/2002	COAL	33581	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	21655	4/22/2002	PHOSPHAT CHEMICAL, BULK	15063	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	21659	4/21/2002	COAL	22171	I	U	4144	TPA	D	LA	TEGA
DANA DUNN	21665	4/22/2002	PHOSPHATE, ROCK, BULK	24531	E	L	4101	LA	D	TPA	TEBB
DIANE LUDWIG	21670	4/22/2002	COAL	21581	I	U	4144	TPA	D	LA	TEGA
PAT CANTRELL	21678	4/23/2002	COAL	26643	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	21678	4/23/2002	SLAG	5021	I	U	4101	TPA	D	LA	TEBB
JUDY LITRICO	21697	4/30/2002	COAL	28546	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	21710	4/27/2002	COKE	20865	I	U	219	TPA	D	LA	KT
GAYLE EUSTACE	21721	4/25/2002	COAL	28157	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	21721	4/27/2002	PHOSPHATE, ROCK, BULK	29586	E	L	4103	LA	D	TPA	AGRI
DIANA T	21727	4/27/2002	PHOSPHATE, ROCK, BULK	25992	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	21746	4/28/2002	COAL	21279	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	21754	4/27/2002	GRAINS, NOS, BULK	13536	I	U	256	TPA	D	LA	CARG
BARBARA VAUGHT	21754	4/29/2002	COAL	4963	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	21754	5/1/2002	PHOSPHAT CHEMICAL, BULK	10387	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	21756	4/28/2002	COAL	33053	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	21756	4/30/2002	PHOSPHAT CHEMICAL, BULK	34513	E	L	204	LA	D	TPA	CFI
PAT CANTRELL	21758	4/28/2002	COAL	31568	I	U	4101	TPA	D	LA	TEBB
DANA DUNN	21761	4/30/2002	PHOSPHATE, ROCK, BULK	24363	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	21803	5/3/2002	COAL	31950	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	21811	5/4/2002	COAL	22872	I	U	4144	TPA	D	LA	TEGA
DIANA T	21832	5/5/2002	PHOSPHATE, ROCK, BULK	26109	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	21885	5/9/2002	PHOSPHATE, ROCK, BULK	24336	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	21890	5/7/2002	COAL	9585	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	21890	5/7/2002	COAL	18323	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	21890	5/8/2002	PHOSPHATE, ROCK, BULK	29717	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	21905	5/10/2002	COAL	32395	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	21919	5/11/2002	COAL	31748	I	U	4101	TPA	D	LA	TEBB
DIANA T	21921	5/12/2002	COAL	16195	I	U	4144	TPA	D	LA	TEGA
DIANA T	21921	5/13/2002	PHOSPHATE, ROCK, BULK	26124	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	21928	5/7/2002	COAL	32441	I	U	4101	TPA	D	LA	TEBB
SHEILA McDEVITT	21951	5/14/2002	COAL	32440	I	U	4101	TPA	D	LA	TEBB
DANA DUNN	21971	5/16/2002	PHOSPHATE, ROCK, BULK	24277	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	21990	5/16/2002	COAL	10439	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	21990	5/17/2002	COAL	19002	I	U	4144	TPA	D	LA	TEGA

GAYLE EUSTACE	21990	5/18/2002	PHOSPHATE, ROCK, BULK	29529	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	21996	5/19/2002	COAL	32009	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	22016	5/18/2002	COAL	6849	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	22016	5/19/2002	COAL	25260	I	U	4144	TPA	D	LA	TEGA
PAT CANTRELL	22016	5/21/2002	PHOSPHAT CHEMICAL, BULK	34503	E	L	204	LA	D	TPA	CFI
DIANA T	22021	5/21/2002	COAL	16414	I	U	4144	TPA	D	LA	TEGA
DIANA T	22021	5/22/2002	PHOSPHATE, ROCK, BULK	26092	E	L	4103	LA	D	TPA	AGRI
MARIE FLOOD	22023	5/21/2002	COAL	33630	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	22030	5/17/2002	COAL	8769	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	22030	5/18/2002	COAL	23371	I	U	4144	TPA	D	LA	TEGA
DANA DUNN	22062	5/25/2002	PHOSPHATE, ROCK, BULK	24706	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	22068	5/26/2002	COAL	18270	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	22079	5/25/2002	COAL	8971	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	22079	5/26/2002	COAL	23606	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	22089	5/26/2002	COAL	29007	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	22089	5/27/2002	PHOSPHATE, ROCK, BULK	30056	E	L	4103	LA	D	TPA	AGRI
MARIE FLOOD	22091	5/28/2002	COAL	33393	I	U	4101	TPA	D	LA	TEBB
DIANA T	22127	5/29/2002	COAL	15513	I	U	4144	TPA	D	LA	TEGA
DIANA T	22127	5/30/2002	PHOSPHATE, ROCK, BULK	26307	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	22146	6/1/2002	PHOSPHATE, ROCK, BULK	24497	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	22152	6/1/2002	COAL	8310	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	22152	6/1/2002	COAL	23412	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	22156	6/2/2002	COAL	22369	I	U	4144	TPA	D	LA	TEGA
MARIE FLOOD	22160	6/3/2002	COAL	34457	I	U	4101	TPA	D	LA	TEBB
BETTY WOOD	22183	7/25/2002	PETROLEUM, BKRS, ALL OTHS	260.4	E	R	024B	TPA	D	TPA	PS
GAYLE EUSTACE	22204	6/5/2002	COAL	28878	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	22204	6/6/2002	PHOSPHATE, ROCK, BULK	30305	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	22228	6/7/2002	COAL	8393	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	22228	6/8/2002	COAL	23676	I	U	4144	TPA	D	LA	TEGA
MARIE FLOOD	22232	6/8/2002	COAL	34768	I	U	4101	TPA	D	LA	TEBB
DIANA T	22234	6/9/2002	COAL	16131	I	U	4144	TPA	D	LA	TEGA
DIANA T	22234	6/10/2002	PHOSPHATE, ROCK, BULK	25870	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	22243	6/9/2002	PHOSPHATE, ROCK, BULK	24694	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	22245	6/9/2002	COAL	17957	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	22254	6/10/2002	COAL	21797	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	22269	6/11/2002	COAL	26224	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	22269	6/13/2002	PHOSPHATE, ROCK, BULK	35277	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	22284	6/13/2002	COAL	32066	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	22296	6/14/2002	COAL	29010	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	22296	6/15/2002	PHOSPHATE, ROCK, BULK	29458	E	L	4103	LA	D	TPA	AGRI
MARIE FLOOD	22303	6/15/2002	COAL	35257	I	U	4101	TPA	D	LA	TEBB
LOUISE KIRKPATRI	22307	6/15/2002	COAL	18857	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	22320	6/15/2002	COAL	14838	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	22320	6/16/2002	PHOSPHAT CHEMICAL, BULK	10494	E	L	4146	LA	D	TPA	ROCK
PEGGY PALMER	22320	6/17/2002	COAL	16707	I	U	4144	TPA	D	LA	TEGA
DIANA T	22328	6/18/2002	COAL	15949	I	U	4144	TPA	D	LA	TEGA
DIANA T	22328	6/19/2002	PHOSPHATE, ROCK, BULK	26142	E	L	4103	LA	D	TPA	AGRI

MARY TURNER	22366	6/21/2002	COAL	27591	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	22366	6/22/2002	PHOSPHATE, ROCK, BULK	35468	E	L	4103	LA	D	TPA	AGRI
MARIE FLOOD	22371	6/21/2002	COAL	34871	I	U	4101	TPA	D	LA	TEBB
DANA DUNN	22391	7/9/2002	PHOSPHATE, ROCK, BULK	24524	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	22398	6/23/2002	COAL	29405	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	22398	6/24/2002	PHOSPHATE, ROCK, BULK	29849	E	L	4103	LA	D	TPA	AGRI
AMERICAN FREED(	22404	6/24/2002	COAL	33107	I	U	4101	LA	D	LA	TEBB
LOUISE KIRKPATRI	22426	6/25/2002	GRAINS, NOS, BULK	9793	I	U	256	TPA	D	LA	CARG
LOUISE KIRKPATRI	22426	6/26/2002	COAL	8715	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	22441	6/24/2002	COAL	8434	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	22441	6/25/2002	COAL	23390	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	22441	6/26/2002	PHOSPHAT CHEMICAL, BULK	34230	E	L	204	LA	D	TPA	CFI
DIANA T	22443	6/26/2002	COAL	15319	I	U	4144	TPA	D	LA	TEGA
DIANA T	22443	6/28/2002	PHOSPHATE, ROCK, BULK	26402	E	L	4103	LA	D	TPA	AGRI
MARIE FLOOD	22472	6/28/2002	COAL	34773	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	22484	6/30/2002	SEAWATER, BULK	1063	I	U	271	TPA	D	LA	GARR
MARY TURNER	22484	6/30/2002	COAL	30002	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	22484	7/1/2002	PHOSPHATE, ROCK, BULK	34749	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	22489	7/1/2002	SLAG	4753	I	U	219	TPA	D	LA	KT
DIANE LUDWIG	22489	7/2/2002	COAL	17317	I	U	4144	TPA	D	LA	TEGA
DIANE LUDWIG	22489	7/4/2002	PHOSPHAT CHEMICAL, BULK	4422	E	L	4148	LA	D	TPA	EAT
AMERICAN FREED(	22500	7/1/2002	COAL	8826	I	U	4101	TPA	D	LA	TEBB
AMERICAN FREED(	22500	7/2/2002	COAL	23299	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	22513	7/2/2002	COAL	10124	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	22513	7/4/2002	COAL	19430	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	22513	7/5/2002	PHOSPHATE, ROCK, BULK	29986	E	L	4103	LA	D	TPA	AGRI
DIANA T	22528	7/5/2002	COAL	16010	I	U	4144	TPA	D	LA	TEGA
DIANA T	22528	7/6/2002	PHOSPHATE, ROCK, BULK	26286	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	22536	7/6/2002	COAL	21871	I	U	4144	TPA	D	LA	TEGA
MARIE FLOOD	22553	7/4/2002	COAL	35014	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	22581	7/9/2002	COAL	26438	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	22581	7/10/2002	PHOSPHATE, ROCK, BULK	35061	E	L	4103	LA	D	TPA	AGRI
AMERICAN FREED(	22591	7/8/2002	COAL	9237	I	U	4101	TPA	D	LA	TEBB
AMERICAN FREED(	22591	7/9/2002	COAL	24047	I	U	4144	TPA	D	LA	TEGA
AMERICAN FREED(	22591	7/11/2002	PHOSPHAT CHEMICAL, BULK	21890	E	L	204	LA	D	TPA	CFI
AMERICAN FREED(	22591	7/13/2002	PHOSPHAT CHEMICAL, BULK	9983	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	22592	7/9/2002	COAL	18388	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	22594	7/9/2002	COAL	8853	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	22594	7/11/2002	COAL	23478	I	U	4144	TPA	D	LA	TEGA
DIANE LUDWIG	22601	7/12/2002	COAL	22419	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	22624	7/13/2002	COAL	9915	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	22624	7/14/2002	COAL	19387	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	22624	7/15/2002	PHOSPHATE, ROCK, BULK	32756	E	L	4103	LA	D	TPA	AGRI
DIANA T	22633	7/14/2002	COAL	18022	I	U	4144	TPA	D	LA	TEGA
DIANA T	22633	7/16/2002	PHOSPHATE, ROCK, BULK	27616	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	22646	7/17/2002	PHOSPHATE, ROCK, BULK	24159	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	22680	7/18/2002	COAL	28090	I	U	4101	TPA	D	LA	TEBB

MARY TURNER	22680	7/19/2002	PHOSPHATE, ROCK, BULK	37687	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	22690	7/20/2002	COAL	18034	I	U	4144	TPA	D	LA	TEGA
AMERICAN FREED(	22692	7/20/2002	COAL	15015	I	U	4101	TPA	D	LA	TEBB
AMERICAN FREED(	22692	7/21/2002	COAL	17289	I	U	4144	TPA	D	LA	TEGA
LISA W	22705	7/22/2002	PETROLEUM, BKRS, ALL OTHS	88.2	E	R	024B	TPA	D	TPA	PS
DIANE LUDWIG	22706	7/22/2002	COAL	22004	I	U	4101	TPA	D	TX	TEBB
DORIS GUENTHER	22713	7/21/2002	COAL	22001	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	22721	7/23/2002	COAL	29215	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	22721	7/24/2002	PHOSPHATE, ROCK, BULK	32134	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	22739	7/25/2002	PHOSPHATE, ROCK, BULK	24294	E	L	4103	LA	D	TPA	AGRI
DIANA T	22741	7/24/2002	COAL	15943	I	U	4144	TPA	D	LA	TEGA
DIANA T	22741	7/25/2002	PHOSPHATE, ROCK, BULK	27221	E	L	4103	LA	D	TPA	AGRI
AMERICAN FREED(	22791	7/27/2002	COAL	33434	I	U	4101	TPA	D	LA	TEBB
AMERICAN FREED(	22791	7/29/2002	PHOSPHAT CHEMICAL, BULK	34058	E	L	204	LA	D	TPA	CFI
BARBARA VAUGHT	22797	7/28/2002	GRAINS, NOS, BULK	9693	I	U	256	TPA	D	LA	CARG
BARBARA VAUGHT	22797	7/30/2002	COAL	8958	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	22797	7/31/2002	PHOSPHAT CHEMICAL, BULK	17714	E	L	204	LA	D	TPA	CFI
MARY TURNER	22799	7/28/2002	COAL	30448	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	22799	7/29/2002	PHOSPHATE, ROCK, BULK	35859	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	22801	7/29/2002	COAL	22360	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	22830	8/1/2002	COAL	30133	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	22830	8/2/2002	PHOSPHATE, ROCK, BULK	32528	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	22844	8/2/2002	PHOSPHATE, ROCK, BULK	24281	E	L	4103	LA	D	TPA	AGRI
DIANA T	22859	8/2/2002	COAL	16572	I	U	4144	TPA	D	LA	TEGA
DIANA T	22859	8/3/2002	PHOSPHATE, ROCK, BULK	28109	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	22879	8/4/2002	COAL	22863	I	U	4101	TPA	D	LA	TEBB
DIANE LUDWIG	22879	8/5/2002	PHOSPHAT CHEMICAL, BULK	21000	E	L	4110	LA	D	TPA	GARD
DORIS GUENTHER	22882	8/6/2002	COAL	21760	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	22889	8/6/2002	COAL	29984	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	22889	8/7/2002	PHOSPHATE, ROCK, BULK	38532	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	22928	8/11/2002	COAL	30603	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	22928	8/12/2002	PHOSPHATE, ROCK, BULK	32439	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	22929	8/11/2002	GRAINS, NOS, BULK	4757	I	U	256	TPA	D	LA	CARG
BARBARA VAUGHT	22929	8/12/2002	COAL	13139	I	U	4144	TPA	D	LA	TEGA
DANA DUNN	22942	8/13/2002	PHOSPHATE, ROCK, BULK	24198	E	L	4103	LA	D	TPA	AGRI
DIANA T	22982	8/13/2002	COAL	15815	I	U	4144	TPA	D	LA	TEGA
DIANA T	22982	8/16/2002	PHOSPHATE, ROCK, BULK	27730	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	22989	8/17/2002	COAL	29036	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	22989	8/18/2002	PHOSPHATE, ROCK, BULK	36984	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	23022	8/20/2002	COAL	22185	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	23029	8/20/2002	COAL	30067	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	23029	8/21/2002	PHOSPHATE, ROCK, BULK	31105	E	L	4103	LA	D	TPA	AGRI
DANA DUNN	23044	2/3/2003	PHOSPHATE, ROCK, BULK	24421	E	L	4103	LA	D	TPA	AGRI
DIANA T	23062	8/24/2002	COAL	15887	I	U	4144	TPA	D	LA	TEGA
DIANA T	23062	8/25/2002	PHOSPHATE, ROCK, BULK	27740	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	23091	8/26/2002	COAL	28084	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	23091	8/27/2002	PHOSPHATE, ROCK, BULK	38549	E	L	4103	LA	D	TPA	AGRI

GAYLE EUSTACE	23117	8/29/2002	COAL	29586	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	23117	8/30/2002	PHOSPHATE, ROCK, BULK	30897	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	23129	8/30/2002	COAL	8835	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	23129	8/30/2002	COAL	24069	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	23129	9/1/2002	PHOSPHAT CHEMICAL, BULK	15000	E	L	4110	LA	D	TPA	GARD
DIANA T	23157	9/1/2002	COAL	16249	I	U	4144	TPA	D	LA	TEGA
DIANA T	23157	9/2/2002	PHOSPHATE, ROCK, BULK	27659	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	23184	9/2/2002	COAL	34736	I	U	4101	TPA	D	LA	TEBB
SHEILA McDEVITT	23184	9/3/2002	PHOSPHAT CHEMICAL, BULK	30002	E	L	4110	LA	D	TPA	GARD
PAT CANTRELL	23186	9/3/2002	COAL	6154	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	23186	9/4/2002	COAL	25061	I	U	4144	TPA	D	LA	TEGA
PAT CANTRELL	23186	9/5/2002	PHOSPHAT CHEMICAL, BULK	10504	E	L	4103	LA	D	TPA	AGRI
PAT CANTRELL	23186	9/7/2002	PHOSPHAT CHEMICAL, BULK	24018	E	L	204	LA	D	TPA	CFI
MARY TURNER	23191	9/4/2002	COAL	30650	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	23191	9/5/2002	PHOSPHATE, ROCK, BULK	37095	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	23201	9/5/2002	COAL	22018	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	23227	9/7/2002	COAL	30613	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	23227	9/8/2002	PHOSPHATE, ROCK, BULK	30344	E	L	4103	LA	D	TPA	AGRI
DIANA T	23264	9/10/2002	COAL	16087	I	U	4144	TPA	D	LA	TEGA
DIANA T	23264	9/11/2002	PHOSPHATE, ROCK, BULK	28207	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	23268	9/11/2002	COAL	22302	I	U	4144	TPA	D	LA	TEGA
DIANE LUDWIG	23268	9/13/2002	PHOSPHAT CHEMICAL, BULK	19498	E	L	4110	LA	D	TPA	GARD
GAYLE EUSTACE	23298	9/16/2002	COAL	28378	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	23298	9/17/2002	PHOSPHATE, ROCK, BULK	31197	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	23326	9/17/2002	COAL	27617	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	23326	9/19/2002	PHOSPHATE, ROCK, BULK	31325	E	L	4103	LA	D	TPA	AGRI
JUDY LITRICO	23327	9/17/2002	COAL	28864	I	U	4101	TPA	D	LA	TEBB
JUDY LITRICO	23327	9/18/2002	PHOSPHAT CHEMICAL, BULK	31499	E	L	204	LA	D	TPA	CFI
BARBARA VAUGHT	23328	9/17/2002	GRAINS, NOS, BULK	9543	I	U	256	TPA	D	LA	CARG
BARBARA VAUGHT	23328	9/19/2002	COAL	7119	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	23328	9/20/2002	PHOSPHAT CHEMICAL, BULK	8994	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	23358	9/20/2002	COAL	22203	I	U	4144	TPA	D	LA	TEGA
DIANA T	23393	9/23/2002	COAL	15836	I	U	4144	TPA	D	LA	TEGA
DIANA T	23393	9/24/2002	PHOSPHATE, ROCK, BULK	28004	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	23405	9/25/2002	COAL	10389	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	23405	9/26/2002	COAL	18942	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	23405	9/27/2002	PHOSPHATE, ROCK, BULK	31196	E	L	4103	LA	D	TPA	AGRI
JUDY LITRICO	23413	9/26/2002	COAL	30046	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	23422	9/28/2002	POTASH, BULK	4501	I	U	23	TPA	D	LA	PS
PEGGY PALMER	23422	9/29/2002	COKE	25148	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	23422	9/30/2002	PHOSPHAT CHEMICAL, BULK	34473	E	L	204	LA	D	TPA	CFI
MARY TURNER	23434	9/29/2002	SEAWATER, BULK	1063	I	U	271	TPA	D	LA	GARR
MARY TURNER	23434	9/29/2002	COAL	19855	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	23434	9/30/2002	COAL	9156	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	23434	10/1/2002	PHOSPHATE, ROCK, BULK	37016	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	23483	10/2/2002	GRAINS, NOS, BULK	14279	I	U	256	TPA	D	LA	CARG
BARBARA VAUGHT	23483	10/4/2002	COAL	6216	I	U	4101	TPA	D	LA	TEBB

BARBARA VAUGHT	23483	10/5/2002	PHOSPHAT CHEMICAL, BULK	16551	E	L	4110	LA	D	TPA	GARD
SHEILA McDEVITT	23508	10/6/2002	COAL	34139	I	U	4101	TPA	D	LA	TEBB
SHEILA McDEVITT	23508	10/7/2002	PHOSPHAT CHEMICAL, BULK	35886	E	L	204	LA	D	TPA	CFI
DIANA T	23512	10/6/2002	COAL	16474	I	U	4144	TPA	D	LA	TEGA
DIANA T	23512	10/7/2002	PHOSPHATE, ROCK, BULK	28092	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	23543	10/9/2002	COAL	10150	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	23543	10/9/2002	COAL	19004	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	23543	10/10/2002	PHOSPHATE, ROCK, BULK	30704	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	23571	10/11/2002	COAL	22316	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	23571	10/12/2002	COAL	6854	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	23571	10/13/2002	PHOSPHATE, ROCK, BULK	37814	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	23581	10/12/2002	COAL	23491	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	23598	3/4/2002	COAL	29667	I	U	4101	TPA	D	LA	TEBB
DIANA T	23614	10/15/2002	COAL	16975	I	U	4144	TPA	D	LA	TEGA
DIANA T	23614	10/15/2002	PHOSPHATE, ROCK, BULK	27991	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	23623	10/16/2002	COAL	34941	I	U	4101	TPA	D	LA	TEBB
SHEILA McDEVITT	23623	10/17/2002	PHOSPHAT CHEMICAL, BULK	36158	E	L	204	LA	D	TPA	CFI
DIANE LUDWIG	23640	10/18/2002	COAL	21907	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	23643	10/18/2002	COAL	30713	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	23643	10/19/2002	PHOSPHATE, ROCK, BULK	31716	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	23656	10/19/2002	COAL	18637	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	23673	10/20/2002	COAL	28349	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	23673	10/21/2002	PHOSPHATE, ROCK, BULK	37245	E	L	4103	LA	D	TPA	AGRI
DIANA T	23703	10/23/2002	COAL	14734	I	U	4101	TPA	D	LA	TEBB
DIANA T	23703	10/23/2002	PHOSPHATE, ROCK, BULK	28173	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	23715	10/24/2002	COAL	22349	I	U	4144	TPA	D	LA	TEGA
SHEILA McDEVITT	23723	10/25/2002	COAL	33989	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	23739	10/26/2002	COAL	18581	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	23739	10/27/2002	PHOSPHAT CHEMICAL, BULK	10921	E	L	4148	LA	D	TPA	EAT
DORIS GUENTHER	23757	10/28/2002	COAL	22916	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	23762	10/28/2002	COAL	28285	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	23762	10/29/2002	PHOSPHATE, ROCK, BULK	30900	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	23774	10/29/2002	COAL	33678	I	U	4101	TPA	D	LA	TEBB
DIANE LUDWIG	23793	10/30/2002	COAL	22057	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	23801	10/31/2002	COAL	26335	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	23801	10/31/2002	PHOSPHATE, ROCK, BULK	37981	E	L	4103	LA	D	TPA	AGRI
DIANA T	23803	10/31/2002	COAL	16045	I	U	4144	TPA	D	LA	TEGA
DIANA T	23803	11/2/2002	PHOSPHATE, ROCK, BULK	28160	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	23838	11/3/2002	COAL	35240	I	U	4101	TPA	D	LA	TEBB
SHEILA McDEVITT	23838	11/4/2002	PHOSPHAT CHEMICAL, BULK	18414	E	L	4148	LA	D	TPA	EAT
SHEILA McDEVITT	23838	11/6/2002	PHOSPHAT CHEMICAL, BULK	9448	E	L	4110	LA	D	TPA	GARD
GAYLE EUSTACE	23870	11/6/2002	COAL	26207	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	23870	11/7/2002	PHOSPHATE, ROCK, BULK	31871	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	23882	11/7/2002	GRAINS, NOS, BULK	9488	I	U	256	TPA	D	LA	CARG
BARBARA VAUGHT	23882	11/9/2002	COAL	9033	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	23882	11/9/2002	PHOSPHAT CHEMICAL, BULK	17999	E	L	204	LA	D	TPA	CFI
DIANA T	23900	11/9/2002	COAL	16189	I	U	4144	TPA	D	LA	TEGA

DIANA T	23900	11/10/2002	PHOSPHATE, ROCK, BULK	28373	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	23923	11/12/2002	COAL	30470	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	23929	11/8/2002	COAL	29153	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	23929	11/13/2002	PHOSPHATE, ROCK, BULK	38177	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	23942	11/12/2002	COAL	22566	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	23942	11/14/2002	PHOSPHAT CHEMICAL, BULK	22495	E	L	204	LA	D	TPA	CFI
GAYLE EUSTACE	23961	11/15/2002	COAL	29649	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	23961	11/16/2002	PHOSPHATE, ROCK, BULK	33031	E	L	4103	LA	D	TPA	AGRI
DIANA T	23992	11/19/2002	COAL	16114	I	U	4144	TPA	D	LA	TEGA
DIANA T	23992	11/20/2002	PHOSPHATE, ROCK, BULK	28434	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	24003	11/20/2002	COAL	18421	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	24003	11/21/2002	PHOSPHAT CHEMICAL, BULK	4503	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	24027	11/21/2002	COAL	28210	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	24027	11/22/2002	PHOSPHATE, ROCK, BULK	36467	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	24049	11/24/2002	COAL	30594	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	24049	11/25/2002	PHOSPHATE, ROCK, BULK	32084	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	24091	11/27/2002	COAL	31838	I	U	4101	TPA	D	LA	TEBB
DIANA T	24100	11/28/2002	COAL	16523	I	U	4101	TPA	D	LA	TEBB
DIANA T	24100	11/29/2002	PHOSPHATE, ROCK, BULK	32084	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	24110	11/30/2002	COAL	22612	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	24110	12/1/2002	COAL	5142	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	24110	12/1/2002	PHOSPHATE, ROCK, BULK	38536	E	L	4103	LA	F	TPA	AGRI
GAYLE EUSTACE	24153	12/2/2002	COAL	31079	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	24153	12/3/2002	PHOSPHATE, ROCK, BULK	32328	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	24167	12/3/2002	COAL	20295	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	24174	12/4/2002	COAL	32809	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	24174	12/6/2002	PHOSPHAT CHEMICAL, BULK	15001	E	L	4148	LA	D	TPA	EAT
DEBBIE RANKIN	24210	2/18/2003	PETROLEUM, BKRS, ALL OTHS	178.2	E	R	024B	TPA	D	TPA	PS
DIANA T	24211	12/8/2002	COAL	15860	I	U	4144	TPA	D	LA	TEGA
DIANA T	24211	2/28/2003	PHOSPHATE, ROCK, BULK	28135	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	24218	12/9/2002	SEAWATER, BULK	1063	I	U	271	TPA	D	LA	GARR
MARY TURNER	24218	12/10/2002	COAL	27829	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	24234	12/9/2002	GRAINS, NOS, BULK	9152	I	U	256	TPA	D	LA	CARG
BARBARA VAUGHT	24234	12/11/2002	COAL	8690	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	24243	12/11/2002	COAL	30772	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	24243	12/12/2002	PHOSPHATE, ROCK, BULK	30810	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	24303	12/16/2002	COAL	7998	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	24303	12/16/2002	COAL	18791	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	24303	12/16/2002	SLAG	5029	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	24387	12/18/2002	COAL	20628	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	24399	12/20/2002	COAL	20175	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	24399	12/21/2002	COAL	10362	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	24399	12/22/2002	PHOSPHATE, ROCK, BULK	31860	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	24417	12/23/2002	COAL	27775	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	24417	12/23/2002	PHOSPHATE, ROCK, BULK	37223	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	24451	12/30/2002	COAL	10542	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	24451	12/31/2002	COAL	15664	I	U	4144	TPA	D	LA	TEGA

GAYLE EUSTACE	24451	1/1/2003	PHOSPHATE, ROCK, BULK	31243	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	30022	1/2/2003	COAL	24212	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	30022	1/4/2003	PHOSPHAT CHEMICAL, BULK	8998	E	L	4148	LA	D	TPA	EAT
DORIS GUENTHER	30022	1/7/2003	PHOSPHAT CHEMICAL, BULK	14905	E	L	4110	LA	F	TPA	GARD
MARY TURNER	30052	1/4/2003	COAL	28656	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	30052	1/5/2003	PHOSPHATE, ROCK, BULK	37652	E	L	4103	LA	D	TPA	AGRI
WANDA WHEELOC	30066	1/6/2003	COAL	18163	I	U	4144	TPA	D	LA	TEGA
PAT CANTRELL	30113	1/9/2003	COAL	33766	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	30125	1/11/2003	COAL	30005	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	30156	1/13/2003	COAL	28959	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	30156	1/14/2003	PHOSPHATE, ROCK, BULK	39209	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	30158	1/13/2003	COAL	22008	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	30194	1/16/2003	COAL	30507	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	30194	1/17/2003	PHOSPHATE, ROCK, BULK	30990	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	30228	1/19/2003	COAL	23395	I	U	4144	TPA	D	LA	TEGA
DIANE LUDWIG	30228	1/21/2003	PHOSPHAT CHEMICAL, BULK	15023	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	30241	1/20/2003	COAL	30241	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	30264	1/21/2003	COAL	27985	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	30264	1/22/2003	PHOSPHATE, ROCK, BULK	38621	E	L	4103	LA	D	TPA	AGRI
WANDA WHEELOC	30273	1/23/2003	COAL	18111	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	30319	1/25/2003	COAL	30263	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	30319	1/26/2003	PHOSPHATE, ROCK, BULK	31623	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	30332	1/28/2003	COAL	21795	I	U	4101	TPA	D	LA	TEBB
WANDA WHEELOC	30356	1/30/2003	COAL	18960	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	30384	2/1/2003	COAL	27569	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	30384	2/2/2003	PHOSPHATE, ROCK, BULK	39202	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	30399	2/3/2003	COAL	23174	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	30415	2/3/2003	COAL	10361	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	30415	2/4/2003	COAL	20184	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	30415	2/5/2003	PHOSPHATE, ROCK, BULK	32176	E	L	4103	LA	D	TPA	AGRI
MARIE FLOOD	30451	2/7/2003	COAL	36666	I	U	4101	TPA	D	LA	TEBB
WANDA WHEELOC	30459	2/7/2003	COAL	18074	I	U	4144	TPA	D	LA	TEGA
WANDA WHEELOC	30459	2/9/2003	PHOSPHAT CHEMICAL, BULK	9002	E	L	4110	LA	D	TPA	GARD
MARY TURNER	30469	2/10/2003	COAL	27168	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	30469	2/10/2003	PHOSPHATE, ROCK, BULK	40871	E	U	4103	LA	D	TPA	AGRI
DIANE LUDWIG	30487	2/11/2003	COAL	22421	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	30489	2/11/2003	COAL	18511	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	30520	2/12/2003	COAL	33447	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	30520	2/13/2003	PHOSPHAT CHEMICAL, BULK	34497	E	L	204	LA	D	TPA	CFI
DANA DUNN	30522	2/13/2003	PHOSPHATE, ROCK, BULK	24029	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	30578	2/17/2003	COAL	30578	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	30578	2/18/2003	PHOSPHATE, ROCK, BULK	30578	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	30580	2/17/2003	COAL	22059	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	30580	2/18/2003	PHOSPHAT CHEMICAL, BULK	10519	E	L	4103	LA	D	TPA	AGRI
WANDA WHEELOC	30587	2/19/2003	COAL	18359	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	30594	2/19/2003	COAL	28237	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	30594	2/20/2003	PHOSPHATE, ROCK, BULK	37757	E	L	4103	LA	D	TPA	AGRI

DANA DUNN	30629	2/21/2003	PHOSPHATE, ROCK, BULK	23914	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	30662	2/24/2003	COAL	33617	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	30662	2/25/2003	PHOSPHAT CHEMICAL, BULK	34403	E	L	204	LA	D	TPA	CFI
WANDA WHEELOC	30669	2/26/2003	COAL	18725	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	30683	2/26/2003	COAL	16852	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	30683	2/27/2003	PHOSPHAT CHEMICAL, BULK	9000	E	L	4148	LA	D	TPA	EAT
BARBARA VAUGHT	30683	2/28/2003	PHOSPHAT CHEMICAL, BULK	5876	E	L	4110	LA	D	TPA	GARD
GAYLE EUSTACE	30685	2/26/2003	COAL	10301	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	30685	2/27/2003	COAL	21407	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	30685	3/1/2003	PHOSPHATE, ROCK, BULK	31736	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	30735	3/2/2003	SEAWATER, BULK	1063	I	U	271	TPA	F	LA	GARR
MARY TURNER	30735	3/2/2003	COAL	28127	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	30735	3/3/2003	PHOSPHATE, ROCK, BULK	39245	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	30800	3/9/2003	COAL	31248	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	30800	3/10/2003	PHOSPHATE, ROCK, BULK	32854	E	L	4103	LA	D	TPA	AGRI
WANDA WHEELOC	30820	3/10/2003	COAL	18581	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	30822	3/10/2003	COAL	34688	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	30822	3/11/2003	PHOSPHAT CHEMICAL, BULK	19500	E	L	4110	UNK	F	TPA	GARD
PEGGY PALMER	30822	3/13/2003	PHOSPHAT CHEMICAL, BULK	10514	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	30834	3/11/2003	COAL	22359	I	U	4144	TPA	D	LA	TEGA
DIANE LUDWIG	30834	3/13/2003	PHOSPHAT CHEMICAL, BULK	22106	E	L	204	LA	D	TPA	CFI
DIANA T	30846	3/13/2003	COAL	16735	I	U	4144	TPA	D	LA	TEGA
DIANA T	30846	3/14/2003	PHOSPHATE, ROCK, BULK	26298	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	30857	3/14/2003	COAL	28046	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	30857	3/15/2003	PHOSPHATE, ROCK, BULK	38085	E	L	4103	LA	D	TPA	AGRI
MARIE FLOOD	30859	3/14/2003	COAL	36286	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	30898	3/18/2003	COAL	31655	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	30898	3/19/2003	PHOSPHATE, ROCK, BULK	32087	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	30959	3/20/2003	POTASH, BULK	6032	I	U	23	TPA	D	LA	PS
BARBARA VAUGHT	30959	3/21/2003	COAL	9597	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	30959	3/22/2003	PHOSPHAT CHEMICAL, BULK	18004	E	L	4110	LA	D	TPA	GARD
MARIE FLOOD	30961	3/20/2003	COAL	37018	I	U	4101	TPA	D	LA	TEBB
MARIE FLOOD	30961	3/22/2003	PHOSPHAT CHEMICAL, BULK	8710	E	L	4103	LA	D	TPA	AGRI
MARIE FLOOD	30961	3/23/2003	PHOSPHAT CHEMICAL, BULK	18070	E	L	4146	LA	D	TPA	ROCK
DIANA T	30964	3/22/2003	COAL	16407	I	U	4144	TPA	D	LA	TEGA
DIANA T	30964	3/23/2003	PHOSPHATE, ROCK, BULK	28620	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	30969	3/23/2003	COAL	22361	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	30971	3/24/2003	COAL	29221	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	30971	3/24/2003	PHOSPHATE, ROCK, BULK	38703	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	30977	3/22/2003	COAL	9290	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	30977	3/23/2003	COAL	25798	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	30977	3/24/2003	PHOSPHAT CHEMICAL, BULK	33889	E	L	204	LA	D	TPA	CFI
GAYLE EUSTACE	31014	3/26/2003	COAL	10955	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	31014	3/27/2003	COAL	20432	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	31014	3/28/2003	PHOSPHATE, ROCK, BULK	33523	E	L	4103	LA	D	TPA	AGRI
MARIE FLOOD	31060	3/31/2003	COAL	37949	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	31093	4/2/2003	COAL	36277	I	U	4101	TPA	D	LA	TEBB

MARY TURNER	31099	4/4/2003	PHOSPHATE, ROCK, BULK	38815	E	L	4103	LA	D	TPA	AGRI
DIANA T	31106	4/4/2003	COAL	16865	I	U	4144	TPA	D	LA	TEGA
DIANA T	31106	4/5/2003	PHOSPHATE, ROCK, BULK	28056	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	31127	4/5/2003	COAL	31127	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	31127	4/7/2003	PHOSPHATE, ROCK, BULK	32240	E	U	4103	LA	D	TPA	AGRI
PEGGY PALMER	31167	4/10/2003	COAL	34566	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31230	4/13/2003	COAL	28411	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31230	4/14/2003	PHOSPHATE, ROCK, BULK	38938	E	L	4103	LA	D	TPA	AGRI
DIANA T	31239	4/14/2003	COAL	17061	I	U	4144	TPA	D	LA	TEGA
DIANA T	31239	4/15/2003	PHOSPHATE, ROCK, BULK	28783	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	31255	4/16/2003	COAL	31321	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	31255	4/17/2003	PHOSPHATE, ROCK, BULK	32766	E	U	4103	LA	D	TPA	AGRI
PEGGY PALMER	31264	4/17/2003	COAL	35600	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	31264	4/18/2003	PHOSPHAT CHEMICAL, BULK	5975	E	L	4148	LA	D	TPA	EAT
MARY TURNER	31327	4/22/2003	COAL	28673	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31327	4/23/2003	PHOSPHATE, ROCK, BULK	38244	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	31334	4/22/2003	COAL	34990	I	U	4101	TPA	D	LA	TEBB
DIANE LUDWIG	31336	4/23/2003	COAL	22207	I	U	4144	TPA	D	LA	TEGA
DIANE LUDWIG	31336	4/24/2003	PHOSPHAT CHEMICAL, BULK	10514	E	L	4146	LA	D	TPA	ROCK
DIANA T	31346	4/24/2003	COAL	17054	I	U	4144	TPA	D	LA	TEGA
DIANA T	31346	4/25/2003	PHOSPHATE, ROCK, BULK	33039	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	31355	4/24/2003	COAL	34228	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	31371	4/25/2003	COAL	18942	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	31416	4/30/2003	COAL	34699	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	31428	5/1/2003	COAL	19116	I	U	4101	TPA	D	LA	TEBB
DIANE LUDWIG	31430	5/1/2003	COAL	22125	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31439	5/2/2003	COAL	27995	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31439	5/3/2003	PHOSPHATE, ROCK, BULK	38867	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	31460	4/26/2003	COAL	30779	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	31460	4/27/2003	PHOSPHATE, ROCK, BULK	33039	E	L	4103	LA	D	TPA	AGRI
DIANA T	31469	5/4/2003	COAL	15545	I	U	4101	TPA	D	LA	TEBB
DIANA T	31469	5/5/2003	PHOSPHATE, ROCK, BULK	29267	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	31480	5/5/2003	COAL	34525	I	U	4101	TPA	D	LA	TEBB
DIANE LUDWIG	31487	5/6/2003	COAL	22175	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31534	5/11/2003	COAL	28330	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31534	5/12/2003	PHOSPHATE, ROCK, BULK	38089	E	L	4103	LA	D	TPA	AGRI
DIANA T	31564	5/13/2003	COAL	16013	I	U	4101	TPA	D	LA	TEBB
DIANA T	31564	5/14/2003	PHOSPHATE, ROCK, BULK	28943	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	31568	5/14/2003	COAL	21538	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	31579	5/12/2003	COAL	35452	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	31579	5/17/2003	PHOSPHAT CHEMICAL, BULK	34389	E	L	204	LA	D	TPA	CFI
BARBARA VAUGHT	31587	5/14/2003	COAL	18477	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	31637	5/17/2003	COAL	21549	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	31637	5/19/2003	PHOSPHAT CHEMICAL, BULK	18907	E	L	4146	LA	D	TPA	ROCK
MARY TURNER	31640	5/19/2003	COAL	27947	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31640	5/21/2003	PHOSPHATE, ROCK, BULK	39341	E	L	4103	LA	D	TPA	AGRI
DIANA T	31664	5/21/2003	COAL	16729	I	U	4144	TPA	D	LA	TEGA

DIANA T	31664	5/22/2003	PHOSPHATE, ROCK, BULK	25903	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	31674	5/23/2003	COAL	18786	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	31674	5/25/2003	PHOSPHAT CHEMICAL, BULK	13109	E	L	4132	LA	F	TPA	IMC
PEGGY PALMER	31699	5/26/2003	COAL	35034	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	31732	5/27/2003	COAL	22396	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	31732	5/29/2003	PHOSPHAT CHEMICAL, BULK	22480	E	L	204	LA	D	TPA	CFI
MARY TURNER	31742	5/30/2003	COAL	27960	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31742	5/31/2003	PHOSPHATE, ROCK, BULK	38987	E	L	4103	LA	D	TPA	AGRI
DIANA T	31769	6/1/2003	COAL	15175	I	U	4101	TPA	D	LA	TEBB
DIANA T	31769	6/2/2003	PHOSPHATE, ROCK, BULK	28137	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	31777	5/31/2003	COAL	34366	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	31777	6/1/2003	PHOSPHAT CHEMICAL, BULK	34483	E	L	204	LA	D	TPA	CFI
PAT CANTRELL	31813	6/6/2003	COAL	32043	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	31825	6/8/2003	COAL	23795	I	U	4144	TPA	D	LA	TEGA
MARY TURNER	31838	6/9/2003	SEAWATER, BULK	1063	I	U	271	TPA	D	LA	GARR
MARY TURNER	31838	6/9/2003	COAL	30236	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31838	6/10/2003	PHOSPHATE, ROCK, BULK	38209	E	L	4103	LA	D	TPA	AGRI
DIANA T	31850	6/10/2003	COAL	17129	I	U	4101	TPA	D	LA	TEBB
DIANA T	31850	6/11/2003	PHOSPHATE, ROCK, BULK	28199	E		4103	LA	D	4101	AGRI
PEGGY PALMER	31862	6/11/2003	COAL	32828	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	31886	6/13/2003	COAL	13648	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	31886	6/14/2003	SLAG	5111	I	U	219	TPA	D	LA	KT
DIANE LUDWIG	31896	6/14/2003	COAL	21927	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31930	6/18/2003	COAL	29313	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	31930	6/19/2003	PHOSPHATE, ROCK, BULK	37949	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	31937	6/19/2003	COAL	21927	I	U	4101	TPA	D	LA	TEBB
DIANA T	31939	6/19/2003	COAL	16532	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	31946	6/20/2003	COAL	18535	I	U	4101	TPA	D	LA	TEBB
DORIS GUENTHER	31969	6/14/2003	COAL	22094	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	31990	6/23/2003	COAL	33894	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	31990	6/24/2003	PHOSPHAT CHEMICAL, BULK	28884	E	L	4148	LA	F	TPA	EAT
DIANE LUDWIG	31992	6/24/2003	COAL	22287	I	U	4101	TPA	D	LA	TEBB
DIANA T	31996	6/25/2003	COAL	15923	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	32038	6/26/2003	COAL	19034	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	32041	6/27/2003	COAL	35507	I	U	4101	TPA	D	LA	TEBB
SHEILA McDEVITT	32046	6/28/2003	COAL	30693	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	32052	6/28/2003	COAL	28871	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	32052	6/29/2003	PHOSPHATE, ROCK, BULK	37949	E	L	4103	LA	D	TPA	AGRI
DIANE LUDWIG	32060	6/30/2003	COAL	8930	I	U	4144	TPA	D	LA	TEGA
DIANA T	32062	6/30/2003	COAL	16805	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	32111	7/4/2003	COAL	34394	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	32111	7/5/2003	PHOSPHAT CHEMICAL, BULK	11999	E	L	4148	LA	D	TPA	EAT
PEGGY PALMER	32111	7/6/2003	PHOSPHAT CHEMICAL, BULK	2989	E	L	4110	LA	F	TPA	GARD
MARY TURNER	32115	7/6/2003	COAL	28243	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	32118	7/4/2003	COAL	33608	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	32118	7/6/2003	PHOSPHAT CHEMICAL, BULK	34070	E	L	204	LA	D	TPA	CFI
DIANA T	32126	7/6/2003	COAL	16458	I	U	4144	TPA	D	LA	TEGA

BARBARA VAUGHT	32155	7/10/2003	COAL	18733	I	U	4101	TPA	D	LA	TEBB
DIANA T	32164	7/11/2003	COAL	17114	I	U	4101	TPA	D	LA	TEBB
DIANA T	32164	7/11/2003	PHOSPHATE, ROCK, BULK	28209	E	U	4103	LA	D	TPA	AGRI
MARY TURNER	32180	7/13/2003	COAL	27113	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	32240	7/18/2003	COAL	28376	I	U	4101	TPA	D	LA	TEBB
DIANA T	32243	7/19/2003	COAL	15590	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	32301	7/22/2003	COAL	35882	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	32301	7/24/2003	PHOSPHAT CHEMICAL, BULK	33550	E	L	4148	LA	D	TPA	EAT
MARY TURNER	32306	7/23/2003	COAL	27278	I	U	4101	TPA	D	LA	TEBB
DIANA T	32317	7/25/2003	COAL	15714	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	32335	7/28/2003	COAL	31069	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	32351	7/29/2003	COAL	27764	I	U	4101	TPA	D	LA	TEBB
DIANA T	32381	7/30/2003	COAL	15991	I	U	4144	TPA	D	LA	TEGA
DIANA T	32381	8/8/2003	PHOSPHATE, ROCK, BULK	28365	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	32405	8/2/2003	COAL	10548	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	32405	8/3/2003	COAL	19660	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	32405	8/5/2003	PHOSPHATE, ROCK, BULK	32367	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	32415	8/4/2003	PHOSPHAT CHEMICAL, BULK	35653	E	L	204	LA	D	TPA	CFI
MARY TURNER	32429	8/5/2003	COAL	27346	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	32429	8/6/2003	PHOSPHATE, ROCK, BULK	38391	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	32454	8/8/2003	COAL	17453	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	32487	8/8/2003	COKE	32837	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	32487	8/11/2003	PHOSPHAT CHEMICAL, BULK	34496	E	L	204	LA	D	TPA	CFI
GAYLE EUSTACE	32508	8/13/2003	COAL	31228	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	32508	8/14/2003	PHOSPHATE, ROCK, BULK	31907	E	U	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	32513	8/15/2003	COAL	35011	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	32521	8/15/2003	COAL	13437	I	U	4144	TPA	D	LA	TEGA
BARBARA VAUGHT	32521	8/17/2003	SLAG	4939	I	U	23	TPA	D	LA	PS
DIANA T	32560	8/17/2003	COAL	16576	I	U	4144	TPA	D	LA	TEGA
DIANA T	32560	8/19/2003	PHOSPHATE, ROCK, BULK	28758	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	32562	8/18/2003	COAL	26932	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	32562	8/19/2003	PHOSPHATE, ROCK, BULK	39271	E	U	4103	LA	D	TPA	AGRI
PAT CANTRELL	32602	8/21/2003	COAL	34896	I	U	4101	TPA	D	LA	TEBB
PAT CANTRELL	32602	8/22/2003	PHOSPHAT CHEMICAL, BULK	7929	E	L	4110	LA	D	TPA	GARD
GAYLE EUSTACE	32605	8/23/2003	COAL	31217	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	32605	8/24/2003	PHOSPHATE, ROCK, BULK	33172	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	32623	8/22/2003	COAL	9315	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	32623	8/23/2003	COAL	28763	I	U	4144	TPA	D	LA	TEGA
PEGGY PALMER	32623	8/25/2003	PHOSPHAT CHEMICAL, BULK	34502	E	L	204	LA	D	TPA	CFI
BARBARA VAUGHT	32625	8/23/2003	COAL	18653	I	U	4144	TPA	D	LA	TEGA
PAT CANTRELL	32672	8/31/2003	COAL	36079	I	U	4101	TPA	D	LA	TEBB
DIANA T	32684	8/28/2003	COAL	16395	I	U	4101	TPA	D	LA	TEBB
DIANA T	32684	8/29/2003	PHOSPHATE, ROCK, BULK	28256	E	L	4103	LA	D	TPA	AGRI
MARY TURNER	32689	8/27/2003	COAL	28997	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	32689	8/28/2003	PHOSPHATE, ROCK, BULK	38035	E	L	4103	LA	D	TPA	AGRI
GAYLE EUSTACE	32703	9/2/2003	COAL	29841	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	32703	9/3/2003	PHOSPHATE, ROCK, BULK	33495	E	L	4103	LA	D	TPA	AGRI

DIANA T	32740	9/7/2003	COAL	16043	I	U	4144	TPA	D	LA	TEGA
DIANA T	32740	9/8/2003	PHOSPHATE, ROCK, BULK	28426	E	L	4103	LA	D	TPA	AGRI
PAT CANTRELL	32743	9/6/2003	COAL	34970		U	4101	TPA	D	LA	TEBB
PAT CANTRELL	32743	9/7/2003	PHOSPHAT CHEMICAL, BULK	34498	E	L	204	LA	D	TPA	CFI
MARY TURNER	32745	9/6/2003	COAL	27678	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	32745	9/8/2003	PHOSPHATE, ROCK, BULK	37616	E	L	4103	LA	D	TPA	AGRI
BARBARA VAUGHT	32764	9/4/2003	GRAINS, NOS, BULK	9464	I	U	256	TPA	D	LA	CARG
BARBARA VAUGHT	32764	9/6/2003	COAL	8613	I	U	4101	TPA	D	LA	TEBB
BARBARA VAUGHT	32764	9/10/2003	PHOSPHAT CHEMICAL, BULK	17600	E	L	4146	LA	F	TPA	ROCK
GAYLE EUSTACE	32794	9/11/2003	COAL	14828	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	32794	9/12/2003	COAL	16355	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	32794	9/13/2003	PHOSPHATE, ROCK, BULK	31853	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	32806	9/9/2003	COAL	34494	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	32806	9/12/2003	PHOSPHAT CHEMICAL, BULK	6005	E	L	4148	LA	D	TPA	EAT
PEGGY PALMER	32806	9/13/2003	PHOSPHAT CHEMICAL, BULK	21012	E	L	4110	LA	D	TPA	GARD
DIANA T	32821	9/15/2003	COAL	15695	I	U	4144	TPA	D	LA	TEGA
DIANA T	32821	9/16/2003	PHOSPHATE, ROCK, BULK	28594	E	L	4103	LA	D	TPA	AGRI
DORIS GUENTHER	32830	9/16/2003	COAL	22013	I	U	4144	TPA	D	LA	TEGA
DORIS GUENTHER	32830	9/17/2003	PHOSPHAT CHEMICAL, BULK	22503	E	L	204	LA	D	TPA	CFI
MARY TURNER	32832	9/16/2003	COAL	27404	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	32832	9/17/2003	PHOSPHATE, ROCK, BULK	38105	E	L	4103	LA	D	TPA	AGRI
SHEILA McDEVITT	32855	9/19/2003	COAL	36007	I	U	4101	TPA	D	LA	TEBB
JUDY LITRICO	32857	9/18/2003	COAL	29019	I	U	4101	TPA	D	LA	TEBB
JUDY LITRICO	32857	9/19/2003	PHOSPHAT CHEMICAL, BULK	28827	E	L	4146	LA	D	TPA	ROCK
GAYLE EUSTACE	32899	9/21/2003	COAL	10460	I	U	4101	TPA	D	LA	TEBB
GAYLE EUSTACE	32899	9/22/2003	COAL	19012	I	U	4144	TPA	D	LA	TEGA
GAYLE EUSTACE	32899	9/25/2003	PHOSPHATE, ROCK, BULK	32320	E	L	4103	LA	D	TPA	AGRI
DIANA T	32904	9/23/2003	COAL	15713	I	U	4144	TPA	D	LA	TEGA
DIANA T	32904	9/24/2003	PHOSPHATE, ROCK, BULK	28252	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	32906	9/23/2003	COAL	33474	I	U	4101	TPA	D	LA	TEBB
PEGGY PALMER	32906	9/25/2003	PHOSPHAT CHEMICAL, BULK	4509	E	L	4103	LA	D	TPA	AGRI
PEGGY PALMER	32906	9/26/2003	PHOSPHAT CHEMICAL, BULK	19501	E	L	4110	LA	D	TPA	GARD
MARY TURNER	32918	9/25/2003	SEAWATER, BULK	1063	I	U	271	TPA	D	LA	GARR
MARY TURNER	32918	9/26/2003	COAL	27936	I	U	4101	TPA	D	LA	TEBB
MARY TURNER	32918	9/27/2003	PHOSPHATE, ROCK, BULK	39459	E	L	4103	LA	D	TPA	AGRI
PAT CANTRELL	32932	9/26/2003	PHOSPHAT CHEMICAL, BULK	34448	E	L	204	LA	D	TPA	CFI

CONFIDENTIAL

(MJM-3)	**CONFIDENTIAL,** Backhaul calculation

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 16
COMPANY/ OPC/FIPUG
WITNESS: MJM-3
DATE: 05/27-28/04

Tampa Electric Company Waterborne Coal Transportation

Calculation of Ocean Rate by Vessel
Dibner Model with Backhaul and Preference Trade Premium Removed

		Vessel						
		Peggy Palmer	Gayle Eustace	Doris Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught
Backhaul Ratio Based on Days (Trips)	1/	51.16%	88.24%	38.46%	92.42%	26.47%	96.83%	38.89%
Tons to Big Bend @ 33 feet ST - Actual Delivery		33,700	32,000	21,500	28,000	22,000	16,000	18,500
Calculation of Time Charter								
TC Cost Base								
Preference TC								
Average TC (Dibner)								
TC Used								
Big Bend Delivery Analysis								
Time								
Voyage Time at Sea	2/							
Big Bend Unload in Free Days								
Load Rate as Above								
Shifting Time at Big Bend								
Channel Maneuvering/Docking/Undocking								
Delay @ 15% of Voyage Time at Sea	2/							
Total Time								
Voyage Rate Assessment								
Total Time Charter Expense	3/							
Fuel at Sea	2/							
Tug Generating Fuel	2/							
Barge Fuel	2/							
Lube Oil	2/							
Tug Assist at Davant								
Tug Assist at Big Bend								
Misc. Port Expenses								
Total Cost Per Voyage								
Per Short Ton (Big Bend)		$	$	$	$	$	$	$

1/ Percentage of round trips between LA and TPA that carried backhaul.
Based on Port of Tampa data. See Exhibit___(MJM-2), page 1.
2/ Adjusted for backhaul. Dibner amount less 1/2 backhaul percentage.
3/ Reflects Dibner calculated Time Charter rate without Preference Trade premium.

CONFIDENTIAL

Tampa Electric Company Waterborne Coal Transportation

Calculation of Average Ocean Rate
Dibner Model with Backhaul and Preference Trade Premium Removed

Barge	Est Rate	Capacity (000 Tons)	Tons/Yr (000)	Cum Tons (000)	Cum. Cost ($000)	Avg. Rate
Peggy Palmer	$				$	$
Mary Turner	$				$	$
Diane Ludwig	$				$	$
Doris Guenther	$				$	$
Gayle Eustace	$				$	$
Diana T	$				$	$
Barbara Vaught	$				$	$

Average Rate with No Preference Trade Premium and Backhaul Based on Days $

CONFIDENTIAL

Tampa Electric Company
Waterborne Coal Transportation

Adjustment of Dibner Average River Rate
For Backhaul

	Dibner a	Average Ocean Backhaul b	Dibner Adjusted c
Patriot	[redacted]	69.34%	[redacted]
Powhatan Pt		69.34%	
Southern IN		69.34%	
Overland Camp Dock		69.34%	
Shawneetown		69.34%	
DeKoven		69.34%	
Cook		69.34%	
Cora		69.34%	
Average	$		$

a = Dibner Report, page 41. See Exhibit___(MJM-3), page 4.
b = Average backhaul experienced by cross-Gulf vessels.
See Exhibit___(MJM-2), page 1.
c = a-(a*(b/2))

CONFIDENTIAL

ENTIRE DOCUMENT IS CONFIDENTIAL

21 West Church Street
Jacksonville, Florida 32202-3139

February 20, 2004

JEA

E C T R I C

A T E R ,

E W E R

STATE OF FLORIDA
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street
Room 812
Tallahassee, FL 32399-1400
Attn: Mr. R. Earl Poucher
Senior Legislative Analyst

Dear Mr. Poucher:

Per your request to JEA on February 11, 2004 to provide specific billing information in our possession pertaining to purchases of coal and/or petcoke from Gulf Coast sources that identify the cost of transport as a separate item for the period starting with shipments received after January 1, 2002 to current, attached please find copies of the following invoices that apply to your request:

CUSTOMER	COMMODITY	INVOICE DATE
Energy Coal s.p.a.	Petcoke	09 24 2002
" " "	"	02 02 2003
SSM PETCOKE LLC	"	07 29 2003
" " "	"	08 07 2003
" " "	"	08 20 2003
" " "	"	09 26 2003
" " "	"	10 17 2003
" " "	"	10 29 2003

For your information, JEA received seven (6 petcoke, 1 coal) additional shipments during the period requested, however, none of the invoicing covering these deliveries identified the transport as a separate line item.

RECEIVED
FEB 2 6 2004
Office of
Public Counsel

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 17
COMPANY/ OPC/FIPUG
WITNESS: MJM-4
DATE: 05/27-28/04

PAGE 2,

Also attached, please find the notarized affidavit requested covering the information provided to your office from JEA.

Respectfully submitted,

Michael J. Crosse
Contract Fuels Administrator

cc: J.T. Myers
Ellen Becker

attch.

energy
coal s.p.a.

Viale Brigata Bisagno, 2 - 16129 GENOVA Italy
Tel. +39 010 5479.1 - Fax +39 010 5479.200 - Tlx 272526
E-mail: info@energycoal.com

Cap. Soc. € 3.600.000 i.v.
Cod. Fisc. e Partita IVA IT 03647280100
C.C.I.A.A. GE 366577 - Registro delle Imprese di Genova n. 50511-1997

JEA - JE Tower 11th floor
21 West Church Street
JACKSONVILLE, FL 32202-3139 USA

	N. ORDINE/*ORDER NR.*	TIPO/*TYPE*	N. PAG.	N. FATTURA/*INVOICE*	DATA/*DATE*
		FATTURA	1	V1 200356	24/09/02

CODICE/*CODE*	COD. FISC. - P. IVA/*FISCAL CODE*	RIF. ORDINE/*ORDER NR.*
2171		PURCHASE AGREEMENT DD. 3/09/02

CONDIZIONI DI PAGAMENTO/*PAYMENT TERMS*	BANCA D'APPOGGIO/*BANK*
15 CALENDAR DAYS FROM B/L	

CODICE ART./*CODE*	DESCRIZIONE/*DESCRIPTION*	U.M.	QUANTITÀ/*QUANTITY*	PREZZO UNIT./*UNIT PRICE*	IMPORTO/*AMOUNT*	C.
	M/V SHEILA MCDEVITT - B/L 24/09/02 ST. 37.907,074 (MT 34.388,76) OF PETROLEUM COKE FROM PT. ARTHUR, TX - CIF JACKSONVILLE, FL FOB PRICE : USD 10,49/ST FREIGHT AND INSURANCE : USD 9,00/ST UNIT PRICE USD 19,49/ST					
1012171	ST 37.907,074 X USD 19,49/ST =				USD 738.808,87	N
	UNRATEABLE VALUE AS PER ART. 7 COMMA 1 DPR. 633 DATED 26/10/72 AND SUBS. MODIF. STAMPS EURO 1.29 ON THE ORIGINAL PLEASE DISPOSE PAYMENT WITHIN OCTOBER 9TH, 2002 ON: COMIT NEW YORK SWIFT CODE : BCITUS33 for : BANCA INTESA BCI RETE CARIPLO GENOA BRANCH ACCOUNT NR. 161834 Swift Code : b c i t i t 3 3 4 7 5					

MARCA DA BOLLO 2 SET 2002 1,29 Euro

IMPONIBILE FISCALE/*TAXABLE VALUE*	IVA/*VAT*	IMPORTO IVA/*VAT AMOUNT*
738.808,87	NON SOGG. ART 7	

CL to pay jlh 10/1/0

IMPONIBILE/*AMOUNT*	TOT. IMPORTI IVA/*VAT AMOUNT*	BOLLO/*STAMP*		TOTALE DOCUMENTO/*TOTAL AMOUNT*
			USD	738.808,87

Valuta Fissa a Nostro Favore: 09/10/02

energy coal s.p.a.
Viale Brigata Bisagno, 2 - 16129 GENOVA Italy
Tel. +39 010 5479.1 - Fax +39 010 5479.200 - Tlx 272526
E-mail: info@energycoal.com
Cap. Soc. € 3.600.000 i.v.
Cod. Fisc. e Partita IVA IT 03647280100
C.C.I.A.A. GE 366577 - Registro delle Imprese di Genova n. 50511-1997

JEA - JEA Tower 11th floor
21 West Church Street
JACKSONVILLE, FL 32202-3139 USA

	N. ORDINE/*ORDER NR.*	TIPO/*TYPE*	N. PAG.	N. FATTURA/*INVOICE*	DATA/*DATE*
		FATTURA	1	V1 300084	28/02/03

CE/*CODE*	COD. FISC. - P. IVA/*FISCAL CODE*	RIF. ORDINE/*ORDER NR.*
2171		

DIZIONI DI PAGAMENTO/*PAYMENT TERMS*	BANCA D'APPOGGIO/*BANK*
35 CALENDAR DAYS FROM B/L	

DICE ART./*CODE*	DESCRIZIONE/*DESCRIPTION*	U.M.	QUANTITÀ/*QUANTITY*	PREZZO UNIT./*UNIT PRICE*	IMPORTO/*AMOUNT*	C. IV.
	M/V MARIE FLOOD - B/L 27/02/03					
	ST. 32.488.983 OF PETROLEUM COKE					
	FROM PT. ARTHUR. TX - CIF JACKSONVILLE, FL					
	FOB PRICE : USD 18,53/ST					
	FREIGHT AND INSURANCE : USD 9,00/ST					
	UNIT PRICE USD 27,53/ST					
13042	ST 32.488,983 X USD 27,53/ST =				USD 894.421,70	NS
	UNRATEABLE VALUE AS PER ART. 7					
	COMMA 1 DPR. 633 DATED 26/10/72					
	AND SUBS. MODIF.					
	STAMPS EURO 1.29 ON THE ORIGINAL					
	PLEASE DISPOSE PAYMENT WITHIN MARCH 14TH, 2003 ON:					
	AMERICAN EXPRESS BANK					
	SWIFT CODE : aeibus33					
	for : MONTE DEI PASCHI DI SIENA - HEAD OFFICE IN GENOA					
	CAB 01400 - ABI 01030 - ACCOUNT N. 40997.50					
	Swift Code : pascitmmgen					

MARCA DA BOLLO 1,29 Euro 28/02/2003

ONIBILE FISCALE/*TAXABLE VALUE*	IVA/*VAT*	IMPORTOIVA/*VAT AMOUNT*
894.421,70	NON SOGG.ART 7	

IMPONIBILE/*AMOUNT*	TOT. IMPORTI IVA/*VAT AMOUNT*	BOLLO/*STAMP*		TOTALE DOCUMENTO/*TOTAL AMOUNT*
			USD	894.421,70

Valuta Fissa a Nostro Favore: 14/03/03

Docket 031033-EI
Majoros Exhibits No. 4
MJM-4 Page 5 of 11
JEA Data

RECEIVED-J.E.A.
ACCOUNTS PAYABLE
03 AUG -8 AM 9:22

SSM PETCOKE LLC

10500 Little Patuxent Parkway
Suite 510
Columbia, MD 21044
Tel: 410-910-0640
Fax: 410-910-0630

Invoice No. P429B
Invoice Date 08/06/03

Rec'd 8/11/03

Bill To:
Jacksonville Electric Authority
Accounts Payable
P.O. Box 4910
Jacksonville, FL 32201-4910
USA

Ship To:
Jacksonville Electric Authority
JEA Northside Marine Facility
Jacksonville, FL
USA

Ship Date	Sold To	Ship Via	Payment Terms
07/29/03	Sheila McD	CIF NSMF	Net 30 Days

Contract Number	SSM Customer Number	Billing Code
47824	6830222	JEA

CHEVRON PASCAGOULA PETCOKE	NT	38288.020	7.300	279,502.55
OCEAN FREIGHT	NT	38288.020	9.000	344,592.18
S LFUR ADJUSTMENT ST.40 x (6.50 - 5.97) = $0.742/NT	NT	38288.020	0.742	28,409.71
BTU ADJUSTMENT $7.30 x (14,361 - 14,000) / 14,000 = $0.19/NT	NT	38288.020	0.190	-7,274.72

a: M/V Sheila McDevitt
B/L Date: July 29, 2003
L Weight: 38,288.02 NT
oisture: 4.88%
Sulfur AR: 5.97%
TU AR: 14,361
GI: 36

Please remit payment via telegraphic transfer to:
UNTRUST BANK, ATLANTA, GA, U.S.A.
wift Code: SNTRUS3A
ABA Routing Number: 061000104
Account Name: SSM Petcoke LLC
ccount Number: 209188707

Jessica Killingsworth
904-7345
8/8

Non Taxable Subtotal	659,779.16
Taxable Subtotal	0.00
Tax	0.00
Total Invoice - USD	$659,779.16

Print Date: 08/06/03 2:55 PM Customer Original (Reprinted)

SSM

ill To:
Jacksonville Electric Authority
Accounts Payable
P.O. Box 4910
Jacksonville, FL 32201-4910
USA

Ship To:
Jacksonville Electric Authority
JEA Northside Marine Facility
Jacksonville, FL
USA

Invoice No. 1437
Invoice Date 08/25/03

B/L Date	Ship Via	Shipping Terms	Payment Terms
08/07/03	Pat Cantrell	CIF NSMF	Net 30 Days

Customer Purchase Order Number	SSM order Number	Customer	Due Date
47824	6830222	JEA	

Item Description	Unit of Measure	Quantity Shipped	Unit Price	Extended Price
EVRON PASCAGOULA PETCOKE	NT	32,998.060	7.300	240,885.84
OCEAN FREIGHT	NT	33,670.820	9.000	303,037.38
J ADJUSTMENT 7.30 x (14,164 - 14,000) / 14,000 = $0.09/NT	NT	32,998.060	0.085	2,804.84
FUR ADJUSTMENT 1.40 x (6.50 - 5.88) = $0.87/NT	NT	32,998.060	0.868	28,642.32
Barge Pat Cantrell /L Date: August 7, 2003 /l Weight: 33,671.164 NT ture: 6.12% ulfur AR: 5.88% T AR: 14,164 36				

Nontaxable Subtotal	575,370.38
Taxable Subtotal	0.00
Tax	0.00
Total Invoice - USD	575,370.38

RE TRANSFER INSTRUCTIONS:
ank: SUNTRUST BANK, ATLANTA, GEORGIA, U.S.A.
v Code: SNTRUS3A
BA Routing Number: 061000104
count Name: SSM PETCOKE LLC
unt Number: 209188707

SSM Petcoke LLC
10500 Little
Patuxent Parkway
Suite #510
Columbia, MD 21044
TEL 410.910.0640
FAX 410.910.0630

Received 8/27/03
Receipt # 2C19713

RWE Trading

TKOI V1

From: Mark Innes

Bill To:
Jacksonville Electric Authority
Accounts Payable
P.O. Box 4910
Jacksonville, FL 32201-4910
USA

Ship To:
Jacksonville Electric Authority
JEA Northside Marine Facility
Jacksonville, FL
USA

Invoice No. 1447
Invoice Date 08/26/03

B/L Date	Ship Via	Shipping Terms	Payment Terms
08/20/03	Sheila McD 2		Net 30 Days

Customer Purchase Order Number	SSM order Number	Customer	Due Date
	6830222	JEA	

Item Description	Unit of Measure	Quantity Shipped	Unit Price	Extended Price
CHEVRON PASCAGOULA PETCOKE	NT	38,551.310	7.300	281,424.56
OCEAN FREIGHT	NT	38,551.310	9.000	346,961.79
BTU ADJUSTMENT 7.30 x (14,252 - 14,000) / 14,000 = $0.131/NT	NT	38,551.310	0.131	5,050.22
SULFUR ADJUSTMENT 1.40 x (6.50 - 5.88) = $0.868/NT	NT	38,551.310	0.868	33,462.54

Via: M/V Sheila McDevitt (V2)
B/L Date: August 20, 2003
B/L Weight: 38,551.49 Net Tons
Moisture: 5.43%
Sulfur AR: 5.88%
BTU AR: 14,252
HGI: 34

Nontaxable Subtotal	666,899.11
Taxable Subtotal	0.00
Tax	0.00
Total Invoice - USD	666,899.11

WIRE TRANSFER INSTRUCTIONS:
Bank: SUNTRUST BANK, ATLANTA, GEORGIA, U.S.A.
Swift Code: SNTRUS3A
ABA Routing Number: 061000104
Account Name: SSM PETCOKE LLC
Account Number: 209188707

RECEIPT # 202463

Bill To:

Jacksonville Electric Authority
Att Mike Cross, Jennifer Horn
21 West Church Street
Jacksonville, FL 32202-3139
USA

Ship To:

Jacksonville Electric Authority
JEA Northside Marine Facility
Jacksonville, FL
USA

Invoice No. 1518
Invoice Date 09/30/03

B/L Date	Ship Via	Shipping Terms	Payment Terms
9/26/03	Sheila McD		Net 30 Days

Customer Purchase Order Number	SSM order Number	Customer	Due Date
	6830222	JEA	

Item Description	Unit of Measure	Quantity Shipped	Unit Price	Extended Price
CHEVRON PASCAGOULA PETCOKE	MT	38,946.840	7.300	284,311.93
CLEAN FREIGHT	MT	38,946.840	9.000	350,521.56
FUEL ADJUSTMENT $1.30 x (14,129 - 14,000) / 14,000 = $0.067/NT	MT	38,946.840	0.067	2,609.44
SULFUR ADJUSTMENT $1.40 x (6.50 - 6.07) = $0.602/NT	MT	38,946.840	0.602	23,446.00

Vessel: M/V Sheila McDevitt
B/L Date: September 26, 2003
B/L Weight: 38,946.84 Net Tons
Moisture: 6.16%
Sulfur AR: 6.07%
BTU AR: 14,129
Coal: 36

Nontaxable Subtotal	660,888.93
Taxable Subtotal	0.00
Tax	0.00
Total Invoice - USD	660,888.93

WIRE TRANSFER INSTRUCTIONS:
Bank: SUNTRUST BANK, ATLANTA, GEORGIA, U.S.A.
Swift Code: SNTRUS3A
ABA Routing Number: 061000104
Account Name: SSM PETCOKE LLC
Account Number: 209188707

Rec'd FMS 10/13/03
Receipt # 206017

SSM Petcoke LLC
10500 Little
Patuxent Parkway
Suite #510
Columbia, MD 21044
TEL 410.910.0640
FAX 410.910.0630

Trading

To:
Jacksonville Electric Authority
tt Mike Cross, Jennifer Horn
l West Church Street
Jacksonville, FL 32202-3139
'SA

Ship To:
Jacksonville Electric Authority
JEA Northside Marine Facility
Jacksonville, FL
USA

Invoice No. 1547
Invoice Date 10/22/03

B/L Date	Ship Via	Shipping Terms	Payment Terms
10/17/03	Shiela McD		Net 30 Days

Customer Purchase Order Number	SSM order Number	Customer	Due Date
	6830222	JEA	

Item Description	Unit of Measure	Quantity Shipped	Unit Price	Extended Price
EVRON PASCAGOULA PETCOKE	NT	39,009.960	7.300	284,772.71
OCEAN FREIGHT	NT	39,009.960	9.000	351,089.64
BTU ADJUSTMENT 7.30 x (14,077 - 14,000) / 14,000 = $0.040/NT	NT	39,009.960	0.040	1,560.40
SULFUR ADJUSTMENT 10 x (6.50 - 5.96) = $0.756	NT	39,009.960	0.756	29,491.53

Via: M/V Sheila McDevitt
B/ Date: October 17, 2003
B/C Weight: 39,009.96 Net Tons
Moisture: 6.75%
Sulfur AR: 5.96%
BTU AR: 14,077
HGI: 36

Nontaxable Subtotal	666,914.28
Taxable Subtotal	0.00
Tax	0.00
Total Invoice - USD	666,914.28

WIRE TRANSFER INSTRUCTIONS:
Bank: SUNTRUST BANK, ATLANTA, GEORGIA, U.S.A.
Swift Code: SNTRUS3A
ABA Routing Number: 061000104
Account Name: SSM PETCOKE LLC
Account Number: 209188707

SSM Petcoke LLC
10500 Little
Patuxent Parkway
Suite #510
Columbia, MD 21044
TEL 410.910.0640
FAX 410.910.0630

TMS Rec'd 11/4/03 Receipt #?

Bill To:
Jacksonville Electric Authority
tt Mike Cross, Jennifer Horn
1 West Church Street
Jacksonville, FL 32202-3139
SA

Ship To:
Jacksonville Electric Authority
JEA Northside Marine Facility
Jacksonville, FL
USA

Invoice No. 1575
Invoice Date 10/31/03

B/L Date	Ship Via	Shipping Terms	Payment Terms
10/29/03	Sheila McD		Net 30 Days

Customer Purchase Order Number	SSM order Number	Customer	Due Date
	6830222	JEA	

Item Description	Unit of Measure	Quantity Shipped	Unit Price	Extended Price
EVRON PASCAGOULA PETCOKE	NT	34,742.100	7.300	253,617.33
OCEAN FREIGHT	NT	34,742.100	9.000	312,678.90
BTU ADJUSTMENT 7 30 x (14,058 - 14,000) / 14,000 = $0.030/NT	NT	34,742.100	0.030	1,042.26
ULFUR ADJUSTMENT 10 x (6.50 - 6.06) = $0.616/NT	NT	34,742.100	0.616	21,401.13

Via: M/V Sheila McDevitt
Date: October 29, 2003
B/L Weight: 34,742.10 Net Tons
Moisture: 6.62%
Sulfur AR: 6.06%
BTU AR: 14,058
HGI: 35

Nontaxable Subtotal	588,739.62
Taxable Subtotal	0.00
Tax	0.00
Total Invoice - USD	588,739.62

WIRE TRANSFER INSTRUCTIONS:
Bank: SUNTRUST BANK, ATLANTA, GEORGIA, U.S.A.
Swift Code: SNTRUS3A
ABA Routing Number: 061000104
Account Name: SSM PETCOKE LLC
Account Number: 209188707

Rec'd FMS 11/10/03
Receipt # 206965

SSM Petcoke LLC
10500 Little
Patuxent Parkway
Suite #510
Columbia, MD 21044
TEL 410.910.0640
FAX 410.910.0630

AFFIDAVIT

STATE OF Florida

COUNTY OF Duval

BEFORE ME, the undersigned authority, personally appeared Michael J. Crosse, who deposed and stated that he/she provided the billing invoices for coal/petcoke purchases and coal/petcoke transport received by Jacksonville Electric Authority since January 1, 2002 to date, and are true and correct to the best of his/her information and belief.

DATED at 21 W. Church St. Jacksonville FL. 20th, this day of February, 2004. Michael J. Crosse (personally Known)

Sworn to and subscribed before me this 20th day of February, 2004.

Beverly A. Poole
NOTARY PUBLIC

State of Florida at Large

My Commission Expires: 3-15-05

Beverly A. Poole MY COMMISSION EXPIRES March 15, 2005 #DD004268 Bonded thru Troy Fain-Insurance NOTARY PUBLIC, STATE OF FLORIDA

CONFIDENTIAL

(MJM-5)	**CONFIDENTIAL**, Rate Matrix

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 18
COMPANY/ OPC/FIPUG
WITNESS: MJM-5
DATE: 05/27-28/04

Tampa Electric Company

Comparison of Rates

		TECO						JEA	SNAVELY KING
		Current (1)	Dibner (2)	CSXT Bid (3)	ACBL Bid (4)	IMT Bid (5)	Dibner Adjusted (6)	JEA Rates (7)	SK (8)
1.	River	[redacted]	[redacted]		[redacted]		[redacted]		[redacted]
2.	Terminal	[redacted]	[redacted]			[redacted]	[redacted]		[redacted]
3.	Ocean	[redacted]	[redacted]				[redacted]		[redacted]
4.	Total	[redacted]	[redacted]	14[redacted]			[redacted]		[redacted]
5.	Pet coke from East TX	1[redacted]	[redacted]					9.00	

Source by Column

Col. (1), Lines 1-3 - Dibner Report, page 68 (this reflects prior contract). See Exhibit___(MJM-5), page 2.
Col. (1), Line 5 - OPC's 1st Request for Production of Documents, Question 8, bates page 930. See Exhibit___(MJM-5), page 3.
Col. (2), Lines 1-3 - Dibner Report, page 68 (rates proposed to TECO Transport, not adjusted for error found later). See Exhibit___(MJM-5), page 2.
Col. (2), Line 5 - Dibner report, page 66. See Exhibit___(MJM-5), page 4.
Col. (3), Line 4 - McNulty October 23, 2003 testimony, conservative estimate vs. liberal estimate. See Exhibit___(MJM-5), page 5 for calculation.
Col. (4), Line 1 - Exhibit___(MJM-5), page 6.
Col. (5), Line 2 - Dibner report, page 50. See Exhibit___(MJM-5), page 8.
Col. (6), Lines 1 & 3 - Dibner ocean adjusted for backhaul and removal of preference premium. River adjusted for backhaul. See Exhibit___(MJM-3).
Col. (7), Line 5 - Exhibit___(MJM-4).
Col. (8), Lines 1 & 3 - Exhibit___(MJM-3).
Col. (8), Line 2 - Dibner Report, page 68 (this reflects prior contract). See Exhibit___(MJM-5), page 2.

Docket No. 031033-EI
Majoros Exhibit No. 5
(MJM-5) Page 1 of 8
Matrix of all available rates

ENTIRE DOCUMENT IS CONFIDENTIAL

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Tampa Electric Company

Calculation of Maximum Volume Discount
Per CSXT Bid

1.	Average Rail Rate	$ [redacted]
2.	Maximum Tons	[redacted]
3.	Total Maximum Charge (L. 1 * L. 2)	[redacted]
4.	Discount	$ [redacted]
5.	Discounted Tons	[redacted]
6.	Maximum Discount (L. 4 * L. 5)	$ [redacted]
7.	Total Discounted Charge (L. 3 - L. 6)	$ [redacted]
8.	Average Discounted Rate (L. 7 / L. 2)	$ [redacted]

Calculation of Average ACBL Bid

	Dibner 1/	ACBL 2/
Patriot	[redacted]	[redacted]
Powhatan Pt		
Southern IN		
Overland Camp Dock		
Shawneetown		
DeKoven		
Cook		
Cora		
Average	$ [redacted]	$ [redacted]

1/ Dibner report, page 41. See Exhibit___(MJM-3), page 4.
2/ Bates page 927 from OPC's 1st Request for POD, Q5. See Exhibit___(MJM-5), page 7

ENTIRE DOCUMENT IS CONFIDENTIAL

ENTIRE DOCUMENT IS CONFIDENTIAL

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Testimony and Exhibits of Michael J. Majoros, Jr. has been furnished by (*) hand delivery, (**) electronic mail or U.S. Mail this 29th day of March 2004, to the following:

(*) Wm. Cochran Keating IV
Florida Public Service Commission
Division of Legal Services
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399

(**) Mike Twomey
Post Office Box 5256
Tallahassee, Florida 32314-5256

(*) Lee L. Willis
James D. Beasley
Ausley & McMullen
227 S. Calhoun Street
Tallahassee, Florida 32302

(*) R. Sheffel Wright
Landers & Parsons
301 West College Avenue
Tallahassee, Florida 32301

Harold McLean
Public Counsel
Robert D. Vandiver
Associate Public Counsel

Office of Public Counsel
c/o the Florida Legislature
111 W. Madison Street
Room 812
Tallahassee, Florida 32399-1400
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Attorneys for the Florida Industrial
Power Users Group

ROBERT WHITE

201 Azalea Point Drive South
Ponte Vedra Beach, FL 32082

OBJECTIVE

To continue a successful management career which provides opportunity to create an atmosphere promoting team building and unity with a focus on providing safe, efficient, quality service to customers.

EXPERIENCE

CSX Transportation **2002 – Present**

Logistics Manager – Business Development

Reports to Assistant Vice President Coal

- Develop opportunities for CSXT to participate in new coal transportation service
- Develop infrastructure plans that allow CSXT to provide service to non rail receivers
- Analyze Utility South logistical issues and recommend solutions
- Assist Utility customers with internal logistical issues and develop solutions
- Deliver revenue goals for target accounts

Daily responsibilities include: Development of opportunities to participate in new rail business, participate in customer conference calls to address logistical issues, organize and direct consultants in development plans and engineering studies, organize internal teams to address service issues, daily customer interaction regarding service issues

Fed Ex Home Delivery **1999 - 2002**

Senior Manager, Regional Office, Irvine, CA

Reports to Western Regional Manager

- Orchestrated start-up terminal (Irvine) for new division of Fed Ex
- Regional Quality Team Leader/Trainer
- Cultivated team approach
- Developed Managers, both Assistants promoted to Terminal Managers in less than one year
- ISO 9002 Certified

Daily responsibilities include: Assembly and reporting of daily production statistics, manage staff of 41 people, including three managers, to ensure attainment of daily production goals, analyze reports to ensure timely and accurate data reporting, P&L responsibility, weekly interaction with sales representatives and participation in sales calls, daily customer interaction (recipient of six Blue Ribbon Awards for outstanding customer service)

Kinder Morgan Bulk Terminals **1999**

Consultant, Pier IX Terminal, Newport News, VA

Reported to Vice President of Operations

- Hired to review all aspects of Terminal Operations, Transportation and Marketing and to implement changes that positively impact the bottom line
- Reduced the workforce from 48 to 41 employees and reduced overtime, for a net annual savings in excess of $350K
- Facilitated changes in the Railroad transportation contract
- Changed accounting procedures to more accurately capture and segregate costs and instituted new reporting procedures
- Made numerous marketing contacts and stimulated activities which will lead to growth
- Identified and justified capital improvement projects in excess of $1M
- Reported activities weekly to Company Vice President
- Prepared and distributed Monthly Operating Report outlining achievements at the Terminal

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 031033-E EXHIBIT NO. 19
COMPANY/ CSX
WITNESS: RFW-1
DATE: 05/27-28/04

EXHIBIT NO. 19 (RFW-1)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 1 OF 3

Pacific Carbon Services **1997 - 1999**

VP and General Manager, Los Angeles, CA
Reported to Vice President of Operations

- Responsible for the daily operations, engineering, and maintenance of the new Los Angeles Export Terminal
- Hired and managed staff of 54 employees to operate and maintain the facility
- Cultivated and produced a team approach to operations and maintenance emphasizing cross-training
- Successfully built a non-union team in a strong union environment
- Responsible for Terminal P&L
- Managed daily and long term logistics of trains, trucks, and vessels
- Exceeded annual operating budget goals in the first two years of operation, despite a 20% shortfall in tonnage
- Maintained a perfect safety record

Daily responsibilities included: Reporting of production statistics, interaction with customers regarding scheduling and operational planning of trucks, trains and vessels, management of staff to ensure attainment of short and long term goals, tactical and strategic planning, management of daily operating budget (a unique system which captured all costs daily)

CSX Transportation **1977 – 1997**

Director Interline Service Scheduling, Jacksonville, FL
Reported to Vice President of Service Design

- Developed interline train plans (service agreements) with partner railroads
- Cultivated relationships with partner railroads to provide reliable, seamless service to customers
- Established measurements to ensure compliance with joint line train plans
- Developed system to create, store, and distribute Interline Service Agreements among all North American Railroads

Daily responsibilities included: coordinating with Service Design Department, field operations and partner railroad representatives to develop interline train plans, customer interaction to ensure that plans met or exceeded customer requirements, consistently exceeded goal of two interline service agreements per month.

Director Coal Operations, Jacksonville, FL
Reported to Vice President of Operations Center

- Responsible for daily planning and logistics of coal, coke and iron ore on the CSXT network
- Directly supervised 21 managers involved in the daily delivery of rail services to the largest commodity group
- Responsible for tactical and strategic planning of the coal network
- Direct customer contact for service-related issues
- Developed Coal Transportation Workstation to facilitate daily management of resources

Daily responsibilities included: management of the entire fleet of open top hoppers (in excess of 35,000 rail cars), compilation and reporting of daily performance statistics, directed 21 managers to ensure that rail car load per month goals were consistently met or exceeded, constant contact with customers to ensure that their expectations were met, coordinated with Sales and Marketing Department to develop new business opportunities

Director Bulk Terminals (Sales and Marketing Dept.) Baltimore, MD/Jacksonville, FL
Reported to Vice President of Coal Marketing

- Responsible for daily operations, engineering, and maintenance of three bulk-handling facilities with a total annual volume of 26 million tons
- Managed up to 350 employees including 21 management positions
- Led marketing efforts to increase tonnage levels and develop new markets at each facility
- Responsible for long-term planning and capital improvements
- Chief labor contract negotiator with International Longshoremen's Association
- Reduced employees by 30% due to effective labor negotiations

- Improved safety performance dramatically, including an unprecedented zero injury rate for a full year
- Consistently operated within the operating budget
- Instituted numerous programs to improve logistical performance of trains, trucks and vessels
- Chairman of Ore and Coal Exchange, an organization which coordinated the movement of all lake cargo between the North American railroads and the vessel owners
- Member of Corporate Safety Steering Committee

Daily responsibilities included: management of three World Class export facilities, compiled statistics and analyzed trends, ensured that terminals remained focused on short and long term goals, interacted with major customers to ensure that their expectations were met or exceeded, met with customers to develop business opportunities, communicated with Ore and Coal exchange to ensure customer satisfaction, coordinated daily train movements with Operations Center

EDUCATION

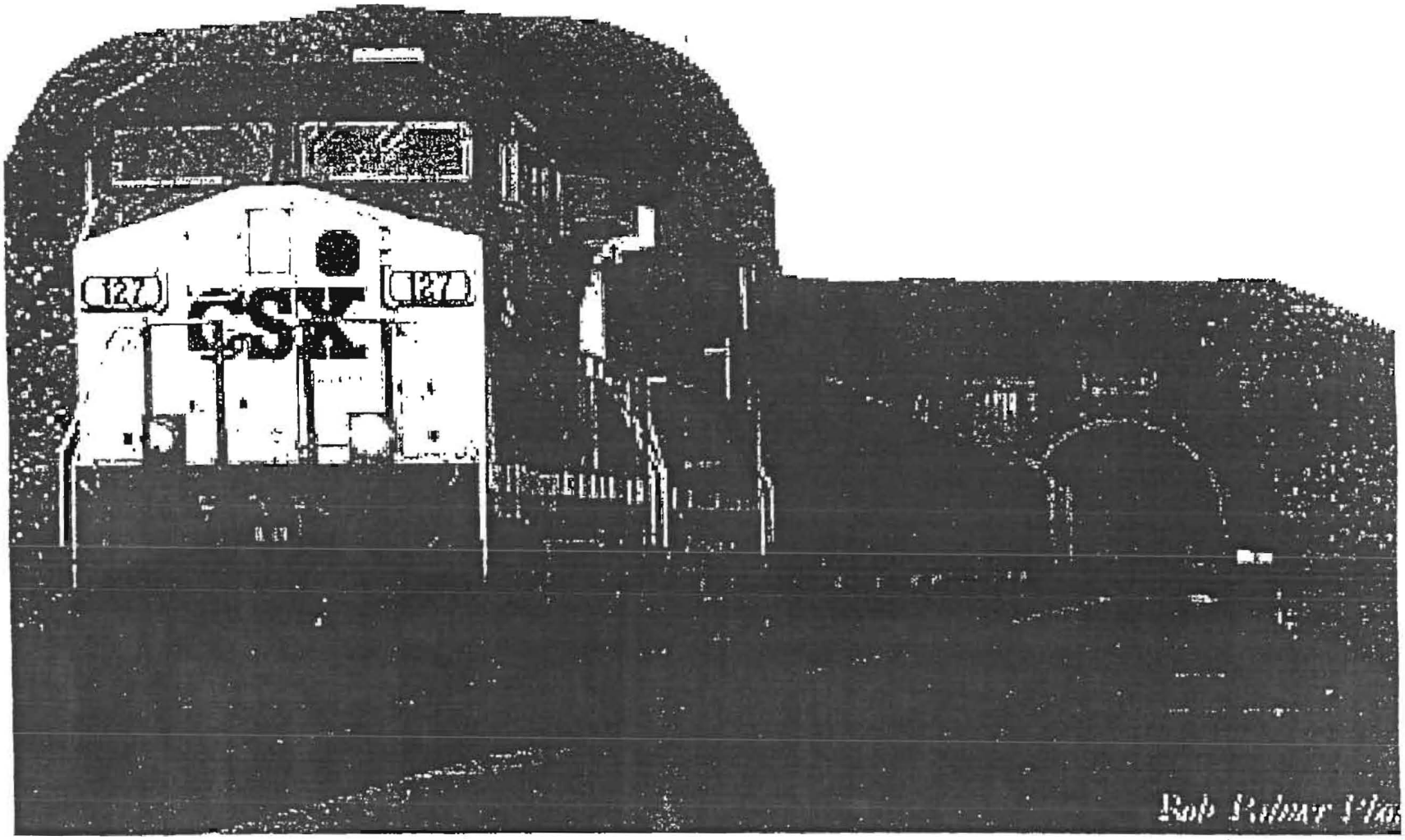
University of Baltimore, Baltimore, MD **1972 – 1976**

- Bachelor of Science Degree, Management

EXHIBIT NO. _____ (RFW-1)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 3 OF 3

CSXT & Coal

March 12, 2003



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 031033-EI EXHIBIT NO. 20
COMPANY/ CSX
WITNESS. RFW-2
DATE: 05/27-28/04

EXHIBIT NO. 20 (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 1 OF 23

CSX TRANSPORTATION

CSX Transportation

The Largest Railroad in Eastern North America

Serves all major markets in the eastern United States, and more ports than any other railroad

Operates 144 terminals

Covers 23,400 route miles in 23 states, the District of Columbia, and two Canadian Provinces

Operates a fleet of over 3,500 locomotives and 100,000 freight cars

Employs 35,000 dedicated individuals

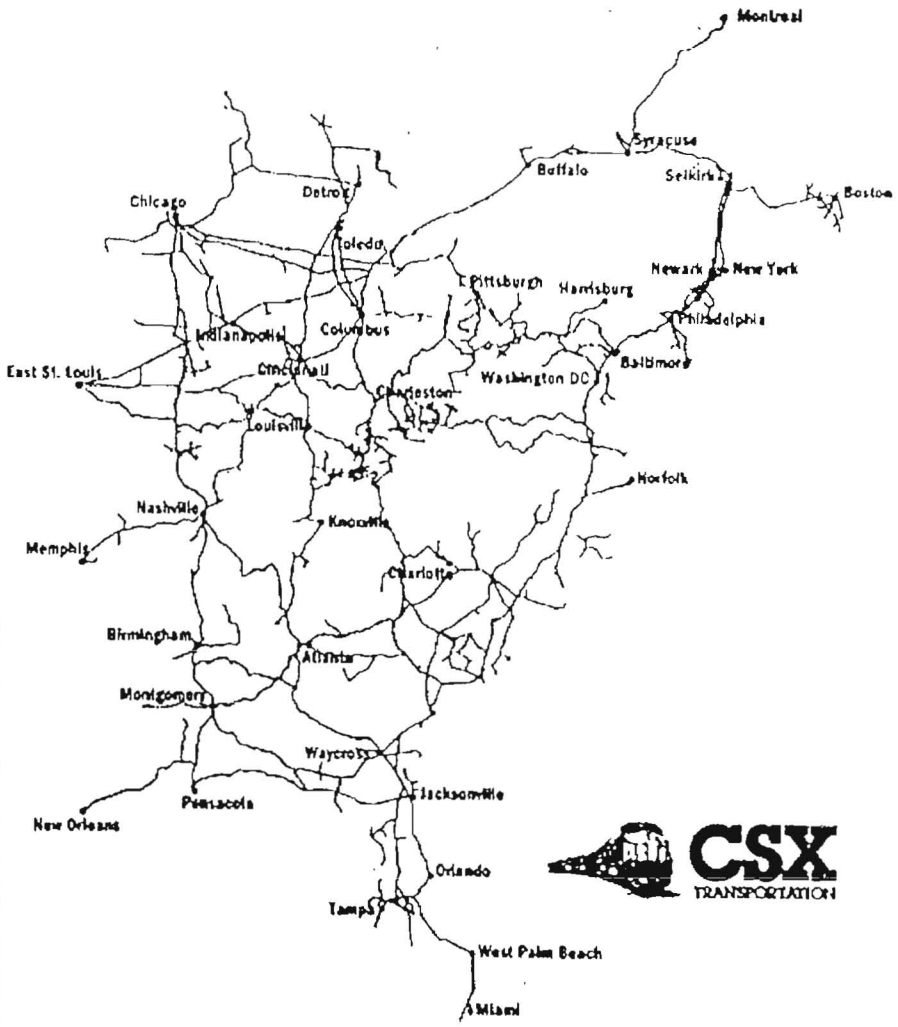
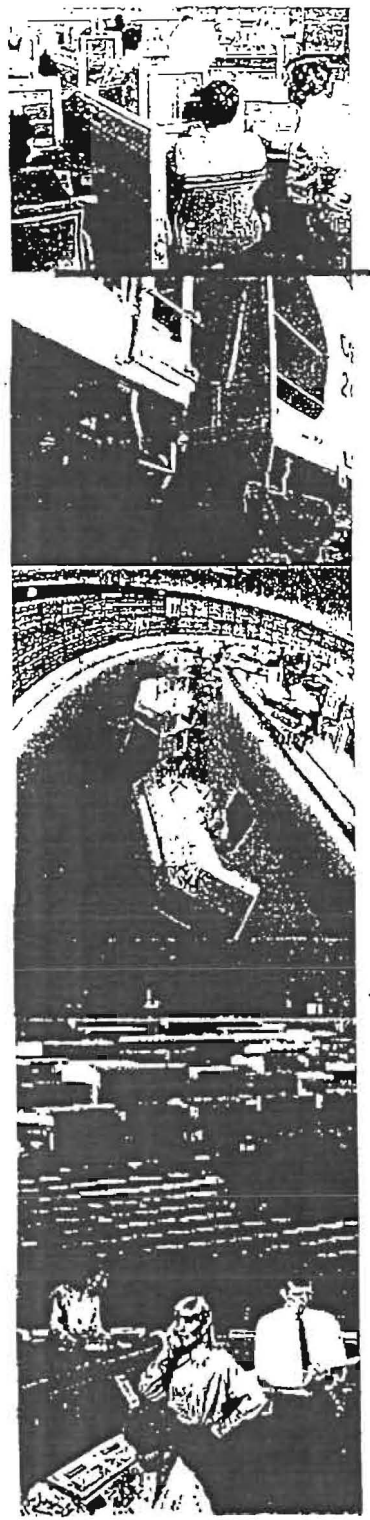


EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 2 OF 23



A review of our core ideology...

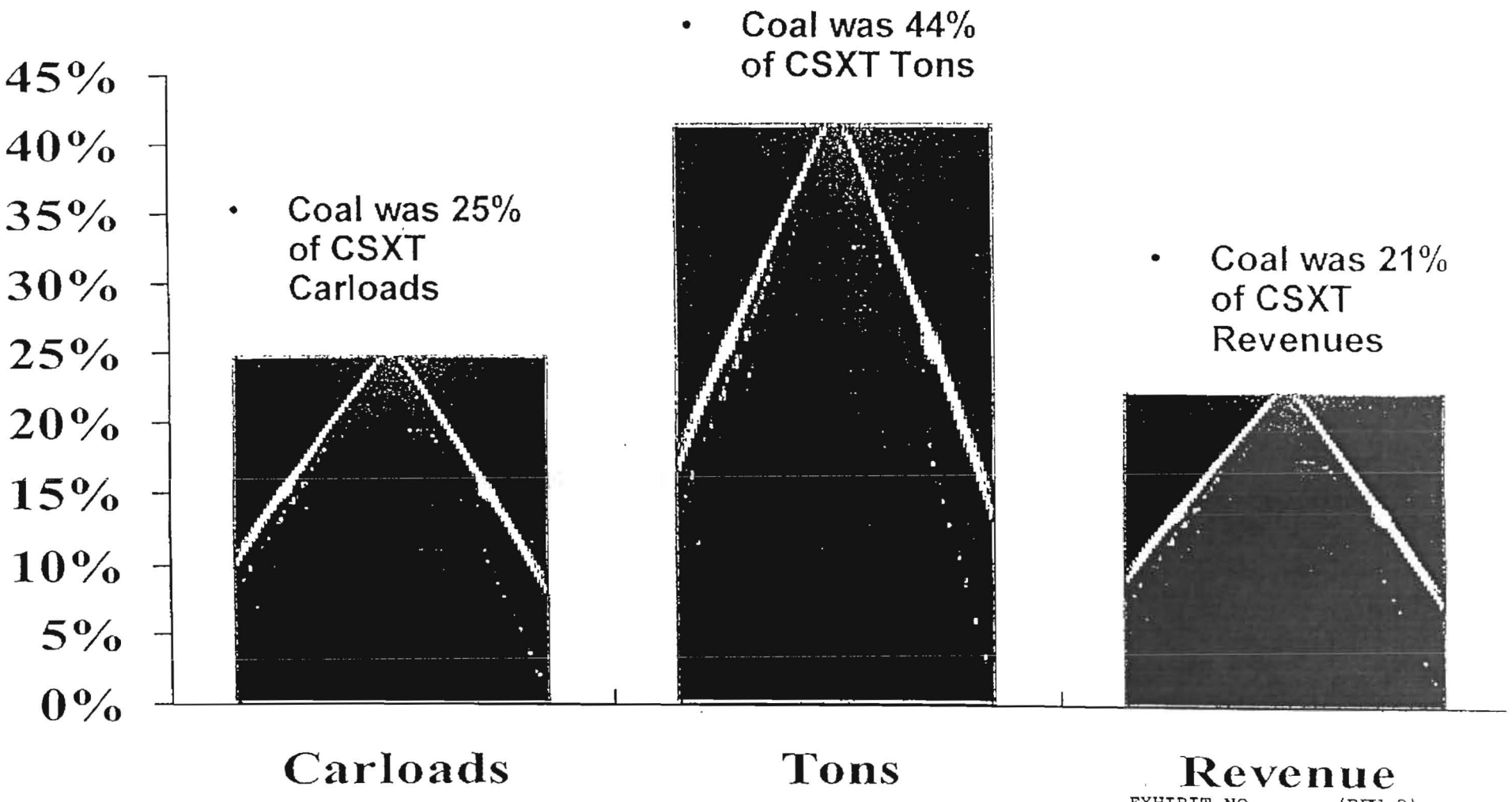
- Vision:
  - To be the safest, most progressive North American railroad, relentless in the pursuit of customer and employee excellence

- Purpose:
  - To capitalize on the efficiency of rail transportation to serve America

- Core Values:
  - It starts with the customer
  - People make the difference
  - Safety is a way of life
  - Fact - based
  - Right results; right way

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 3 OF 23

Coal is CSXT's backbone



Source: AAR March 2002

CSX TRANSPORTATION

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 4 OF 23

CSXT serves all of the major Eastern Coal reserves

- CSX serves reserves in all the states highlighted in gray

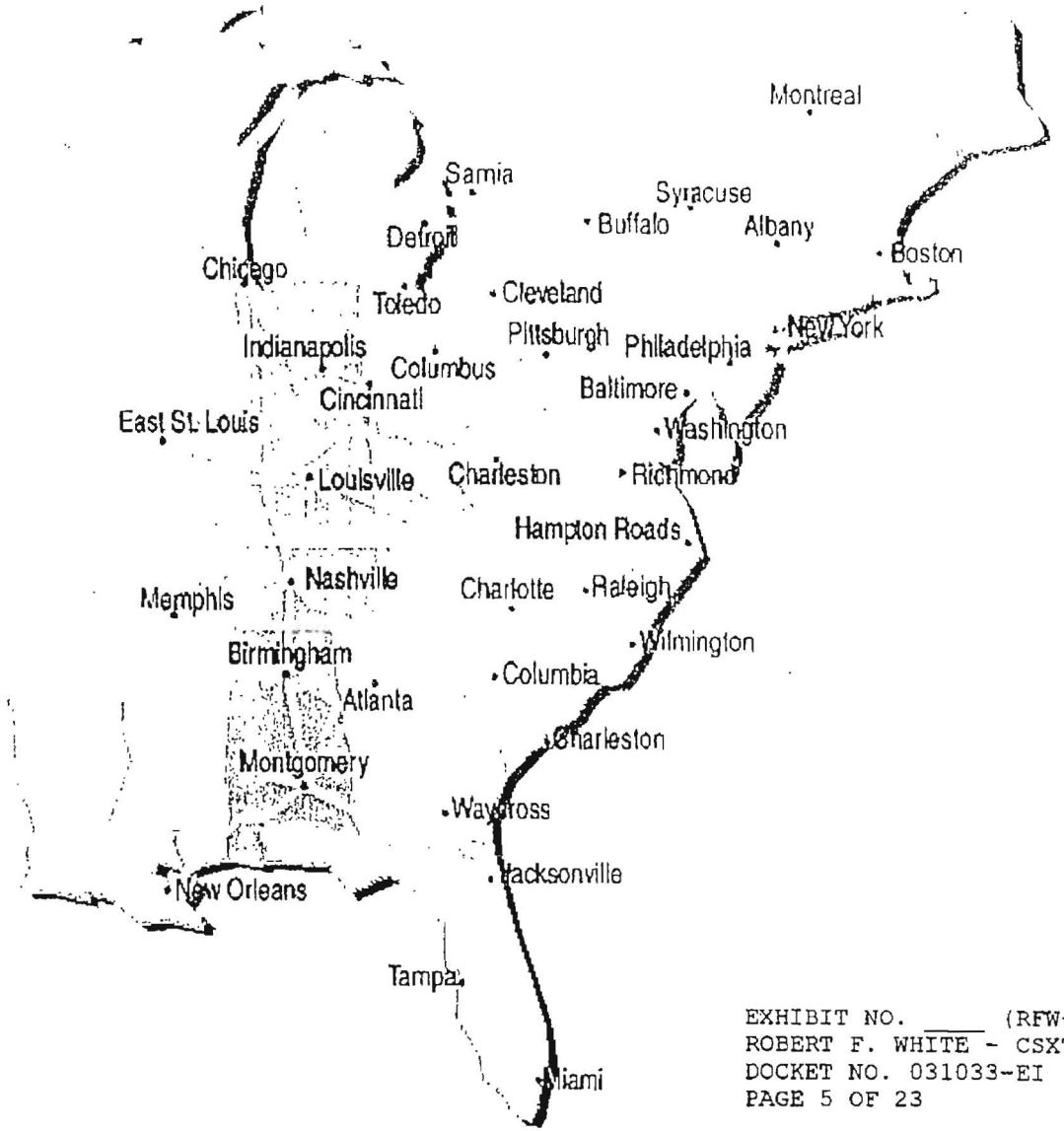


EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
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CSX TRANSPORTATION

CSXT's Coal geography has remained virtually constant 1991 thru 2000

- **CSXT has maintained its large coal field infrastructure to the benefit of consumers**
  - » **C&O/LN/SBD/Clinchfield/B&O largely unchanged during the decade**
- **Steam coal prices on CSXT continue to be reported as lower than other Eastern CAPP RR's**
- **CSXT continues to work with coal producers to develop, increase efficiencies and expand coal loadings on CSXT**

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
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CSX TRANSPORTATION

Roughly 3/4 th's of CSXT originated coal is former C&O/LN CAPP origins

- The consolidation and merger of Chessie and Seaboard has provided southeast buyers with the opportunity to source cheaper coals

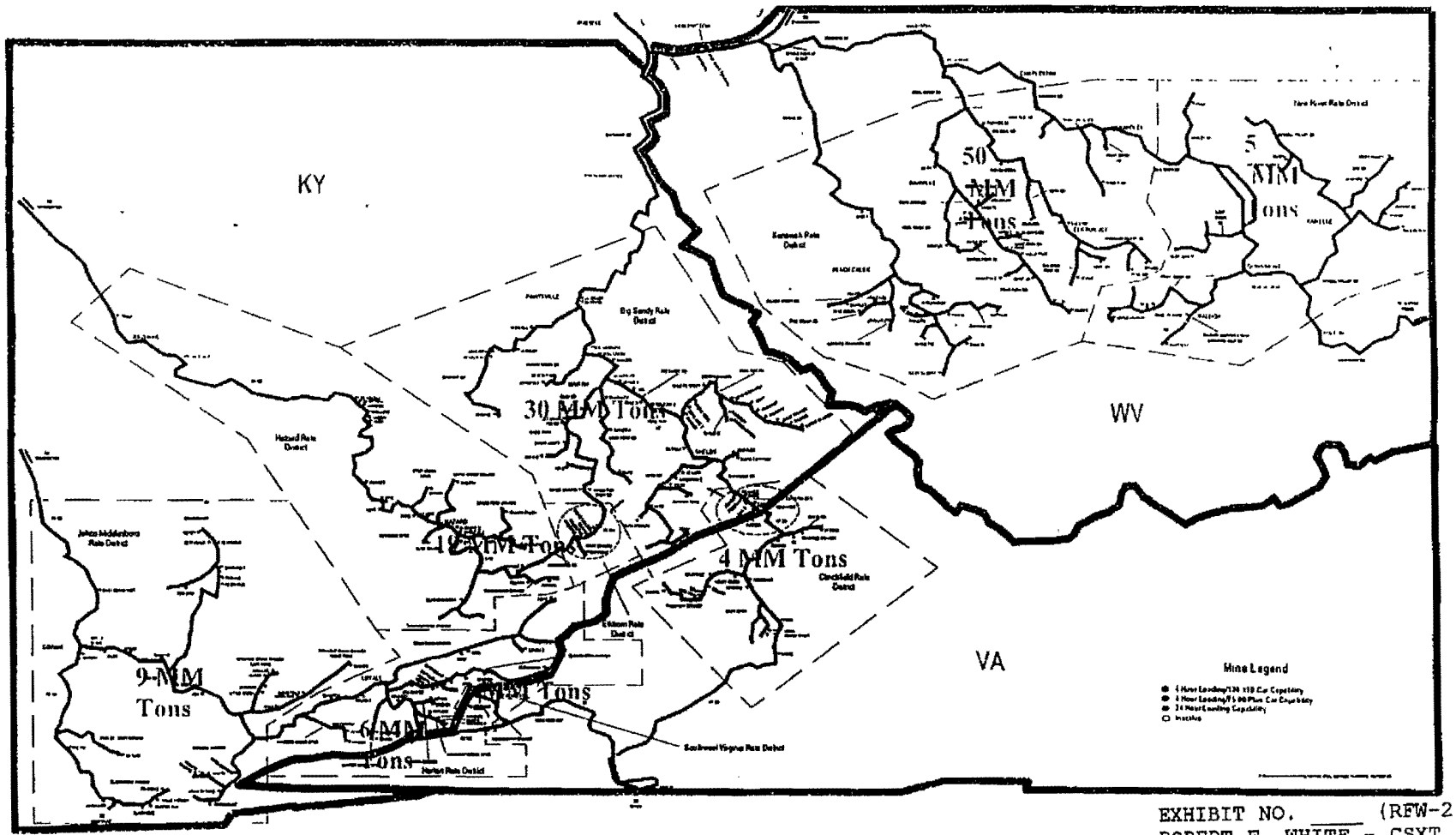

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
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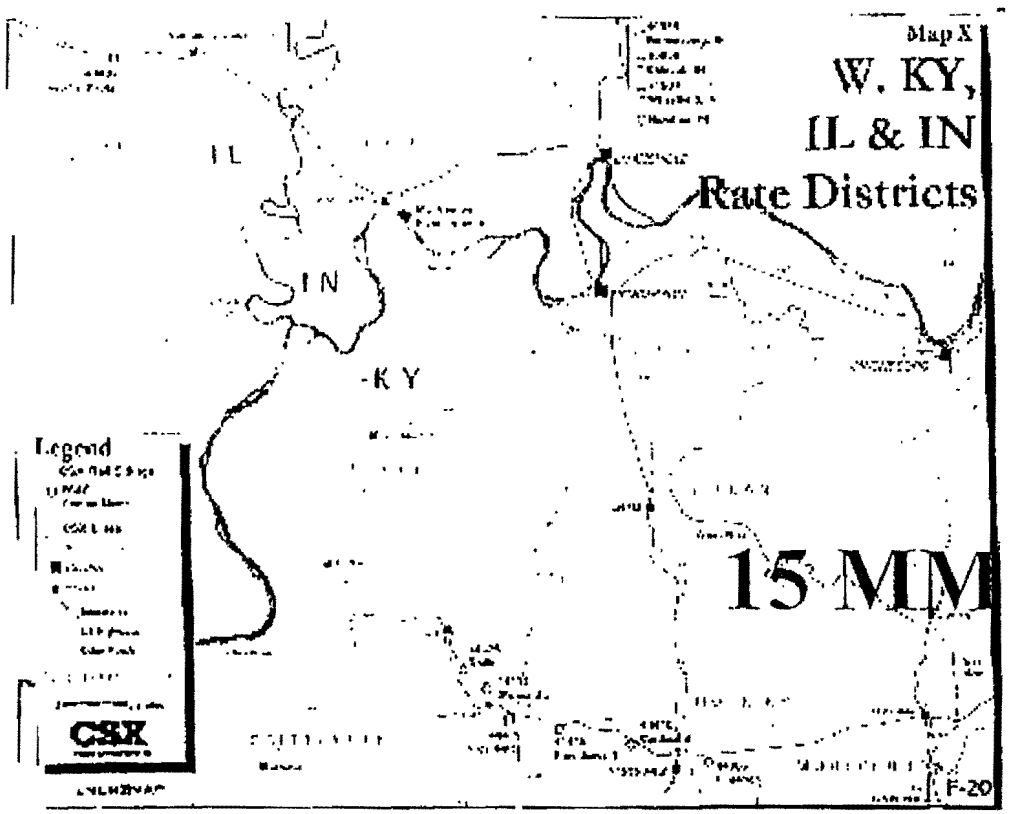
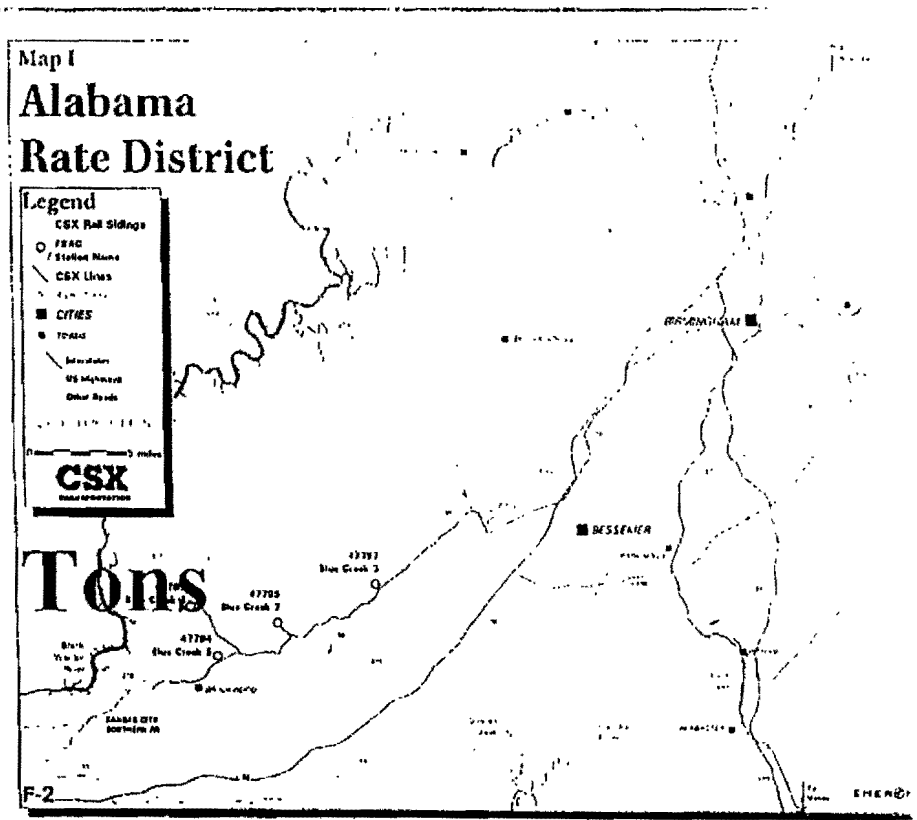
PAGE 7 OF 23

CSX TRANSPORTATION

West Kentucky and Alabama origins account for 9% of CSXT loadings



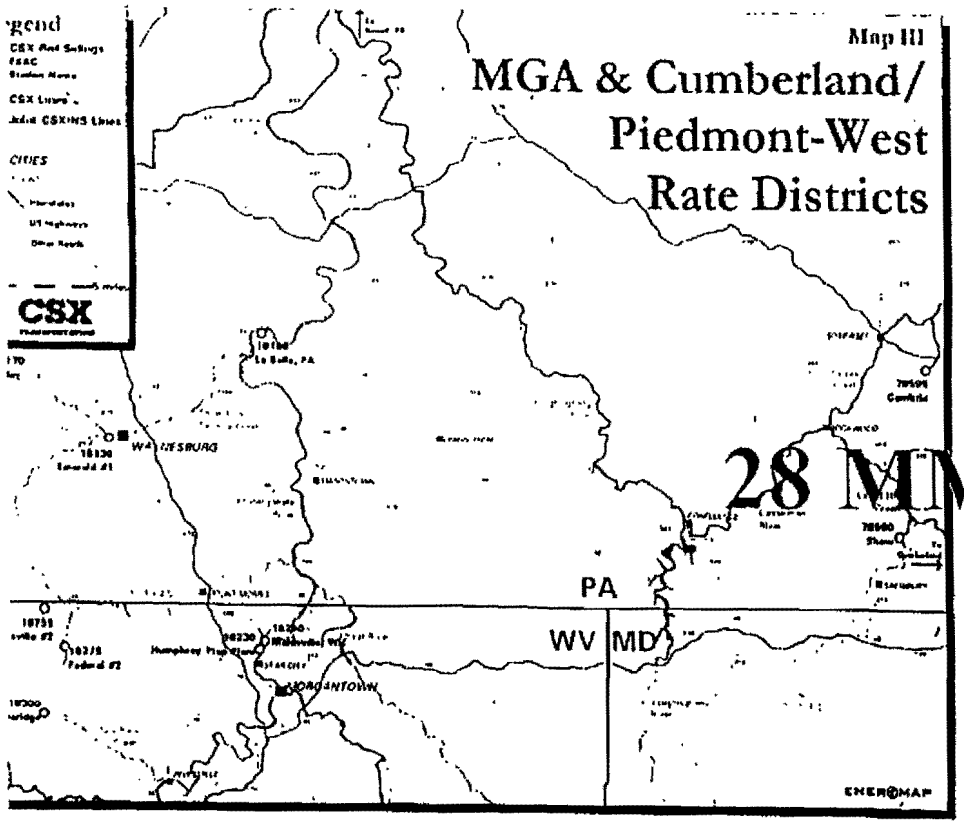


15 MM Tons

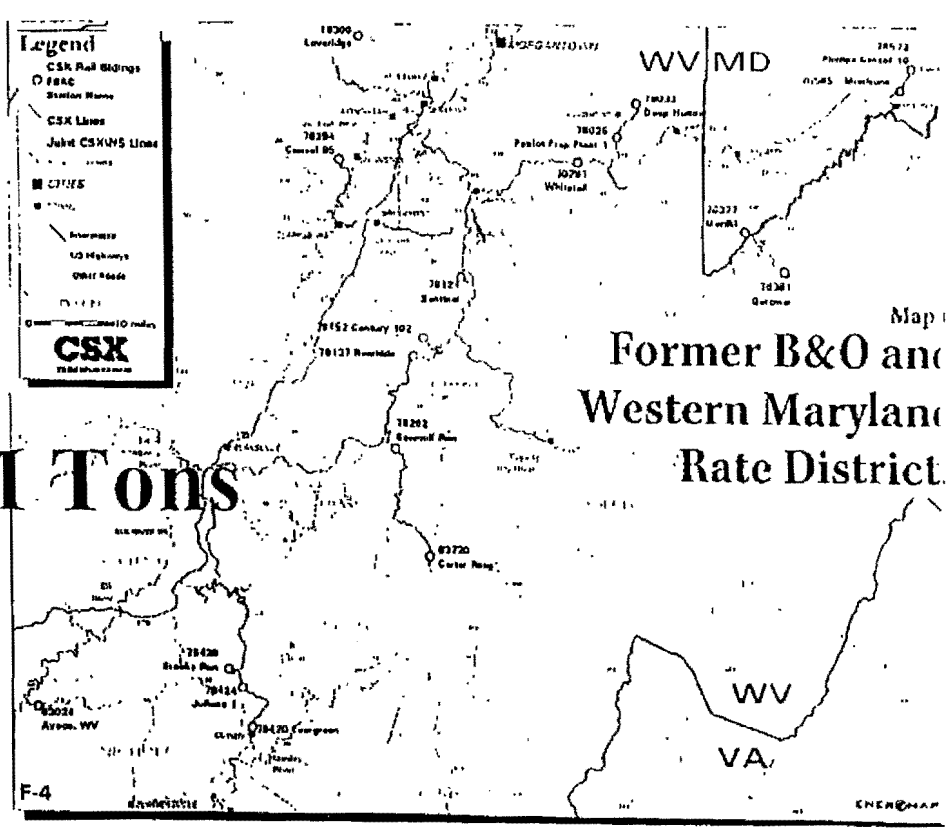
CSX TRANSPORTATION

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI

MGA and former B&O districts account for 17 % of CSXT loadings



28 MM Tons



CSX TRANSPORTATION

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
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CSXT delivers coal throughout its system

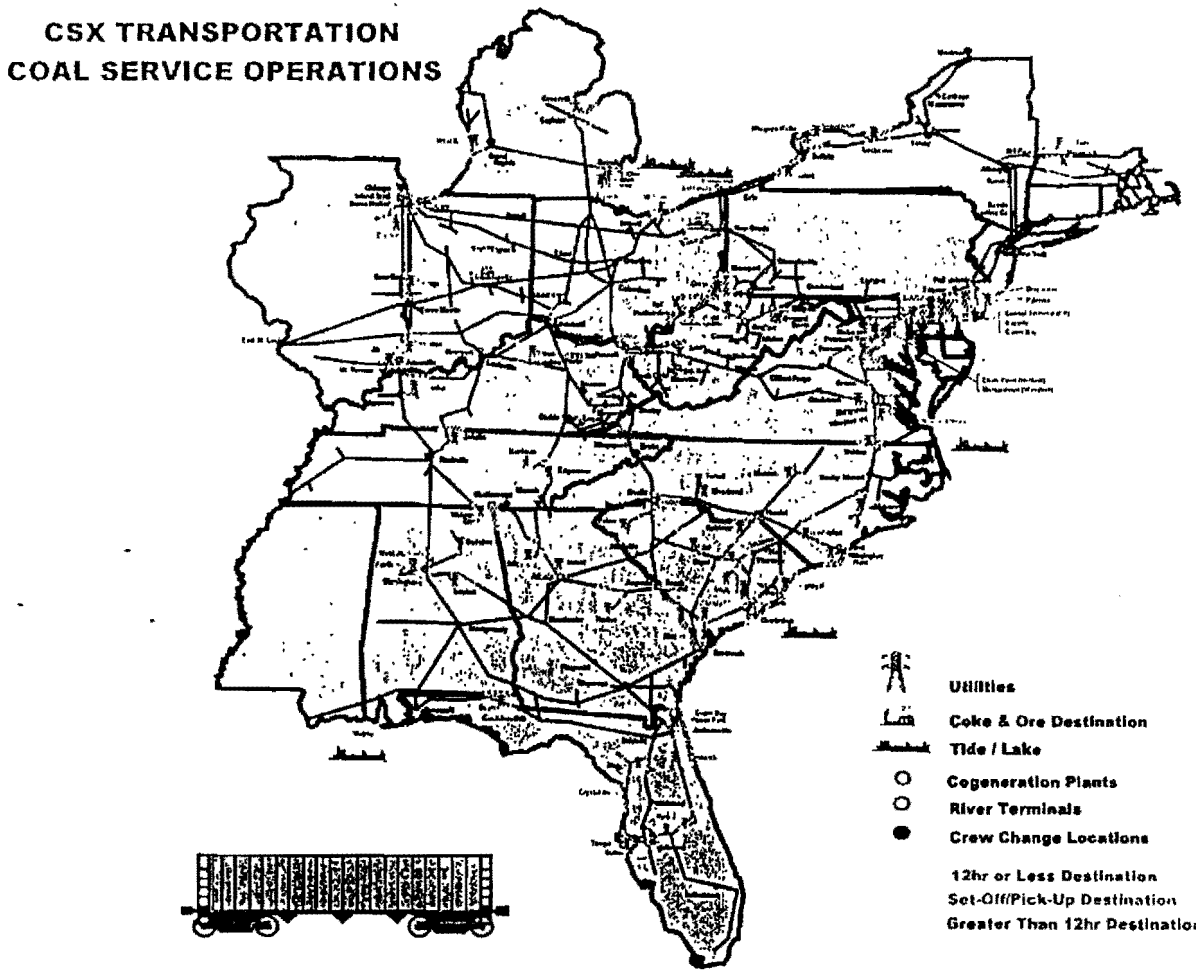

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
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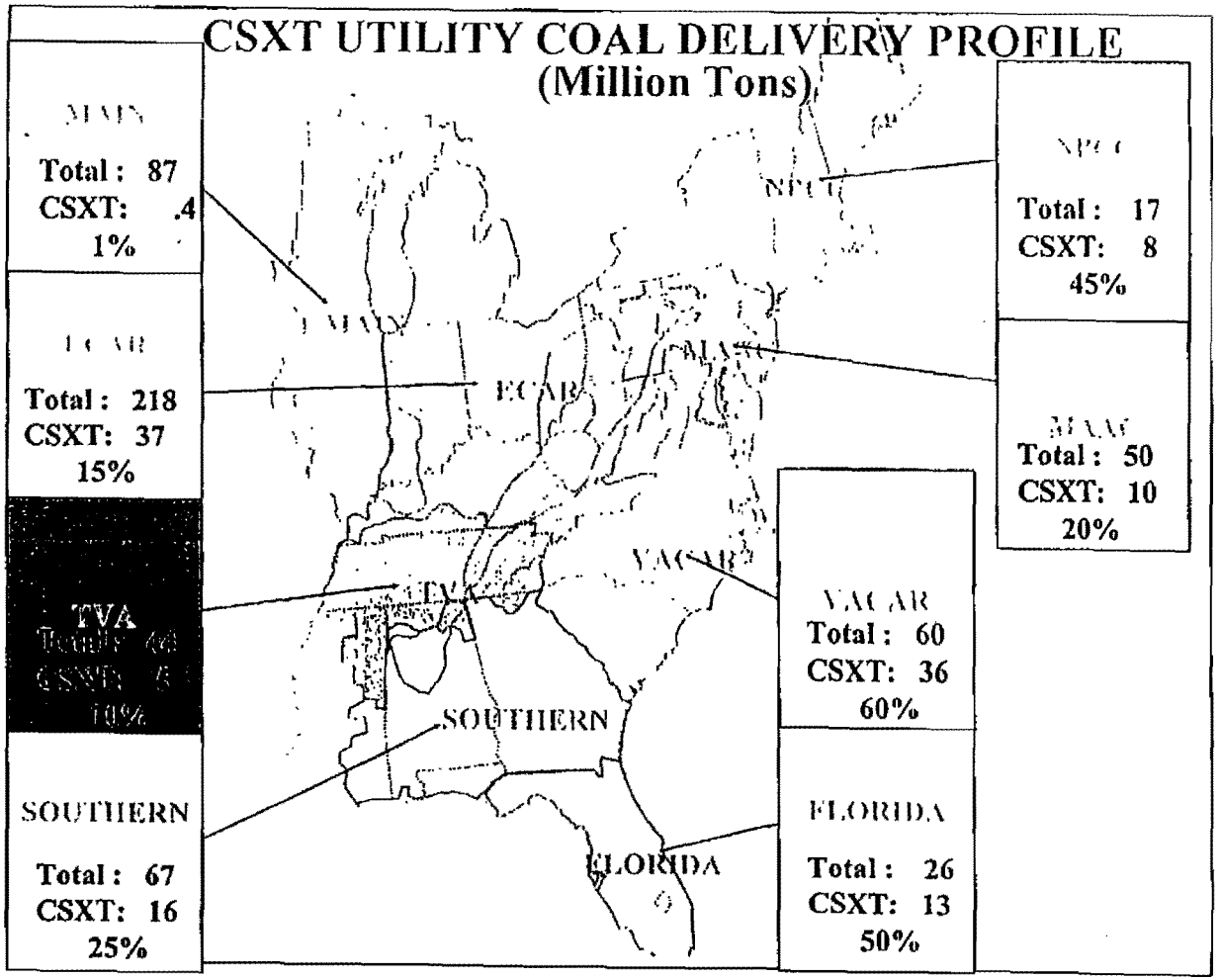
CSXT has a presence in each of the NERC regions East of the Mississippi



CSX TRANSPORTATION

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 11 OF 23

CSXT owns and operates a fleet of 28,000 coal cars

- **Of the total 100,000 rail cars owned by CSXT 28 % are coal cars**
- **CSXT owned cars provide 45-50 % of all loadings on CSXT**
- **Coal bottom drops, rotary tubs and coal tubs make up the coal fleet**

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 12 OF 23

CSX TRANSPORTATION

CSXT owns and operates a fleet of over 3,500 locomotives

- **CSXT's locomotive fleet purchases are AC powered technology**
- **CSXT operates many of the AC units in coal service on CSXT**
- **CSXT typically utilizes two AC locomotives per 90 car train with helper service in strategic locations**

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 13 OF 23

CSX TRANSPORTATION

CSXT has created value for its customer base through improved service

Service levels in 2002 exceed any short term performance period post-Staggers.

Q1 2002 Improvements

Service continues to improve

Category	Measurement	First Quarter 2001	First Quarter 2002	Percent Improvement
Car Inventory	Cars-on-Line	245,313	233,384	4.8%
Crews	Recrews	29	22	24.1%
Locomotives	Setback Hours	53	11	79.2%
Locomotives	# of Locomotives Deployed	3,830	3,791	1.0%
Velocity	Velocity - All Trains	21.3	23.0	8.0%
Yard/Terminal	Terminal Dwell	26.5	23.4	11.7%
Yard/Terminal	On-time Originations (+2hrs.)	84.5%	91.4%	8.2%
Yard/Terminal	On-time Destination Arrivals	72.0%	81.0%	12.5%

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 14 OF 23

CSX TRANSPORTATION

TAMPA ELECTRIC - CSXT

MEETING

MARCH 12, 2003

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 15 OF 23

OPPORTUNITY OVERVIEW

PROJECT OBJECTIVE:

Create value for Tampa Electric by establishing rail infrastructure at Big Bend and Polk providing lower transportation costs and alternatives to the current water mode.

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT 2
DOCKET NO. 031033-EI
PAGE 16 OF 23

TECO BENEFITS IN USING CSXT

- TRANSPORTATION
  - Expand competitive options via rail
  - Decrease TECO exposure to increased fuel prices for barge and truck deliveries
  - Increased coal source competition
  - Decreased transit time- Inventory Carrying Cost
  - Fewer transfers resulting in less degradation and loss
  - Single invoice option - F.O.B. Delivered
- COAL SOURCING
  - Access to CSXT coal origins: MGA, C&O, Illinois, Kentucky
  - Broader range of coal qualities

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 17 OF 23

CSXT's UNDERSTANDING OF TECO'S CURRENT COMMITMENT

- Restructuring activities to accommodate cost reductions
- Integrated coal gasification combined cycle IGCC at Polk "Monetizing the Gasifier"
- SO2 emissions reduction at Big Bend
- Transportation commitment through 2003
- Purchased primary coal requirements through 2003

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 18 OF 23

PLANT INFRASTRUCTURE NEEDS

- Long-Term
  - CSXT- Rail access, dumper, conveyor system
- Possible Short-Term or Contingency Period
  - Conrad Yelvington / CSXT
    - Construction / Operating / Investment

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 19 OF 23

CONTINGENCY PERIOD

- CSXT will utilize Conrad-Yelvington's Distribution Facilities for the Rail to Truck transfer for final delivery to both plants

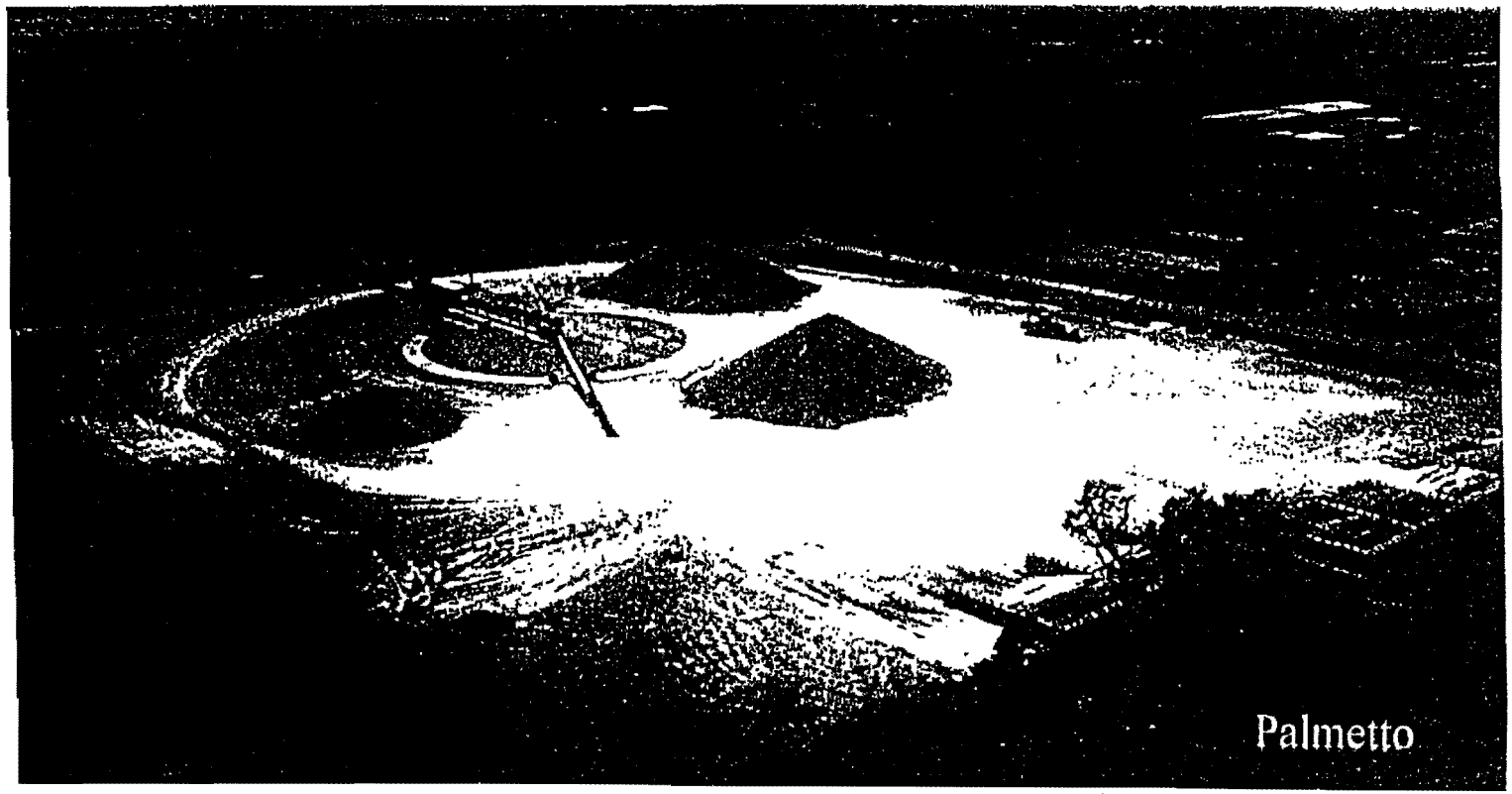


EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 20 OF 23

LONG TERM REQUIREMENT FOR CAPITAL IMPROVEMENTS

- CSXT is prepared to provide capital funding:
  - Big Bend: upgrade to the existing railcar dumping system, construction of a new truck dump for limestone, additional trackage, additional conveyance system and a radial stacker
  - Polk: improvements to include a rail loop track, dumping system, additional covered storage and required conveyance systems.

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 21 OF 23

BIG BEND MODIFICATIONS

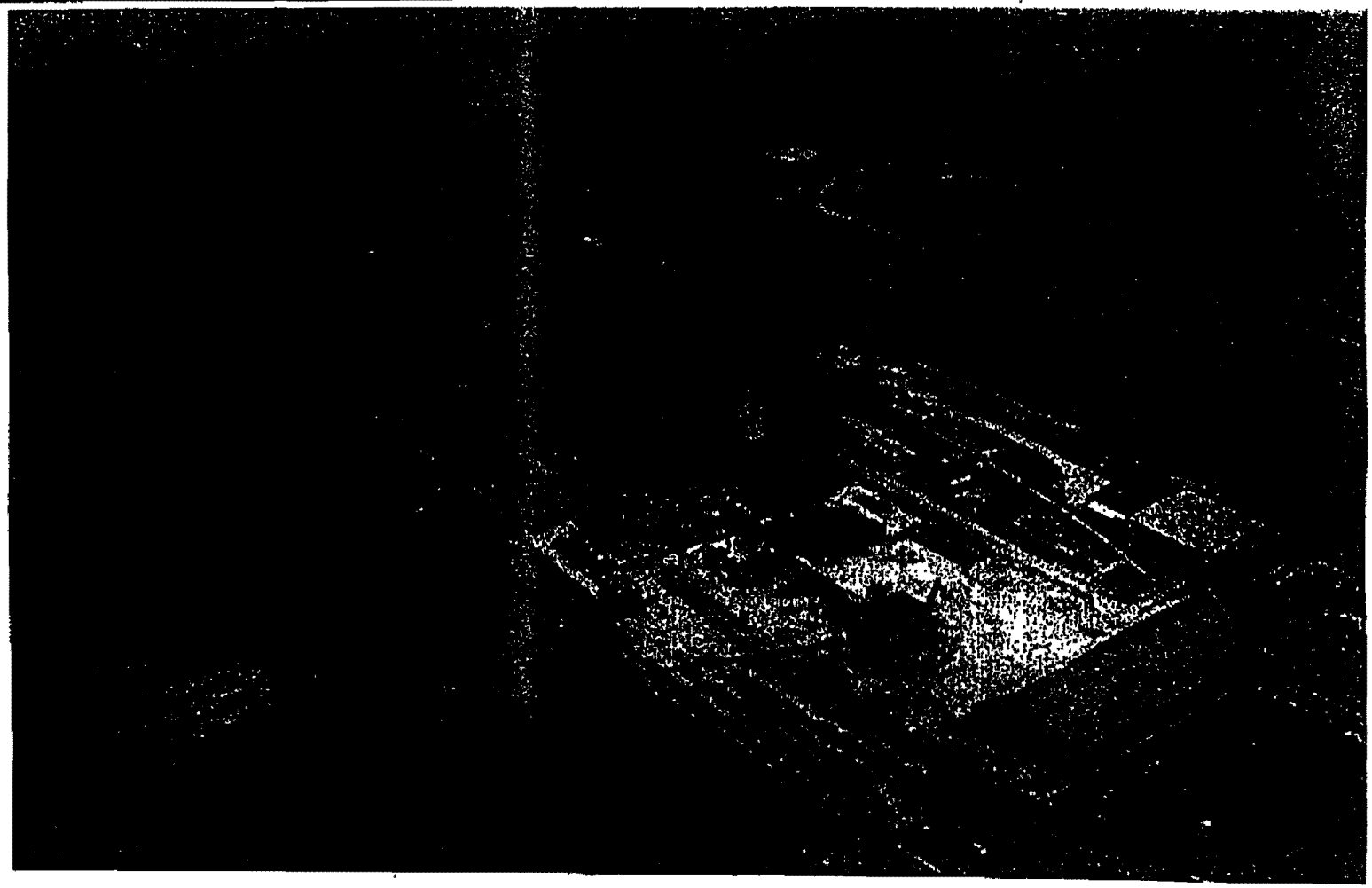


EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 22 OF 23

Next Steps

- Feedback
  - Determine TECO economic target and coal sourcing needs
  - CSXT's proposal- indicative of CSXT offer and TECO's needs
- Timing
  - Agree on project timeline and milestones
- Engineering Plans
  - Work with Teco's engineering group to provide a more detailed outline of plant requirements
- Test Shipments
  - Secure several test shipments prior to start-up

EXHIBIT NO. ____ (RFW-2)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 23 OF 23

TAMPA ELECTRIC - CSXT

MEETING

MAY 9th, 2002

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 21
COMPANY/ CSX
WITNESS. RFW-3
DATE 05/27-28/04

EXHIBIT NO. 21 (RFW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 1 OF 17

OPPORTUNITY OVERVIEW

PROJECT DESCRIPTION:

Develop CSXT competitive rail option to Tampa Electric –Big Bend/Polk for Modal Conversion from current water mode. Create competitive "value" for Tampa Electric.

TAMPA ELECTRIC AND CSXT HAVE A LONG HISTORY OF DOING BUSINESS

BUT TONS HAVE DECLINED:

YEAR	TONS
1996	1,186,801
1997	951,341
1998	811,916
1999	506,199
2000	213,011
2001	382,224
2002	-

EXHIBIT NO. ____ (REW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 3 OF 17

CSXT HAS SEVERAL OBJECTIVES IN WORKING WITH TAMPA ELECTRIC

- Modal Conversion from current water and truck modes to rail
- Short-Term - Develop CSXT/Truck Transfer to Big Bend, Gannon, and Polk plants as well as barge transfer option through CSXT Rockport
- Long-Term - Develop CSXT direct rail option to Big Bend and Polk plants
- Potential volume of 0.5 MM to 1.5 MM tons in 2003/04
- Test shipments targeted for 3Q 2002
- Bottom Line- Create value for Tampa Electric
  - Earn revenue growth for CSXT

EXHIBIT NO. ____ (RFW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 4 OF 17

FOR TECO THERE ARE SEVERAL DERIVED BENEFITS IN USING CSXT

- TRANSPORTATION
  - Expand competitive options via rail
  - Lower cost
  - Access to CSXT coal origins: MGA, C&O, Illinois, Kentucky
  - Decreased transit time- Inventory Carrying Cost
  - Fewer transfers
  - Less product loss
- COAL SOURCING
  - Increased coal source competition
  - Broader range of coal qualities
  - Single invoice option - F.O.B. Delivered

EXHIBIT NO. ____ (RFW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 5 OF 17

FOR TECO THERE ARE SEVERAL DERIVED BENEFITS IN USING CSXT

- PLANT INFRASTRUCTURE
  - Rail access, Dumper, conveyor system
  - Potential for capital contribution from CSXT & Coal Company
  - CSXT logistics and engineering assistance
    - Project Manager-Logistics
    - RAS Engineering
  - Conrad Yelvington / CSXT / Coal Company
    - Construction / Operating / Investment
- OTHER
  - Scrubber limestone via CSXT

EXHIBIT NO. ____ (RFW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 6 OF 17

TAMPA ELECTRIC HAS SEVERAL COAL SUPPLY OPTIONS VIA CSXT

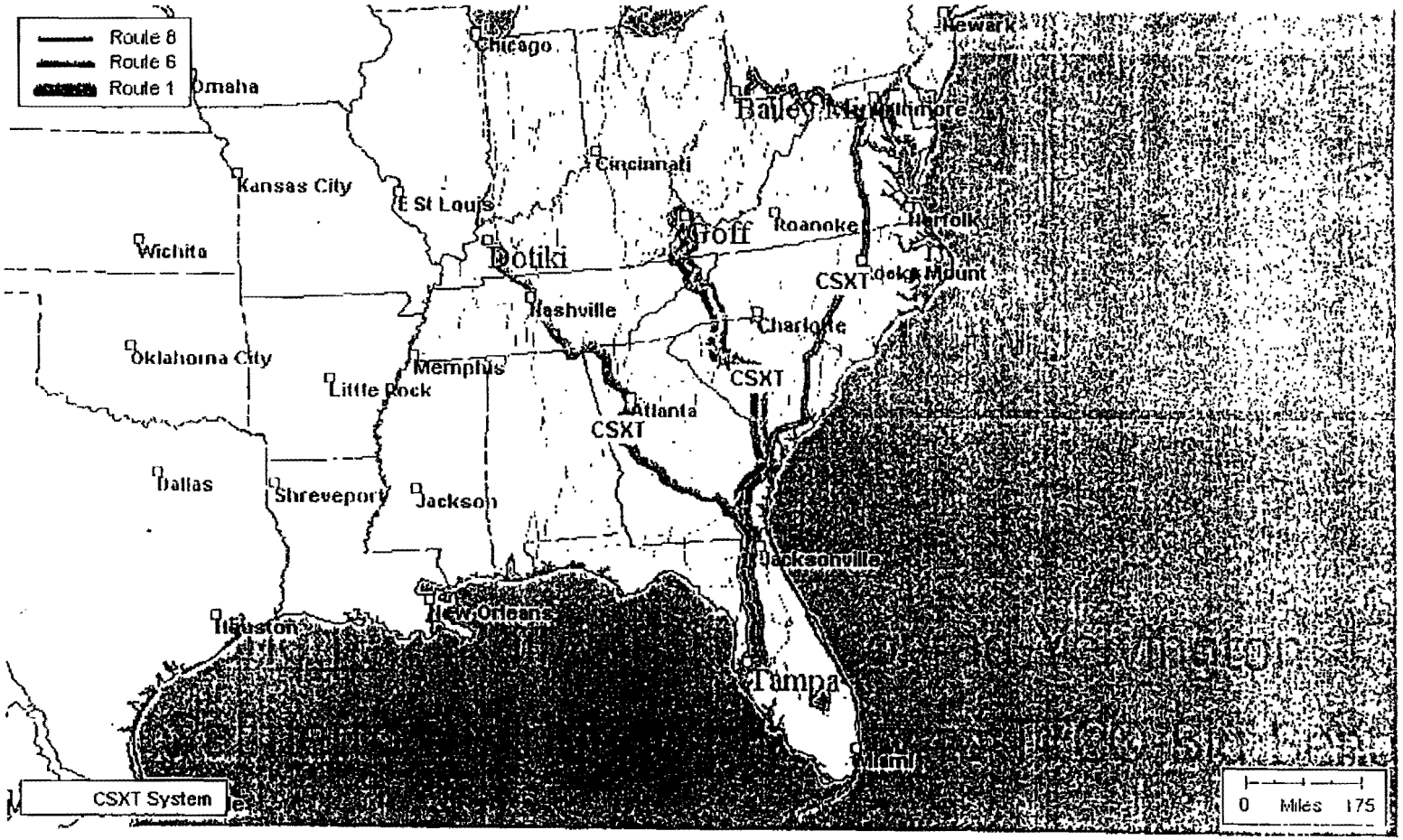


EXHIBIT NO. ____ (REW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 7 OF 17

SHORT TERM OPTIONS

- Short-term
  - Option A: Rail/Truck via Conrad-Yelvington Palmetto Distribution Facility to TECO-Big Bend, Gannon, Polk
  - Option B: Rail/Barge via Rockport to Big Bend, Gannon

CONRAD YELVINGTON-
PALMETTO YARD

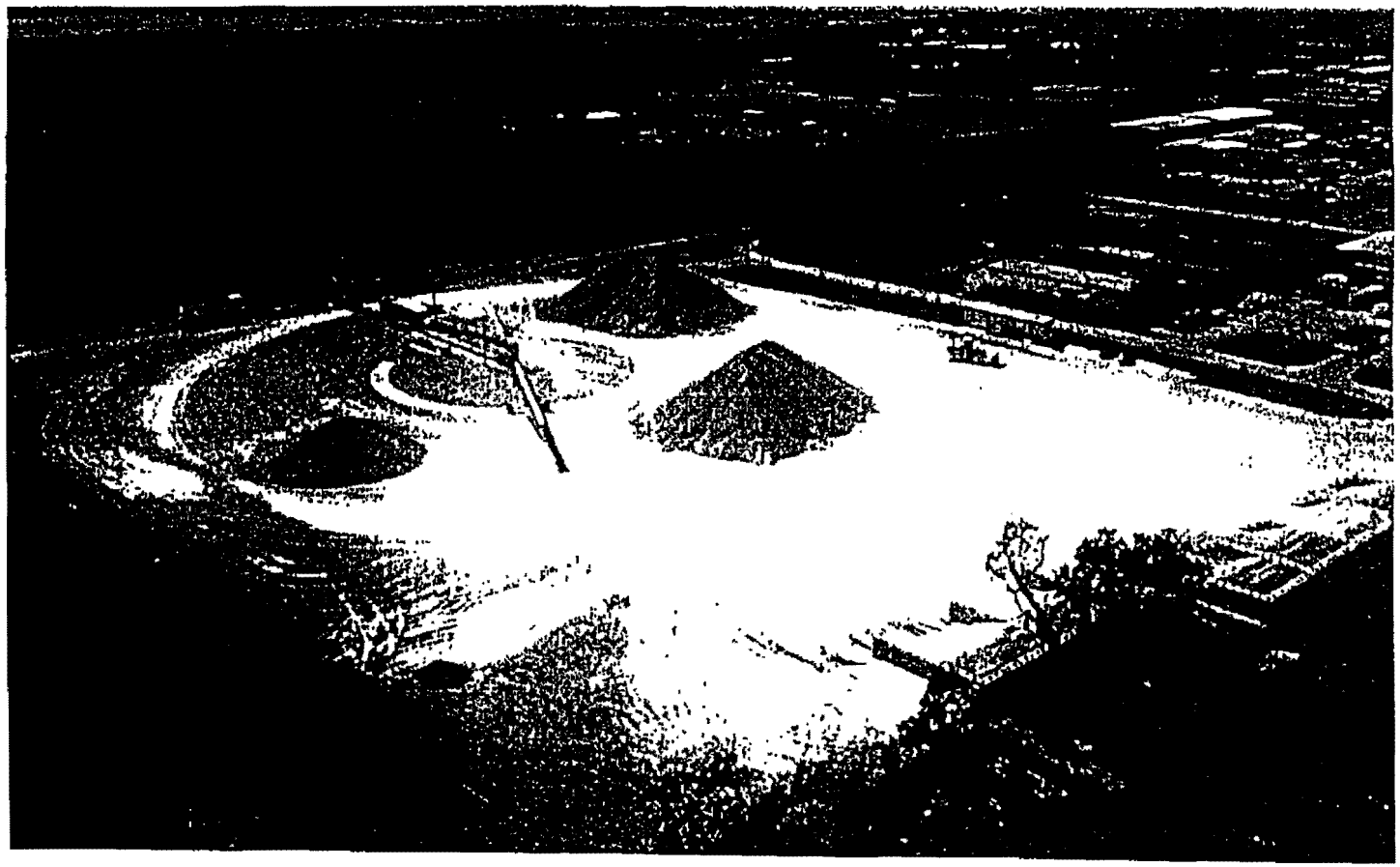


EXHIBIT NO. ____ (RFW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 9 OF 17

CSXT's ROCKPORT TERMINAL

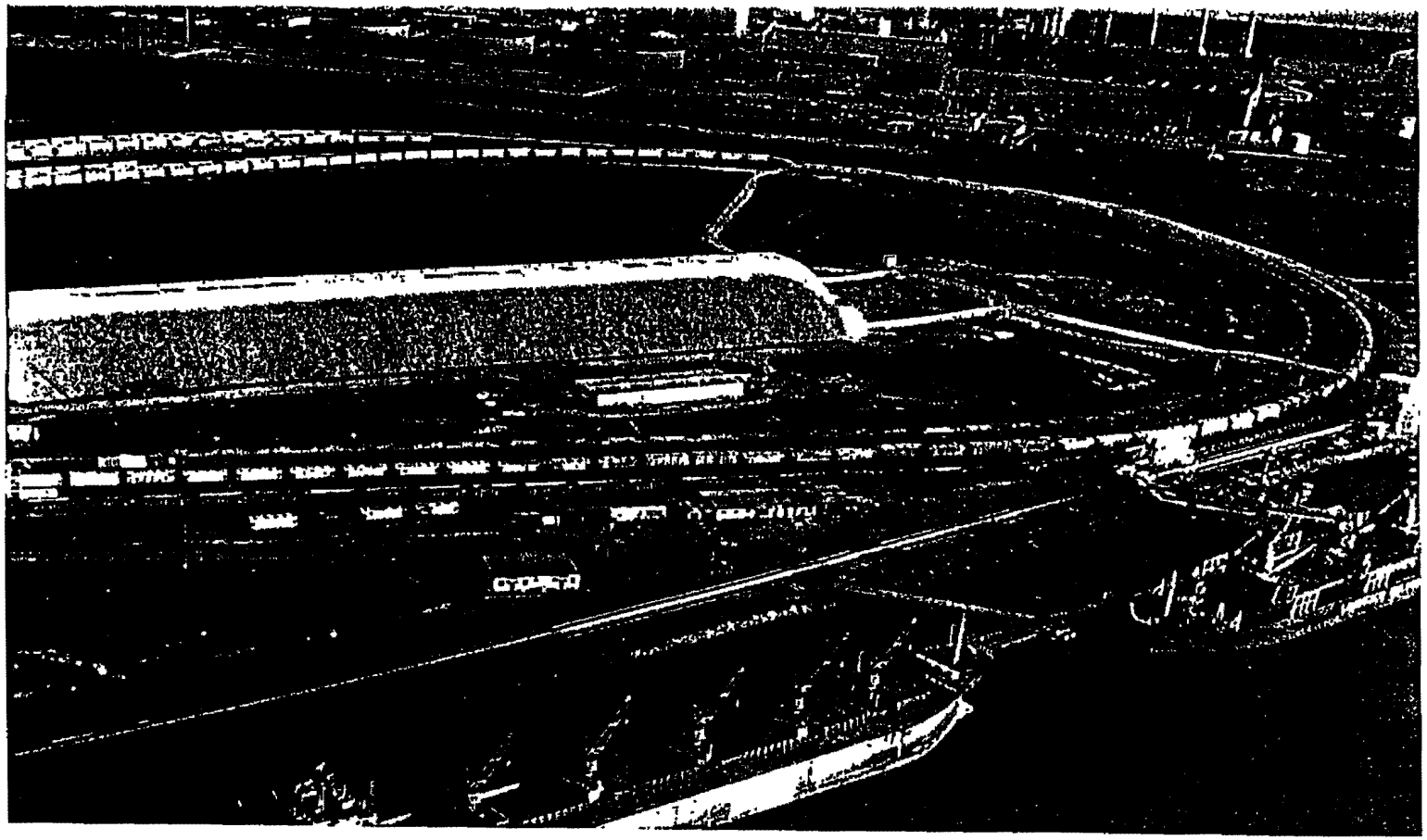


EXHIBIT NO. ____ (RFW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 10 OF 17

LONG TERM OPTIONS

- Long-term
  - Option A: Rail build-in to Big Bend and Polk
  - Option B: Short haul rail Big Bend to Polk
  - Option C: Develop rail/truck with Brewster Yard (CSXT) and Conrad Yelvington

TAMPA ELECTRIC- BIG BEND PLANT

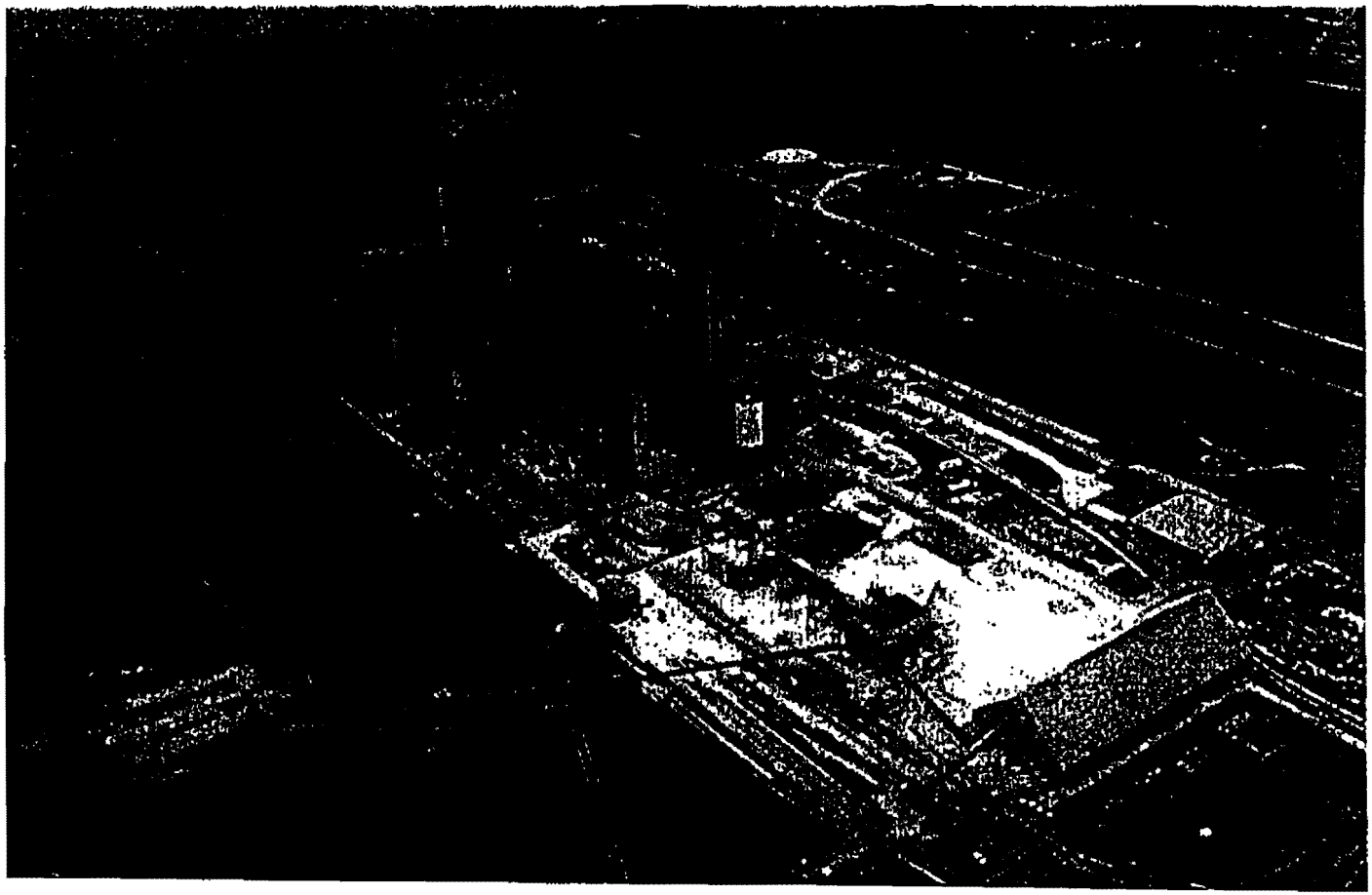


EXHIBIT NO. ____ (RFW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 12 OF 17

VIEW OF TAMPA ELECTRIC'S POLK PLANT FROM BREWSTER YARD

EXHIBIT NO. ____ (REW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 13 OF 17

TAMPA ELECTRIC INFRASTRUCTURE
DIRECT RAIL

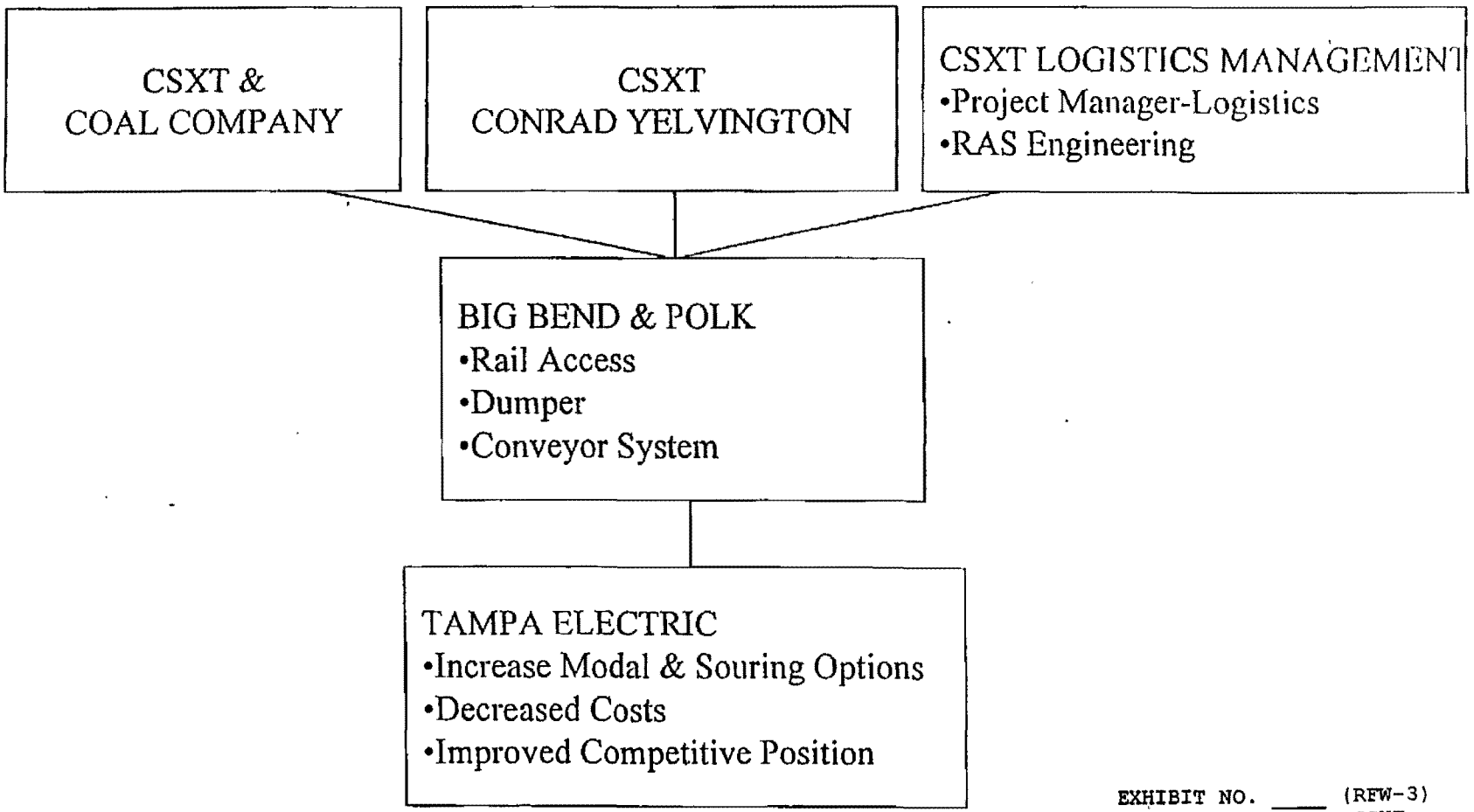


EXHIBIT NO. ____ (RFW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
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THE PROPOSAL

HOW THE SHORT & LONG TERM OFFERS WORK

	Short Term	Long Term
Origins:	IL, IN, KY, WV, PA	IL, IN, KY, WV, PA
Destination:	Big Bend, Polk, Gannon	Big Bend, Polk
Route:	CSXT-Palmetto-Truck CSXT-Rockport-Barge	CSXT Direct
Term:	1-3 Years	5 Years
Equipment:	CSXT Ownership	CSXT Ownership
Payment:	Single invoice or separate billing	Single invoice or separate billing
Annual Volume:	.5 to 1.0MM tons	1.0 to 1.5MM tons
Rate:	At long term rate if agree to rail build-in and L.T. contract	TBA- Market Competitive
Infrastructure Investment:	None	CSXT or Coal Company Refund-Negotiable
Logistics Management:	CSXT Project Manager- Logistics Conrad Yelvington	CSXT Project Manager- Logistics Conrad Yelvington RAS Engineering

EXHIBIT NO. ____ (RFW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
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PROPOSED NEXT STEPS TO INITIATE THE PROCESS

- FEEDBACK FROM TAMPA ELECTRIC
  - Transportation Requirements
  - Coal Souring Needs
  - Economic Targets
- FINALIZE SHORT TERM OPTIONS
  - Conrad Yelvington
  - Rockport
- DEVELOP LONG TERM PARAMETERS- Rail Capacity
  - Big Bend
  - Polk
  - Brewster Option

EXHIBIT NO. ____ (RFW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 16 OF 17

PROPOSED NEXT STEPS TO INITIATE THE PROCESS (Cont.)

- COMPREHENSIVE CSXT PROPOSAL TO TAMPA ELECTRIC
  - Coal Company
  - Conrad Yelvington
- TAMPA ELECTRIC / CSXT PARTNERSHIP
  - Create value for both companies

EXHIBIT NO. ____ (RFW-3)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 17 OF 17

EXHIBITS 4 THROUGH 8 TO ROBERT F. WHITE'S TESTIMONY ARE CONFIDENTIAL AND HAVE BEEN REDACTED FROM THIS PUBLICLY FILED VERSION OF MR. WHITE'S TESTIMONY.

CONFIDENTIAL

(RFW-4)	**CONFIDENTIAL**, CSX's October 23, 2002 Proposal to TECO

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 22
COMPANY/ CSX
WITNESS: RFW-4
DATE: 05/27-28/04

CONFIDENTIAL

(RFW-5)	**CONFIDENTIAL,** Diagram of Facilities for Big Bend 1 to 2 MMTPY Rail Delivery Option

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 23
COMPANY/ CSX
WITNESS: RFW-5
DATE: 05/27-28/04

CONFIDENTIAL

(RFW-6)	**CONFIDENTIAL,** Diagram of Facilities for Big Bend 2 to 5.5 MMTPY Rail Delivery Option

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 24
COMPANY/ CSX
WITNESS: RFW-6
DATE: 05/27-28/04

CONFIDENTIAL

(RFW-7)	**CONFIDENTIAL,** Diagram of Facilities for Polk Station Direct Rail Delivery Option

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 25
COMPANY/ CSX
WITNESS: RFW-7
DATE: 05/27-28/04

CONFIDENTIAL

(RFW-8)	**CONFIDENTIAL,** Diagram of Facilities for Polk Shuttle Rail Delivery Option

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 26
COMPANY/ CSX
WITNESS: RFW-8
DATE: 05/27-28/04

CSX
TRANSPORTATION
Mike Bullock
Director Utility Coal

500 Water Street - J842
Jacksonville, FL 32202

March 21, 2003

Ms. Joann Wehle
Director Fuels Department
Tampa Electric Company
PO Box 111
Tampa, FL 33601-0111

Dear Joann,

I appreciate the Fuel departments availability and comments on Wednesday where CSXT reconfirmed it's desire to provide transportation service for Tampa Electric including possible build-ins at the Big Bend and Polk plants.

Reviewing our things to do, as requested we provided Karen with a CSXT origin mine directory and we are easily reached should any questions arise regarding possible coal sources. As outlined in our presentation, Bob White is available to meet with your engineering group to better understand the plants requirements and to eliminate any remaining logistical issues that could challenge our ability to service both plants. This is a critical next step in order to finalize and secure the capital required for this project. Regarding your concern as to possible environmental issues, we can enlist our State Relations group to address any impediments to the project. Finally, from your side we understand that you will be providing CSXT with needed feedback to our proposed plan.

Again, I appreciate the time that your group took to listen to our proposal and as stated in our meeting we will work through your response to ensure that we create value for Tampa Electric. We look forward to hearing from you.

Sincerely,

M. C. Bullock

cc: H. W. Smith
K. Bramley
M. C. Duff
V. L. Saunier
M. P. Sullivan
R. F. White

EXHIBIT NO. 27 (RFW-9)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 1 OF 4

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 27
COMPANY/ CSX
WITNESS: RFW-9
DATE: 05/27-28/04

CSX TRANSPORTATION

500 Water Street-J842
Jacksonville, FL 32202-4057

June 13, 2003

JoAnn T. Wehle
Director - Fuels Department
Tampa Electric Company
P. O. Box 111
Tampa, FL 33601-0111

Dear JoAnn,

This letter follows my letter of March 21, 2003 given that three months has elapsed since our meeting I felt that it is appropriate that I drop you a letter as a reminder.

As part of the follow-up action plan it was agreed that CSXT would get together with TECO's engineering personnel to better estimate the physical constraints and logistical issues at the plant. This visit will enable us to refine the capital requirement for infrastructure improvements to serve the plants directly. We remain excited about this opportunity.

I look forward to hearing from you.

Best regards,

Michael C. Bullock
Director Utility South

EXHIBIT NO. ____ (RFW-9)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 2 OF 4

CSX TRANSPORTATION
Michael C. Bullock
Director
Utility South

500 Water Street - J843
Jacksonville, FL 32202-4057
Phone: (904) 359-3153
Fax: (904) 359-3341

July 11, 2003

Ms. Joann T. Wehle
Tampa Electric Company
Director – Fuels Department
P. O. Box 111
Tampa, FL 33601-0111

Subject: Tampa Electric's Big Bend and Polk Plants Visits

Dear Joann,

We understand you've been extremely busy these last few months, so instead of exchanging voice messages, we decided a letter would be best to express our continued interest in rail direct coal. We were disappointed that we were unable to meet with your engineering teams to review and discuss our proposed rail construction and operations at Big Bend and Polk. However, we remain very excited about the opportunity to deliver rail coal direct to these plants.

It is our understanding you are planning to solicit coal bids in the near future and we look forward to it considering FOB Rail as well as FOB Barge options. We would like to get down their prior to the bid solicitation so we can obtain your feedback prior to submitting our capital requirement for next year's capital budget. Some of your recent coal sourcing has included Galatia 56, Zeigler, Eagle Valley, and Dotiki. Are there other sources you are interested in because we would like to better understand your anticipated coal origins in order that we may provide the rates you require.

We stand ready to work with you during the bidding period to identify and develop opportunities that not only diversify Tampa Electric's supply chain but add value as well. If you have any question or would like to discuss, please feel free to contact me.

Respectfully,

Michael C. Bullock

Cc: M. Duffy – TECO
M. Sullivan – CSXT
G. Davis – CSXT
B. White – CSXT

EXHIBIT NO. ____ (RFW-9)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 3 OF 4

CSX
TRANSPORTATION

500 Water Street - J842
Jacksonville, FL 32202-4057
Phone: (904) 359-3153
Fax: (904) 359-3341

Michael C. Bullock
Director
Utility South

July 16, 2003

Ms. Joann T. Wehle
Tampa Electric Company
Director – Fuels Department
P. O. Box 111
Tampa, FL 33601-0111

Subject: Tampa Electric's Solicitation

Dear Joann,

Recently the Coal Transportation Report stated that Tampa Electric has issued a solicitation for waterborne transportation services for deliveries of solid fuel. If so, I wanted to let you know that CSXT has not received a solicitation to date. As previously discussed, CSXT does have the capability of delivering solid fuel via water through our Tampa facility (Rockport Terminal). This facility is strategically located near Tampa Electric's Big Bend plant.

CSXT assumes a rail transportation proposal in addition to the water delivery via Rockport will receive proper consideration. Even though rail infrastructure is required, CSXT can provide either waterborne or truck delivery during the time required to build in at both destinations.

Again, we stand ready to work with you during the bidding period to identify and develop opportunities that not only diversify Tampa Electric's supply chain but add value as well. If a bid has been solicited please forward a package to me. If not, please give us a best indication when you will be soliciting the bid and again we would like to get together with TECO's engineering personnel to better estimate the physical constraints and logistical issues at the plant.

Thank you,

Michael C. Bullock

Cc: M. C. Duff – TECO
M. P. Sullivan – CSXT
G. W. Davis – CSXT
R. F. White – CSXT

EXHIBIT NO. ____ (RFW-9)
ROBERT F. WHITE - CSXT
DOCKET NO. 031033-EI
PAGE 4 OF 4

EXHIBIT 10 TO ROBERT F. WHITE'S TESTIMONY IS CONFIDENTIAL AND HAS BEEN REDACTED FROM THIS PUBLICLY FILED VERSION OF MR. WHITE'S TESTIMONY.

CONFIDENTIAL

(RFW-10)	**CONFIDENTIAL,** CSX's July 30, 2003 Proposal to TECO

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 28
COMPANY/ CSX
WITNESS: RFW-10
DATE: 05/27-28/04

EXPERIENCE OF

DR. ROBERT L. SANSOM

Education

- ★ Robert Sansom graduated (B.S.) from U.S. Air Force Academy in 1964.
- ★ In 1965, Dr. Sansom received a Masters degree in economics from Georgetown University.
- ★ In 1968/69, he received a B. Phil and D. Phil in economics from Oxford University.

Honors

- ★ Dr. Sansom was a Fulbright Scholar, Rhodes Scholar, and White House Fellow.

Experience

- ★ From 1968 to 1969, Dr. Sansom was a White House Fellow assigned to Assistant to the President for National Security Affairs.
- ★ From 1969 to 1971, he was on Dr. Henry Kissinger's National Security Council staff.
- ★ From 1971 to 1972, he was Deputy Assistant Administrator for Planning and Evaluation for the Environmental Protection Agency.
- ★ From 1972 to 1974, he was Assistant Administrator for Air and Water Programs at the Environmental Protection Agency.
- ★ From 1974 to 1980, Dr. Sansom was President of Energy and Environmental Analysis, Inc.
- ★ From 1981 to the Present, Dr. Sansom has been President of Energy Ventures Analysis, Inc.

Sansom has been active in energy and environmental consulting since 1974 and throughout the period has focused on the coal, natural gas and electric utilities industries and on related environmental issues.

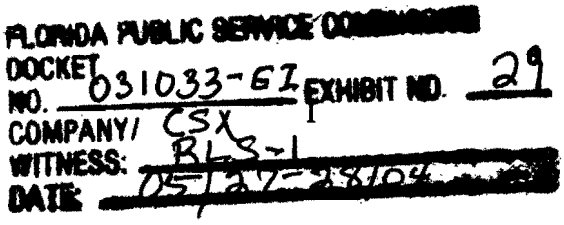
- ★ coal, gas, and oil production, markets and prices,
- ★ coal and gas contracts and procurement,
- ★ coal suitability and the environmental effects of coal combustion,
- ★ electric power markets and projects, and
- ★ coal transportation.

Electric Power Markets

Dr. Sansom analyzes and testifies on electric power markets and prices. In several cases (PEPCO, PP&L, NIPSCO, Entergy, Sierra Pacific, AEPCO, Bonneville Power Administration, for example), Sansom has examined power pricing and power transactions. EVA's analysis employs public and proprietary data and models at the NERC or NERC subregion level and develops forward pricing curves. Sansom presented testimony before FERC in 1996 on Order 888A: promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services.

Coal Markets and Coal Property Transactions

Coal market studies by EVA's coal group cover all the major coal producing and using regions of the United States. Clients include the major U.S. coal companies, major U.S. utilities, and groups such as EPRI and the National Mining Association.



EVA maintains large data bases on all U.S. mines and utility coal users. For clients it utilizes its proprietary coal production cost models and tracks and forecasts demand and prices for U.S. steam and metallurgical coals.

The U.S. coal market is regionalized with the reach of a particular coal mine limited by its transportation costs to various markets, its competition as well as the quality of its coal and its production cost. EVA addresses these issues in its market studies on a regional and international basis with analyses sold to clients on a job-specific basis or through its COALCAST subscription coal service.

In coal property and coal company valuations for buyers and sellers, EVA employs its market, cost of mining, and coal contract expertise using discounted cash flow and comparable transactions methods.

Coal and Transportation Contracts

Major U.S. coal transactions occur pursuant to coal and rail transportation contracts between buyers and sellers. Sansom has reviewed over 300 long-term coal contracts and many coal transportation contracts. He has advised utilities and coal companies on coal and rail transportation contract terms and conditions. His expertise is frequently sought and utilized in contract disputes.

Electric Utility Audits

EVA is frequently hired by Public Utility Commissions to conduct prudency audits of utility coal procurement practices and wholesale power transactions. Sansom has participated in such utility audits in Ohio, Delaware, Florida, Utah, Wyoming, California, Oregon, and Washington, and before FERC.

Natural Gas And Oil Markets

Dr. Sansom has been engaged in analysis of natural gas markets. He has examined U.S. and Canadian natural gas production. Other work has addressed world oil markets and OPEC's role therein. Dr. Sansom has examined the role of natural gas combined cycle technology as a source of base load generating capacity.

Coal Suitability and the Environmental Effects of Coal Use

Sansom's original involvement in the coal industry was in response to the adverse environmental effects of coal use. He has been active in studies on sulfur dioxide, nitrous oxides, particulates, air toxins, and CO_2 emissions. EVA has estimated the cost of specific environmental control technologies at plant sites and the cost of national environmental programs for clients such as the U.S. Environmental Protection Agency, EPRI, and the Department of Energy. It has advised electric utilities on how to comply with acid rain legislation. Coal suitability involves how a particular coal burns in a particular boiler and how that coal's emissions are treated before discharge to the atmosphere. EVA's studies have included examination of the performance of most U.S. coals used in a broad range of U.S. boilers.

International Coal and Utility Experience

Sansom has been active in international coal since the mid-1970's, analyzing overseas coal markets and inter-fuel competition. In 1989 Sansom testified in an international arbitration involving a large Canadian coal producer and the Japanese steel industry. In 1998 Sansom testified in an international arbitration involving an independent power project in the Phillippines.

Western Coal, Utility, and Transportation Experience

EVA has broad experience in the western U.S. Sansom's western coal and coal transportation expertise is the basis for his testimony on the Powder River Basin, the fastest growing producing region in the United States.

Expert Testimony

Sansom's expert testimony most often addresses coal contracts, coal markets, coal transportation and the prudency of coal procurements. Since 1995, Sansom has testified in the following court and arbitration cases:

	On Behalf of	Other Party	Year	Court or Regulatory Body
C	Louisville G&E	Various Plaintiffs	1995	State Court Kentucky
C	Island Creek Corp et al Defendants	Holland et al Plaintiffs	1995	U.S. District Court District of Columbia
A	Westmoreland Res, Inc.	Wisconsin P&L/Dairyland	1996	Chicago, IL
A	CMS Energy	Luzon Power	1998	Hong Kong, China
A	Otter Tail Power/Minnkota Pwr Coop/NW Pub Svc	Knife River Coal Company	1998	Chicago, IL
C	Cedar Bay Generating	Florida Power & Light	1999	Jacksonville, FL
A	Seminole Electric Coop, Inc.	Mt. Vernon Transfer Terminal	2000	Washington, D.C.
A	CMS Energy	Adams Affiliates, Inc. & Cottonwood Partnership	2001	Chicago, IL

A Arbitration
C Court

Sansom has testified in the following Surface Transportation Board cases:

STB Docket No.	On Behalf of	Other Party		Date
41191	West Texas Utilities	Burlington Northern Railroad		8/10/95
32760	Union Pacific (Control/Merger)	Southern Pacific Rail	Rebuttal	4/29/96
41242	Assn of American Railroads (Competitive Forces on Rail Rates in 1980's and 1990's)			10/15/96
41989	CSX Transportation	Potomac Electric Power		5/05/97 Rebuttal 8/11/97
41295	Conrail, CSX and Norfolk Southern	Pennsylvania Power & Light		6/11/97
33388	CSX and Norfolk Southern (Acquisition)	Conrail		6/1997
42012	Union Pacific	Sierra Pacific Power/Idaho Power		5/26/98
Ex Parte 627	Assn of American Railroads (Market Dominance Determinations: Product and Geographic Competition)		Comment Reply	5/29/98 6/29/98

EXHIBIT NO. ____ (RLS-1)
ROBERT L. SANSOM - CSXT
DOCKET NO. 031033-EI
PAGE 3 OF 6

Publications

"Looking Past California: The Emerging Shape of the Generation Sector", Public Utilities Fortnightly, June 1, 2001, pp. 44-50.

"Gas Turbine Mania: The Merchant Power Plant Stakeout", Public Utilities Fortnightly, June 15, 2002.

EXHIBIT NO. ____ (RLS-1)
ROBERT L. SANSOM - CSXT
DOCKET NO. 031033-EI
PAGE 4 OF 6

Expert Testimony

Sansom's expert testimony most often addresses coal contracts, coal markets, coal transportation and the prudency of coal procurements. Sansom has testified in the following cases:

Client (State)	Other Party (State)	Year	Court or Regulatory Body
Black Butte (WY)	Commonwealth Edison (IL)	1985	WY Federal Court
Carbon County (WY)	NIPSCO (IN)	1985	IN Federal Court
Gulf & Western (VA)	Coal Resources (VA)	1981-1986	OH Federal Court
Big Horn (WY) and Black Butte (WY)	Commonwealth Edison (IL)	1986	WY Federal Court
Amax (WY)	Dairyland (WI)	1986	WI Federal Court
Wisconsin PSC (WI)	Mapco (KY)	1987	Arbitration
U.S. Fuels (UT)	Nevada Power (NV)	1987	UT Federal Court
Decker (MT)	LCRA (TX)	1988	TX Federal Court
Texas Utilities (TX)	Santa Fe Pacific (IL)	1989	NM Federal Court
Quintette (CAN)	Japanese Steel Industry	1989	Arbitration
Coastal Coal (UT)	Sierra Pacific Power (NV)	1990	Arbitration
Minnesota Power (MN)	Peabody Coal Company	1990	Arbitration
NE Oklahoma Electric (OK)	GRDA	1991	OK State Court
AEPCO	Berkley	1992	Arbitration
Northwestern Res/HL&P	International Screening	1992	TX State Court
Commonwealth Edison	Peabody Coal Company	1993	Arbitration
First Boston/Touche Ross Jacobs Group	KSC Recovery	1993	CO Federal Court
Central Power & Light	Colowyo	1994	Arbitration
Lauhoff Grain	Babcock & Wilcox	1994	Arbitration
Northwestern Res/HL&P	TCA Bldg Inc.	1994	TX Federal Court
Evergreen Coal	UMWA Employee Benefits Plans	1994	U.S. District Court
Virginia Power	Birchwood/SEI	1994	Arbitration
Louisville G&E	Various Plaintiffs	1995	State Court Kentucky
Island Creek Corp et al Defendants	Holland et al Plaintiffs	1995	U.S. District Court District of Columbia
Westmoreland Res, Inc.	Wisconsin P&L/Dairyland	1996	Arbitration
CMS Energy	Luzon Power	1998	Arbitration
Otter Tail Power/Minnkota Pwr Coop/NW Pub Svc	Knife River Coal Company	1998	Arbitration
Cedar Bay Generating	Florida Power & Light	1999	FL State Court
Seminole Electric Coop, Inc.	Mt. Vernon Transfer Terminal	2000	Arbitration
CMS Energy	Adams Affiliates, Inc. & Cottonwood Partnership	2001	Arbitration
Government of Turkey	PSE&G Global	2004	Arbitration
Peabody Coal Co/Indianapolis P&L	John Wasson	2004	IN Federal Court

Sansom's testimony on the prudency of coal procurements as well as coal markets and transportation were the focus of his testimony in the following proceedings:

Client	Other Party	Year	Regulatory Body
DE Public Advocate	Delmarva P&L	1981	DE PSC
KY Municipals	Kentucky Utilities	1985-1986	FERC
Wisconsin PSC	Wisconsin PSC Staff	1986	WI PUC
Oxy Chemical	Florida Power	1988	FL PSC
Georgia Power	Georgia PSU Staff	1988	GA PSC

EXHIBIT NO. ____ (RLS-1)
ROBERT L. SANSOM - CSXT
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In addition, in 1998 Sansom testified in a Florida power plant Siting Board proceeding involving the burning of Orimulsion at Florida Power & Light's Manatee plant. He presented testimony before FERC in 1996 on Order 888A: Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services. He also testified in the following Surface Transportation Board cases:

STB Docket No.	On Behalf of	Other Party	Date
41191	West Texas Utilities	Burlington Northern Railroad	8/10/95
32760	Union Pacific (Control/Merger)	Southern Pacific Rail	Rebuttal 4/29/96
41242	Assn of American Railroads (Competitive Forces on Rail Rates in 1980's and 1990's)		10/15/96
41989	CSX Transportation	Potomac Electric Power	5/05/97 Rebuttal 8/11/97
41295	**Conrail**, CSX and Norfolk Southern	Pennsylvania Power & Light	6/11/97
33388	**CSX** and Norfolk Southern (Acquisition)	Conrail	6/1997
42012	Union Pacific	Sierra Pacific Power/Idaho Power	5/26/98
Ex Parte 627	Assn of American Railroads (Market Dominance Determinations: Product and Geographic Competition)		Comment 5/29/98 Reply 6/29/98
42069	Norfolk Southern	Duke Energy Corporation	2003
42072	Norfolk Southern	Carolina Power & Light	2003

EXHIBIT NO. ____ (RLS-1)
ROBERT L. SANSOM - CSXT
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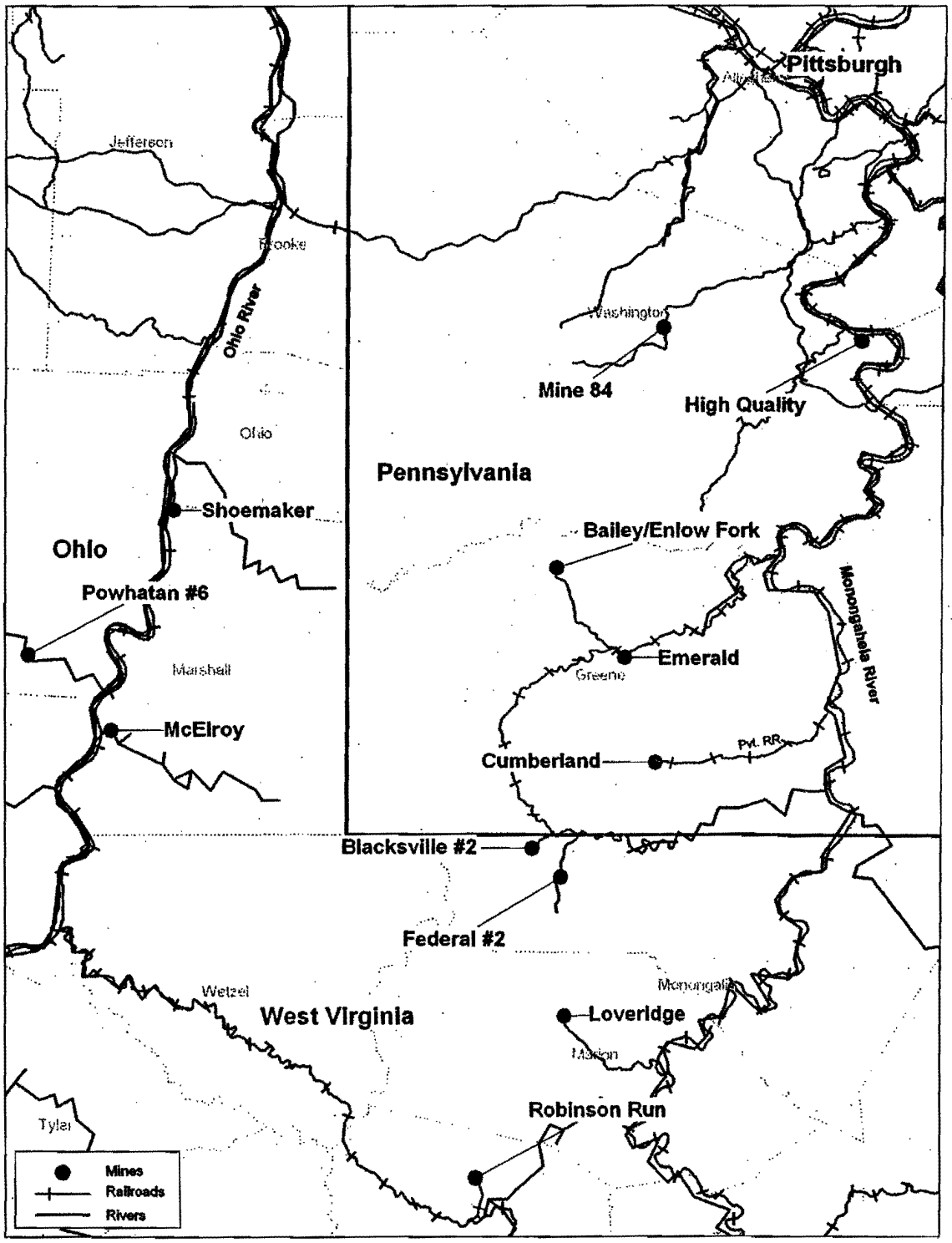
PAGE 6 OF 6

RLS Exhibit 2
PITTSBURGH 8 MINES NORTHERN APPALACHIAN COAL



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 30
COMPANY/ CSX RLS-2
WITNESS:
DATE: 05/22-28/04

EXHIBIT NO. 30 (RLS-2)
ROBERT L. SANSOM - CSXT
DOCKET NO. 031033-EI
PAGE 1 OF 1

EXHIBITS 3 AND 4 TO DR. SANSOM'S TESTIMONY ARE CONFIDENTIAL AND HAVE BEEN REDACTED FROM THIS PUBLICLY FILED VERSION OF HIS TESTIMONY.

CONFIDENTIAL

(RLS-3)	**CONFIDENTIAL**, CSX's October 23, 2002 Proposal to TECO

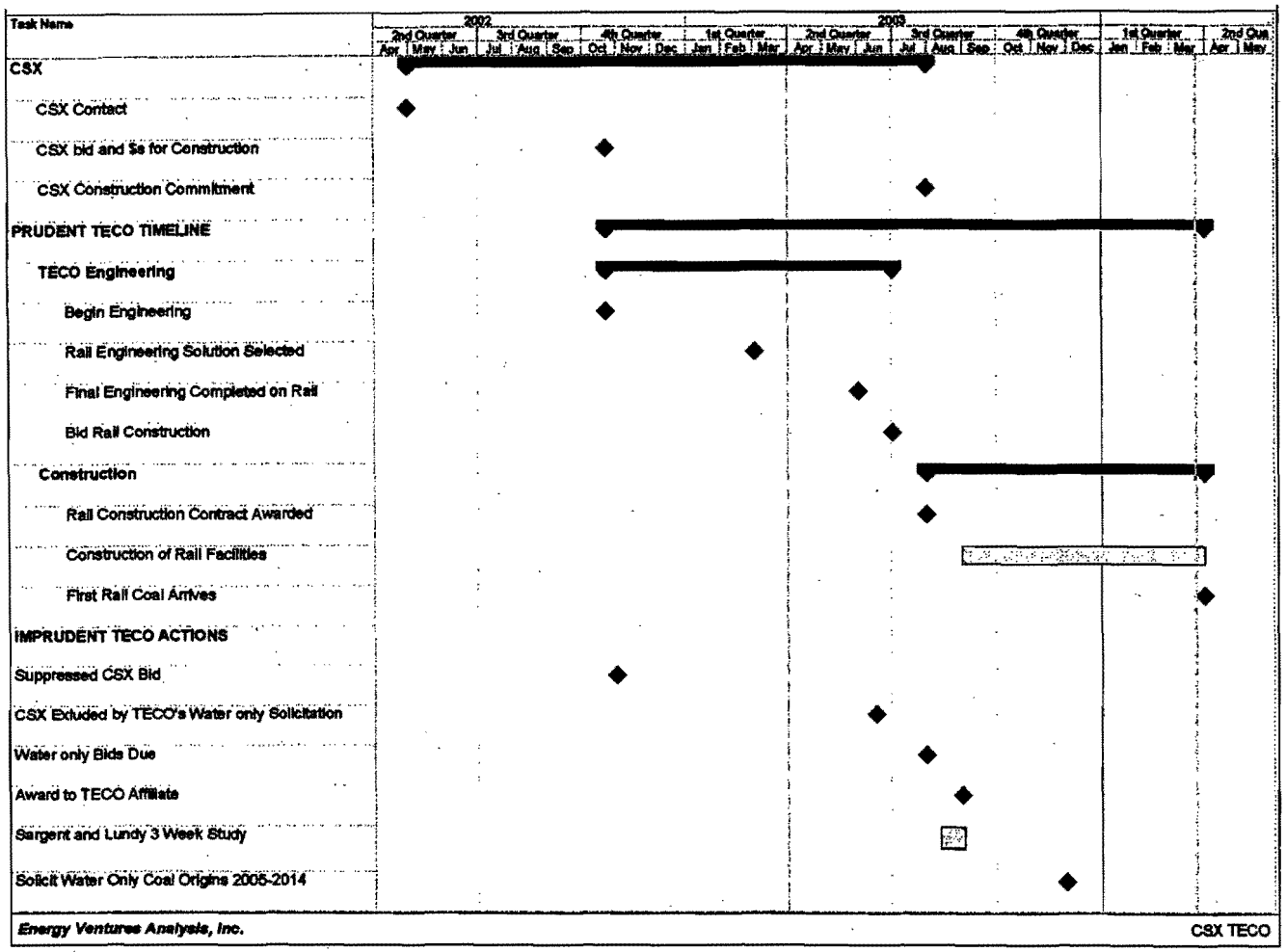
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 31
COMPANY/ CSX
WITNESS: RLS-3
DATE: 05/27-28/04

CONFIDENTIAL

(RLS-4)	**CONFIDENTIAL,** Screening Analysis, Water vs. Rail Coal, October 2002

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 32
COMPANY/ CSX
WITNESS: RLS-4
DATE: 05/27-28/04

RLS Exhibit 5
PROJECT TIMELINE'S FOR TECO ACTIONS VS. TECO'S INACTION



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 33
COMPANY/ CSX RLS-5
WITNESS:
DATE: 05/22-28/04

EXHIBIT NO. 33 (RLS-5)
ROBERT L. SANSOM - CSXT
DOCKET NO. 031033-EI
PAGE 1 OF 1

EXHIBITS 6a, 6b, AND 6c TO DR. SANSOM'S TESTIMONY ARE CONFIDENTIAL AND HAVE BEEN REDACTED FROM THIS PUBLICLY FILED VERSION OF HIS TESTIMONY.

CONFIDENTIAL

(RLS-6a)	**CONFIDENTIAL,** Evaluation of Rail vs. Water Delivery Economics for Western Kentucky Coal in 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 34
COMPANY/ CSX
WITNESS: RLS-6a
DATE: 05/27-28/04

CONFIDENTIAL

(RLS-6b)	**CONFIDENTIAL,** Evaluation of Rail vs. Water Delivery Economics for Pitt 8 Coal in 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 35
COMPANY/ CSX
WITNESS: RLS-6b
DATE: 05/27-28/04

CONFIDENTIAL

(RLS-6c)	**CONFIDENTIAL,** Evaluation of Rail vs. Water Delivery in 2004 for Indiana Coal (Summerville Mine)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 36
COMPANY/ CSX
WITNESS: RLS-6c
DATE: 05/27-28/04

RLS Exhibit 7
WATER LOSSES AND HIGHER INVENTORY COSTS

(1) Extra cost of water route movement caused by BTU loss due to oxidation, moisture and extra handling, is 2%. Assuming the delivered cost is $45/ton (a non-confidential placeholder), the loss is (.02) (45) = 90 cents/ton. On 5 MMTpy this is $4.5 million/year.

(2) Extra working capital caused by longer transit time via water route:

River Barge Transit	6 days
Unload at Electro Coal	2 days
On Ground at ECT	30 days
Cross Gulf & Unload	6 days
Subtotal	44 days
vs. Rail	7 days
Net Additional Time	37 days

(5 MMTpy) (37 days / 365) ($45/ton) (10% per year Charge) = $2,280,822 in capital cost per year.

(3) Added cost of extra inventory at Electro Coal, and Big Bend vs. a typical all rail delivery utility inventory of 45 to 60 days. If the rough burn rate is 450,000 tpm for Big Bend and Polk, an extra 60 days of inventory minus the 30 days already included in (2) above results in the following additional inventory carrying charge of:

(450,000 tons) ($45/ton) (10%) = $2,025,000 per year.

(4) Added costs of evaporating moisture at the boiler @ $0.25/ton times 5 MMTpy = $1,250,000.

(5) Total extra cost of water route per year.

	Dollars
Losses	4,500,000
Working Capital	2,280,822
Additional Inventory	2,025,000
Evaporation losses in boiler	1,250,000
Total	**10,055,822**

Divided by 5 MMTpy = $2.011/ton.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 37
COMPANY/ CSX
WITNESS: RLS-7
DATE: 05/27-28/04

EXHIBIT NO. 37 (RLS-7)
ROBERT L. SANSOM - CSXT
DOCKET NO. 031033-EI
PAGE 1 OF 2

MOSITURE LOSSES ON
COAL MOVEMENT BY WATER
THROUGH NEW ORLEANS

Ashland Coal

Conclusion 300 Btu / 2 to 2 1/2% / $1.20 ton

Discussion 5/4/88
Rick J. Fiesher
Manager, Technical Services
(304) 526-3631

Said on water route to N.O. can count on moisture loss of 2 to 2 1/2% or 300 Btu in uncovered river barge movements. They have carefully collected data on export movements to Italy. He estimates this cost at $1.20/ton losing 300 Btu. During dry spell can be as low as 1% but that is minimum; you can count on 2 to 2 1/2%.

Two years ago went to covered river barges @ 15 cents/ton cost now only 0.2% to 0.3% loss.

Experience no significant losses from bottom dump hoppers thru leakage.

Southern Company Services (5/3/88)

Note used pentalty of $1.00/ton per % moisture in Daniel solicit.

Talked to Mr. Henshaw

1. Southern Company studied wind losses on Bit. Coal from Utah/Colorado to Daniel, MS. Sprayed every other car and tested carefully. Found no losses from wind even if untreated. Coal vibrates down quickly.

2. Moisture losses via water to Watson. Have been studied this carefully. Result 1% or 150 Btu/lb is the best # to use and this is for all barge to Watson Illinois Basin Coal w/o transloading at New Orleans, which would add to moisture addition.

3. Also you must evaporate the moisture in boiler - affects Heat Rate. Their estimate 25 cent/ton penalty for added moisture.

4. Are there losses from bottom dump cars? ANS No. There is no leakage. Had a few cars with bad doors, used wrong metal on Aluminum cars. These were replaced.

5. No oxidation of bit coals in movement.

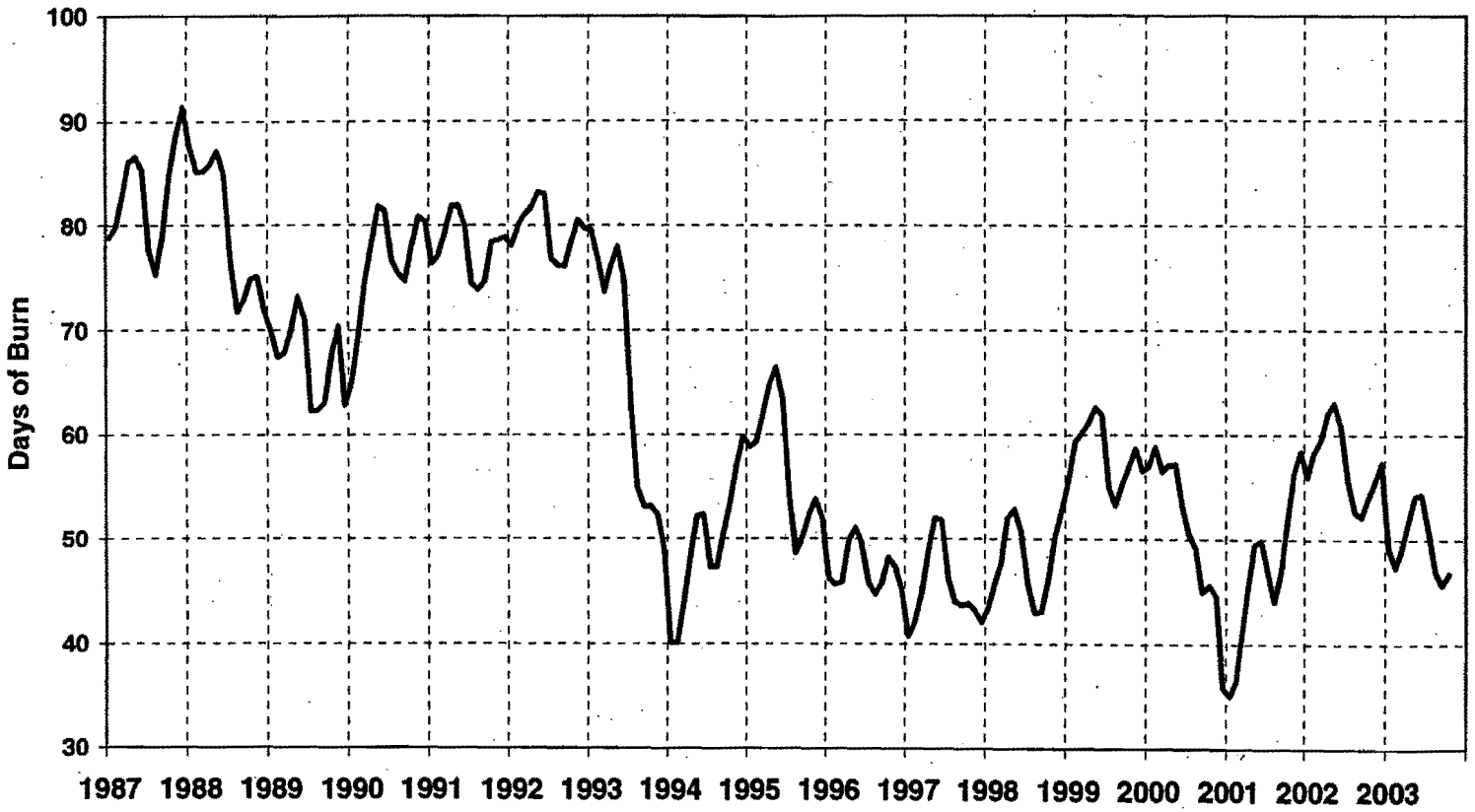
6. Time in transit big factor in moisture addition.

7. Would you know if losses from bottom dump? ANS Yes. I would know. "It is not a factor."

EXHIBIT NO. ____ (RLS-7)
ROBERT L. SANSOM - CSXT
DOCKET NO. 031033-EI
PAGE 2 OF 2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 38
COMPANY/ CSX
WITNESS: RLS-8
DATE: 05/27-28/04

RLS Exhibit 8
EASTERN U.S. UTILITY STOCKPILES DAYS OF BURN – NOVEMBER 2003



Note: 1999 Data Includes NUGs
Source: FERC and EIA

EXHIBIT NO. 38 (RLS-8)
ROBERT L. SANSOM - CSXT
DOCKET NO. 031033-EI
PAGE 1 OF 1

EXHIBITS 9a, 9b, AND 9c TO DR. SANSOM'S TESTIMONY ARE CONFIDENTIAL AND HAVE BEEN REDACTED FROM THIS PUBLICLY FILED VERSION OF HIS TESTIMONY.

CONFIDENTIAL

(RLS-9a)	**CONFIDENTIAL,** Summary of TECO Overpayments in 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 39
COMPANY/ CSX
WITNESS: RLS-9a
DATE: 05/27-28/04

CONFIDENTIAL

(RLS-9b)	**CONFIDENTIAL,** TECO Overpayments in 2004-Pitt 8 Coal from Northern Appalachia

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 40
COMPANY/ CSX
WITNESS: RLS-9b
DATE: 05/27-28/04

CONFIDENTIAL

(RLS-9c)	**CONFIDENTIAL,** TECO Overpayments on Illinois Basin Coal, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 41
COMPANY/ CSX
WITNESS: RLS-9c
DATE: 05/27-28/04

RESUME OF

JOHN B. STAMBERG, P.E.

EDUCATIONAL BACKGROUND

1967	M.S. (Sanitary Civil Engineering), Stanford University
1966	B.S. (Civil Engineering), University of Maryland

PROFESSIONAL EXPERIENCE

1981-Present **Energy Ventures Analysis, Inc.**
Vice President

Mr. Stamberg is responsible for directing Energy Ventures Analysis, Inc. (EVA) engineering studies. His areas of expertise include utility and industrial boilers; combustion turbine and combined cycle powerplants; electric, combustion turbine and reciprocating powered natural gas pipeline compressors, mining engineering, and pollution control systems for air and water.

Mr. Stamberg has developed capital and O&M cost for a variety of natural gas compression options for LDC's, utilities and EPRI, including fixed speed and variable speed electrical compression, combustion turbine compression, and reciprocating compression, as well as conversion of existing reciprocating units to electric drive. He has performed numerous studies on the pipeline delivery capacity and cost of looping or adding compression to existing interstate and intrastate pipelines. He has prepared feasibility studies of routes, compression needs, and cost of supplying electric utilities and industry switching to natural gas. He has performed on-site evaluations of booster compression needed to supply new combustion turbines with the higher pressure demands of these units. He has engineered energy recovery systems for greenhouse heating using natural gas compressor drive exhaust, and evaluated compressed air energy storage and recovery to generate electricity.

Mr. Stamberg has also conducted a variety of studies of utility and industrial boiler and combustor facilities for fuel choice, efficiency, and environmental control. He has assessed a broad range of combustion, cogeneration, and environmental control systems. He recently completed work for EPRI on utility derating caused by switching pulverized coal boilers from Illinois Basin coal to various types of low-sulfur coals. He has prepared the industrial coal demand analysis for COALCAST reporting service using his knowledge of boiler engineering, boiler capital cost, and boiler operating cost.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 42
COMPANY/ CXS
WITNESS: JBS-1
DATE: 05/20-28/04

EXHIBIT NO. 42 (JBS-1)
JOHN B. STAMBERG - CSXT
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PAGE 1 OF 3

Mr. Stamberg has prepared feasibility studies, design cost evaluations, labor productivity studies and equipment inspection for the coal mining industry. His experience with underground mining covers conventional sections, continuous miners, mixed sections, and longwall having a variety of seam and roof conditions. His surface mining experience covers contour, open pit and mountaintop surface mining with large capacity draglines, shovels, or conventional truck/loader equipment. He has prepared feasibility studies, designed and inspected coal preparation facilities from those with simple coarse circuit technology to those with complex multi-circuited systems. He has conducted a variety of site investigations and sampling programs and prepared a variety of environmental assessments, reclamation studies and permit applications for the mining industry. He has used his knowledge to provide capital and operating costs for use in EVA's economic and financial analysis of mining and reclamation plans, coal price analyses, coal competition evaluation studies, and coal company acquisition studies.

1974-81 **Energy and Environmental Analysis, Inc.**
Director

In addition to his responsibilities for water pollution control, Mr. Stamberg managed both the reactivation and the conversion from natural gas or coal of industrial boilers. This work included design specifications and purchase of coal unloading, storage, ash handling, and reclaiming equipment. He was responsible for structural inspections and analysis of the boiler buildings, coal silos, and duct and stack supports. He has evaluated a second generation fluidized bed combustor (FBC) using petroleum coke as a fuel to support process steam and electricity to a petrochemical process.

Mr. Stamberg has designed a mineral processing system for Virginia Vermiculite, Ltd. which utilizes an integrated series of hydraulic sizers, classifiers, screenings, cyclones, rock floatation, vermiculite floatation, tables, vacuum filtration, and drying. He has also performed engineering and economic feasibility studies on five locations for a centralized coal cleaning and unit-train tipple in West Virginia. He has performed various coal cleaning studies for DOE, and reviewed technological developments at various DOE labs/facilities involving conventional cleaning to solvent refined coal (SRC).

Mr. Stamberg has directed and participated in a variety of environmental and permit studies for coal and mineral mining activities. He has conducted numerous site visits, prepared permit applications and prepared environmental impact statements or assessments on a variety of coal mines in most major coal producing states of Northern, Central and Southern Appalachia as well as in the western states of Colorado and Wyoming. He has done similar studies for phosphate rock, sand and gravel, limestone, and vermiculite mining industries.

1972-74 **U.S. Environmental Protection Agency**
Office of Air and Water Programs
Chief, Municipal Technology Branch

Formulated policies and regulations required to implement PL92-500. Responsible for area-wide planning, facilities planning, effluent guidelines for municipal pollution control, operation and maintenance of advanced waste treatment facilities, combined sewer control, urban run-off, and cost-effectiveness analysis.

1967-71 **U.S. Environmental Protection Agency**
Office of Research and Development
National Environmental Research Center
Chief, Biological Treatment

Developed research objectives; designed and operated pilot- to full-scale plants to achieve various effluent objectives using a variety of biological or biological/chemical treatment techniques. Did engineering development work which was the basis for design for the District of Columbia's 309 MGD advanced waste treatment at Blue Plains and numerous other advanced waste treatment plants.

HONORS

Chi Epsilon National Civil Engineering Honor Fraternity
Pi Mu Epsilon Honorary Mathematical Fraternity
Phi Kappa Phi Honor Society
Phi Theta Kappa National Honorary Scholastic Society
U.S. EPA Bronze Medal for Commendable Service

PROFESSIONAL REGISTRATION AND MEMBERSHIPS

Registered Professional Engineer, Delaware, Louisiana
Water Pollution Control Federation
Federal Water Quality Association

PATENTS AND PUBLICATIONS

Holder of Wastewater Treatment Systems and Mineral Processing Patents Pending and has 17 technical publications.

EXHIBIT NO. _____ (JBS-1)
JOHN B. STAMBERG - CSXT
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FLORIDA PUBLIC SERVICE COMMISSION
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COMPANY/ CSX
WITNESS: JRS-2
DATE: 05/27-28/04

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2003

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2003 RS MEANS SQUARE FOOT COSTS

Historical Cost Indexes

Year	National 30 City Average	Connecticut Norwalk	Connecticut Stamford	Connecticut Waterbury	Delaware Wilmington	D.C. Washington	Fort Lauderdale	Florida Jacksonville	Florida Miami	Florida Orlando	Florida Tallahassee	Florida Tampa	Georgia Albany	Georgia Atlanta	Georgia Columbus	Georgia Macon
an 2003	130.2E	137.8E	140.5E	137.1E	132.1E	123.9E	109.1E	105.7E	109.5E	108.0E	98.4E	103.9E	101.0E	116.0E	99.5E	103.0E
2002	126.7	133.5	136.2	133.9	129.4	120.3	107.1	104.6	107.4	106.7	97.3	102.8	99.7	113.0	98.3	101.9
2001	122.2	128.2	131.5	128.8	124.8	115.9	104.3	100.8	104.6	103.8	94.8	100.3	96.4	109.1	95.5	99.0
2000	118.9	121.5	126.4	123.2	117.4	113.8	102.4	99.0	101.8	101.2	93.6	98.9	94.9	106.1	94.1	97.0
1999	116.6	120.0	122.0	121.2	116.6	111.5	101.4	98.0	100.8	100.1	92.5	97.9	93.5	102.9	92.8	95.8
1998	113.6	118.8	120.8	120.1	112.3	109.6	99.4	96.2	99.0	98.4	90.9	96.3	91.4	100.8	90.4	93.3
1997	111.5	118.9	120.9	120.2	110.7	106.4	98.6	95.4	98.2	97.2	89.9	95.5	89.9	98.5	88.7	91.6
1996	108.9	117.0	119.0	118.4	108.6	105.4	95.9	92.6	95.9	95.1	88.0	93.6	86.6	94.3	83.9	88.3
1995	106.6	115.5	117.9	117.3	106.1	102.3	94.0	90.9	93.7	93.5	86.5	92.2	85.0	92.0	82.6	86.8
1994	103.0	113.9	116.4	115.8	105.0	99.6	92.2	88.9	91.8	91.5	84.5	90.2	82.3	89.6	80.6	83.7
1993	100.0	108.8	110.6	104.8	101.5	96.3	87.4	86.1	87.1	88.5	82.1	87.7	79.5	85.7	77.8	80.9
1992	97.9	107.7	109.0	103.1	100.3	94.7	85.7	84.0	85.3	87.1	80.8	86.2	78.2	84.3	76.5	79.6
1991	95.7	100.6	103.2	96.5	94.5	92.9	86.1	82.8	85.2	85.5	79.7	86.3	76.3	82.6	75.4	78.4
1990	93.2	96.3	98.9	95.1	92.5	90.4	83.9	81.1	84.0	82.9	78.4	85.0	75.0	80.4	74.0	76.9
1989	91.0	94.4	97.0	93.4	89.5	87.5	82.4	79.7	82.5	81.6	76.9	83.5	73.4	78.6	72.4	75.3
1988	88.5	92.3	94.9	91.8	87.7	85.0	80.9	78.0	81.0	80.1	75.4	81.9	71.8	76.9	70.8	73.6
1987	85.7	92.0	92.7	92.5	85.1	82.1	78.8	76.0	77.9	76.6	74.4	79.4	72.2	73.6	70.3	72.3
1986	83.7	88.2	89.7	87.8	83.8	80.8	78.9	75.0	79.9	76.2	72.3	79.1	68.5	72.0	67.5	69.8
1985	81.8	86.3	86.8	85.6	81.1	78.8	76.7	73.4	78.3	73.9	70.6	77.3	66.9	70.3	66.1	68.1
1984	80.6	82.6	83.7	82.5	79.7	79.1	73.8	72.6	75.6	73.0	69.6	76.5	65.9	68.6	65.2	67.5
1983	78.2	78.5	79.8	78.7	76.3	76.0	71.5	70.4	72.9	71.1	67.6	73.6	65.6	68.6	64.7	65.3
1982	72.1	71.7	72.0	71.8	69.1	69.4	65.4	65.2	65.7	66.0	62.8	67.7	60.1	61.9	59.3	60.0
1981	66.1	66.2	66.2	67.3	63.4	64.9	60.3	61.0	60.7	62.0	58.6	62.1	56.2	58.3	55.7	56.1
1980	60.7	60.7	60.9	62.3	58.5	59.6	55.3	55.8	56.5	56.7	53.5	57.2	51.7	54.0	51.1	51.3
1975	43.7	44.7	45.0	46.3	42.9	43.7	42.1	40.3	43.2	41.5	38.1	41.3	37.5	38.4	36.2	36.5
1970	27.8	28.1	28.2	28.9	27.0	26.3	25.7	22.8	27.0	26.2	24.5	24.2	23.8	25.2	22.8	23.4
1965	21.5	21.6	21.7	22.2	20.9	21.8	19.8	17.4	19.3	20.2	18.9	18.6	18.3	19.8	17.6	18.0
1960	19.5	19.7	19.7	20.2	18.9	19.4	18.0	15.8	17.6	18.3	17.2	16.9	16.7	17.1	16.0	16.4
1955	16.3	16.5	16.5	17.0	15.9	16.3	15.1	13.2	14.7	15.4	14.4	14.1	14.0	14.4	13.4	13.7
1950	13.5	13.6	13.7	14.0	13.1	13.4	12.5	11.0	12.2	12.7	11.9	11.7	11.5	11.9	11.0	11.3
1945	8.6	8.7	8.7	8.9	8.4	8.6	7.9	7.0	7.8	8.1	7.6	7.5	7.4	7.6	7.0	7.2
1940	6.6	6.7	6.7	6.9	6.4	6.6	6.1	5.4	6.0	6.2	5.8	5.7	5.7	5.8	5.5	5.6

Year	National 30 City Average	Georgia Savannah	Hawaii Honolulu	Idaho Boise	Idaho Pocatello	Illinois Chicago	Illinois Decatur	Illinois Joliet	Illinois Peoria	Illinois Rockford	Illinois Springfield	Indiana Anderson	Indiana Evansville	Indiana Fort Wayne	Indiana Gary	Indiana Indianapolis
2003	130.2E	103.4E	159.9E	120.4E	119.1E	147.0E	127.1E	141.9E	132.8E	135.7E	128.8E	119.6E	121.0E	118.8E	131.7E	127.6E
2002	126.7	102.0	157.2	118.3	117.1	141.2	123.8	138.5	129.6	132.9	125.3	117.5	119.0	116.4	129.1	120.5
2001	122.2	99.0	150.0	114.3	113.4	135.8	120.1	133.7	124.3	127.8	119.8	113.4	115.6	112.1	123.4	116.4
2000	118.9	97.6	144.8	112.9	112.1	131.2	115.1	124.6	119.0	122.2	116.2	109.8	111.5	108.4	117.8	113.2
1999	116.6	96.0	143.0	110.2	109.6	129.6	113.0	122.6	116.4	120.7	113.8	107.1	109.3	106.8	112.8	110.6
1998	113.6	93.7	140.4	107.4	107.0	125.2	110.1	119.8	113.8	115.5	111.1	105.0	107.2	104.5	111.1	108.0
1997	111.5	92.0	139.8	104.6	104.7	121.3	107.8	117.5	111.5	113.1	108.9	101.9	104.4	101.8	110.3	105.2
1996	108.9	88.6	134.5	102.2	102.1	118.8	106.6	116.2	109.3	111.5	106.5	100.0	102.1	99.9	107.5	102.7
1995	105.6	87.4	130.3	99.5	98.2	114.2	98.5	110.5	102.3	103.6	98.1	96.4	97.2	95.0	100.7	100.1
1994	103.0	85.3	124.0	94.8	95.0	111.3	97.3	108.9	100.9	102.2	97.0	93.6	95.8	93.6	99.1	97.1
1993	100.0	82.0	122.0	92.2	92.1	107.6	95.6	106.8	98.9	99.6	95.2	91.2	94.3	91.5	96.7	93.9
1992	97.9	80.8	120.0	91.0	91.0	104.3	94.4	104.2	97.3	98.2	94.0	89.5	92.9	89.9	95.0	91.5
1991	95.7	79.5	106.1	89.5	89.4	100.9	92.3	100.0	95.9	95.8	91.5	87.8	91.4	88.3	93.3	89.1
1990	93.2	77.9	104.7	88.2	88.1	98.4	90.9	98.4	93.7	94.0	90.1	84.6	89.3	83.4	88.4	87.1
1989	91.0	76.0	102.8	86.6	86.5	93.7	89.4	92.8	91.6	92.1	88.6	82.3	87.8	81.7	86.5	85.1
1988	88.5	74.5	101.1	83.9	83.7	90.6	87.5	89.8	88.5	87.9	86.8	80.8	85.5	80.0	84.6	83.1
1987	85.7	72.0	99.1	81.4	81.5	86.6	84.4	86.7	86.3	85.2	85.0	78.8	82.4	78.1	81.7	80.4
1986	83.7	70.8	97.5	80.6	80.3	84.4	83.5	85.3	85.1	84.5	83.4	77.0	80.9	76.5	79.6	78.6
1985	81.8	68.9	94.7	78.0	78.0	82.4	81.9	83.4	83.7	83.0	81.5	75.2	79.8	75.0	77.8	77.1
1984	80.6	67.9	90.7	76.6	76.8	80.2	80.4	82.2	83.6	80.6	80.1	73.5	77.4	73.5	77.3	75.9
1983	78.2	66.3	87.2	76.0	75.8	79.0	78.8	80.6	81.5	78.9	78.8	70.9	75.0	71.2	75.2	74.0
1982	72.1	61.1	79.3	71.0	70.1	75.0	72.7	74.4	75.3	72.6	72.7	66.4	69.8	67.1	70.5	68.2
1981	66.1	57.1	73.4	65.4	64.8	68.6	67.2	68.8	70.3	67.3	67.0	61.5	64.3	61.5	65.3	62.4
1980	60.7	52.2	68.9	60.3	59.5	62.8	62.3	63.4	64.5	61.6	61.1	56.5	59.0	56.7	59.8	57.9
1975	43.7	36.9	44.6	40.8	40.5	45.7	43.1	44.5	44.7	42.7	42.4	39.5	41.7	39.9	41.9	40.6
1970	27.8	21.0	30.4	26.7	26.6	29.1	28.0	28.6	29.0	27.5	27.6	25.4	26.4	25.5	27.1	26.2
1965	21.5	16.4	21.8	20.6	20.5	22.7	21.5	22.1	22.4	21.2	21.3	19.5	20.4	19.7	20.8	20.7
1960	19.5	14.9	19.8	18.7	18.6	20.2	19.6	20.0	20.3	19.2	19.3	17.7	18.7	17.9	18.9	18.4
1955	16.3	12.5	16.6	15.7	15.6	16.9	16.4	16.8	17.0	16.1	16.2	14.9	15.7	15.0	15.9	15.5
1950	13.5	10.3	13.7	13.0	12.9	14.0	13.6	13.9	14.0	13.3	13.4	12.3	12.9	12.4	13.1	12.8
1945	8.6	6.6	8.8	8.3	8.2	8.9	8.6	8.9	9.0	8.5	8.6	7.8	8.3	7.9	8.4	8.1
1940	6.6	5.1	6.8	6.4	6.3	6.9	6.7	6.8	6.9	6.5	6.6	6.0	6.4	6.1	6.5	6.3

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MARSHALL & SWIFT
THE BUILDING COST PEOPLE

1999 DODGE UNIT COST BOOK

	01 - General Requirements	02 - Sitework	2a) Demolition	03 - Concrete	3a) Formwork	3b) Reinforcement	3c) Concrete only	04 - Masonry	05 - Metals	06 - Wood and Plastics	07 - Therm. And Moist. Prot.	7a) Insulation	7b) Roofing	08 - Doors and Windows	09 - Finishes	9a) Lath and Plaster	9b) Drywall	9c) Flooring	9d) Painting	Divisions 10 through 14	15 - Mechanical	16 - Electrical	Overall
Florida																							
324	0.71	0.87	0.69	0.83	0.79	0.80	0.87	0.78	0.71	0.92	0.86	0.90	0.80	0.84	0.77	0.75	0.88	0.79	0.70	0.86	0.91	0.90	0.84
325	0.72	0.91	0.69	0.84	0.81	0.78	0.90	0.82	0.71	0.94	0.87	0.90	0.83	0.85	0.85	0.86	0.91	0.83	0.82	0.87	0.93	0.90	0.87
326	0.78	0.90	0.78	0.85	0.85	0.78	0.91	0.75	0.86	0.92	0.89	0.92	0.86	0.87	0.87	0.82	0.94	0.82	0.83	0.89	0.90	0.89	0.86
327	0.71	0.85	0.69	0.80	0.79	0.83	0.97	0.80	0.84	0.90	0.87	0.86	0.86	0.88	0.86	0.89	0.87	0.83	0.81	0.86	0.96	0.90	0.84
328	0.71	0.85	0.69	0.80	0.79	0.83	0.97	0.80	0.84	0.90	0.87	0.86	0.86	0.88	0.86	0.89	0.87	0.83	0.81	0.86	0.96	0.90	0.84
329	0.80	0.80	0.81	0.83	0.79	0.81	0.87	0.78	0.84	0.83	0.85	0.85	0.85	0.87	0.82	0.84	0.89	0.79	0.84	0.91	0.87	0.90	0.83
330	0.72	0.83	0.67	0.80	0.77	0.88	0.73	0.83	0.95	0.86	0.91	0.92	0.89	0.91	0.88	0.81	0.84	0.87	0.79	0.89	0.90	0.93	0.83
331	0.72	0.83	0.67	0.80	0.77	0.88	0.73	0.83	0.95	0.86	0.91	0.92	0.89	0.91	0.88	0.81	0.84	0.87	0.79	0.89	0.90	0.93	0.83
332	0.72	0.83	0.67	0.80	0.77	0.88	0.73	0.83	0.95	0.86	0.91	0.92	0.89	0.91	0.88	0.81	0.84	0.87	0.79	0.89	0.90	0.93	0.83
333	0.73	0.86	0.69	0.80	0.77	0.85	0.75	0.84	0.95	0.86	0.91	0.91	0.89	0.90	0.89	0.83	0.85	0.87	0.79	0.92	0.92	0.95	0.84
334	0.71	0.87	0.64	0.79	0.75	0.86	0.72	0.80	0.95	0.86	0.91	0.90	0.88	0.90	0.85	0.80	0.84	0.85	0.78	0.92	0.93	0.95	0.84
335	0.73	0.88	0.67	0.93	0.83	0.90	1.01	0.83	0.87	0.93	0.87	0.86	0.84	0.91	0.87	0.84	0.91	0.85	0.81	0.89	0.88	0.92	0.86
336	0.75	0.90	0.69	0.95	0.85	0.90	1.03	0.83	0.91	0.93	0.87	0.87	0.84	0.91	0.88	0.86	0.93	0.84	0.84	0.90	0.88	0.90	0.87
337	0.74	0.88	0.69	0.94	0.83	0.90	1.01	0.84	0.87	0.93	0.87	0.86	0.84	0.91	0.87	0.84	0.91	0.85	0.87	0.89	0.88	0.92	0.86
338	0.74	0.88	0.69	0.93	0.82	0.90	1.01	0.84	0.87	0.92	0.87	0.87	0.84	0.91	0.87	0.84	0.91	0.85	0.82	0.89	0.88	0.92	0.86
339	0.70	0.87	0.65	0.88	0.75	0.87	0.97	0.79	0.87	0.88	0.86	0.83	0.85	0.88	0.83	0.84	0.84	0.82	0.75	0.86	0.87	0.91	0.83
340	0.72	0.83	0.67	0.80	0.77	0.88	0.73	0.83	0.95	0.86	0.91	0.92	0.89	0.91	0.88	0.81	0.84	0.87	0.79	0.89	0.90	0.93	0.83
341	0.70	0.87	0.65	0.88	0.75	0.87	0.97	0.79	0.87	0.88	0.86	0.83	0.85	0.88	0.83	0.84	0.84	0.82	0.75	0.86	0.87	0.91	0.83
342	0.73	0.88	0.67	0.93	0.83	0.90	1.01	0.83	0.87	0.93	0.87	0.86	0.84	0.91	0.87	0.84	0.91	0.85	0.81	0.89	0.88	0.92	0.86
344	0.73	0.88	0.67	0.93	0.83	0.90	1.01	0.83	0.87	0.93	0.87	0.86	0.84	0.91	0.87	0.84	0.91	0.85	0.81	0.89	0.88	0.92	0.86
345	0.73	0.88	0.67	0.93	0.83	0.90	1.01	0.83	0.87	0.93	0.87	0.86	0.84	0.91	0.87	0.84	0.91	0.85	0.81	0.89	0.88	0.92	0.86
347	0.71	0.85	0.69	0.88	0.79	0.83	0.97	0.80	0.84	0.90	0.87	0.86	0.86	0.88	0.86	0.89	0.87	0.83	0.81	0.86	0.86	0.90	0.84
348	0.71	0.87	0.64	0.79	0.75	0.86	0.72	0.80	0.95	0.86	0.91	0.90	0.88	0.90	0.85	0.80	0.84	0.85	0.78	0.92	0.93	0.95	0.84
Georgia																							
300	0.75	0.89	0.73	0.89	0.80	0.90	0.93	0.83	0.86	0.90	0.90	0.91	0.88	0.89	0.87	0.92	0.87	0.85	0.87	0.89	0.94	0.98	0.87
301	0.75	0.89	0.73	0.89	0.80	0.90	0.93	0.83	0.86	0.90	0.90	0.91	0.88	0.89	0.87	0.92	0.87	0.85	0.87	0.89	0.94	0.98	0.87
302	0.78	0.94	0.73	0.91	0.82	0.95	0.94	0.85	0.92	0.92	0.91	0.91	0.88	0.91	0.89	0.92	0.89	0.87	0.86	0.92	0.97	1.00	0.90
303	0.78	0.94	0.73	0.91	0.82	0.95	0.94	0.85	0.92	0.92	0.91	0.91	0.88	0.91	0.89	0.92	0.89	0.87	0.86	0.92	0.97	1.00	0.90
304	0.71	0.88	0.66	0.82	0.84	0.82	0.80	0.74	0.85	0.93	0.88	0.90	0.85	0.87	0.81	0.78	0.94	0.80	0.69	0.87	0.93	0.94	0.85
305	0.72	0.87	0.70	0.87	0.79	0.83	0.93	0.84	0.82	0.89	0.89	0.89	0.88	0.87	0.86	0.88	0.86	0.84	0.85	0.87	0.92	0.96	0.86
306	0.73	0.87	0.70	0.88	0.79	0.85	0.93	0.84	0.82	0.89	0.89	0.89	0.88	0.88	0.86	0.88	0.86	0.85	0.85	0.88	0.92	0.96	0.86
307	0.75	0.89	0.73	0.89	0.80	0.90	0.93	0.83	0.86	0.90	0.90	0.91	0.88	0.89	0.87	0.92	0.87	0.85	0.87	0.89	0.94	0.98	0.87
308	0.71	0.88	0.66	0.82	0.84	0.82	0.80	0.74	0.85	0.93	0.88	0.90	0.85	0.87	0.81	0.78	0.94	0.80	0.69	0.87	0.93	0.94	0.85
309	0.71	0.88	0.66	0.82	0.84	0.82	0.80	0.74	0.85	0.93	0.88	0.90	0.85	0.87	0.81	0.78	0.94	0.80	0.69	0.87	0.93	0.94	0.85
310	0.70	0.88	0.65	0.87	0.81	0.91	0.88	0.75	0.87	0.92	0.91	0.93	0.86	0.88	0.81	0.80	0.89	0.82	0.80	0.87	0.93	0.94	0.85
311	0.78	0.94	0.73	0.91	0.82	0.95	0.94	0.85	0.92	0.92	0.91	0.91	0.88	0.91	0.89	0.92	0.89	0.87	0.86	0.92	0.97	1.00	0.90
312	0.71	0.89	0.68	0.89	0.79	0.95	0.93	0.78	0.86	0.92	0.89	0.89	0.87	0.87	0.80	0.83	0.86	0.82	0.82	0.87	0.93	0.94	0.85
313	0.77	0.88	0.68	0.84	0.82	0.88	0.85	0.77	0.89	0.93	0.93	0.99	0.85	0.84	0.82	0.78	0.92	0.84	0.83	0.87	0.91	0.91	0.86
314	0.72	0.88	0.68	0.84	0.82	0.88	0.85	0.77	0.89	0.93	0.93	0.99	0.85	0.84	0.82	0.78	0.92	0.84	0.83	0.87	0.91	0.91	0.86
315	0.67	0.85	0.61	0.84	0.77	0.81	0.90	0.75	0.82	0.90	0.85	0.90	0.79	0.82	0.79	0.83	0.87	0.81	0.73	0.86	0.89	0.88	0.82
316	0.60	0.85	0.65	0.84	0.78	0.82	0.90	0.72	0.82	0.89	0.84	0.87	0.80	0.84	0.74	0.77	0.88	0.78	0.71	0.86	0.87	0.86	0.81

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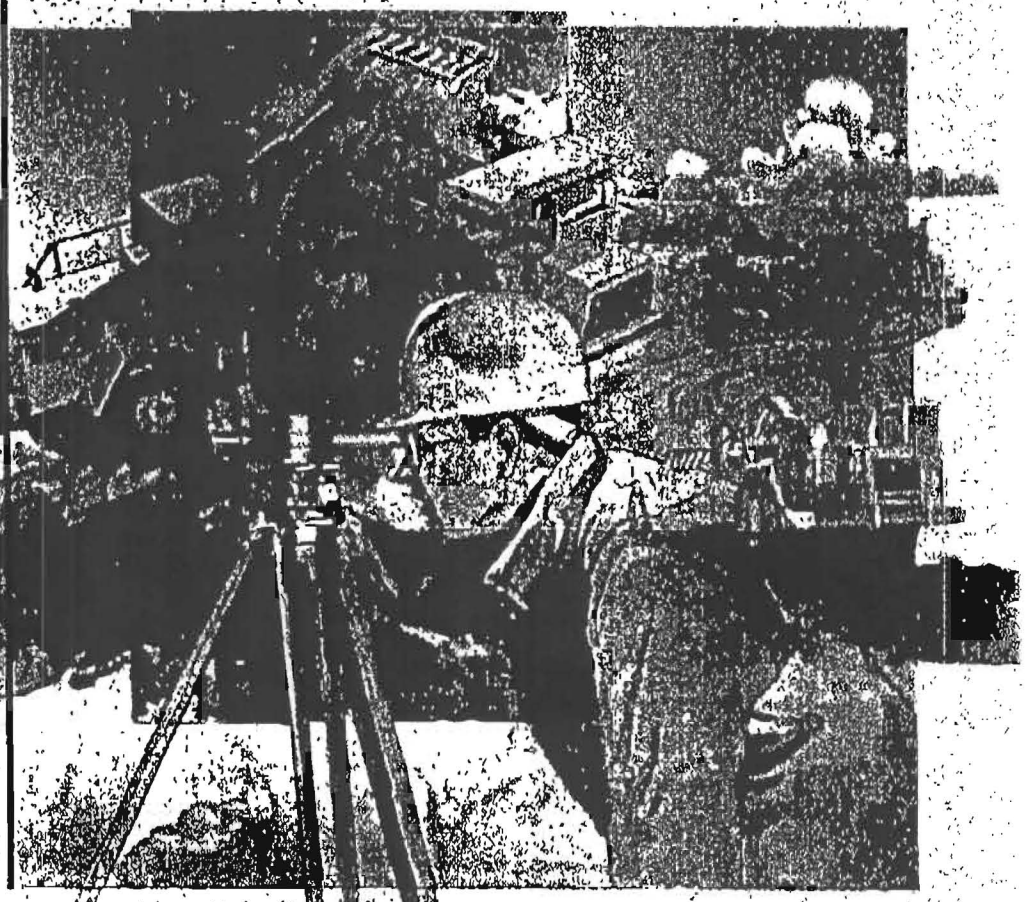

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EXHIBIT NO. _____ (JBS-2)
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Location Factors

Costs shown in *Means cost data publications* are based on National Averages for materials and installation. To adjust these costs to a specific location, simply multiply the base cost by the factor and divide by 100 for that city. The data is arranged alphabetically by state and postal zip code numbers. For a city not listed, use the factor for a nearby city with similar economic characteristics.

STATE/ZIP	CITY	MAT.	INST.	TOTAL
ALABAMA				
350-352	Birmingham	96.5	77.0	87.1
354	Tuscaloosa	96.2	62.2	79.8
355	Jasper	97.5	53.3	76.2
356	Decatur	96.3	68.4	82.8
357-358	Huntsville	96.1	68.4	82.7
359	Gadsden	97.0	66.2	82.2
360-361	Montgomery	97.1	60.8	79.6
362	Anniston	95.1	53.1	74.8
363	Dothan	96.6	59.5	78.7
364	Evergreen	95.9	61.3	79.2
365-366	Mobile	97.0	68.9	83.4
367	Selma	96.2	59.5	78.5
368	Phenix City	96.9	60.1	79.2
369	Butler	96.3	59.5	78.6
ALASKA				
995-996	Anchorage	133.1	117.7	125.7
997	Fairbanks	129.3	120.7	125.1
998	Juneau	131.2	118.0	124.8
999	Ketchikan	140.6	118.0	129.7
ARIZONA				
850,853	Phoenix	100.6	79.0	90.2
852	Mesa/Tempe	100.6	69.5	85.6
855	Globe	101.4	73.9	88.1
856-857	Tucson	99.4	77.6	88.9
859	Show Low	101.5	74.0	88.2
860	Flagstaff	102.8	78.2	91.0
863	Prescott	100.3	73.6	87.4
864	Kingman	99.1	74.4	87.2
865	Chambers	99.1	74.2	87.1
ARKANSAS				
716	Pine Bluff	95.4	62.0	79.3
717	Camden	93.8	47.5	71.5
718	Texarkana	94.7	53.4	74.8
719	Hot Springs	93.0	46.9	70.7
720-722	Little Rock	95.9	62.3	79.7
723	West Memphis	95.2	64.8	80.5
724	Jonesboro	95.2	64.8	80.5
725	Batesville	93.9	59.1	77.1
726	Harrison	95.3	59.1	77.8
727	Fayetteville	92.4	40.8	67.5
728	Russellville	94.1	56.9	76.1
729	Fort Smith	96.1	60.7	79.0
CALIFORNIA				
900-902	Los Angeles	105.0	116.5	110.6
903-905	Inglewood	101.2	114.3	107.5
906-908	Long Beach	103.0	114.3	108.5
910-912	Pasadena	100.6	114.4	107.2
913-916	Van Nuys	104.5	114.1	109.2
917-918	Alhambra	103.2	114.4	108.6
919-921	San Diego	104.9	109.5	107.1
922	Palm Springs	102.5	112.0	107.1
923-924	San Bernardino	100.1	111.8	105.7
925	Riverside	104.6	112.8	108.6
926-927	Santa Ana	102.3	112.3	107.2
928	Anaheim	104.9	115.1	109.8
930	Oxnard	105.4	113.8	109.4
931	Santa Barbara	104.6	112.9	108.6
932-933	Bakersfield	104.3	107.0	105.6
934	San Luis Obispo	106.2	111.5	108.8
935	Mojave	102.8	108.9	105.8
936-938	Fresno	105.3	112.3	108.7
939	Salinas	107.3	116.7	111.8
940-941	San Francisco	111.0	138.2	124.2
942,956-958	Sacramento	106.9	114.5	110.5
943	Palo Alto	105.0	127.8	116.0
944	San Mateo	108.0	127.1	117.2
945	Vallejo	105.5	127.0	115.9
946	Oakland	109.9	126.5	117.9
947	Berkeley	109.5	127.9	118.4
948	Richmond	109.3	125.3	117.0
949	San Rafael	111.2	125.7	118.2
950	Santa Cruz	110.8	118.4	114.5
CALIFORNIA (CONT'D)				
951	San Jose	110.1	129.7	119.6
952	Stockton	105.9	113.2	109.4
953	Modesto	106.0	113.3	109.5
954	Santa Rosa	107.2	129.0	117.7
955	Eureka	108.6	112.1	110.3
959	Marysville	107.3	113.7	110.4
960	Redding	108.4	108.9	108.6
961	Susanville	108.6	108.3	108.5
COLORADO				
800-802	Denver	101.9	84.8	93.6
803	Boulder	100.0	69.5	85.3
804	Golden	102.4	76.9	90.1
805	Fort Collins	103.2	77.9	91.0
806	Greeley	100.2	69.1	85.2
807	Fort Morgan	100.7	77.7	89.6
808-809	Colorado Springs	100.7	80.3	90.8
810	Pueblo	102.6	79.2	91.3
811	Alamosa	101.9	70.3	86.2
812	Salida	104.8	70.4	88.2
813	Durango	105.6	66.0	86.5
814	Montrose	103.9	63.3	84.3
815	Grand Junction	106.9	63.7	86.0
816	Glenwood Springs	105.0	75.6	90.6
CONNECTICUT				
060	New Britain	103.0	105.0	104.0
061	Hartford	103.3	105.3	104.3
062	Willimantic	103.8	104.0	103.9
063	New London	100.2	105.8	102.9
064	Meriden	102.9	104.5	103.7
065	New Haven	103.2	105.3	104.2
066	Bridgeport	104.4	102.5	103.5
067	Waterbury	103.7	105.0	104.4
068	Norwalk	103.7	102.7	103.2
069	Stamford	103.9	106.1	105.0
D.C.				
200-205	Washington	99.6	92.0	96.0
DELAWARE				
197	Newark	99.5	97.2	98.4
198	Wilmington	98.8	97.2	98.0
199	Dover	99.5	97.2	98.4
FLORIDA				
320,322	Jacksonville	98.6	68.6	84.1
321	Daytona Beach	98.7	75.9	87.7
323	Tallahassee	99.1	58.6	79.6
324	Panama City	99.6	45.6	73.5
325	Pensacola	99.2	68.5	84.4
326	Gainesville	100.0	64.6	82.9
327-328,347	Orlando	100.4	70.6	86.1
329	Melbourne	100.6	75.1	88.3
330-332,340	Miami	98.0	74.3	86.6
333	Fort Lauderdale	97.9	75.1	86.9
334,349	West Palm Beach	96.8	69.2	83.5
335-336,346	Tampa	99.8	67.6	84.2
337	St. Petersburg	101.5	67.5	85.1
338	Lakeland	98.5	67.3	83.5
339	Fort Myers	98.2	64.2	81.8
342	Sarasota	100.0	64.6	82.9
GEORGIA				
300-303,399	Atlanta	96.9	79.3	88.4
304	Statesboro	96.8	36.9	67.9
305	Gainesville	96.0	52.2	74.9
306	Athens	95.1	64.5	80.3
307	Dalton	96.8	34.8	66.9
308-309	Augusta	95.7	62.2	79.8
310-312	Macon	95.7	67.6	82.2
313-314	Savannah	97.8	65.6	82.3
315	Waycross	97.7	52.0	75.6
316	Valdosta	97.3	55.6	77.1
317	Albany	97.4	61.6	80.1
318-319	Columbus	97.5	59.7	79.2

EXHIBIT NO. _____ (JBS-2)
JOHN B. STAMBERG - CSXT
DOCKET NO. 031033-EI
PAGE 6 OF 6

FAX

To: John Stamberg

Voice Phone Number:

From: Richard Samit

Company: Cubic Storage Systems, INC.

Fax Number: 813 287 2807

Voice Number:

MESSAGE

John,

Here is the budget based on the information you provided. I am trying to anticipate steel prices for the short term. Lets keep in touch as the project parameters unfold. We cannot figure any footings for the stands until location and soil testing is completed.

Thank You,

Richard Samit

Date: 3/24/04

Pages: 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 44
COMPANY/ CSX
WITNESS: JBS-3
DATE: 05/27-28-04

EXHIBIT NO. 44 (JBS-3)
JOHN B. STAMBERG - CSXT
DOCKET NO. 031033-EI
PAGE 1 OF 10

Cubic Storage & Office Systems, Inc.

March 22, 2004

Energy Ventures

Project: Tampa – CSX coal distribution conveyor.

Attention: Mr. John Stamberg

We would like to submit BUDGET system pricing for the
Coal transport conveyor as discussed for your Project.

P-1- P-4 – 525' long Truss frame, trough belt conveyor.
2100 feet total length x 54" wide belt with Supports on 30' centers.
Throughput of 2500 tons @ 740 FPM
Horizontal design to be placed on concrete footings
Each section is powered by a 75HP- 3 phase motor.
Galvanized sheet metal covers over the belt open bottom
Other specifications and design criteria will follow once the full specification is provided.

Budget price delivered and installed less sales tax.... $ 1,300,000.00

Terms: To be specified
Warranty: On mechanical components is 1 year. The warranty does not include labor costs.
Delivery: 8-12 weeks A.R.O.
F.O.B: Delivered
Installation: Included
Sales tax: Not included

All materials, labor and delivery charges are subject sales tax, not included in the above price. This is a budget proposal is not valid as an order. Due to the volatility in the steel market prices are subject to change daily.

Thank You,

Richard Samit

4917 W. Nassau St. Tampa, FL. 33607 - PH: (813) 289-7795 FAX: (813) 287-2807

EXHIBIT NO. _____ (JBS-3)
JOHN B. STAMBERG - CSXT
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Approach #1 @ 3800 LF

Adjust

Cubic Storage and Office Supply, Inc

$\frac{\$1,300,000 \text{ modified}}{2100 \text{ LF}} \times 3800 = \$2,352,380$

Hoisted 30' on Cubic

10 foot deep /

$\frac{3800}{30' \text{ span}} \times 2$ = 130 caissons

24" dia @ $29/VLF

@ 3.14 ft² caisson

130 caissons x 10ft x $29/VLF = 37,700

~~2500~~ Pickup Truck

$\frac{4500\#}{4 \times 0.5} = 2250\#$ Soil mass about 2250#/ft²

12" @ 2.45 ft²/LF OK with pickup

3.14 x 2250+ = Over 7000#

Caissons

Steel (Rebar)

$\frac{130 \times 200\#/\text{caisson}}{2000} \times 530 + 51.50$ = $7560

Say $50,000

EXHIBIT NO. _____ (JBS-3)
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Excavation	380,000	100/LF
Lights		
$780 130 low pressure sodium @ 135 watts 30' on supports	101,400	
Pipe for Fire Protection System		
59.50 x 3800	226,100	
Check Valve 4 x 880	3520	
Valves Risers 20 x 1150 or Heads	23,000	
Sub Total	$784,020	
Conveyor	$2,352,380	
	$3,136,400	
Escalation 1,061		
Engr / Indirects 1.164		
	$3,873,467	
3800	= $1020	

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Steel Supports for Short Conveyor

$\frac{\$265{,}000}{3300}$ for Elevated Convey = $\$80.30$/LF

10

Short Conveyor $\left(\underset{\$1100.30}{\$1020} + 80.30\right) \times 500 = 550{,}150$

EXHIBIT NO. _____ (JBS-3)
JOHN B. STAMBERG - CSXT
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151 | Pipe & Fittings

151 550 | Plastic Pipe

			CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	1999 BARE COSTS MAT.	LABOR	EQUIP.	TOTAL	TOTAL INCL O&P	
558	7390	2"	Q-1	26	.615	Ea.	4.34	18.05		22.39	32.50	558
	7400	2-1/2"		24	.667		6.70	19.55		26.25	37	
	7410	3"		18	.889		7.40	26		33.40	47.50	
	7420	4"		15	1.067		9.35	31.50		40.85	58	
	7430	6"		10	1.600		14.70	47		61.70	87	
	7440	8"	Q-2	11	2.182		24	66.50		90.50	128	
	7550	Union, schedule 40, socket joints, 1/2"	1 Plum	19	.421		1.71	13.75		15.46	23	
	7560	3/4"		18	.444		2.24	14.50		16.74	24.50	
	7570	1"		15	.533		2.56	17.40		19.96	29.50	
	7580	1-1/4"		14	.571		5.10	18.65		23.75	33.50	
	7590	1-1/2"		13	.615		5.75	20		25.75	37	
	7600	2"	Q-1	20	.800		7.80	23.50		31.30	44	

151 700 | Steel Pipe

701	0010	PIPE, STEEL R151 -050										701
	0020	All pipe sizes are to Spec. A-53 unless noted otherwise										
	0050	Schedule 40, threaded, with couplings, and clevis type										
	0060	hangers sized for covering, 10' O.C.										
	0540	Black, 1/4" diameter	1 Plum	66	.121	L.F.	1.20	3.95		5.15	7.30	
	0550	3/8" diameter		65	.123		1.35	4.01		5.36	7.60	
	0560	1/2" diameter		63	.127		1.15	4.14		5.29	7.50	
	0570	3/4" diameter		61	.131		1.29	4.28		5.57	7.90	
	0580	1" diameter		53	.151		1.64	4.92		6.56	9.25	
	0590	1-1/4" diameter	Q-1	89	.180		1.98	5.30		7.28	10.20	
	0600	1-1/2" diameter		80	.200		2.26	5.85		8.11	11.40	
	0610	2" diameter		64	.250		3.06	7.35		10.41	14.45	
	0620	2-1/2" diameter		50	.320		4.81	9.40		14.21	19.55	
	0630	3" diameter		43	.372		6.05	10.90		16.95	23	
	0640	3-1/2" diameter		40	.400		7.90	11.75		19.65	26.50	
	0650	4" diameter		36	.444		8.75	13.05		21.80	29.50	
	0660	5" diameter		26	.615		19.50	18.05		37.55	49	
	0670	6" diameter	Q-2	31	.774		22	23.50		45.50	59.50	
	0680	8" diameter		27	.889		31	27		58	75	
	0690	10" diameter		23	1.043		45	32		77	97.50	
	0700	12" diameter		18	1.333		62	40.50		102.50	130	
	0809	A-106, gr. A/B, seamless w/cplgs. & hangers										
	0811	1/4" diameter	1 Plum	66	.121	L.F.	2.51	3.95		6.46	8.75	
	0812	3/8" diameter		65	.123		2.37	4.01		6.38	8.70	
	0813	1/2" diameter		63	.127		2.40	4.14		6.54	8.90	
	0814	3/4" diameter		61	.131		2.56	4.28		6.84	9.30	
	0815	1" diameter		53	.151		3.05	4.92		7.97	10.80	
	0816	1-1/4" diameter	Q-1	89	.180		3.35	5.30		8.65	11.70	
	0817	1-1/2" diameter		80	.200		3.52	5.85		9.37	12.80	
	0819	A-53, 2" diameter		64	.250		3.79	7.35		11.14	15.25	
	0821	2-1/2" diameter		50	.320		6.50	9.40		15.90	21.50	
	0822	3" diameter		43	.372		8.20	10.90		19.10	26.50	
	0823	4" diameter		36	.444		12.70	13.05		25.75	34	
	1220	To delete coupling & hanger, subtract										
	1230	1/4" diam. to 3/4" diam.					31%	56%				
	1240	1" diam. to 1-1/2" diam.					23%	51%				
	1250	2" diam. to 4" diam.					23%	41%				
	1260	5" diam. to 12" diam.					21%	45%				
	1280	All pipe sizes are to Spec. A-53 unless noted otherwise										
	1281	Schedule 40, threaded, with couplings and clevis type										
	1282	hangers sized for covering, 10' O. C.										
	1290	Galvanized, 1/4" diameter	1 Plum	66	.121	L.F.	1.46	3.95		5.41	7.60	

EXHIBIT NO. _____ (JBS-3)
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023 | Tunneling, Piles & Caissons

023 600 | Driven Piles

			CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	1999 BARE COSTS MAT.	LABOR	EQUIP.	TOTAL	TOTAL INCL O&P	
612	2800	25,000 L.F. pile job, add R023 -620	B-19	8,500	.008	V.L.F.		.21	.17	.38	.53	612
	2900	Mobilization by water for barge driving rig, add								100%		

023 700 | Bored/Augered Piles

704	0010	PRESSURE INJECTED FOOTINGS or Displacement Caissons R023 -710										704
	0100	incl. mobilization and demobilization, up to 50 miles										
	0200	Uncased shafts, 30 to 80 tons cap., 17" diam., 10' depth	B-44	88	.727	V.L.F.	12.20	19.85	8.90	40.95	56	
	0300	25' depth		165	.388		8.70	10.60	4.75	24.05	32.50	
	0400	80-150 ton capacity, 22" diameter, 10' depth		80	.800		15.25	22	9.80	47.05	63.50	
	0500	20' depth		130	.492		12.20	13.45	6.05	31.70	42.50	
	0700	Cased shafts, 10 to 30 ton capacity, 10-5/8" diam., 20' depth		175	.366		8.70	9.95	4.48	23.13	31	
	0800	30' depth		240	.267		8.15	7.25	3.26	18.66	24.50	
	0850	30 to 60 ton capacity, 12" diameter, 20' depth		160	.400		12.20	10.90	4.90	28	37	
	0900	40' depth		230	.278		9.40	7.60	3.41	20.41	26.50	
	1000	80 to 100 ton capacity, 16" diameter, 20' depth		160	.400		17.45	10.90	4.90	33.25	42.50	
	1100	40' depth		230	.278		16.25	7.60	3.41	27.26	34	
	1200	110 to 140 ton capacity, 17-5/8" diameter, 20' depth		160	.400		18.75	10.90	4.90	34.55	44	
	1300	40' depth		230	.278		17.45	7.60	3.41	28.46	35.50	
	1400	140 to 175 ton capacity, 19" diameter, 20' depth		130	.492		20.50	13.45	6.05	40	51.50	
	1500	40' depth		210	.305		18.75	8.30	3.73	30.78	38.50	
	1700	Over 30' long, L.F. cost tends to be lower										
	1900	Maximum depth is about 90'										

023 800 | Caissons

804	0010	CAISSONS incl. excav., concrete, 50 lbs. reinf. per C.Y., not R023 -620										804
	0020	incl. mobilization, boulder removal, disposal										
	0100	Open style, machine drilled, to 50' deep, in stable ground, no										
	0110	casings or ground water, 18" diam., 0.065 C.Y./L.F.	B-43	200	.240	V.L.F.	4.82	5.65	8.90	19.37	24	
	0200	24" diameter, 0.116 C.Y./L.F.		190	.253		8.65	5.95	9.35	23.95	29	
	0300	30" diameter, 0.182 C.Y./L.F.		150	.320		13.50	7.55	11.85	32.90	39.50	
	0400	36" diameter, 0.262 C.Y./L.F.		125	.384		19.45	9.05	14.20	42.70	51	
	0500	48" diameter, 0.465 C.Y./L.F.		100	.480		34.50	11.30	17.75	63.55	75	
	0600	60" diameter, 0.727 C.Y./L.F.		90	.533		54	12.55	19.75	86.30	101	
	0700	72" diameter, 1.05 C.Y./L.F.		80	.600		78	14.10	22	114.10	133	
	0800	84" diameter, 1.43 C.Y./L.F.		75	.640		106	15.05	23.50	144.55	167	
	1000	For bell excavation and concrete, add										
	1020	4' bell diameter, 24" shaft, 0.444 C.Y.	B-43	20	2.400	Ea.	27	56.50	89	172.50	216	
	1040	6' bell diameter, 30" shaft, 1.57 C.Y.		5.70	8.421		96	198	310	604	760	
	1060	8' bell diameter, 36" shaft, 3.72 C.Y.		2.40	20		227	470	740	1,437	1,800	
	1080	9' bell diameter, 48" shaft, 4.48 C.Y.		2	24		273	565	890	1,728	2,150	
	1100	10' bell diameter, 60" shaft, 5.24 C.Y.		1.70	28.235		320	665	1,050	2,035	2,525	
	1120	12' bell diameter, 72" shaft, 8.74 C.Y.		1	48		535	1,125	1,775	3,435	4,275	
	1140	14' bell diameter, 84" shaft, 13.6 C.Y.		.70	68.571		830	1,625	2,525	4,980	6,225	
	1200	Open style, machine drilled, to 50' deep, in wet ground, pulled										
	1300	casing and pumping, 18" diameter, 0.065 C.Y./L.F.	B-48	160	.350	V.L.F.	4.82	8.40	12.35	25.57	32	
	1400	24" diameter, 0.116 C.Y./L.F.		125	.448		8.65	10.80	15.80	35.25	43.50	
	1500	30" diameter, 0.182 C.Y./L.F.		85	.659		13.50	15.85	23.50	52.85	65	
	1600	36" diameter, 0.262 C.Y./L.F.		60	.933		19.45	22.50	33	74.95	92.50	
	1700	48" diameter, 0.465 C.Y./L.F.	B-49	55	1.600		34.50	40	46	120.50	152	
	1800	60" diameter, 0.727 C.Y./L.F.		35	2.514		54	63	72	189	239	
	1900	72" diameter, 1.05 C.Y./L.F.		30	2.933		78	73.50	84	235.50	295	
	2000	84" diameter, 1.43 C.Y./L.F.		25	3.520		106	88.50	101	295.50	370	
	2100	For bell excavation and concrete, add										
	2120	4' bell diameter, 24" shaft, 0.444 C.Y.	B-48	19.80	2.828	Ea.	27	68	100	195	245	
	2140	6' bell diameter, 30" shaft, 1.57 C.Y.		5.70	9.825		96	236	345	677	850	
	2160	8' bell diameter, 36" shaft, 3.72 C.Y.		2.40	23.333		227	560	825	1,612	2,025	

EXHIBIT NO. _____ (JBS-3)
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032 | Concrete Reinforcement

032 100 | Reinforcing Steel

				CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	1999 BARE COSTS MAT.	LABOR	EQUIP.	TOTAL	TOTAL INCL O&P	
102	2420	12" long	R032 -080				C	230			230	253	102
	2500	3/4" diameter, for 1-1/2" I.D. pipe, 6" long						250			250	275	
	2520	12" long						410			410	455	
	2700	Screw anchor for bolts, plain, 1/2" diameter						90			90	99	
	2720	1" diameter						271			271	298	
	2740	1-1/2" diameter						450			450	495	
	2800	Screw eye bolts, 1/2" x 5" long						1,100			1,100	1,200	
	2820	1" x 9" long						4,000			4,000	4,425	
	2840	1-1/2" x 14" long						10,200			10,200	11,200	
	2900	Screw anchor bolts, 1/2" x up to 7" long						420			420	460	
	2920	1" x up to 12" long						1,375			1,375	1,500	
	3000	Slab lifting inserts, single, 3/4" dia., galv., 4" high						280			280	310	
	3010	6" high						340			340	375	
	3030	7" high						390			390	430	
	3100	1" diameter, 5" high						440			440	485	
	3120	7" high						465			465	510	
	3200	Double lifting inserts, 1" diameter, 5" high						875			875	965	
	3220	7" high						925			925	1,025	
	3330	1-1/4" diameter, 5" high						950			950	1,050	
	3500	Sleeper clips for wood sleepers, 20 ga., galv., 2" wide					M	330			330	365	
	3520	4" wide						410			410	450	
	3600	Spacers, plastic for 1" bar clearance, average						48			48	53	
	3620	For 2" bar clearance, average						58			58	64	
	3800	Subgrade chairs, 1/2" diameter, 3-1/2" high					C	270			270	297	
	3850	12" high						770			770	845	
	3900	3/4" diameter, 3-1/2" high						350			350	385	
	3950	12" high						840			840	925	
	4200	Subgrade stakes, 3/4" diameter, 12" long						277			277	305	
	4250	24" long						375			375	415	
	4300	1" diameter, 12" long						420			420	465	
	4350	24" long						630			630	690	
	4500	Tie wire, 16 ga. annealed steel, under 500 lbs.					Cwt.	80			80	88	
	4520	2,000 to 4,000 lbs.					"	75			75	82.50	
	4550	Tie wire holder, plastic case					Ea.	31			31	34	
	4600	Aluminum case					"	36			36	39.50	
104	0010	COATED REINFORCING Add to material											104
	0100	Epoxy coated, A775					Cwt.	23.50			23.50	26	
	0150	Galvanized, #3						31.50			31.50	34.50	
	0200	#4						31.50			31.50	34.50	
	0250	#5						31			31	34	
	0300	#6 or over						31			31	34	
	1000	For over 20 tons, #6 or larger, minimum						28.50			28.50	31.50	
	1500	Maximum						34.50			34.50	38	
105	0010	REINFORCING A615 Grade 40, incl. freight from mill	R032 -060										105
	0200	Average price, cut, bent, and delivered					Ton	460			480	530	
	0500	Grade 60, incl. freight from mill											
	0700	Average price, cut, bent, and delivered					Ton	460			460	505	
	1000	Reinforcing extras, add to base											
	1020	Shop bending, light					Ton	82			82	90	
	1050	Heavy						36.50			36.50	40	
	1200	Detailing under 50 tons						46.50			46.50	51.50	
	1250	50 to 150 tons						36.50			36.50	40	
	1300	150 to 500 tons						31.50			31.50	34.50	
	1350	Over 500 tons						22.50			22.50	24.50	
	1700	Listing						4.15			4.15	4.57	

For expanded coverage of these items see *Means Concrete & Masonry Cost Data 1999*

EXHIBIT NO. _____ (JBS-3)
JOHN B. STAMBERG + CSXT
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166 | Lighting

166 100 | Lighting

			CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	1999 BARE COSTS MAT.	LABOR	EQUIP.	TOTAL	TOTAL INCL O&P
115	2250	Low pressure sodium, 55 watt	1 Elec	2.70	2.963	Ea.	485	94.50		579.50	675
	2270	90 watt		12	4		535	128		663	780
	2290	180 watt		2	4		680	128		808	940
	2340	High pressure sodium, 70 watt		2.70	2.963		190	94.50		284.50	350
	2360	100 watt		2.70	2.963		215	94.50		309.50	380
	2380	150 watt		2.70	2.963		220	94.50		314.50	385
	2400	400 watt	2 Elec	4.40	3.636		335	116		451	545
	2600	1000 watt	"	4	4		500	128		628	740
	2610	Incandescent, 300 watt	1 Elec	4	2		85	64		149	189
	2620	500 watt	"	4	2		128	64		192	237
	2630	1000 watt	2 Elec	6	2.667		138	85		223	279
	2640	1500 watt	"	6	2.667		151	85		236	293
	2650	Roadway area luminaire, low pressure sodium, 135 watt	1 Elec	2	4		535	128		663	780
	2700	180 watt	"	2	4		565	128		693	810
	2720	Mercury vapor, 400 watt	2 Elec	4.40	3.636		340	116		456	550
	2730	1000 watt		4	4		425	128		553	660
	2750	Metal halide, 400 watt		4.40	3.636		410	116		526	625
	2760	1000 watt		4	4		490	128		618	730
	2780	High pressure sodium, 400 watt		4.40	3.636		465	116		581	685
	2790	1000 watt		4	4		515	128		643	755
	2800	Light poles, anchor base									
	2820	not including concrete bases									
	2840	Aluminum pole, 8' high	1 Elec	4	2	Ea.	435	64		499	575
	2850	10' high		4	2		455	64		519	595
	2860	12' high		3.80	2.105		475	67		542	625
	2870	14' high		3.40	2.353		495	75		570	655
	2880	16' high		3	2.667		545	85		630	725
	3000	20' high	R-3	2.90	6.897		595	218	47	860	1,025
	3200	30' high		2.60	7.692		1,100	243	52	1,395	1,650
	3400	35' high		2.30	8.696		1,200	275	59	1,534	1,800
	3600	40' high		2	10		1,375	315	68	1,758	2,050
	3800	Bracket arms, 1 arm	1 Elec	8	1		75	32		107	130
	4000	2 arms		8	1		150	32		182	213
	4200	3 arms		5.30	1.509		225	48		273	320
	4400	4 arms		5.30	1.509		300	48		348	400
	4500	Steel pole, galvanized, 8' high		3.80	2.105		410	67		477	550
	4510	10' high		3.70	2.162		430	69		499	580
	4520	12' high		3.40	2.353		465	75		540	620
	4530	14' high		3.10	2.581		495	82.50		577.50	670
	4540	16' high		2.90	2.759		525	88		613	710
	4550	18' high		2.70	2.963		555	94.50		649.50	750
	4600	20' high	R-3	2.60	7.692		730	243	52	1,025	1,225
	4800	30' high		2.30	8.696		860	275	59	1,194	1,425
	5000	35' high		2.20	9.091		940	287	61.50	1,288.50	1,525
	5200	40' high		1.70	11.765		1,150	370	80	1,600	1,925
	5400	Bracket arms, 1 arm	1 Elec	8	1		120	32		152	180
	5600	2 arms		8	1		185	32		217	252
	5800	3 arms		5.30	1.509		200	48		248	292
	6000	4 arms		5.30	1.509		280	48		328	380
	6100	Fiberglass pole, 1 or 2 fixtures, 20' high	R-3	4	5		345	158	34	537	655
	6200	30' high		3.60	5.556		540	175	37.50	753.50	900
	6300	35' high		3.20	6.250		675	197	42.50	914.50	1,100
	6400	40' high		2.80	7.143		825	226	48.50	1,099.50	1,300
	6420	Wood pole, 4-1/2" x 5-1/8", 8' high	1 Elec	6	1.333		220	42.50		262.50	305
	6430	10' high		6	1.333		250	42.50		292.50	340
	6440	12' high		5.70	1.404		300	45		345	395

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151 | Pipe & Fittings

151 950 | Valves

				CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	1999 BARE COSTS MAT.	LABOR	EQUIP.	TOTAL	TOTAL INCL O&P
955	8760	1-1/4" size	R151 -050	1 Plum	15	.533	Ea.	310	17.40		327.40	365
	8770	1-1/2" size			13	.615		335	20		355	400
	8780	2" size			11	.727		505	23.50		528.50	590
960	0010	VALVES, IRON BODY	R151 -050									
	1020	Butterfly, wafer type, gear actuator, 200 lb.										
	1030	2" size		1 Plum	14	.571	Ea.	109	18.65		127.65	147
	1040	2-1/2" size		Q-1	9	1.778		112	52		164	202
	1050	3" size			8	2		116	58.50		174.50	217
	1060	4" size			5	3.200		145	94		239	300
	1070	5" size		Q-2	5	4.800		175	146		321	415
	1080	6" size			5	4.800		198	146		344	440
	1650	Gate, 125 lb., N.R.S.										
	2150	Flanged										
	2200	2" size		1 Plum	5	1.600	Ea.	250	52		302	355
	2240	2-1/2" size		Q-1	5	3.200		256	94		350	425
	2260	3" size			4.50	3.556		287	104		391	475
	2280	4" size			3	5.333		410	157		567	690
	2300	6" size		Q-2	3	8		700	243		943	1,150
	3550	OS&Y, 125 lb., flanged										
	3600	2" size		1 Plum	5	1.600	Ea.	179	52		231	275
	3660	3" size		Q-1	4.50	3.556		209	104		313	390
	3680	4" size			3	5.333		222	157		379	480
	3700	6" size		Q-2	3	8		490	243		733	910
	3900	For 250 lb, flanged, add						200%	10%			
	4350	Globe, OS&Y										
	5450	Swing check, 125 lb., threaded										
	5500	2" size		1 Plum	11	.727	Ea.	270	23.50		293.50	335
	5540	2-1/2" size		Q-1	15	1.067		350	31.50		381.50	435
	5550	3" size			13	1.231		375	36		411	470
	5560	4" size			10	1.600		600	47		647	730
	5950	Flanged										
	6000	2" size		1 Plum	5	1.600	Ea.	126	52		178	218
	6040	2-1/2" size		Q-1	5	3.200		160	94		254	320
	6050	3" size			4.50	3.556		239	104		343	420
	6060	4" size			3	5.333		271	157		428	535
	6070	6" size		Q-2	3	8		460	243		703	880
975	0010	VALVES, PLASTIC										
	1150	Ball, PVC, socket or threaded, single union										
	1230	1/2" size		1 Plum	26	.308	Ea.	19.75	10.05		29.80	36.50
	1240	3/4" size			25	.320		23.50	10.45		33.95	42
	1250	1" size			23	.348		28.50	11.35		39.85	48
	1260	1-1/4" size			21	.381		37.50	12.40		49.90	60.50
	1270	1-1/2" size			20	.400		47	13.05		60.05	72
	1280	2" size			17	.471		67.50	15.35		82.85	98
	1290	2-1/2" size		Q-1	26	.615		183	18.05		201.05	230
	1300	3" size			24	.667		168	19.55		187.55	215
	1310	4" size			20	.800		320	23.50		343.50	385
	1360	For PVC, flanged, add						100%	15%			
	3150	Ball check, PVC, socket or threaded										
	3200	1/4" size		1 Plum	26	.308	Ea.	25	10.05		35.05	42.50
	3220	3/8" size			26	.308		25	10.05		35.05	42.50
	3240	1/2" size			26	.308		25	10.05		35.05	42.50
	3250	3/4" size			25	.320		28	10.45		38.45	46.50
	3260	1" size			23	.348		35	11.35		46.35	56.50

FMC Technologies
Material Handling Solutions
FMC Technologies Inc
Homer City PA 15748 1306
724 479 4500

Fax No. (724) 479-4681

Telecopy Message
Fax No: (703) 276-9541
Date: 3/26/04
Page 1 of Many

To: ENERGY VENTURES ANALYSIS
Attn: JOHN STAMBERG

From: RANDY BAIRD

DEAR MR. STAMBERG:

Please find attached as per our discussion. Thanks for the opportunity & I look forward to further discussions on this project.

Questions please call: (724) 479-4657

Sincerely:

RANDY BAIRD
MHS SYSTEMS MANAGER.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 45
COMPANY/ CSX
WITNESS: JBS-4
DATE: 05/27-28/04

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FMC Material Handling Systems

FMC Technologies, Inc.

Material Handling Solutions Division

Budget Conveyor Proposal

March 2004

RBD320401
Attention: Energy Ventures Analysis
Mr. John Stamberg
Phone: (703) 276-8900
Fax: (703) 276-9541
E-mail: stamberg@evainc.com

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BUDGETARY Quotation

Energy Ventures Analysis
March 16, 2004

Executive Summary

Special Conditions and Notes

- Customer responsible for all appropriate permitting and licensing as required
- System designed for maximum 2500TPH (Main) & 1500TPH (Secondary) handling Clean Coal consisting of 50 # per cu. Ft. density.
- Customer to provide all electrical unless noted otherwise in following bid
- Customer responsible for all taxes
- Customer to provide 460/60 line voltage to System.
- Modifications to the original quotation by Customer, including scope of supply, component brand decisions, etc may impact quotation price shown
- No allowance has been made for environmental mitigation, abatement, permitting, licensing or any associated cost required for the successful execution of this project.
- FMC Technologies, Inc reserves the right to suspend the project or supply based upon untimely customer payments, customer and or weather delays or other force majeure events.

General Scope of Work

Design, engineer, supply, deliver, install Clean Coal Handling conveyor system consisting of two (2) Conveyors: Main & Secondary. This includes: Conveyor Truss frames, Head frames, tail frames, gravity Take-up unit. A small Transfer Tower structure for product transfer from C1 to C2 has been included. All items as listed below with furnished documentation for same, including relevant Data Sheets, maintenance documents and applicable drawings.

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This budgetary quote is based solely on the limited information provided by Energy Venture Analysis, which is limited to:

- Clean Coal – 50#/cuft
- Horizontal Conveyor, 18' height through-out entire length
- Walkway one side
- Covers full length
- Bent Spans 30'
- Lighting full length
- (2) drive-ways
- Gravity Take-ups

Additions to specifications or beyond scope of supply may impact budgetary pricing.

Supply Included:

ITEM #1 MAIN 2500TPH One (1) 3300' 54"W 18' high Truss Conveyor equipped with:

- Tail section to include a small skirt-board hopper loading section.
- Horizontal Truss with 18' Bents spaced per design requirements (30' maximum span).
- Dual 200HP drives (Dodge), FTI LinkBelt Pulleys & bearings, Dodge reducers.
- FTI DirtWhacker belt scrappers (primary & secondary)
- Non-contact surfaces painted FP3 Industrial single-coat enamel (Color TBD)
- Full 180 degree covers throughout entire length. Exception is one(1) 30' section of tubular to span road.
- 32" Walkway single side, entire length.
- Lighting posts full length per design/code requirements.
- Goodyear belting. 600 PIW 3 ply to perform task.
- Manual Belt take-up adjustment (Gravity Side Tower).
- FTI C-series Idlers. Rolls 5' on 10' flat return.
- ABB Drive Starter Package.
- Hardware package.

EXCLUSIONS: Foundation design & supply. OPTIONED BELOW
Any Head discharge boxes, etc.

ITEM #2 SECONDARY 1500TPH One(1) 2100' 42"W 18' high Truss Conveyor equipped with:

- Tail section to include a small skirt-board hopper loading section.

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- Horizontal Truss with 18' Bents spaced per design requirements (30' maximum span).
- Dual 125HP drives (Dodge), FTI LinkBelt Pulleys & bearings, Dodge reducers.
- FTI DirtWhacker belt scrappers (primary & secondary)
- Non-contact surfaces painted FP3 Industrial single-coat enamel (Color TBD)
- Full 180 degree covers throughout entire length. Exception is one(1) 30' section of tubular to span road.
- 32" Walkway single side, entire length.
- Lighting posts full length per design/code requirements.
- Goodyear belting. 375 PIW 3 ply to perform task.
- Manual Belt take-up adjustment (Gravity Side Tower).
- FTI C-series Idlers. Rolls 5' on 10' flat return.
- ABB Drive Starter Package
- Hardware package.

EXCLUSIONS: Foundation design & supply. OPTIONED BELOW
Any Head discharge boxes, etc.

ITEM #3 One (1) Lot of Engineering

- General Assembly design and Bill of Materials sufficient for Conveyor fabrication & installation.
- Includes Electrical design

Design Specifications and Criteria

Design & Material Data

Material	Clean Coal
Size of Material	Assume: 0-3"
Bulk density	50 lbs /cu. ft.

Operating Conditions
Continuous; 24/7; outside, typically dry environment, extreme service; Power supply by customer to be 460V/3 phase.

Supplier drawings
FMC Technologies, Inc. shall submit to Energy Venture Analysis AutoCAD drawings and other relevant design/specification information for approval within an acceptable timeframe from order entry date. Requested changes made prior to final approval will be

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discussed and if necessary the original quotation will be modified to reflect the change adders and/or deducts.

BUDGETARY Pricing Summary

NOTE: Pricing provided as Budgetary only. Exact pricing will require further scope development, specification review, and site analysis. Final pricing to occur prior to order acceptance.

Supply of Items # 1-3 (as defined in Scope of Supply) **$ 5,851,000.00**
BUDGETARY RANGE : +15% to -20% Customer to confirm supply.
($4,680,800 - $6,728,650)

Payment Terms:

Amt	Milestone	Timing
15%	Order Entry	(Immediate)
20%	General Arrangement drawings for approval	(Immediate)
25%	Major Component Procurement (Invoiced/ Itemized Monthly with Receipt documentation)	Net 30
30%	At Equipment Shipment (or ready for shipment, if Customer unable to receive) (Invoiced / Itemized Monthly)	Net 30
10%	At substantial completion (ready for production; (clean-up/punch-list items may still need to be addressed)	Net 30

FOB: Tupelo.MS
Delivery: Based upon Project Schedule developed at Order Receipt.

Phone. 662-869-7520

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Fax. 888-580-8597

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TERMS AND CONDITIONS

1. Prices And Payment

1.1. Payments are to be made in U.S funds. Unless otherwise specified all invoices are due net 30 days from date of Shipment. PRICES INVOICED WILL BE THOSE IN EFFECT AT TIME OF SHIPMENT. All prices are f.o.b. point of manufacture. Seller reserves the right to place a service charge on past due accounts at the highest rate permitted by law.

2. Warranty

Seller warrants that the goods delivered under this contract will be free from defect in material and workmanship for a period of 18 months from shipment or 12 months from installation, whichever is earlier. The sole remedy for breach of this warranty is the repair or replacement (at the option of Technologies) of the defective good, and Technologies will not be liable under this warranty for labor to remove or reinstall the good, for transportation or freight on the good or any replacement good, for heavy lift operations, for down time or for any other costs. Goods which Technologies determines to have been subjected to abuse or other improper use will not be entitled to the benefits of any warranty by Technologies. THERE ARE NO OTHER WARRANTIES, STATUTORY, AT LAW, EXPRESS OR IMPLIED, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, WHICH EXTEND BEYOND THE FACE OF THIS AGREEMENT.

2.1. Seller does not in any manner whatsoever warrant seals or packing materials in equipment handling special or corrosive fluids operating at unusual temperatures or pressures, improper lubrication, misapplication, lighting, improper voltage supply, deterioration by chemical action, detrimental well conditions, and wear caused by the presence of abrasive materials, which do not constitute defects.

2.2. This warranty shall not apply to any equipment which has been subjected to misuse, neglect or accident, or has been altered or tampered with, or on which corrective work has been done without Seller's specific written, consent. Seller does not recommend and will not assume any responsibility for rebuilding, repairing, special plating, coating, welding, or heat treating done outside Seller's plant by or at the request of Buyer. Products not of Seller's manufacture, and included in Seller's proposal, and special plating, coatings or heat treatment applied to Seller's products are not warranted in any way by Seller but carry only the manufacturer's warranty, if any.

3. Limitation Of Remedy And Liability

3.1. Seller's liability, including that for breach of contract, negligence, strict liability in tort, or otherwise, for its products and Buyer's exclusive remedy is limited to (a) the repair or replacement (but not installation) of parts found defective by Seller, f.o.b. Seller's factory if returned to the factory for inspection, transportation charges paid, or (b) if in Seller's opinion repair or replacement will not remedy a claimed product deficiency, or if a product of Seller's manufacture does not comply with the description or specification set forth on Seller's Order Acknowledgment to repayment of any amounts paid on the purchase price, cancellation of the order and acceptance of the product f.o.b. point of manufacture. However, if the product has been in use for a period in excess of 30 days, Seller reserves the right to make a reasonable depreciation charge for such use.

4. CONSEQUENTIAL DAMAGES DISCLAIMER
Neither party shall be liable to the other in contract or in tort, directly or under any indemnity, for loss profits or

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for any indirect, special, or consequential damages, arising out of or related to this contract, including but not limited to loss or delay of production, reservoir loss/damage, environmental pollution damage, however same may be caused.

4.1. FURTHERMORE, SELLER EXPRESSLY DISCLAIMS ANY OBLIGATION OR LIABILITY FOR LABOR PERFORMED IN CONNECTION WITH INSTALLATION OF REPAIRED OR REPLACED PARTS OR FOR ANY OTHER EXPENSE, INJURY, LOSS OR DAMAGE TO PERSONS (INCLUDING DEATH) OR TO PROPERTY OR THINGS OF WHATSOEVER KIND OR NATURE..

5. DELAYS, FORCE MAJEURE, DEFAULTS & REMEDIES Seller has the right to suspend its performance or terminate the contract for non-payment of invoices. Seller shall have a reasonable time period in which to cure or otherwise remedy problems or defects prior to the Buyers right to either take-over performance of the work or to terminate the contract.

5.1. Seller shall not be liable to Buyer for any loss or damage suffered by Buyer directly or indirectly, as a result of Seller's failure to deliver or delay in delivering the equipment or failure to perform, or delay in performing, any other term or condition hereof, where such failure or delay is caused by fire, flood, natural disaster, labor trouble (including without limitation strike, slowdown and lockout), war, riot, civil disorder, embargo, government regulations or restrictions of any and all kinds, expropriation of plant by federal or state authority, interruption of or delay in transportation, power failure, inability to obtain materials and supplies, accident, explosion, act of God or other causes of like or different character beyond Seller's control and the time for delivery specified herein shall be extended during the continuance of such conditions and for a reasonable time thereafter.

6. Risk Of Loss

6.1. The risk of loss or destruction of, or damages to, the product shall be on Buyer after delivery of the product to Buyer or carrier, whichever first occurs.

7. Taxes

7.1. Buyer shall pay the amount of any federal, state, county or municipalities, sales, use compensating, intangibles, gross income or like tax applicable to this transaction which is now in effect or may hereafter become effective, but not including taxes payable upon Seller's net income

8. Returns

8.1. No material will be accepted for credit when returned without written permission from Seller's home office. All material accepted for credit is subject to Seller's normal restocking charge. No material will be accepted for credit after one year from date of shipment.

9. Special Products

9.1. Products incorporating variations from catalog items are considered special and are not subject to return or cancellation without charge.

10. Patented Process

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10.1. The purchase of the product does not entitle Buyer to employ the same with any patented process owned by Sellers or others except where Buyer is expressly authorized to use such process.

11. Patent Infringement

11.1. Except in the case of articles, materials and designs furnished or sponsored by Buyer, Seller at its own expense, shall defend any suit brought against Buyer on the ground that use of the product for the intended purpose or purposes, as furnished by Seller infringes any United States patent in effect on the purchase date and shall pay the amount of any judgment that may be awarded against Buyer in any such suit provided and upon condition that Buyer shall have made all payments due under this Agreement and shall (a) promptly deliver to Seller all infringement notices and other papers received by or served upon Buyer, (b) permit Seller to take complete charge of the defense of such suit and compromise the same, if deemed advisable by Seller, and (c) assist in every reasonable way in the conduct of such defense. In the event that Buyer shall be enjoined by a court of competent jurisdiction from which no appeal can be taken, from selling or using the product for the intended purpose or purposes on the ground that such sale or use of the product infringes any such United States patent, or it is established to Seller's satisfaction, upon due investigation, that sale or use of the product infringes any such United States patent, Seller at its option may either (a) procure for Buyer a license to sell and/or use the product, (b) modify the product so as to make it non-infringing without seriously impairing its performance, (c) replace the product with a product that is substantially equal but non-infringing, or (d) accept the return of the product from Buyer, in which event Seller shall refund to Buyer the purchase price less depreciation at the rate of 15 percent per year (measured from the date Seller shipped the product). The foregoing sets forth Seller's entire liability to Buyer for patent infringement based on the possession, use or sale of the product by Buyer, it being understood and agreed that the aforesaid obligations of Seller do not extend to, and are not applicable in the case of any patent infringement claims directed to a method or a process. Buyer agrees to defend and indemnify Seller against any claims or liabilities for, or by reason of, any alleged patent infringement arising from the manufacture or sale of all or any part of the product which is manufactured in accordance with the specifications furnished by Buyer.

12. Transfer of Title

12.1. Title to the products supplied hereunder, to any and all accessories hereto and substitutions therefor, shall remain in Seller as a purchase money security interest (including the right of repossession) until Buyer has completed payment of the purchase price, plus accrued interest, if any, and fully performed all of the terms and conditions hereof.

13. Indemnification

13.1. It is understood that Seller has relied upon data furnished by and on behalf of Buyer with respect to the safety aspects of the products supplied hereunder and/or representations by or on behalf of Buyer that such products will not be applied or used by Buyer or its customers in such a way as to detract materially from their safety in use, including, without limitation, in the manufacture of a product of which Seller's products will be a component and that it is Buyer's responsibility to assure that such products, when installed and put in use, will be in compliance with safety requirements fixed by applicable law and will be otherwise legally adequate to safeguard against injuries to persons or property. BUYER HEREBY AGREES TO INDEMNIFY, HOLD HARMLESS AND DEFEND SELLER, AND ITS DIRECTORS, OFFICERS, EMPLOYEES AND AGENTS AGAINST ANY AND ALL LOSSES, COST, DAMAGES, CLAIMS, LIABILITIES OR EXPENSES, INCLUDING, BUT NOT LIMITED TO, REASONABLE ATTORNEYS' FEES, ARISING OUT OF OR RESULTING FROM ANY INJURY TO ANY PERSON OR DAMAGE TO ANY PROPERTY CAUSED BY THE INADEQUACY FOR THE BUYER'S INTENDED USE OF THE SAFETY FEATURES, DEVICES OR CHARACTERISTICS OF THE PRODUCTS SPECIFIED HEREIN, OR IN THE INSTALLATION, USE OR OPERATION OF SUCH PRODUCTS, EXCEPT CLAIMS

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SOLELY FOR REPAIR OR REPLACEMENT OF DEFECTIVE PARTS COVERED BY THE WARRANTY SET FORTH IN PARAGRAPH 2 HEREOF.

13.2. Customer shall release, defend, hold harmless and indemnify Technologies and its subcontractors against personal injury suits by employees of customer, its affiliates and its other contractors arising out of the Work. Likewise, Technologies shall release, defend, hold harmless and indemnify customer, its affiliates and its other contractors against personal injury suits by employees of Technologies and its subcontractors arising out of the Work.

13.3. "The parties hereby agree that the indemnities each party provides under this contract shall be supported by equal amounts of liability insurance."

14. Written Acceptance

14.1. Any purchase order received by Seller shall be construed to be a written acceptance of this quotation and offer to sell. Buyer may purchase equipment offered in this quotation only on the Seller's terms and conditions included in this quotation. Buyer may choose to issue a purchase order to identify equipment for purchase and for its own internal purposes. However, unless accepted in writing by an authorized employee of FMC, any terms and conditions contained in any purchase order, acceptance, acknowledgment, or other document Buyer submits to FMC which are inconsistent with, different from, or additional to the terms and conditions of this quotation will be null and void, and in lieu thereof the terms and conditions of this quotation shall control.

15. Additional Charges

15.1. If substitute or additional equipment, or repair parts, are purchased by Buyer from Seller, the terms and conditions of the contract created upon acceptance of this offer to sell shall be applicable thereto, the same as if such substitute or additional equipment or repair parts had been originally purchased hereunder.

16. Termination By Seller

16.1. Seller reserves the right to terminate the contract created upon acceptance of this offer if governmental controls do not permit the Seller to perform this Agreement.

17. Repudiation By Buyer

17.1. Buyer may not terminate the contract created upon acceptance of this offer to sell without Seller's prior written consent. If Buyer shall attempt to terminate without Seller's consent or shall otherwise repudiate this contract, Buyer shall be liable to Seller for all of Seller's costs and other commitments incurred to date of repudiation, plus Seller's incidental damages, and the profit Seller would have made from full performance of this contract.

18. General

18.1.1. No modification hereof shall be binding upon Seller unless such modification is in writing signed by a duly authorized representative of Seller,

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18.1.2. If any part hereof is contrary to, prohibited by, or deemed invalid under applicable laws or regulations, such provision shall be deemed inapplicable and omitted to the extent contrary, prohibited or invalid, but the remainder shall not be less invalid and shall be given full force and effect., and

18.1.3. The entire understanding between the parties hereto is set forth herein and any promises, representations, warranties or guarantees not herein contained shall have no force and effect unless in writing signed by Seller and Buyer.

19. POLLUTION

Seller shall release, defend, indemnify and hold harmless Buyer, its affiliates and its other contractors for pollution or contamination arising above the surface of the land or water and which escapes or emanates directly from Technologies' equipment which equipment is wholly within Technologies' control. And Buyer shall release, defend, indemnify and hold harmless Seller for all other pollution not specifically assumed by Seller.

20. LIMITATION OF LIABILITY

The total aggregate liability under any contract for all Seller exposures (e.g., pollution, warranty, indemnification, or liquidating damages) may not exceed the total contract value or $25,000,000 dollars whichever is less.

21. DISPUTE RESOLUTION

In the event of any dispute, or difference arising out of, or relating to this contract, or the breach thereof, the parties shall use their best endeavors to settle such dispute, or difference by consulting and negotiating with each other, in good faith, and understanding of their mutual interests, to reach a just and equitable resolution which is satisfactory to the parties. In the event the parties cannot resolve such dispute up to the level of each party's Division Manager or President within ninety (90) days after a party's initial notice of the dispute, the parties shall be free to litigate their differences in accordance with Mississippi law and shall submit to this forum.

22. CHOICE OF LAW & FORUM

In the event of a contract dispute, Buyer and Seller agree to apply the Mississippi laws without regard to conflicts of laws rules, and litigate in the state or federal courts of the Seller.

23. SUCCESSORS AND ASSIGNS

This contract shall inure to the benefit of and bind any successor in interest to a party to this contract. This contract may not be assigned by either party without the prior written consent of the other party. Notwithstanding the foregoing, Seller may assign this contract to any successor in interest to that portion of FTI Technologies' business involved in the subject matter of this contract.

24. RAW MATERIAL SURCHARGE

The Seller may pass on a price increase due to an industry wide raw material surcharge. This increase will be limited to cover the actual cost increase, which is beyond the control of the Seller. Raw materials surcharges will be invoiced to the customer separately with adequate documentation to support the surcharge.

FMC EnergySystems
FMC Material Handling Systems

Phone. 662-869-7520
Fax. 888-580-8597

EXHIBIT NO. _____ (JBS-4)
JOHN B. STAMBERG - CSXT
DOCKET NO. 031033-EI
PAGE 12 OF 13

Reply-To: <rbeach@continentalconveyor.com>
From: "Russell Beach",<rbeach@continentalconveyor.com>
To: <stamberg@evainc.com>
Cc: <jsmothers@continentalconveyor.com>,
<rstough@continentalconveyor.com>,
<mroberts@continentalconveyor.com>,
<runred@hotmail.com>,
<bill@tiscotampa.com>,
<njmadison@continentalconveyor.com>
Subject: Budgets for Big Bend
Date: Fri, 26 Mar 2004 14:48:21 -0600
Organization: Continental Conveyor
X-Mailer: Microsoft Outlook, Build 10.0.2627
Importance: Normal
X-pstn-levels: (S:99.90000/99.90000 R:95.9108 P:95.9108 M:99.4056 C:79.5348)
X-pstn-settings: 5 (2.0000:8.0000) r p m C
X-pstn-addresses: from <rbeach@continentalconveyor.com> [3624/154]

John,

Attached for your use is budget pricing for the two conveyors we discussed at the Big Ben Power Plant.

Please call if you need more information .

Best Regards,

Russell Beach, CET
Estimator/Engineered Systems

CONFIDENTIALY NOTICE: The information contained in this electronic message is intended only for the personal and confidential use of the recipients designated in the original message. The message may contain privileged and confidential information, or information of a proprietary nature. If you are not the intended recipient, or any agent responsible for delivering it to the intended recipient, you are hereby notified that you have received this document in error, and that any review, dissemination, printing, or copying of this message is strictly prohibited. If you have received this communication in error, please delete it immediately. Thank You.

Big Ben Budget Conv Options 0326.doc

EXHIBIT NO. _____ (JBS-4)
JOHN B. STAMBERG - CSXT
DOCKET NO. 031033-EI
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CONTINENTAL CONVEYOR
& EQUIPMENT COMPANY
The World Leader in Conveyors and Conveyor Technology

438 Industrial Drive
Post Office Box 400
Winfield, Alabama 35594-0400
Telephone: 205/487-6492
Fax: 205/487-4233
E-mail: info@continentalconveyor.com

SALES OFFICES: JASPER, AL - BOSTON, MA - CORBIN, KY - DELTA, BRITISH COLUMBIA - GARRAWAY, WV - MADISONVILLE, KY - HOUSTON, TX - LAKEWOOD, CO - LOS ANGELES, CA - NEW YORK, NY - OAK HILL, WV
OMAHA, NE - PHILADELPHIA, PA - PITTSBURGH, PA - PORTLAND, OR - PUEBLA, MEXICO - SALT LAKE CITY, UT - SALTERSVILLE, KY - TAMPA, FL - WINFIELD, AL

March 26, 2004

Energy Ventures Analysis, Inc.
1901 N Moore St, Suite 1200
Arlington VA 22209-1706

Attention: Mr. John Stamberg

Subject: Budget Pricing for the Big Ben Plant

Dear John:

Continental Conveyor is pleased to provide the following budget pricing per your request for the Big Ben Plant.

1. 1 One (1) 54" B.W. Conveyor with 3,300 foot horizontal pulley centers and with a lift of 15 ft. to handle 2500 STPH of 50 PCF coal (3" X 0 lump) operating at a speed of approximately 725 FPM.

Terminals include one (1) 450 HP head end drive, motor, belt scrapers, discharge hood, tail loading hopper, impact idlers, pulley outfits, bearings and gravity take-up.

Intermediate structure (3,290 LF) includes truss with belt covers, pull cord and switches, walkway one side, idlers, belt, average span length of 80 feet and 42 bents at 18'-0 height.

Your budget price, F.O.B. Factory, Winfield, Alabama, is: **$1,953,000.00.**
Estimated erection cost is .....: **$ 780,000.00.**

$2,733,000 / 3300 LF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 46
COMPANY/ CSX
WITNESS: JBS-5
DATE: 05/27-28/04

EXHIBIT NO. 46 (JBS-5)
JOHN B. STAMBERG - CSXT
DOCKET NO. 031033-EI
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2. One (1) 42" B.W. Conveyor with 2,100 foot horizontal pulley centers and with a lift of 15 ft. to handle 2500 STPH of 50 PCF coal (3" X 0 lump) operating at a speed of approximately 725 FPM.

Terminals include one (1) 200 HP head end drive, motor, belt scrapers, discharge hood, tail loading hopper, impact idlers, pulley outfits, bearings and gravity take-up.

Intermediate structure (2,090 LF) includes truss with belt covers, pull cord and switches, walkway one side, idlers, belt, average span length of 80 feet and 26 bents at 18'-0 height.

Your budget price, F.O.B. Factory, Winfield, Alabama, is: **$1,150,000.00.**
Estimated erection cost is .....: **$ 460,000.00.**

The above prices do not include MCC's and controls, etc.

Please call with any questions or if you need more information.

Best regards,

CONTINENTAL CONVEYOR & EQUIPMENT COMPANY

Russell Beach, CET
Estimator/Engineered Systems

cc: Jim Smothers
Ron Stough
Mike Roberts
Bill Taylor

THIS QUOTATION IS SUBJECT TO CONTINENTAL CONVEYOR'S EXCLUSIVE TERMS AND CONDITIONS OF SALE, F71-109, REV. 00-8-1-05.

EXHIBIT NO. _____ (JBS-5)
JOHN B. STAMBERG - CSXT
DOCKET NO. 031033-EI
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Exhibit 47 (JBS-6)

Rapid Discharge Pit and Conveyor –
EVA Estimates

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 47
COMPANY/ CSX
WITNESS: JBS-6
DATE 05/27-28/04

EXHIBIT NO. 47 (JBS-6)
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Rapid Unloading Pit & Conveyor

Non Concrete	Conveyor	190,052	
	Hoppers	96,000	4 each
	Gates	96,000	4 each
	Transfer House	230,000	
		802,104	
Dewatering		107,264	
Sheet Pilings		187,264	
Excavation		2000	
Concrete		187,130	
		1,285,762	
		x 1.061	
		x 1.164	
		$1,590,391	

EXHIBIT NO. ____ (JBS-6)
JOHN B. STAMBERG - CSXT
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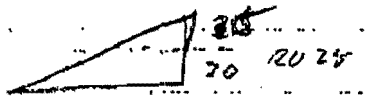
PAGE 2 OF 12

Rapid Drainage System

Rapid Procedure Conveyor



180
32400

Conveyor @ 190'

Steel Conv $\frac{550,150}{550} \times 190$ = 190,052.72

190,052.00

Hoppers
2 @ 48000 — 96,000

Pinch
2 @ 48000 — 96,000

$572,104

Timber Items — 230,000

Non Concrete — 802,104

EXHIBIT NO. _____ (JBS-6)
JOHN B. STAMBERG - CSXT
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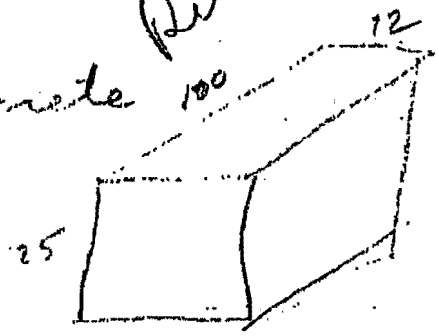
Concrete Pit



150 6

100 3

12 12/62

100

150
150
62
62
424

Demolition

Log Guard Panels

6 424

163 LF Wall x 424 x $70,000

33.50 x 30 ft deep x 18 weeks = $18,000

$720/day Pump x 30 day 21,600

109,690

Sheet Piling Left in Place

40' @ 38 #/ft²

100 + 100 + 12 + 12 = 224 x 40

= 8960 ft²

38 #/ft² x 8960 = 340,480 #

170.24 tons x 1,100 187,264

EXHIBIT NO. _____ (JBS-6)
JOHN B. STAMBERG - CSXT
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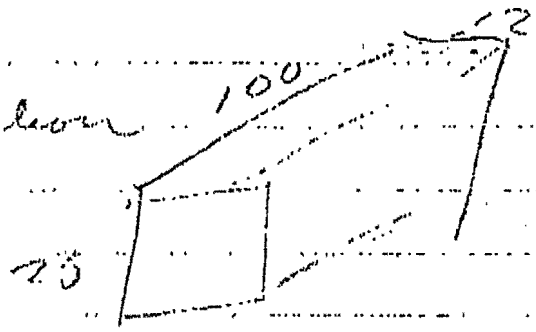
Excavation



$\frac{12 \times 100 \times 25}{27} = 1111 \text{ yd}^3 \times 1.79 \quad \$2000$

2 yd Bucket

Backhoe

Concrete 2.5 x 12 x 2 600 M2
100 x 25 x 2 5000
5600

Town Wall

10.55 x 5600 $59,080

ft² called Igloo

Concrete

$197 /yd3

100
25 x 2 = 5000 M²
12 x 25 x 2 = 600
2500
2100 M² x 1½ M = 12,150 M³
27 27

450
$88650

~~147,750~~

Tunnel

100 M x 9' x 4 = 3600 x 1.5 = 5400 M3
27

10 - 25' x 4 2

200
x197
39,400 187,130

EXHIBIT NO. _____ (JBS-6)
JOHN B. STAMBERG - CSXT
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033 | Cast-In-Place Concrete

033 100 | Structural Concrete

		CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	1999 BARE COSTS MAT.	LABOR	EQUIP.	TOTAL	TOTAL INCL O&P	
3800	Footings, spread under 1 C.Y.	C-14C	38.07	2.942	C.Y.	89.50	77	.97	167.47	223	130
3850	Over 5 C.Y.		81.04	1.382		82.50	36	.46	118.96	149	
3900	Footings, strip, 18" x 9", plain		41.04	2.729		80.50	71.50	.90	152.90	204	
3950	36" x 12", reinforced		61.55	1.820		83	47.50	.60	131.10	168	
4000	Foundation mat, under 10 C.Y.		38.67	2.896		113	75.50	.96	189.46	247	
4050	Over 20 C.Y.		56.40	1.986		101	52	.66	153.66	194	
4200	Grade walls, 8" thick, 8' high	C-14D	45.83	4.364		97.50	119	14.90	231.40	310	
4250	14' high		27.26	7.337		124	199	25	348	480	
4260	12" thick, 8' high		64.32	3.109		89.50	84.50	10.65	184.65	244	
4270	14' high		40.01	4.999		90.50	136	17.10	252.60	345	
4300	15" thick, 8' high		80.02	2.499		85.50	68	8.55	162.05	210	
4350	12' high		51.26	3.902		89	106	13.35	208.35	281	
4400	18" high		48.85	4.094		99	111	14	224	300	
4520	Handicap access ramp, railing both sides, 3' wide	C-14H	14.58	3.292	L.F.	94.50	89	2.57	186.07	248	
4525	5' wide		12.22	3.928		108	106	3.06	217.06	290	
4530	With check walls and rails both sides, 3' wide		8.55	5.614		96.50	151	4.38	251.88	350	
4535	5' wide		7.31	6.566		97	177	5.10	279.10	395	
4650	Slab on grade, not including finish, 4" thick	C-14E	60.75	1.449	C.Y.	73.50	39	.62	113.12	145	
4700	6" thick	"	92	.957	"	70.50	25.50	.41	96.41	120	
4751	Slab on grade, incl. troweled finish, not incl. forms										
4760	or reinforcing, over 10,000 S.F., 4" thick slab	C-14F	3,425	.021	S.F.	.79	.52	.01	1.32	1.67	
4820	6" thick slab		3,350	.021		1.16	.53	.01	1.70	2.09	
4840	8" thick slab		3,184	.023		1.59	.56	.01	2.16	2.60	
4900	12" thick slab		2,734	.026		2.38	.65	.01	3.04	3.63	
4960	15" thick slab		2,505	.029		2.99	.71	.01	3.71	4.39	
5000	Slab on grade, incl. textured finish, not incl. forms										
5001	or reinforcing, 4" thick slab	C-14G	2,873	.019	S.F.	.79	.48	.01	1.28	1.61	
5010	6" thick		2,590	.022		1.24	.53	.01	1.78	2.18	
5020	8" thick		2,320	.024		1.62	.59	.02	2.23	2.70	
5200	Lift slab in place above the foundation, incl. forms,										
5210	reinforcing, concrete and columns, minimum	C-14B	2,113	.098	S.F.	4.74	2.69	.32	7.75	9.85	
5250	Average		1,650	.126		5.20	3.45	.41	9.06	11.70	
5300	Maximum		1,500	.139		5.80	3.79	.45	10.04	12.90	
5500	Lightweight, ready mix, including screed finish only,										
5510	not including forms or reinforcing										
5550	1:4 for structural roof decks	C-14B	260	.800	C.Y.	91.50	22	2.62	116.12	139	
5600	1:6 for ground slab with radiant heat	C-14F	92	.783		86.50	19.40	.41	106.31	125	
5650	1:3:2 with sand aggregate, roof deck	C-14B	260	.800		91.50	22	2.62	116.12	139	
5700	Ground slab	C-14F	107	.673		91.50	16.70	.35	108.55	127	
5900	Pile caps, incl. forms and reinf., sq. or rect., under 5 C.Y.	C-14C	54.14	2.069		86	54	.68	140.68	182	
5950	Over 10 C.Y.		75	1.493		83.50	39	.49	122.99	155	
6000	Triangular or hexagonal, under 5 C.Y.		53	2.113		79	55	.70	134.70	176	
6050	Over 10 C.Y.		85	1.318		83.50	34.50	.43	118.43	147	
6200	Retaining walls, gravity, 4' high see division 022-708	C-14D	66.20	3.021		81	82	10.35	173.35	230	
6250	10' high		125	1.600		72	43.50	5.45	120.95	164	
6300	Cantilever, level backfill loading, 8' high		70	2.857		88	77.50	9.75	175.25	241	
6350	16' high		91	2.198		85.50	59.50	7.50	152.50	197	
6800	Stairs, not including safety treads, free standing, 3'-6" wide	C-14H	83	.578	LF Nose	5.75	15.60	.45	21.80	32	
6850	Cast on ground		125	.384	"	4.05	10.35	.30	14.70	21	
7000	Stair landings, free standing		200	.240	S.F.	2.25	6.50	.19	8.94	13	
7050	Cast on ground		475	.101	"	1.30	2.73	.08	4.11	5.85	
0010	CURING Burlap, 4 uses assumed, 7.5 oz.	2 Clab	55	.291	C.S.F.	2.55	6.25		8.80	12.60	134
0100	12 oz.		55	.291		3.74	6.25		9.99	13.90	
0200	Waterproof curing paper, 2 ply, reinforced		70	.229		4.71	4.90		9.61	12.90	
0300	Sprayed membrane curing compound		95	.168		2.42	3.61		6.03	8.35	

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031 | Concrete Formwork

031 100 | Struct C.I.P. Formwork

			CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	1999 BARE COSTS MAT.	LABOR	EQUIP.	TOTAL	TOTAL INCL O&P
182	2150	4 use, below grade	C-2	435	110	SFCA	.62	2.94		3.56	5.30
	2400	Over 8' to 16' high, 1 use		280	.171		3.60	4.57		8.17	11.15
	2450	2 use		345	.139		1.16	3.71		4.87	7.15
	2500	3 use		375	.128		.83	3.41		4.24	6.25
	2550	4 use		395	.122		.68	3.24		3.92	5.85
	2700	Over 16' high, 1 use		235	.204		2.34	5.45		7.79	11.10
	2750	2 use		290	.166		1.29	4.41		5.70	8.35
	2800	3 use		315	.152		.93	4.06		4.99	7.45
	2850	4 use		330	.145		.76	3.88		4.64	6.95
	3000	For architectural finish, add		1,820	.026		.58	.70		1.28	1.75
	4000	Radial wall forms, smooth curved, 1 use		245	.196		2.30	5.20		7.50	10.75
	4050	2 use		300	.160		1.26	4.27		5.53	8.10
	4100	3 use		325	.148		.92	3.94		4.86	7.20
	4150	4 use		335	.143		.75	3.82		4.57	6.80
	4200	Wall forms, smooth curved, below grade, job built plyform, 1 use		225	.213		2.78	5.70		8.48	12
	4210	2 use		225	.213		1.54	5.70		7.24	10.65
	4220	3 use		225	.213		1.25	5.70		6.95	10.30
	4230	4 use		225	.213		.90	5.70		6.60	9.95
	4300	Curved, with 2' chords, 1 use		290	.166		1.89	4.41		6.30	9
	4350	2 use		355	.135		1.04	3.60		4.64	6.80
	4400	3 use		385	.125		.75	3.32		4.07	6.10
	4450	4 use		400	.120		.61	3.20		3.81	5.70
	4500	Over 8' high, 1 use		290	.166		.85	4.41		5.27	7.90
	4525	2 use		355	.135		.48	3.60		4.08	6.15
	4550	3 use		385	.125		.35	3.32		3.67	5.65
	4575	4 use		400	.120		.29	3.20		3.49	5.35
	4600	Retaining wall forms, battered, to 8' high, 1 use		300	.160		1.78	4.27		6.05	8.65
	4650	2 use		355	.135		.98	3.60		4.58	6.75
	4700	3 use		375	.128		.71	3.41		4.12	6.15
	4750	4 use		390	.123		.54	3.28		3.82	5.75
	4900	Over 8' to 16' high, 1 use		240	.200		1.94	5.35		7.29	10.65
	4950	2 use		295	.163		1.07	4.34		5.41	7.95
	5000	3 use		305	.157		.78	4.20		4.98	7.45
	5050	4 use		320	.150		.63	4		4.63	7
	5100	Retaining wall form, smooth curve, 1 use		200	.240		2.89	6.40		9.29	13.25
	5120	2 use		235	.204		1.59	5.45		7.04	10.30
	5130	3 use		250	.192		1.16	5.10		6.26	9.30
	5140	4 use		260	.185		.95	4.92		5.87	8.80
	5500	For gang wall forming, 192 S.F. sections, deduct					10%	10%			
	5550	384 S.F. sections, deduct					20%	20%			
	5750	Liners for forms (add to wall forms), A.B.S. plastic									
	5800	Aged wood, 4" wide, 1 use	1 Carp	250	.032	SFCA	4.75	.87		5.62	6.55
	5820	2 use		400	.020		2.63	.55		3.18	3.75
	5840	4 use		750	.011		1.60	.29		1.89	2.22
	5900	Fractured rope rib, 1 use		250	.032		7.40	.87		8.27	9.50
	6000	4 use		750	.011		2.45	.29		2.74	3.16
	6100	Ribbed look, 1/2" & 3/4" deep, 1 use		300	.027		5.15	.73		5.88	6.80
	6200	4 use		800	.010		1.65	.27		1.92	2.25
	6300	Rustic brick pattern, 1 use		250	.032		4.80	.87		5.67	6.65
	6400	4 use		750	.011		1.60	.29		1.89	2.22
	6500	Simulated, random, 3/8" x 3/8" deep, 1 use		300	.027		5.10	.73		5.83	6.75
	6600	4 use		800	.010		1.65	.27		1.92	2.25
	6800	Reduction strips, A.B.S. plastic, 2 piece snap-on									
	6850	1" deep x 1-3/8" wide, 1 use	C-2	400	.120	L.F.	3.75	3.20		6.95	9.20
	6900	2 use		600	.080		2.10	2.13		4.23	5.65
	6950	4 use		800	.060		1.25	1.60		2.85	3.90

EXHIBIT NO. _____ (JBS-6)
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022 200 | Excav./Backfill/Compact.

		CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	1999 BARE COSTS MAT.	LABOR	EQUIP.	TOTAL	TOTAL INCL O&P	
100	Boulders under 1/2 C.Y., loaded on truck, no hauling	B-10O	80	.150	C.Y.		3.91	6.40	10.31	13	234
200	Boulders, drilled, blasted	B-47	100	.240	↓	1.60	5.75	6.20	13.55	17.50	
400	Jackhammer operators with foreman compressor, air tools	B-9	1	40	Day		875	180	1,055	1,575	
500	Track drill, compressor, operator and foreman	B-47	1	24	"		575	620	1,195	1,575	
700	Blasting caps				Ea.	.3			.3	.33	
800	Blasting mats, rent, for first day					90			90	99	
900	Per added day					30			30	33	
1000	Preblast survey for 6 room house, individual lot, minimum	A-6	2.40	6.667			171		171	260	
1100	Maximum	"	1.35	11.852	↓		305		305	460	
1400	City block within zone of influence, minimum	A-8	25,200	.001	S.F.		.03		.03	.05	
1500	Maximum	"	15,100	.002	"		.05		.05	.08	
2000	Excavate and load boulders, less than 0.5 C.Y.	B-10T	80	.150	C.Y.		3.91	5.65	9.56	12.20	
2100	0.5 C.Y. to 1 C.Y.	B-10U	100	.120			3.13	9.25	12.38	15	
2200	Excavate and load blasted rock, 3 C.Y. power shovel	B-12T	1,530	.010			.28	.80	1.08	1.30	
2300	Haul boulders, 25 ton off highway dump, 1 mile round trip	B-34E	330	.024			.54	2.12	2.66	3.15	
2400	2 mile round trip		275	.029			.64	2.54	3.18	3.78	
2500	3 mile round trip		225	.036			.79	3.11	3.90	4.62	
2600	4 mile round trip	↓	200	.040	↓		.88	3.50	4.38	5.20	
2700	Bury boulders on site, less than 0.5 C.Y., 300 H.P. dozer										
2800	150' haul	B-10M	310	.039	C.Y.		1.01	3.65	4.66	5.55	
2900	300' haul		210	.057			1.49	5.40	6.89	8.20	
3000	0.5 to 1 C.Y., 300 H.P. dozer, 150' haul		300	.040			1.04	3.77	4.81	5.75	
3100	300' haul	↓	200	.060	↓		1.56	5.65	7.21	8.60	
	EXCAVATING, BULK BANK MEASURE Common earth piled (1022-240)										238
	For loading onto trucks, add								15%	15%	
	For mobilization and demobilization, see division 022-274 (1022-250)										
	For hauling, see division 022-266										
4000	Backhoe, hydraulic, crawler mtd., 1 C.Y. cap. = 75 C.Y./hr.	B-12A	600	.027	C.Y.		.71	.91	1.62	2.08	
4040	1-1/2 C.Y. cap. = 100 C.Y./hr.	B-12B	800	.020			.53	.69	1.22	1.59	
4200	2 C.Y. cap. = 130 C.Y./hr.	B-12C	1,040	.015			.41	.98	1.39	1.71	
4220	3 C.Y. cap. = 160 C.Y./hr.	B-12D	1,280	.013			.33	1.68	2.01	2.36	
4240	Wheel mounted, 1/2 C.Y. cap. = 30 C.Y./hr.	B-12E	240	.067			1.78	1.40	3.18	4.25	
4400	3/4 C.Y. cap. = 45 C.Y./hr.	B-12F	360	.044			1.19	1.25	2.44	3.18	
4420	Clamshell, 1/2 C.Y. cap. = 20 C.Y./hr.	B-12G	160	.100			2.67	3.26	5.93	7.65	
4440	1 C.Y. cap. = 35 C.Y./hr.	B-12I	280	.057			1.53	2.05	3.58	4.57	
5000	Dragline, 1/2 C.Y. cap. = 30 C.Y./hr.	B-12I	240	.067			1.78	2.19	3.97	5.10	
5020	3/4 C.Y. cap. = 35 C.Y./hr.	"	280	.057			1.53	1.88	3.41	4.38	
5040	1 1/2 C.Y. cap. = 65 C.Y./hr.	B-12P	520	.031			.82	1.45	2.27	2.84	
5200	3 C.Y. cap. = 112 C.Y./hr.	B-12V	900	.018			.47	1.12	1.59	1.96	
5220	Front end loader, track mtd., 1 1/2 C.Y. cap. = 70 C.Y./hr.	B-10N	560	.021			.56	.63	1.19	1.55	
5240	2-1/2 C.Y. cap. = 95 C.Y./hr.	B-10O	760	.016			.41	.67	1.08	1.37	
5400	3 C.Y. cap. = 130 C.Y./hr.	B-10P	1,040	.012			.30	.83	1.13	1.38	
5420	5 C.Y. cap. = 160 C.Y./hr.	B-10Q	1,280	.009			.24	.89	1.13	1.36	
5440	Wheel mounted, 3/4 C.Y. cap. = 45 C.Y./hr.	B-10R	360	.033			.87	.68	1.55	2.09	
5500	1-1/2 C.Y. cap. = 80 C.Y./hr.	B-10S	640	.019			.49	.50	.99	1.30	
5510	2-1/4 C.Y. cap. = 100 C.Y./hr.	B-10T	800	.015			.39	.56	.95	1.22	
5520	3 C.Y. cap. = 140 C.Y./hr.	"	1,120	.011			.28	.40	.68	.87	
5530	5 C.Y. cap. = 185 C.Y./hr.	B-10U	1,480	.008			.21	.63	.84	1.01	
5540	Hydraulic excavator, track mtd., 1/2 C.Y. = 30 C.Y./hr.	B-12J	240	.067			1.78	2.65	4.43	5.65	
5550	48 inch bucket, 1 C.Y. = 45 C.Y./hr.	B-12K	360	.044			1.19	2.24	3.43	4.27	
5560	Shovel, 1/2 C.Y. capacity = 55 C.Y./hr.	B-12L	440	.036			.97	1.20	2.17	2.80	
5570	3/4 C.Y. capacity = 85 C.Y./hr.	B-12M	680	.024			.63	.87	1.50	1.92	
5580	1 C.Y. capacity = 120 C.Y./hr.	B-12N	960	.017			.45	.66	1.11	1.41	
6000	1-1/2 C.Y. capacity = 160 C.Y./hr.	B-12O	1,280	.013			.33	.68	1.01	1.26	
6010	3 C.Y. cap. = 250 C.Y./hr.	B-12T	2,000	.008	↓		.21	.61	.82	1.01	

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021 | Site Preparation & Excavation Support

021 610 | Sheet Piling

			CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	1999 BARE COSTS MAT.	LABOR	EQUIP.	TOTAL	TOTAL INCL O&P
614	0010	SHEET PILING Steel, not incl. wales, 22 psf, 15' excav., left in place	B-40	10.81	5.920	Ton	795	163	178	1,136	1,350
	0100	Drive, extract & salvage		6	10.667		211	294	320	825	1,075
	0300	20' deep excavation, 27 psf, left in place R021 -610		12.95	4.942		795	136	149	1,080	1,275
	0400	Drive, extract & salvage		6.55	9.771		211	270	294	775	1,000
	0600	25' deep excavation, 38 psf, left in place R021 -620		19	3.368		795	93	101	989	1,150
	0700	Drive, extract & salvage		10.50	6.095		211	168	183	562	710
	0900	40' deep excavation, 38 psf, left in place		21.20	3.019		795	83.50	90.50	969	1,100
	1000	Drive, extract & salvage		12.25	5.224		211	144	157	512	645
	1200	15' deep excavation, 22 psf, left in place		983	.065	S.F.	9.25	1.80	1.96	13.01	15.30
	1300	Drive, extract & salvage		656	.098		2.37	2.09	2.93	7.09	10.30
	1500	20' deep excavation, 27 psf, left in place		960	.067		11.60	1.84	2	15.44	18.05
	1600	Drive, extract & salvage		640	.100		3.08	2.76	3.01	8.85	11.25
	1800	25' deep excavation, 38 psf, left in place		1,000	.064		17.10	1.77	1.92	20.79	24
	1900	Drive, extract & salvage		670	.096		4.22	2.64	2.87	9.73	12.15
	2100	Rent steel sheet piling and wales, first month				Ton	230			230	253
	2200	Per added month					23			23	25.50
	2400	Rental piling left in place, add to rental					450			450	495
	2500	Wales, connections & studs, 2/3 salvage					173			173	190
	2700	High strength piling, 50,000 psi, add					60			60	66
	2800	55,000 psi, add					65			65	71.50
	3000	Tie rod, not upset, 1-1/2" to 4" diameter with turnbuckle					1,200			1,200	1,325
	3100	No turnbuckle					1,000			1,000	1,100
	3300	Upset, 1 3/4" to 4" diameter with turnbuckle					1,500			1,500	1,650
	3400	No turnbuckle					1,300			1,300	1,425
	3600	Lightweight, 18" to 28" wide, 7 ga., 9.22 psf, and									
	3610	9 ga., 8.6 psf, minimum				Lb.	.50			.50	.55
	3700	Average					.55			.55	.61
	3750	Maximum					.62			.62	.68
	3900	Wood, solid sheeting, incl. wales, braces and spacers,									
	3910	drive, extract & salvage, 8' deep excavation	B-31	330	.121	S.F.	1.52	2.79	.46	4.77	6.55
	4000	10' deep, 50 S.F./hr. in & 150 S.F./hr. out		300	.133		1.56	3.07	.51	5.14	7.10
	4100	12' deep, 45 S.F./hr. in & 135 S.F./hr. out		270	.148		1.61	3.41	.56	5.58	7.75
	4200	14' deep, 42 S.F./hr in & 126 S.F./hr. out		250	.160		1.66	3.68	.61	5.95	8.30
	4300	16' deep, 40 S.F./hr. in & 120 S.F./hr. out		240	.167		1.71	3.84	.64	6.19	8.65
	4400	18' deep, 38 S.F./hr. in & 114 S.F./hr. out		230	.174		1.76	4	.66	6.42	8.95
	4500	20' deep, 35 S.F./hr. in & 105 S.F./hr. out		210	.190		1.82	4.38	.73	6.93	9.70
	4520	Left in place, 8' deep, 55 S.F./hr		440	.091		2.73	2.09	.35	5.17	6.70
	4540	10' deep, 50 S.F./hr		400	.100		2.88	2.30	.38	5.56	7.20
	4560	12' deep, 45 S.F./hr.		360	.111		3.04	2.56	.42	6.02	7.85
	4565	14' deep, 42 S.F./hr.		335	.119		3.22	2.75	.45	6.42	8.35
	4570	16' deep, 40 S.F./hr.		320	.125		3.42	2.88	.48	6.78	8.80
	4580	18' deep, 38 S.F./hr.		305	.131		3.65	3.02	.50	7.17	9.30
	4590	20' deep, 35 S.F./hr.		280	.143		3.91	3.29	.54	7.74	10.05
	4700	Alternate pricing, left in place, 8' deep		1.76	22.727	M.B.F.	615	525	86.50	1,226.50	1,600
	4800	Drive, extract and salvage, 8' deep		1.32	30.303		545	700	115	1,360	1,825
	5000	For treated lumber add cost of treatment to lumber									
	5010	See division 063-102									

021 620 | Cribbing & Walers

624	0010	SOLDIER BEAMS & LAGGING H piles with 3" wood sheeting									
	0020	horizontal between piles, including removal of wales & braces									
	0100	No hydrostatic head, 15' deep, 1 line of braces, minimum	B-50	545	.206	S.F.	6.45	5.40	2.74	14.59	19.05
	0200	Maximum		495	.226		7.15	5.95	3.01	16.11	21
	0400	15' to 22' deep with 2 lines of braces, 10" H, minimum		360	.311		7.60	8.20	4.14	19.94	26.50
	0500	Maximum		330	.339		8.60	8.95	4.52	22.07	29

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021 | Site Preparation & Excavation Support

			CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	1999 BARE COSTS MAT.	LABOR	EQUIP.	TOTAL	TOTAL INCL. O&P	
021 400 | Dewatering												
404	2000	24" pipe, corrugated, 14 ga. R021-440	B-6	40	.600	L.F.	21.50	14.15	5.45	40.95	52	404
	2200	Wood lining, up to 4' x 4', add	↓	300	.080	SFCA	3	1.87	.73	5.60	7	
	9950	See div. 021-444 for wellpoints										
	9960	See div. 021 484 for deep well systems										
	9970	See div. 152 400 for pumps										
021 440 | Wellpoints												
444	0010	WELLPOINTS For wellpoint equipment rental, see div. 016-490 R021-440										444
	0100	Installation and removal of single stage system										
	0110	Labor only, .75 labor hours per L.F., minimum	1 Clab	10.70	.748	LF Hdr		16.05		16.05	25	
	0200	2.0 labor-hours per L.F., maximum	"	4	2	"		43		43	67.50	
	0400	Pump operation, 4 @ 6 hr. shifts										
	0410	Per 24 hour day	4 Eqlt	1.27	25.197	Day		685		685	1,050	
	0500	Per 168 hour week, 160 hr. straight, 8 hr. double time		.18	177	Week		4,825		4,825	7,350	
	0550	Per 4.3 week month	↓	.04	800	Month		21,800		21,800	33,100	
	0600	Complete installation, operation, equipment rental, fuel &										
	0610	removal of system with 2" wellpoints 5' O.C.										
	0700	100' long header, 6" diameter, first month	4 Eqlt	3.23	9.907	LF Hdr	100	269		369	520	
	0800	Thereafter, per month		4.13	7.748		80	211		291	410	
	1000	200' long header, 8" diameter, first month		6	5.333		100	145		245	330	
	1100	Thereafter, per month		8.39	3.814		45	104		149	208	
	1300	500' long header, 8" diameter, first month		10.63	3.010		35	82		117	163	
	1400	Thereafter, per month		20.91	1.530		25	41.50		66.50	91	
	1600	1,000' long header, 10" diameter, first month		11.62	2.754		30	75		105	147	
	1700	Thereafter, per month	↓	41.81	.765	↓	15	21		36	48	
	1900	Note: above figures include pumping 168 hrs. per week										
	1910	and include the pump operator and one stand-by pump.										
021 480 | Relief Wells												
484	0010	WELLS For dewatering 10' to 20' deep, 2" diameter										484
	0020	with steel casing, minimum	B-6	165	.145	V.L.F.	2	3.40	1.33	6.73	8.95	
	0050	Average		98	.245		4	5.70	2.23	11.93	15.75	
	0100	Maximum	↓	49	.490	↓	10	11.45	4.47	25.92	33.50	
	0300	For pumps for dewatering, see division 016 420-4100 to 4400										
	0500	For domestic water wells, see division 026-704										
021 520 | Shores												
524	0010	SHORING Excavation, building, with braces, no salvage allowance	B-51	2.20	21.818	M.B.F	645	475	78	1,198	1,550	524
	1000	With 35 ton screw jacks, per box and jack	"	3.60	13.333	Jack	40	291	47.50	378.50	550	
	1100	Masonry openings in walls, see div. 020-704										
021 560 | Underpinning												
564	0010	UNDERPINNING FOUNDATIONS Including excavation,										564
	0020	forming, reinforcing, concrete and equipment										
	0100	5' to 16' below grade, 100 to 500 C.Y.	B-52	2.30	24.348	C.Y.	168	615	188	971	1,350	
	0200	Over 500 C.Y.		2.50	22.400		152	565	173	890	1,250	
	0400	16' to 25' below grade, 100 to 500 C.Y.		2	28		185	705	216	1,106	1,550	
	0500	Over 500 C.Y.		2.10	26.667		175	670	206	1,051	1,475	
	0700	25' to 40' below grade, 100 to 500 C.Y.		1.60	35		202	880	270	1,352	1,900	
	0800	Over 500 C.Y.	↓	1.80	31.111		185	785	240	1,210	1,700	
	0900	For under 50 C.Y., add					10%	40%				
	1000	For 50 C.Y. to 100 C.Y., add				↓	5%	20%				

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021 | Site Preparation & Excavation Support

			CREW	DAILY OUTPUT	LABOR-HOURS	UNIT	1999 BARE COSTS MAT.	LABOR	EQUIP.	TOTAL	TOTAL INCL O&P
021 140 | Stripping											
144	0010	STRIPPING Topsoil, and stockpiling, sandy loam									
	0020	200 H.P. dozer, ideal conditions	B-10B	2,300	.005	C.Y.		.14	.36	.50	.61
	0100	Adverse conditions	"	1,150	.010			.27	.73	1	1.22
	0200	300 HP dozer, ideal conditions	B-10M	3,000	.004			.10	.38	.48	.57
	0300	Adverse conditions	"	1,650	.007	↓		.19	.69	.88	1.04
021 150 | Selective Clearing											
154	0010	SELECTIVE CLEARING									
	1000	Stump removal on site by hydraulic backhoe, 1-1/2 C.Y.									
	1040	4" to 6" diameter	B-17	60	.533	Ea.		12.30	9.70	22	29.50
	1050	8" to 12" diameter	B-30	33	.727			17.60	48.50	66.10	88
	1100	14" to 24" diameter	↓	25	.960			23	64	87	106
	1150	26" to 36" diameter	↓	16	1.500	↓		36.50	100	136.50	166
	2000	Remove selective trees, on site using chain saws and chipper,									
	2050	not incl. stumps, up to 6" diameter	B-7	18	2.667	Ea.		61	66	127	168
	2100	8" to 12" diameter	↓	12	4			97	99	196	262
	2150	14" to 24" diameter	↓	10	4.800			110	119	229	300
	2200	26" to 36" diameter	↓	8	6			138	148	286	380
	2300	Machine load, 2 mile haul to dump, 12" diam. tree, add				↓				150	225
021 200 | Structure Moving											
204	0010	MOVING BUILDINGS One day move, up to 24' wide									
	0020	Reset on new foundation, patch & hook-up, average move				Total					8,700
	0040	Wood or steel frame bldg., based on ground floor area	B-4	185	.259	S.F.		5.70	2.57	8.27	11.70
	0060	Masonry bldg., based on ground floor area	"	137	.350	↓		7.65	3.47	11.12	15.80
	0200	For 24' to 42' wide, add				↓					15%
	0220	For each additional day on road, add	B-4	1	48	Day		1,050	475	1,525	2,175
	0240	Construct new basement, move building, 1 day									
	0300	move, patch & hook up, based on ground floor area	B-3	155	.310	S.F.	5.75	7.15	11.30	24.20	30
021 400 | Dewatering											
404	0010	DEWATERING Excavate drainage trench, 2' wide, 2' deep R021-440	B-11C	90	.178	C.Y.		4.43	2.43	6.86	9.50
	0100	2' wide, 3' deep, with backhoe loader	"	135	.119	↓		2.95	1.62	4.57	6.35
	0200	Excavate sump pits by hand, light soil	1 Clab	7.10	1.127			24		24	38
	0300	Heavy soil	"	3.50	2.286	↓		49		49	77
	0500	Pumping 8 hr., attended 2 hrs. per day, including 20 L.F.									
	0550	of suction hose & 100 L.F. discharge hose									
	0600	2" diaphragm pump used for 8 hours	B-10H	4	3	Day		78	11.10	89.10	132
	0620	Add per additional pump							35	35	40
	0650	4" diaphragm pump used for 8 hours	B-10I	4	3			78	23.50	101.50	146
	0670	Add per additional pump							75	75	85
	0800	8 hrs. attended, 2" diaphragm pump	B-10H	1	12			315	44.50	359.50	530
	0820	Add per additional pump							35	35	40
	0900	3" centrifugal pump	B-10J	1	12			315	58	373	545
	0920	Add per additional pump							49.50	49.50	54.50
	1000	4" diaphragm pump	B-10I	1	12			315	94	409	585
	1020	Add per additional pump							85	85	98
	1100	6" centrifugal pump	B-10K	1	12			315	220	535	720
	1120	Add per additional pump				↓			110	110	125
	1300	CMP, incl. excavation 3' deep, 12" diameter	B6	115	.209	L.F.	8.95	4.88	1.90	15.73	19.45
	1400	18" diameter		100	240	"	9.95	5.60	2.19	17.74	22
	1600	Sump hole construction, incl. excavation and gravel, pit		1,250	.019	C.F.	.56	.45	.18	1.19	1.51
	1700	With 12" gravel collar, 12" pipe, corrugated, 16 ga.		70	.343	L.F.	11.90	8	3.13	23.03	29
	1800	15" pipe, corrugated, 16 ga.		55	.436		14.65	10.20	3.98	28.83	36.50
	1900	18" pipe, corrugated, 16 ga.	↓	50	.480	↓	13.30	11.20	4.38	28.88	37

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Exhibit 48 (JBS-7)

Conceptual Diagram –
EVA "Cooperative" Rail Delivery System

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 03 EXHIBIT NO. 48
COMPANY/ CSX
WITNESS: JBS-7
DATE: 05/27-28/04

EXHIBIT NO. 48 (JBS-7)
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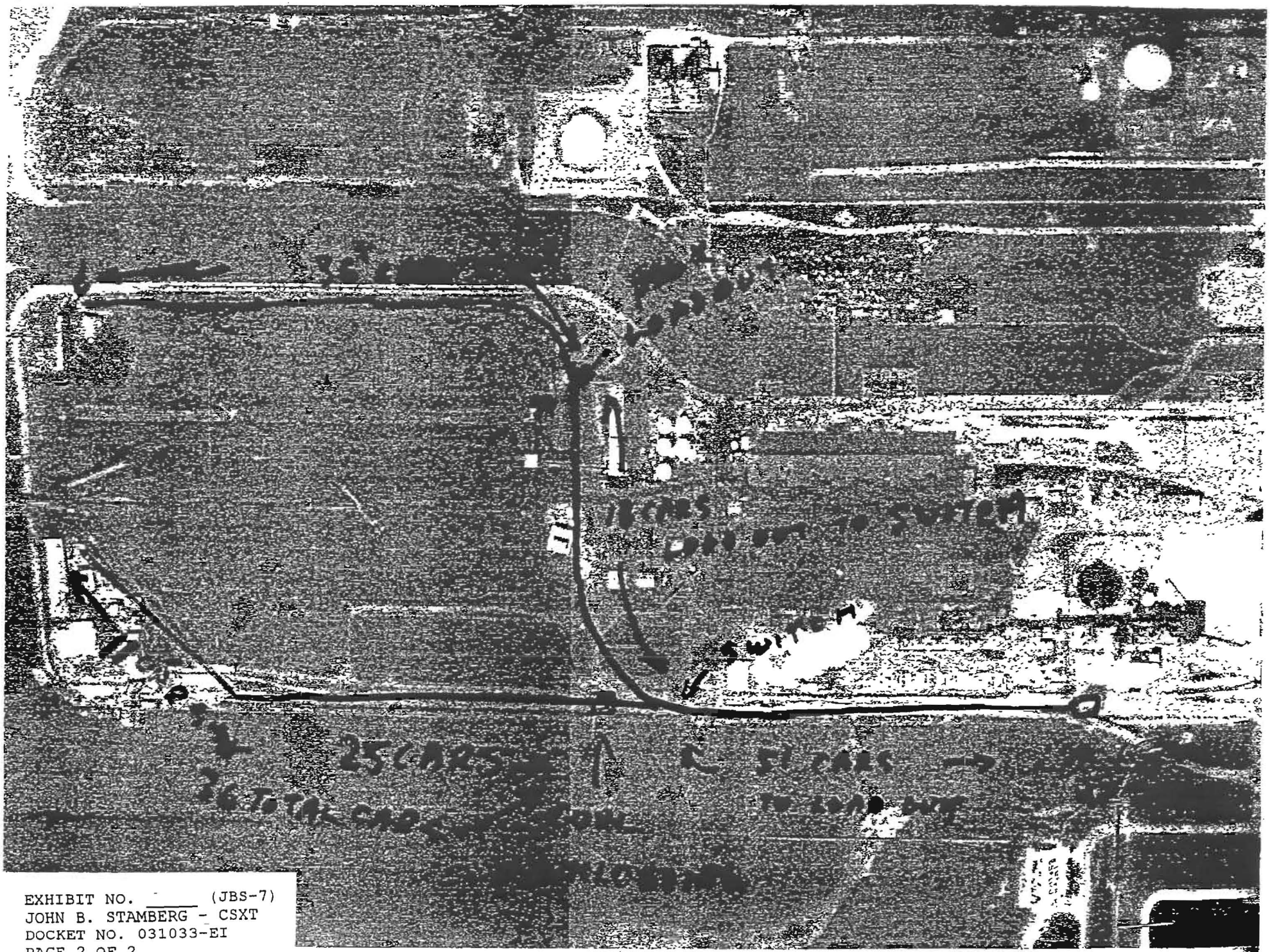

EXHIBIT NO. _____ (JBS-7)
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COOP SYSTEM POLK RELOAD / BIG BEND UNLOAD

EXHIBITS 8, 9, AND 10 TO MR. STAMBERG'S TESTIMONY ARE CONFIDENTIAL AND HAVE BEEN REDACTED FROM THIS PUBLICLY FILED VERSION OF HIS TESTIMONY.

CONFIDENTIAL

(JBS-8)	**CONFIDENTIAL,** Overview of Rail Delivery Options to Big Bend

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 49
COMPANY/ CSX
WITNESS: JBS-8
DATE: 05/27-28/04

CONFIDENTIAL

(JBS-9)	**CONFIDENTIAL,** Sargent & Lundy LLC, Tampa Electric Company Big Bend and Polk Generating Stations, CSX Transportation Alternate Method of Coal Delivery, SL-008160, September 18, 2003

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 50
COMPANY/ CSX
WITNESS: JBS-9
DATE: 05/27-28/04

CONFIDENTIAL

(JBS-10)	**CONFIDENTIAL,** Sargent & Lundy LLC, Tampa Electric Company Big Bend and Polk Generating Stations, CSX Transportation Alternate Method of Coal Delivery, SL-008160, **DRAFT** September 4, 2003

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 51
COMPANY/ CSX
WITNESS: JBS-10
DATE: 05/27-28/04

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 031033-EI

IN RE: TAMPA ELECTRIC COMPANY'S
2004-2008 WATERBORNE TRANSPORTATION
CONTRACT WITH TECO TRANSPORT
AND ASSOCIATED BENCHMARK

TESTIMONY AND EXHIBIT
OF
DR. ANATOLY HOCHSTEIN

REDACTED VERSION

FILED MARCH 31, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NOS. 52-60
COMPANY/ Res. Customers
WITNESS: A. Hochstein AH-1 thru AH-9
DATE: 03/27-28/04

Exhibit 52 (AH-1): Davant, LA - Tampa, FL Required Freight Rates for US Flag Vessels

DWT	25,000	35,000	40,000	50,000	60,000	80,000
LOA	549	608	632	676	715	779
Beam	81	90	93	100	105	114
Draft	32	35	37	40	42	46
Speed	14	14	14	14	14	14

Replacement Cost	47,845,214	52,250,153	54,452,622	58,857,561	63,262,499	75,113,255
per DWT	1,914	1,493	1,361	1,177	1,054	939
Annualized (6.125%, 20 yrs)	4,215,163	4,603,238	4,797,276	5,185,351	5,573,426	6,617,478
Daily (345 days)	**12,218**	**13,343**	**13,905**	**15,030**	**16,155**	**19,181**

Daily Costs ($/Day):

Daily Capital	12,218	13,343	13,905	15,030	16,155	19,181
Operating Daily	13,600	13,990	14,186	14,576	14,966	15,931
Capital + Operating	25,818	27,333	28,091	29,606	31,121	35,112
per DWT	1.03	0.78	0.70	0.59	0.52	0.44
Fuel at Sea	4,203	4,455	4,581	4,938	5,317	5,947
Fuel at Port	421	421	421	526	526	526
Total at Sea	30,021	31,788	32,672	34,544	36,438	41,059
Total at Port	26,239	27,754	28,512	30,132	31,647	35,638
per DWT	1.05	0.79	0.71	0.60	0.53	0.45

Voyage Time, RT (days):

Service Speed	12.60	12.60	12.60	12.60	12.60	12.60
Days at Sea	3.02	3.02	3.02	3.02	3.02	3.02
Days at Port / Slack	3.00	3.00	3.50	4.00	4.00	4.00
Total Days	6.02	6.02	6.52	7.02	7.02	7.02

Voyage Cost ($/RT):

Fuel at Sea	12,676	13,436	13,816	14,892	16,035	17,935
Fuel at Port	1,263	1,263	1,474	2,104	2,104	2,104
Capital	73,501	80,268	90,604	105,449	113,340	134,572
Operating	81,817	84,164	92,433	102,263	105,001	111,769
Total	**169,257**	**179,131**	**198,327**	**224,708**	**236,480**	**266,381**

Freight Cost ($/ton):

Fuel at Sea	0.51	0.38	0.35	0.30	0.27	0.22
Fuel at Port	0.05	0.04	0.04	0.04	0.04	0.03
Capital	2.94	2.29	2.27	2.11	1.89	1.68
Operating	3.27	2.40	2.31	2.05	1.75	1.40
Total	**6.77**	**5.12**	**4.96**	**4.49**	**3.94**	**3.33**

One-way distance 456

Source: US Army Corps of Engineers (2002).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 52
COMPANY/ Res. Cust.
WITNESS. AH-1
DATE: 05/27-28/04

Exhibit 53 (AH- 2): TECOT Schedule in Tampa, FL (September 2003)

Vessel Name	Schedule Number	Activity Date	Commodity Description	Tons	Imp / Exp	Load/ Unload	Berth	Destination	Origin
BARBARA VAUGHT	32764	9/4/2003	GRAINS, NOS, BULK	9,464	I	U	256	TPA	LA
BARBARA VAUGHT	32764	9/6/2003	COAL	8,613	I	U	4101	TPA	LA
BARBARA VAUGHT	32764	9/10/2003	PHOSPHAT CHEMICAL, BULK	17,600	E	L	4146	LA	TPA
DIANA T	32821	9/15/2003	COAL	15,695	I	U	4144	TPA	LA
DIANA T	32821	9/16/2003	PHOSPHATE, ROCK, BULK	28,594	E	L	4103	LA	TPA
DIANA T	32904	9/23/2003	COAL	15,713	I	U	4144	TPA	LA
DIANA T	32090	9/24/2003	PHOSPHATE, ROCK, BULK	28,252	E	L	4103	LA	TPA
DORIS GUENTHER	32830	9/16/2003	COAL	22,013	I	U	4144	TPA	LA
DORIS GUENTHER	32830	9/17/2003	PHOSPHAT CHEMICAL, BULK	22,503	E	L	204	LA	TPA
GAYLE EUSTACE	32794	9/11/2003	COAL	14,828	I	U	4101	TPA	LA
GAYLE EUSTACE	32794	9/12/2003	COAL	16,355	I	U	4144	TPA	LA
GAYLE EUSTACE	32794	9/13/2003	PHOSPHATE, ROCK,BULK	31,853	E	L	4103	LA	TPA
GAYLE EUSTACE	32899	9/21/2003	COAL	10,460	I	U	4101	TPA	LA
GAYLE EUSTACE	32899	9/22/2003	COAL	19,012	I	U	4144	TPA	LA
GAYLE EUSTACE	32899	9/25/2003	PHOSPHATE, ROCK, BULK	32,320	E	L	4103	LA	TPA
JUDY LITRICO	32857	9/18/2003	COAL	29,019	I	U	4101	TPA	LA
JUDY LITRICO	32857	9/19/2003	PHOSPHAT CHEMICAL, BULK	28,827	E	L	4146	LA	TPA
MARY TURNER	32745	9/6/2003	COAL	27,678	I	U	4101	TPA	LA
MARY TURNER	32745	9/8/2003	PHOSPHATE, ROCK,BULK	37,616	E	L	4103	LA	TPA
MARY TURNER	32832	9/16/2003	COAL	27,404	I	U	4101	TPA	LA
MARY TURNER	32832	9/17/2003	PHOSPHATE, ROCK, BULK	38,105	E	L	4103	LA	TPA
MARY TURNER	32918	9/25/2003	SEAWATER, BULK	1,063	I	U	271	TPA	LA
MARY TURNER	32918	9/26/2003	COAL	27,936	I	U	4101	TPA	LA
MARY TURNER	32918	9/27/2003	PHOSPHATE, ROCK, BULK	39,459	E	L	4103	LA	TPA
PAT CANTRELL	32932	9/26/2003	PHOSPHAT CHEMICAL, BULK	34,448	E	L	204	LA	TPA
PEGGY PALMER	32806	9/9/2003	COAL	34,494	I	U	4101	TPA	LA
PEGGY PALMER	32806	9/12/2003	PHOSPHAT CHEMICAL, BULK	6,005	E	L	4148	LA	TPA
PEGGY PALMER	32806	9/13/2003	PHOSPHAT CHEMICAL, BULK	21,012	E	L	4110	LA	TPA
PEGGY PALMER	32906	9/23/2003	COAL	33,474	I	U	4101	TPA	LA
PEGGY PALMER	32906	9/25/2003	PHOSPHAT CHEMICAL, BULK	4,509	E	L	4103	LA	TPA
PEGGY PALMER	32906	9/26/2003	PHOSPHAT CHEMICAL, BULK	19,501	E	L	4110	LA	TPA

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 53
COMPANY/ Res. Cust.
WITNESS: AH-2
DATE: 03/27-28/04

Exhibit 54 (AH- 3): Daily Time Charter Rates based on Preference Trades and US Army Corps of Engineers

Name	Type	$/Day	dwt	$/dwt-Day	Employment	Comments
TECOT Barges						
Diana Lugwig	ATB	11,979	22,944	0.52	TE	Incative in-Class
Gayle Eustace	ATB	13,793	36,659	0.38	TE	
Maria Flood	ATB	23,091	37,768	0.61	Preference	
Pat Cantrell	ATB	19,453	36,906	0.53	Pet Coke	
Peggy Palmer	ATB	15,887	37,700	0.42	TE	
Average	**ATB**	**16,841**	**34,395**	**0.49**		
Adjusted Average		**17,208**	**35,000**			
TECOT Ships						
Cynthia Fagan	Ship	22,914	40,853	0.56	Pet Coke & Preference	
Judy Litrico	Ship	21,859	32,100	0.68	Pet Coke & Preference	
Average	Ship	**22,387**	**36,477**	**0.62**		
Adjusted Average		**21,732**	**35,000**			
COE Ships						
US Replacement	**Ship**	**27,333**	**35,000**			**7-yr old Ship**
US Operating	**Ship**	**13,990**	**35,000**			**7-yr old Ship**
Foreign Replacement	Ship	5,337	35,000			7-yr old Ship
Foreign Operating	Ship	4,725	35,000			7-yr old Ship

All data related to time charter rate, covering capital, crewing, maintenance, supply and administration.

Sources:

- Preference Trade data from DMA final report, manipulated by AH & AA
- US Army Corps of Engineers Guidelines for Ship Cost, FY 2002

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 54
COMPANY/ Res. Cust.
WITNESS: AH-3
DATE: 03/27-28/04

Exhibit 55 (AH- 4): Texas - Jacksonville, FL Required Freight Rates for US Flag Vessels

DWT	25,000	35,000	40,000	50,000	60,000	80,000
LOA	549	608	632	676	715	779
Beam	81	90	93	100	105	114
Draft	32	35	37	40	42	46
Speed	14	14	14	14	14	14
Replacement Cost	47,845,214	52,250,153	54,452,622	58,857,561	63,262,499	75,113,255
per DWT	1,914	1,493	1,361	1,177	1,054	939
Annualized (6.125%, 20 yrs)	4,215,163	4,603,238	4,797,276	5,185,351	5,573,426	6,617,478
Daily (345 days)	**12,218**	**13,343**	**13,905**	**15,030**	**16,155**	**19,181**

Daily Costs ($/Day):

Daily Capital	12,218	13,343	13,905	15,030	16,155	19,181
Operating Daily	13,600	13,990	14,186	14,576	14,966	15,931
Capital + Operating	25,818	27,333	28,091	29,606	31,121	35,112
per DWT	1.03	0.78	0.70	0.59	0.52	0.44
Fuel at Sea	4,203	4,455	4581	4938	5317	5317
Fuel at Port	421	421	421	526	526	526
Total at Sea	30,021	31,788	32,672	34,544	36,438	40,429
Total at Port	26,239	27,754	28,512	30,132	31,647	35,638
per DWT	1.05	0.79	0.71	0.60	0.53	0.45

Voyage Time, RT (days):

Service Speed	12.60	12.60	12.60	12.60	12.60	12.60
Days at Sea	7.03	7.03	7.03	7.03	7.03	7.03
Days at Port / Slack	3.00	3.00	3.50	4.00	4.00	4.00
Total Days	10.03	10.03	10.53	11.03	11.03	11.03

Voyage Cost ($/RT):

Fuel at Sea	29,549	31,321	32,206	34,716	37,381	37,381
Fuel at Port	1,263	1,263	1,474	2,104	2,104	2,104
Capital	122,550	133,833	146,427	165,787	178,195	211,576
Operating	136,415	140,328	149,383	160,779	165,083	175,725
Total	**289,777**	**306,745**	**329,490**	**363,387**	**382,763**	**426,785**

Freight Cost ($/ton):

Fuel at Sea	1.18	0.89	0.81	0.69	0.62	0.47
Fuel at Port	0.05	0.04	0.04	0.04	0.04	0.03
Capital	4.90	3.82	3.66	3.32	2.97	2.64
Operating	5.46	4.01	3.73	3.22	2.75	2.20
Total	**11.59**	**8.76**	**8.24**	**7.27**	**6.38**	**5.33**

One-way distance 1063

Source: US Army Corps of Engineers (2002).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 55
COMPANY/ Res. Cust.
WITNESS: AH-4
DATE: 05-27-2004

Exhibit 56 (AH- 5): Davant, LA - Tampa, FL Required Freight Rates for US and Foreign Ships

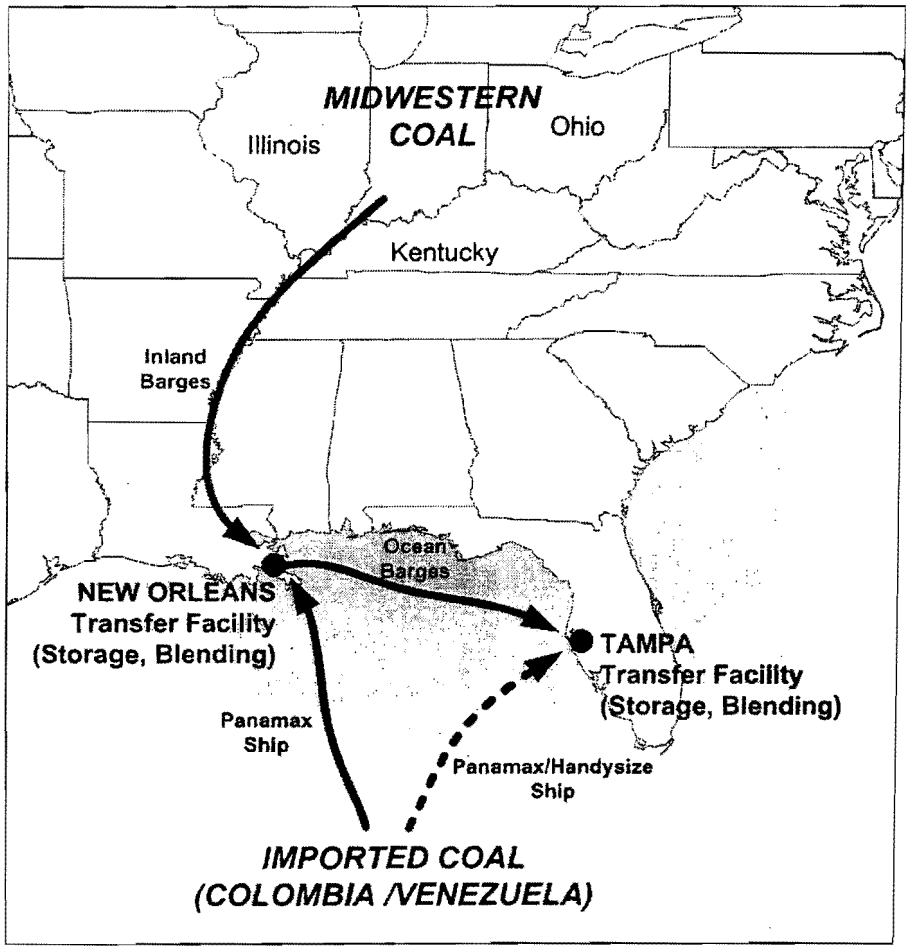
		TECOT Barge		
	US COE	No Backhaul	With Backhaul	Foreign
DWT	35,000	35,000	35,000	35,000
LOA	608			608
Beam	90			90
Draft	35			35
Speed	14	11	11	14
Replacement Cost	52,250,153			20,900,061
per DWT	1,493			597
Annualized (6.125%, 20 yrs)	4,603,238			1,841,295
Daily (345 days)	**13,343**			**5,337**
Daily Costs ($/Day):				
Daily Capital	13,343	12,311	12,311	5,337
Operating Daily	13,990	4,897	4,897	4,725
Capital + Operating	27,333	17,208	17,208	10,062
per DWT	0.78	0.49	0.49	0.29
Fuel at Sea	4,455	4,455	4,455	4,455
Fuel at Port	421	421	421	421
Total at Sea	31,788	21,663	21,663	14,517
Total at Port	27,754	17,629	17,629	10,483
per DWT	0.79	0.50	0.50	0.30
Voyage Time, RT (days):				
Service Speed	12.60	9.90	9.90	12.60
Days at Sea	3.02	3.84	3.84	3.02
Days at Port / Slack	3.00	3.00	5.00	3.00
Total Days	6.02	6.84	8.84	6.02
Voyage Cost ($/RT):				
Fuel at Sea	13,436	17,100	17,100	13,436
Fuel at Port	1,263	1,263	2,105	1,263
Capital	80,268	84,188	108,810	32,107
Operating	84,164	33,485	43,278	28,424
Total	**179,131**	**136,036**	**171,293**	**75,230**
Freight Cost ($/ton):				
Fuel at Sea	0.38	0.27	0.19	0.38
Fuel at Port	0.04	0.04	0.06	0.04
Capital	2.29	2.41	3.11	0.92
Operating	2.40	0.96	1.24	0.81
Total	**5.12**	**3.67**	**4.59**	**2.15**
Total Fronthaul			**2.30**	

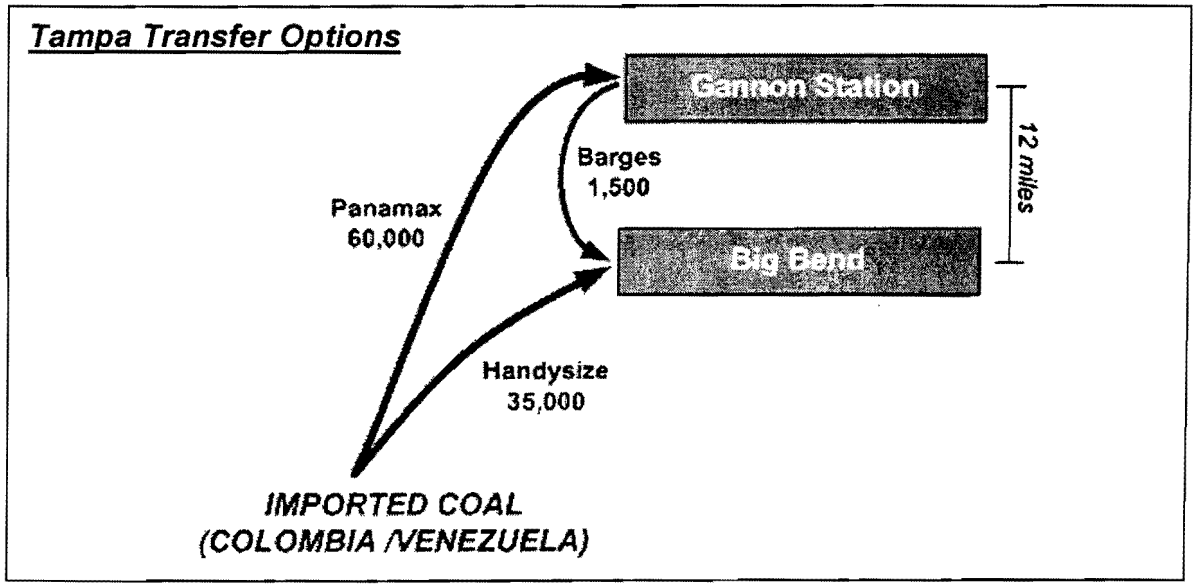
TECOT Capital + Operating cost is based on Figure 2 (Preference Trade).

Operating cost for TECOT barges is assumed as 30% of same-size ships.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 56
COMPANY/ Res. Cust.
WITNESS: AH-5
DATE: 05/27-28/04

Exhibit 57 (AH- 6): Present and Future Transport Options





FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 57
COMPANY/ Res. Cust.
WITNESS: AH-6
DATE: 05/27-28/04

Exhibit 58 (AH- 7): Colombia - Tampa, FL and New Orleans Required Freight Rates for Foreign Ships

	Tampa, FL			New Orleans, LA		
DWT	35,000	50,000	60,000	35,000	50,000	60,000
LOA	608	676	715	608	676	715
Beam	90	100	105	90	100	105
Draft	35	40	42	35	40	42
Speed	14	14	14	14	14	14
Replacement Cost	20,900,061	23,543,024	25,305,000	20,900,061	23,543,024	25,305,000
per DWT	597	471	422	597	471	422
Annualized (6.125%, 20 yrs)	1,841,295	2,074,140	2,229,371	1,841,295	2,074,140	2,229,371
Daily (345 days)	**5,337**	6,012	6,462	**5,337**	6,012	6,462
Daily Costs ($/Day):						
Daily Capital	5,337	6,012	6,462	5,337	6,012	6,462
Operating Daily	4,725	5,017	5,211	4,725	5,017	5,211
Capital + Operating	10,062	11,029	11,673	10,062	11,029	11,673
per DWT	0.29	0.22	0.19	0.29	0.22	0.19
Fuel at Sea	4,455	4,938	5,317	4,455	4,938	5,317
Fuel at Port	421	526	526	421	526	526
Total at Sea	14,517	15,967	16,990	14,517	15,967	16,990
Total at Port	10,483	11,555	12,199	10,483	11,555	12,199
per DWT	0.30	0.23	0.20	0.30	0.23	0.20
Voyage Time, RT (days):						
Service Speed	12.60	12.60	12.60	12.60	12.60	12.60
Days at Sea	8.56	8.56	8.56	9.71	9.71	9.71
Days at Port / Slack	3.00	4.00	4.00	3.00	4.00	4.00
Total Days	11.56	12.56	12.56	12.71	13.71	13.71
Voyage Cost ($/RT):						
Fuel at Sea	38,156	42,293	45,539	43,254	47,943	51,623
Fuel at Port	1,263	2,104	2,104	1,263	2,104	2,104
Capital	61,722	75,540	81,193	67,829	82,418	88,587
Operating	54,643	63,038	65,476	60,049	68,778	71,438
Total	**155,784**	**182,974**	**194,312**	**172,394**	**201,244**	**213,752**
Freight Cost ($/ton):						
Fuel at Sea	1.09	0.85	0.59	1.24	0.96	0.67
Fuel at Port	0.04	0.04	0.04	0.04	0.04	0.04
Capital	1.76	1.51	1.35	1.94	1.65	1.48
Operating	1.56	1.26	1.09	1.72	1.38	1.19
Total	**4.45**	**3.66**	**3.07**	**4.93**	**4.02**	**3.37**

US Preference is based on DMA earning report for TECOT barges

Operating cost for TECOT barges is assumed as 30% of same-size ships

US Army Corps of Engineers Data (2002)

One-way Distance from Colombia	
Tampa	1,295
New Orleans	1,468

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 58
COMPANY/ Res. Cust.
WITNESS: AH-7
DATE 05/27-28/04

Exhibit 59 (AH- 8): Big Bend Channel Improvement Analysis

Investment:

Item	Cost	Explanation
TE Dredging	1,770,000	25% of total cost estimated by COE at $7,454,000
New Unloader	7,454,000	COE estimate
Dock Upgrade	3,458,000	COE estimate
Total TE Investment	**12,682,000**	

Breakdown Volume:

Annualized Investment	1,117,284	Recovery of investgments based on 20 years and 6.125%
Transport Saving ($/ton)	10.73	See text
Breakeven Volume (tons/year)	104,127	

Comments:

1. COE taking responsibility of the channel would save TE on maintenance of existing channel $1,000,000 every 5 years.
2. TE cost estimate for a new unloader is $5,500,000 and for dock upgrade $2,400,000.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 59
COMPANY/ Res. Cust.
WITNESS: AH-8
DATE 05/27-28/04

Exhibit 60 (AH-9)

Florida Utilities Coal Shipments for 2003

This exhibit summarizes information available at the Federal Energy Regulatory Commission. This commission collects data on cost and quality of fuels for electric plants (Form 423 - Monthly Report of Cost and Quality of Fuels for Electric Plants Data) to be used in the determination of electric rates. The following tables list shipments of 2003 domestic and imported bituminous coal for the following electric plants:

- Tampa Electric Company
- Gulf Power
- Florida Power
- Jacksonville Electric Authority

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 60
COMPANY/ Res. Cust.
WITNESS. AH-9
DATE 05/27-28/04

Tampa Electric Co. (TECO) - 2003 Coal Movements

Source: Federal Energy Regulatory Commission (Form 423 - Monthly Report of Cost and Quality of Fuels for Electric Plants Data)

DOMESTIC SHIPMENTS

State	Month	Plant	Source	Tons (000)	BTU Content	Cost (¢/mBtu)	$/Short Ton
IL	01	Transfer Facility	BIG RIDGE MINE	17.81	12,278	170.10	41.77
IL	01	Transfer Facility	GALATIA	128.66	12,162	145.50	35.39
IL	01	Transfer Facility	GALLATIN	9.76	12,369	137.80	34.09
IL	01	Transfer Facility	I-1	11.22	12,494	151.30	37.81
IL	01	Transfer Facility	I-1	58.20	12,494	143.30	35.81
IL	01	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	19.54	12,104	121.70	29.46
IL	01	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	45.67	12,333	142.00	35.03
IL	01	Transfer Facility	ZEIGLER	84.27	10,983	189.40	41.60
IL	02	Transfer Facility	BIG RIDGE MINE	3.39	12,159	170.10	41.36
IL	02	Transfer Facility	EAGLE VALLEY/ WILDCAT	9.39	12,436	147.30	36.64
IL	02	Transfer Facility	GALATIA	136.50	12,186	145.50	35.46
IL	02	Transfer Facility	I-1	62.69	12,408	146.90	36.45
IL	02	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	45.26	12,091	138.50	33.49
IL	02	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	60.55	12,210	113.10	27.62
IL	02	Transfer Facility	ZEIGLER	74.51	10,989	189.40	41.63
IL	03	Transfer Facility	BIG RIDGE MINE	17.33	12,222	170.10	41.58
IL	03	Transfer Facility	EAGLE VALLEY/ WILDCAT	18.86	12,388	147.30	36.50
IL	03	Transfer Facility	GALATIA	112.71	12,045	145.50	35.05
IL	03	Transfer Facility	I-1	76.54	12,428	146.90	36.51
IL	03	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	50.30	12,087	138.50	33.48
IL	03	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	54.20	12,234	114.90	28.11
IL	03	Transfer Facility	ZEIGLER	108.98	11,031	223.10	49.22
IL	04	Transfer Facility	BIG RIDGE MINE	26.88	12,207	174.30	42.55
IL	04	Transfer Facility	GALATIA	216.10	11,929	148.00	35.31
IL	04	Transfer Facility	I-1	68.58	12,478	150.10	37.46
IL	04	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	20.40	12,267	151.60	37.25
IL	04	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	53.81	12,277	134.10	32.93
IL	04	Transfer Facility	ZEIGLER	91.33	11,044	227.10	50.16
IL	05	Transfer Facility	BIG RIDGE MINE	21.38	12,204	174.30	42.54
IL	05	Transfer Facility	EAGLE VALLEY/ WILDCAT	9.91	12,305	150.80	37.11
IL	05	Transfer Facility	GALATIA	129.20	11,997	148.00	35.51
IL	05	Transfer Facility	I-1	67.13	12,478	150.10	37.46
IL	05	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	16.19	12,124	141.70	34.36
IL	05	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	54.35	12,269	143.40	35.24
IL	05	Transfer Facility	ZEIGLER	95.51	10,961	227.10	49.78
IL	06	Transfer Facility	BIG RIDGE MINE	31.56	12,250	174.30	42.70
IL	06	Transfer Facility	GALATIA	95.02	12,062	148.00	35.70
IL	06	Transfer Facility	I-1	47.45	12,595	150.10	37.81
IL	06	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	74.10	12,224	143.40	35.06
IL	06	Transfer Facility	ZEIGLER	89.39	10,975	226.40	49.69
IL	07	Transfer Facility	BIG RIDGE MINE	18.03	12,256	170.90	41.89
IL	07	Transfer Facility	GALATIA	108.15	12,028	145.20	34.93
IL	07	Transfer Facility	I-1	7.19	12,517	146.40	36.65
IL	07	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	76.06	12,321	139.40	34.35
IL	07	Transfer Facility	ZEIGLER	86.95	11,036	222.90	49.20
IL	08	Transfer Facility	BIG RIDGE MINE	23.97	12,142	170.90	41.50
IL	08	Transfer Facility	GALATIA	40.62	12,042	145.20	34.97
IL	08	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	70.38	12,227	139.40	34.09
IL	08	Transfer Facility	ZEIGLER	86.58	10,985	222.90	48.97
IL	09	Transfer Facility	BIG RIDGE MINE	28.78	12,207	170.90	41.72
IL	09	Transfer Facility	GALATIA	13.74	12,070	145.20	35.05
IL	09	Transfer Facility	WILLOW LAKE/ COTTAGE GROVE	81.34	12,228	139.40	34.09
IL	09	Transfer Facility	ZEIGLER	32.62	11,027	222.90	49.16
IL	09	Transfer Facility	ZEIGLER	51.56	11,027	210.90	46.51
IL	10	Transfer Facility	BIG RIDGE MINE	18.53	12,098	172.40	41.71
IL	10	Transfer Facility	GALATIA MINE	5.76	11,942	145.80	34.82
IL	10	Transfer Facility	I-1	15.50	11,947	137.10	32.76
IL	10	Transfer Facility	WILLOW LAKE/COTTAGE GROVE	77.17	12,198	140.20	34.20
IL	10	Transfer Facility	ZEIGLER	81.91	11,048	210.40	46.49
IL	11	Transfer Facility	WILLOW LAKE/COTTAGE GROVE	107.31	12,192	140.20	34.19
IL	11	Transfer Facility	ZEIGLER	86.17	10,942	210.40	46.04
IL	12	Transfer Facility	WILLOW LAKE/COTTAGE GROVE	53.08	12,151	145.00	35.24
IL	12	Transfer Facility	ZEIGLER	75.36	11,014	211.30	46.55
IL Total (Average)				**3,661.41**	**754,462**	**160.90**	**38.36**

Tampa Electric Co. (TECO) - 2003 Coal Movements (continued)

Source: Federal Energy Regulatory Commission (Form 423 - Monthly Report of Cost and Quality of Fuels for Electric Plants Data)

DOMESTIC SHIPMENTS

State	Month	Plant	Source	Tons (000)	BTU Content	Cost (¢/mBtu)	$/Short Ton
KY	01	Transfer Facility	DEKOVEN	33.32	12,662	157.10	39.78
KY	01	Transfer Facility	DOTITKI	16.81	12,374	165.20	40.88
KY	01	Transfer Facility	KNOB LICK #9	14.74	12,059	151.10	36.44
KY	02	Transfer Facility	DEKOVEN	3.00	12,551	158.00	39.66
KY	02	Transfer Facility	DEKOVEN	22.14	12,642	158.30	40.02
KY	02	Transfer Facility	DEKOVEN	3.80	12,836	150.60	38.66
KY	02	Transfer Facility	DOTITKI	15.81	12,390	165.20	40.94
KY	02	Transfer Facility	KNOB LICK #9	3.17	12,047	151.10	36.41
KY	03	Transfer Facility	DEKOVEN	16.70	12,856	152.70	39.26
KY	03	Transfer Facility	DEKOVEN	19.23	12,835	150.60	38.71
KY	03	Transfer Facility	DOTITKI	16.36	12,383	165.20	40.91
KY	04	Transfer Facility	DEKOVEN	18.00	12,777	155.00	39.61
KY	04	Transfer Facility	DEKOVEN	14.00	12,778	153.70	39.28
KY	04	Transfer Facility	DOTITKI	15.68	12,355	165.20	40.82
KY	05	Transfer Facility	DEKOVEN	18.08	12,475	150.50	37.55
KY	05	Transfer Facility	DEKOVEN	12.67	12,543	149.50	37.50
KY	05	Transfer Facility	DOTITKI	14.26	12,381	168.40	41.70
KY	05	Transfer Facility	PATRIOT	11.03	11,114	114.80	25.52
KY	06	Transfer Facility	DEKOVEN	18.62	12,674	154.60	39.19
KY	06	Transfer Facility	DEKOVEN	12.34	12,723	153.10	38.96
KY	06	Transfer Facility	DOTITKI	22.39	12,338	168.40	41.55
KY	06	Transfer Facility	PATRIOT	11.03	11,284	130.70	29.50
KY	07	Transfer Facility	DEKOVEN	17.54	12,771	151.90	38.80
KY	07	Transfer Facility	DEKOVEN	6.82	12,798	149.90	38.37
KY	08	Transfer Facility	DEKOVEN	15.70	12,796	152.20	38.95
KY	08	Transfer Facility	DEKOVEN	8.24	12,791	143.40	36.68
KY	09	Transfer Facility	DEKOVEN	31.16	12,670	151.10	38.29
KY	09	Transfer Facility	DEKOVEN	22.66	12,652	149.00	37.70
KY	10	Transfer Facility	DEVOKEN	24.96	12,642	151.20	38.23
KY	10	Transfer Facility	DEVOKEN	20.07	12,619	149.30	37.68
KY	11	Transfer Facility	DEVOKEN	25.02	12,547	166.90	41.88
KY	11	Transfer Facility	DEVOKEN	22.77	12,541	156.70	39.30
KY	12	Transfer Facility	DEKOVEN	23.54	12,547	165.30	41.48
KY	12	Transfer Facility	DEKOVEN	11.98	12,571	152.40	38.32
KY Total (Average)				**563.66**	**425,022**	**153.94**	**38.56**
OH	09	Transfer Facility	POWHATTAN	34.92	12,634	143.70	36.31
OH	10	Transfer Facility	POWHATTAN	35.15	12,708	143.70	36.52
OH	11	Transfer Facility	POWHATTAN	34.78	12,654	143.70	36.37
OH	12	Transfer Facility	POWHATTAN	17.41	12,740	153.70	39.16
OH Total (Average)				**122.26**	**50,736**	**146.21**	**37.09**
DOMESTIC Total (Average)				**4,347.33**	**1,230,220**	**157.89**	**38.37**

IMPORTED SHIPMENTS

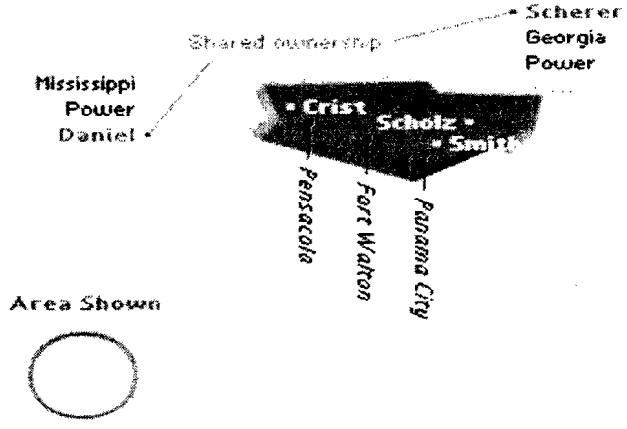
State	Month	Plant	Source	Tons (000)	BTU Content	Cost (¢/mBtu)	$/Short Ton
IM	01	Transfer Facility	PASA DIABLO (VENEZUELA)	38.30	13,165	157.40	41.44
IM	04	Transfer Facility	COLOMBIA	73.25	12,407	151.30	37.54
IM	05	Transfer Facility	VENEZUELA	59.32	13,033	152.30	39.70
IM	06	Transfer Facility	VENEZUELA	54.01	12,997	151.90	39.48
IM	07	Transfer Facility	VENEZUELA	56.41	12,989	151.80	39.43
IM	12	Transfer Facility	PASA DIABLO (VENEZUELA)	56.66	12,792	153.70	39.32
IMPORTED Total (Average)				**337.95**	**77,383**	**153.09**	**39.51**

Gulf Power, Pensacola - 2003 Coal Movements

Source: Federal Energy Regulatory Commission (Form 423 - Monthly Report of Cost and Quality of Fuels for Electric Plants Data)

IMPORTED SHIPMENTS

State	Month	Plant	Source	Tons (000)	BTU Content	Cost (¢/mBtu)	$/Short Ton
IM	01	Crist	PEABODY COAL SALES (Australia)	6.00	12,173	159.60	38.86
IM	01	Crist	PEABODY COAL SALES (Colombia)	25.00	11,824	152.00	35.94
IM	01	Crist	PEABODY COAL SALES (Colombia)	57.00	11,710	152.30	35.67
IM	01	Crist	PEABODY COAL SALES (Colombia)	8.00	11,752	157.60	37.04
IM	01	Smith	PEABODY COAL SALES (Australia)	25.00	12,173	164.70	40.10
IM	01	Smith	PEABODY COAL SALES (Colombia)	15.00	11,710	157.50	36.89
IM	02	Crist	PEABODY COALSALES (Australia)	4.00	12,173	159.60	38.86
IM	02	Crist	PEABODY COALSALES (Colombia)	44.00	11,824	152.00	35.94
IM	02	Crist	PEABODY COALTRADE (Colombia)	8.00	11,710	152.30	35.67
IM	02	Crist	PEABODY COALSALES (Colombia)	139.00	11,730	157.60	36.97
IM	02	Smith	PEABODY COALSALES (Australia)	36.00	12,173	164.70	40.10
IM	03	Crist	PEABODY COALSALES (Australia)	5.00	12,173	159.60	38.86
IM	03	Crist	PEABODY COALSALES (Colombia)	74.00	11,730	152.00	35.66
IM	03	Crist	PEABODY COALSALES (Colombia)	55.00	11,715	157.60	36.93
IM	03	Smith	PEABODY COALSALES (Australia)	30.00	12,173	164.70	40.10
IM	04	Crist	PEABODY COALSALES (Colombia)	91.00	11,730	152.50	35.78
IM	04	Crist	PEABODY COALSALES (Colombia)	90.00	11,879	157.90	37.51
IM	04	Smith	PEABODY COALSALES (Australia)	1.00	12,173	165.30	40.24
IM	05	Crist	PEABODY COALSALES (Colombia)	62.00	11,760	158.00	37.16
IM	05	Crist	INTEROCEAN COAL SALES (Colombia	162.00	11,804	152.60	36.03
IM	06	Crist	PEABODY COAL SALES (Colombia)	65.00	11,760	158.00	37.16
IM	06	Crist	INTEROCEAN COAL SALES (Colombia	146.00	11,768	152.60	35.92
IM	07	Crist	PEABODY COALSALES (Colombia)	102.00	11,803	157.60	37.20
IM	07	Crist	INTEROCEAN COAL SALES (Colombia	12.00	11,726	152.40	35.74
IM	08	Crist	PEABODY COALSALES (Colombia)	67.00	11,796	153.30	36.17
IM	08	Crist	PEABODY COALSALES (Colombia)	43.00	11,703	157.70	36.91
IM	08	Crist	INTEROCEAN COAL SALES (Colombia	126.00	11,726	152.40	35.74
IM	09	Crist	PEABODY COALSALES (Colombia)	7.00	11,796	153.30	36.17
IM	09	Crist	PEABODY COALSALES (Colombia)	13.00	11,730	157.70	37.00
IM	09	Crist	INTEROCEAN COAL SALES (Colombia	233.00	11,712	152.40	35.70
IM	09	Smith	PEABODY COALSALES (Colombia)	0.40	11,730	163.00	38.24
IM	10	Crist	PEABODY COALSALES (Colombia)	37.00	11,771	155.10	36.51
IM	10	Crist	INTEROCEAN COAL SALES (Colombia	68.00	11,696	153.60	35.93
IM	10	Crist	INTEROCEAN COAL SALES (Colombia	4.00	11,599	152.80	35.45
IM	10	Crist	INTEROCEAN COAL SALES (Colombia	11.00	11,664	180.30	42.06
IM	10	Smith	INTEROCEAN COAL SALES (Colombia	52.00	11,696	157.90	36.94
IM	10	Smith	INTEROCEAN COAL SALES (Colombia	13.00	11,599	158.20	36.70
IM	10	Smith	PEABODY COALSALES (Colombia)	4.00	11,771	159.40	37.53
IM	11	Crist	INTEROCEAN COAL SALES (Colombia	62.00	11,767	153.50	36.12
IM	11	Crist	INTEROCEAN COALSALES (Colombia	6.00	11,664	180.30	42.06
IM	11	Smith	INTEROCEAN COAL SALES (Colombia	5.00	11,767	157.80	37.14
IM	11	Smith	INTEROCEAN COAL SALES (Colombia	39.00	11,599	158.20	36.70
IM	12	Crist	INTEROCEAN COAL SALES (Colombia	116.00	11,767	153.50	36.12
IMPORTED Total (Average)				**2,170.40**	**507,699**	**157.72**	**37.26**
			Australia	107.00	85,211	162.60	39.59
			Colombia	2,063.40	422,488	156.74	36.79



Florida Power - 2003 Coal Movements

Source: Federal Energy Regulatory Commission (Form 423 - Monthly Report of Cost and Quality of Fuels for Electric Plants Data)

DOMESTIC SHIPMENTS

State	Month	Plant	Source	Tons (000)	BTU Content	Cost (¢/mBtu)	$/Short Ton
KY	01	Crystal River	Rapid Loader	39.15	12,836	221.13	56.77
KY	01	Crystal River	Scott's Branch	9.97	12,853	194.44	49.98
KY	01	Crystal River	Scott's Branch	19.65	12,837	219.44	56.34
KY	01	Crystal River	Sidewinder	9.70	12,424	213.04	52.94
KY	01	Crystal River	Sidewinder	22.46	12,572	217.44	54.67
KY	01	Crystal River	Sidewinder	35.45	12,643	229.44	58.02
KY	01	Crystal River	Sidney (Goff)	26.65	12,588	226.44	57.01
KY	02	Crystal River	Rapid Loader	57.85	12,852	221.95	57.05
KY	02	Crystal River	Scott's Branch	9.64	12,817	195.28	50.06
KY	02	Crystal River	Scott's Branch	29.97	12,784	220.26	56.32
KY	02	Crystal River	Sidewinder	20.39	12,990	213.88	55.57
KY	02	Crystal River	Sidewinder	29.56	12,634	218.28	55.15
KY	02	Crystal River	Sidewinder	10.59	12,775	198.28	50.66
KY	02	Crystal River	Sidney (Goff)	37.60	12,583	227.28	57.20
KY	03	Crystal River	Rapid Loader	76.92	12,902	222.15	57.32
KY	03	Crystal River	Scott's Branch	9.18	12,755	195.44	49.86
KY	03	Crystal River	Scott's Branch	10.09	12,700	220.44	55.99
KY	03	Crystal River	Sidewinder	29.63	12,649	214.08	54.16
KY	03	Crystal River	Sidewinder	40.17	12,525	218.44	54.72
KY	03	Crystal River	Sidewinder	9.93	12,861	198.44	51.04
KY	03	Crystal River	Sidney (Goff)	46.64	12,601	227.48	57.33
KY	04	Crystal River	Apex 2 Dock	9.65	13,416	198.88	53.36
KY	04	Crystal River	Rapid Loader	58.12	12,887	222.07	57.24
KY	04	Crystal River	Scott's Branch	30.22	12,808	220.40	56.46
KY	04	Crystal River	Scott's Branch	9.30	12,819	193.55	49.62
KY	04	Crystal River	Sidewinder	19.43	12,597	214.00	53.92
KY	04	Crystal River	Sidewinder	38.37	12,535	218.40	54.75
KY	04	Crystal River	Sidewinder	8.06	12,893	198.40	51.16
KY	04	Crystal River	Sidney (Goff)	64.95	12,506	227.40	56.88
KY	05	Crystal River	Rapid Loader	68.54	12,641	222.23	56.18
KY	05	Crystal River	Scott's Branch	29.67	12,833	220.56	56.61
KY	05	Crystal River	Scott's Branch	9.44	12,815	195.56	50.12
KY	05	Crystal River	Sidewinder	9.66	12,721	198.56	50.52
KY	05	Crystal River	Sidewinder	67.76	12,596	214.16	53.95
KY	05	Crystal River	Sidewinder	18.61	12,440	218.56	54.38
KY	05	Crystal River	Sidney (Goff)	38.42	12,564	227.56	57.18
KY	06	Crystal River	Rapid Loader	66.59	12,697	221.37	56.21
KY	06	Crystal River	Scott's Branch	19.91	12,762	219.64	56.06
KY	06	Crystal River	Scott's Branch	9.96	12,748	194.64	49.63
KY	06	Crystal River	Sidewinder	38.19	12,464	213.28	53.17
KY	06	Crystal River	Sidewinder	28.97	12,579	217.64	54.75
KY	06	Crystal River	Sidewinder	9.65	12,867	197.64	50.86
KY	06	Crystal River	Sidney (Goff)	48.32	12,487	226.68	56.61
KY	07	Crystal River	Rapid Loader	68.04	12,786	224.14	57.32
KY	07	Crystal River	Scott's Branch	9.91	12,844	222.52	57.16
KY	07	Crystal River	Scott's Branch	10.00	12,658	197.52	50.00
KY	07	Crystal River	Sidewinder	47.43	12,655	216.12	54.70
KY	07	Crystal River	Sidewinder	38.14	12,615	220.52	55.64
KY	07	Crystal River	Sidewinder	9.78	12,864	195.47	50.29
KY	07	Crystal River	Sidewinder	17.98	12,961	209.54	54.32
KY	07	Crystal River	Sidney (Goff)	48.07	12,480	229.52	57.29
KY	07	Crystal River	Sidney (Goff)	9.64	12,180	214.22	52.18
KY	08	Crystal River	Yellow Creek	17.95	12,910	215.31	55.59
KY	08	Crystal River	Rapid Loader	57.28	12,985	221.84	57.61
KY	08	Crystal River	Scott's Branch	9.81	12,905	220.16	56.82
KY	08	Crystal River	Scott's Branch	9.90	12,872	195.16	50.24
KY	08	Crystal River	Sidewinder	38.86	12,562	213.76	53.71
KY	08	Crystal River	Sidewinder	38.40	12,723	218.16	55.51
KY	08	Crystal River	Sidewinder	9.66	12,894	198.16	51.10
KY	08	Crystal River	Sidewinder	9.41	13,095	207.27	54.28
KY	08	Crystal River	Sidney (Goff)	47.14	12,324	227.16	55.99
KY	09	Crystal River	Yellow Creek	28.08	12,908	213.63	55.20
KY	09	Crystal River	Rapid Loader	67.37	12,785	220.35	56.34
KY	09	Crystal River	Rapid Loader	18.89	12,640	202.77	51.26
KY	09	Crystal River	Scott's Branch	19.54	12,766	218.64	55.82
KY	09	Crystal River	Scott's Branch	9.22	12,731	193.64	49.30
KY	09	Crystal River	Sidewinder	39.29	12,525	212.24	53.17
KY	09	Crystal River	Sidewinder	48.03	12,473	216.64	54.04
KY	09	Crystal River	Sidewinder	10.39	12,778	192.17	49.11
KY	09	Crystal River	Sidewinder	27.85	12,909	205.81	53.14
KY	09	Crystal River	Sidney (Goff)	48.31	12,561	225.64	56.69
KY	10	Crystal River	RAPID LOADER	147.49	12,795	201.64	51.60
KY	10	Crystal River	SCOTT'S BRANCH	27.44	12,796	217.48	55.66
KY	10	Crystal River	SCOTT'S BRANCH	9.93	12,828	192.48	49.38
KY	10	Crystal River	SIDEWINDER	40.07	12,513	211.08	52.82
KY	10	Crystal River	SIDEWINDER	0.12	12,677	215.48	54.63
KY	10	Crystal River	SIDEWINDER	30.11	12,590	215.48	54.26
KY	10	Crystal River	SIDEWINDER	9.00	12,792	195.48	50.01
KY	10	Crystal River	SIDEWINDER	19.69	12,948	204.69	53.01
KY	10	Crystal River	SIDNEY (GOFF)	9.99	12,410	224.48	55.72
KY	10	Crystal River	SIDNEY (GOFF)	19.32	12,549	206.88	51.92

Florida Power - 2003 Coal Movements (continued)

Source: Federal Energy Regulatory Commission (Form 423 - Monthly Report of Cost and Quality of Fuels for Electric Plants Data)

DOMESTIC SHIPMENTS

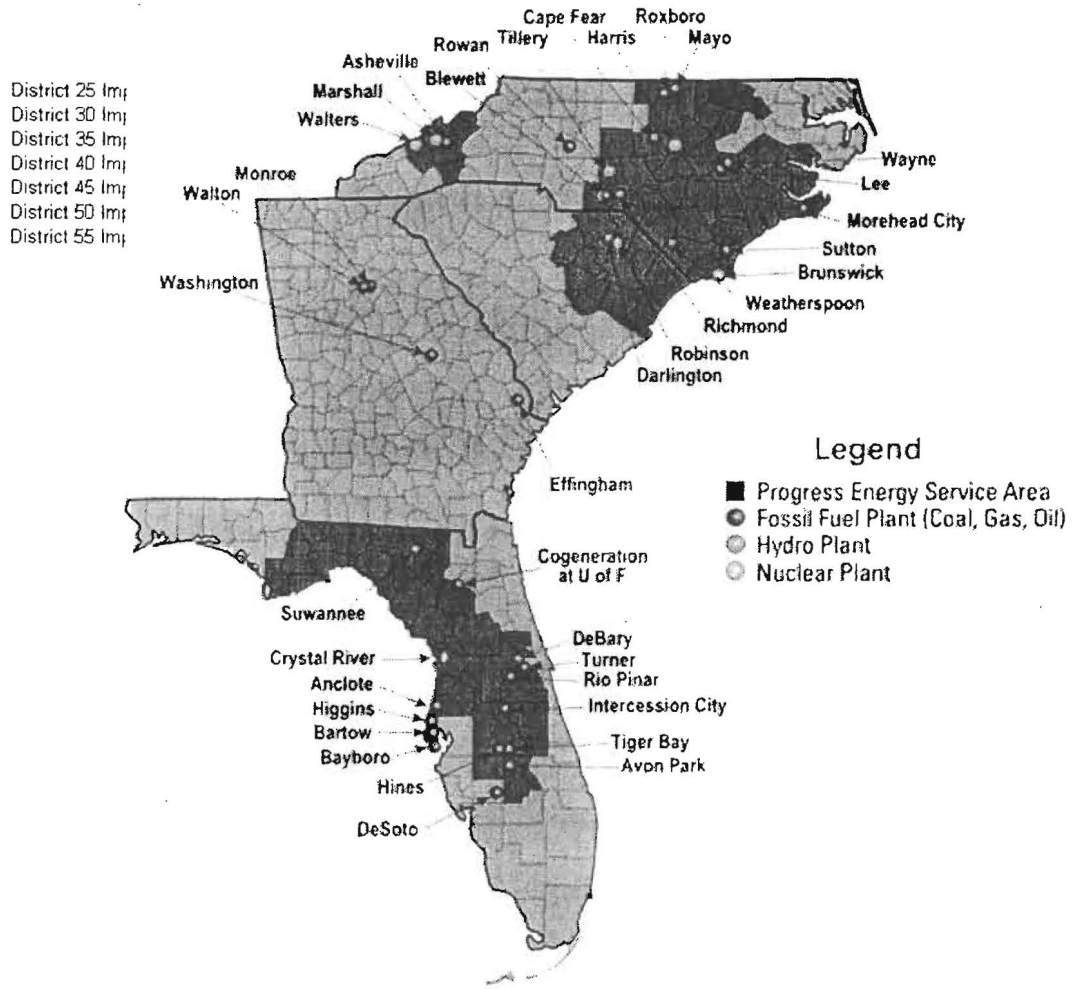
State	Month	Plant	Source	Tons (000)	BTU Content	Cost (¢/mBtu)	$/Short Ton
KY	11	Crystal River	Rapid Loader	128.29	12,790	203.09	51.95
KY	11	Crystal River	Scott's Branch	28.55	12,870	218.96	56.36
KY	11	Crystal River	Scott's Branch	9.49	12,805	193.96	49.67
KY	11	Crystal River	Sidewinder	28.90	12,563	212.56	53.41
KY	11	Crystal River	Sidewinder	38.38	12,574	216.96	54.56
KY	11	Crystal River	Sidewinder	9.59	12,731	217.96	55.50
KY	11	Crystal River	Sidewinder	0.22	12,956	192.34	49.84
KY	11	Crystal River	Sidewinder	9.15	12,956	192.34	49.84
KY	11	Crystal River	Sidewinder	19.08	12,934	206.12	53.32
KY	11	Crystal River	Sidney (Goff)	9.66	12,021	208.36	50.09
KY Total (Average)				2,713.77	1,157,343	211.91	53.90
WV	01	Crystal River	Fola	19.00	12,804	239.08	61.22
WV	01	Crystal River	Hutchinson	8.99	12,120	240.79	58.37
WV	01	Crystal River	Hutchinson	38.46	12,452	240.79	59.97
WV	01	Intern1 Marine TF	Kanawha River Terminal	3.27	12,395	203.28	50.39
WV	01	Intern1 Marine TF	Kanawha River Terminal	14.68	12,810	203.28	52.08
WV	01	Intern1 Marine TF	Kanawha River Terminal	23.98	12,712	203.28	51.68
WV	01	Intern1 Marine TF	Kanawha River Terminal	7.69	12,665	229.28	58.08
WV	01	Intern1 Marine TF	Kanawha River Terminal	13.93	12,897	237.28	61.20
WV	01	Intern1 Marine TF	Marmet Synfuel, LLC	35.46	13,177	231.33	60.96
WV	01	Intern1 Marine TF	Massey Coal Sales Co., Inc.	12.99	12,661	237.28	60.08
WV	01	Intern1 Marine TF	Massey Coal Sales Co., Inc.	9.40	12,682	237.28	60.18
WV	01	Intern1 Marine TF	Massey Coal Sales Co., Inc.	9.07	13,449	237.28	63.62
WV	01	Intern1 Marine TF	Massey Coal Sales Co., Inc.	8.23	12,081	237.28	57.33
WV	02	Crystal River	Fola	18.37	12,518	239.92	60.07
WV	02	Crystal River	Hutchinson	57.11	12,286	241.65	59.38
WV	02	Intern1 Marine TF	Kanawha River Terminal	16.12	12,642	202.44	51.18
WV	02	Intern1 Marine TF	Kanawha River Terminal	1.65	12,545	202.44	50.79
WV	02	Intern1 Marine TF	Marmet Synfuel, LLC	46.54	13,177	230.53	60.75
WV	02	Intern1 Marine TF	Massey Coal Sales Co., Inc.	7.10	12,427	236.44	58.76
WV	02	Intern1 Marine TF	Massey Coal Sales Co., Inc.	13.88	12,469	236.44	58.96
WV	02	Intern1 Marine TF	Massey Coal Sales Co., Inc.	14.36	12,701	236.44	60.06
WV	03	Crystal River	Fola	16.99	12,760	240.08	61.27
WV	03	Crystal River	Hutchinson	46.38	12,550	241.82	60.70
WV	03	Intern1 Marine TF	Kanawha River Terminal	5.69	12,557	202.44	50.84
WV	03	Intern1 Marine TF	Kanawha River Terminal	29.76	12,587	202.44	50.96
WV	03	Intern1 Marine TF	Kanawha River Terminal	52.68	12,571	202.44	50.90
WV	03	Intern1 Marine TF	Marmet Synfuel, LLC	3.37	13,210	230.53	60.91
WV	03	Intern1 Marine TF	Marmet Synfuel, LLC	18.48	13,091	230.53	60.36
WV	03	Intern1 Marine TF	Massey Coal Sales Co., Inc.	47.29	12,383	236.44	58.56
WV	03	Intern1 Marine TF	Riverside Synfuel, LLC	10.02	12,446	226.44	56.67
WV	04	Crystal River	Fola	19.13	12,730	240.08	61.12
WV	04	Crystal River	Hutchinson	48.17	12,400	241.82	59.97
WV	04	Intern1 Marine TF	Kanawha River Terminal	1.93	12,571	202.44	50.90
WV	04	Intern1 Marine TF	Kanawha River Terminal	11.24	12,510	202.44	50.65
WV	04	Intern1 Marine TF	Kanawha River Terminal	3.48	12,491	202.44	50.57
WV	04	Intern1 Marine TF	Marmet Synfuel, LLC	9.73	13,129	230.53	60.53
WV	04	Intern1 Marine TF	Marmet Synfuel, LLC	23.20	12,989	230.53	59.89
WV	04	Intern1 Marine TF	Massey Coal Sales Co., Inc.	53.51	12,372	236.44	58.50
WV	04	Intern1 Marine TF	Riverside Synfuel, LLC	10.21	12,389	226.44	56.60
WV	05	Crystal River	Fola	9.43	12,586	240.24	60.47
WV	05	Crystal River	Hutchinson	47.94	12,543	241.98	60.70
WV	05	Intern1 Marine TF	Marmet Synfuel, LLC	38.32	13,026	230.53	60.06
WV	05	Intern1 Marine TF	Massey Coal Sales Co., Inc.	55.24	12,260	236.44	57.98
WV	06	Crystal River	Fola	17.94	12,555	239.32	60.09
WV	06	Crystal River	Hutchinson	75.78	12,447	241.03	60.00
WV	06	Intern1 Marine TF	Kanawha River Terminal	56.40	12,310	236.44	58.21
WV	06	Intern1 Marine TF	Marmet Synfuel, LLC	34.25	13,060	230.53	60.21
WV	07	Crystal River	Fola	18.58	12,573	242.08	60.87
WV	07	Crystal River	Hutchinson	9.48	12,023	215.77	51.88
WV	07	Crystal River	Hutchinson	46.57	12,167	243.88	59.44
WV	07	Intern1 Marine TF	Kanawha River Terminal	43.07	12,416	236.44	58.71
WV	07	Intern1 Marine TF	Marmet Synfuel, LLC	10.91	12,901	230.53	59.48
WV	07	Intern1 Marine TF	Marmet Synfuel, LLC	23.06	13,002	230.53	59.95
WV	08	Crystal River	Fola	18.04	12,741	239.72	61.09
WV	08	Crystal River	Hutchinson	46.69	12,195	241.45	58.69
WV	09	Intern1 Marine TF	Kanawha River Terminal	53.05	12,265	236.44	58.00
WV	08	Intern1 Marine TF	Marmet Synfuel, LLC	33.80	12,893	230.53	59.44
WV	09	Crystal River	Fola	18.35	12,659	238.20	60.31
WV	09	Crystal River	Hutchinson	19.79	12,825	239.88	61.53
WV	09	Intern1 Marine TF	Kanawha River Terminal	26.65	12,345	236.44	58.38
WV	09	Intern1 Marine TF	Kanawha River Terminal	32.83	12,406	228.44	56.68
WV	09	Intern1 Marine TF	Marmet Synfuel, LLC	33.92	13,025	230.53	60.05
WV	10	Crystal River	FOLA	19.21	12,677	236.96	60.08
WV	10	Crystal River	HUTCHINSON	9.74	13,039	238.60	62.22
WV	10	Crystal River	HUTCHINSON	9.29	13,010	212.46	55.28
WV	10	Intern1 Marine TF	KANAWHA RIVER TERMINAL	53.26	12,288	227.35	55.87
WV	10	Intern1 Marine TF	MARMET SYNFUEL, LLC	33.09	12,973	243.44	63.16
WV	11	Crystal River	Fola	18.58	12,558	238.44	59.89
WV	11	Crystal River	Hutchinson	2.18	12,543	240.12	60.24
WV	11	Crystal River	Hutchinson	25.73	12,532	216.08	54.16
WV	11	Intern1 Marine TF	Kanawha River Terminal	1.71	12,109	227.35	55.06
WV	11	Intern1 Marine TF	Marmet Synfuel, LLC	25.05	12,776	243.44	62.20
WV Total (Average)				1,759.67	909,156	230.22	58.17
DOMESTIC Total (Average)				4,473.44	2,066,499	219.97	55.78

Florida Power - 2003 Coal Movements (continued)

Source: Federal Energy Regulatory Commission (Form 423 - Monthly Report of Cost and Quality of Fuels for Electric Plants Data)

IMPORTED SHIPMENTS

State	Month	Plant	Source	Tons (000)	BTU Content	Cost (¢/mBtu)	$/Short Ton
IM	02	Intern'l Marine TF	Weglokoks (Poland)	7.76	12,801	150.38	38.50
IM	03	Intern'l Marine TF	Drummond (Colombia)	1.49	11,541	130.33	30.08
IM	03	Intern'l Marine TF	Weglokoks (Poland)	21.46	12,855	150.38	38.66
IM	04	Intern'l Marine TF	UL Mickiewicza 29 (Poland)	6.41	12,925	150.38	38.87
IM	05	Intern'l Marine TF	Santa Marta (Colombia)	22.05	12,305	150.21	36.97
IM	05	Intern'l Marine TF	UL Mickiewicza 29 (Poland)	15.33	12,983	150.78	39.15
IM	06	Intern'l Marine TF	Maracaibo (Venezuela)	51.49	12,971	172.73	44.81
IM	07	Intern'l Marine TF	Maracaibo (Venezuela)	43.28	13,566	172.42	46.78
IM	08	Intern'l Marine TF	Drummond (Colombia)	33.25	11,948	150.21	35.89
IM	08	Intern'l Marine TF	Mickiewicza 29 (Poland)	28.13	12,794	150.78	38.58
IM	08	Intern'l Marine TF	Paso Diablo (Venezuela)	51.55	13,153	170.27	44.79
IM	09	Intern'l Marine TF	Drummond (Colombia)	31.65	11,939	150.21	35.87
IM	09	Intern'l Marine TF	Mickiewicza 29 (Poland)	12.80	13,060	150.78	39.38
IM	09	Intern'l Marine TF	Paso Diablo (Venezuela)	43.96	13,193	171.50	45.25
IM	10	Intern'l Marine TF	DRUMMOND	32.40	12,483	164.96	41.18
IM	10	Intern'l Marine TF	PASO DIABLO (Venezuela)	43.29	13,097	206.20	54.01
IM	11	Intern'l Marine TF	Drummond	11.99	12,791	164.96	42.20
IMPORTED Total (Average)				**458.29**	**216,405**	**159.65**	**40.81**



JEA (Jacksonville Electric Authority) - 2003 Coal Movements

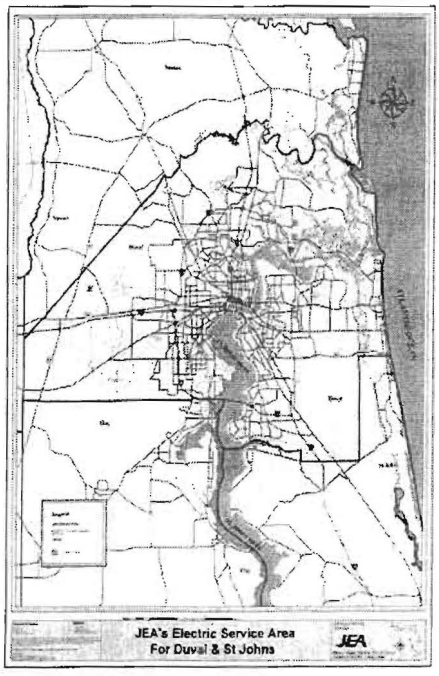
Source: Federal Energy Regulatory Commission (Form 423 - Monthly Report of Cost and Quality of Fuels for Electric Plants Data)

DOMESTIC SHIPMENTS

State	Month	Plant	Source	Tons (000)	BTU Content	Cost (¢/mBtu)	$/Short Ton
KY	01	St Johns River	APEX MINE	9.57	12,571	173.20	43.55
KY	01	St Johns River	CLOVER DTE	128.92	12,596	157.40	39.65
KY	02	St Johns River	CLOVER DTE	106.49	12,567	157.60	39.66
KY	03	St Johns River	CLOVER DTE	96.28	12,613	157.20	39.66
KY	04	St Johns River	CLOVER DTE	85.12	12,555	157.90	39.65
KY	05	St Johns River	CLOVER DTE	95.65	12,572	160.80	40.43
KY	06	St Johns River	CLOVER DTE	62.60	12,545	162.00	40.65
KY	07	St Johns River	CLOVER DTE	73.30	12,514	162.40	40.65
KY	08	St Johns River	CLOVER DTE	73.30	12,657	160.60	40.65
KY	09	St Johns River	CLOVER DTE	104.86	12,594	160.20	40.64
KY	10	St Johns River	CLOVER DTE	83.16	12,645	160.70	40.64
KY	11	St Johns River	CLOVER DTE	62.00	12,641	160.80	40.65
KY	12	St Johns River	CLOVER DTE	72.14	12,643	156.40	39.55
KY Total (Average)				**1,053.59**	**163,803**	**160.57**	**40.46**
PA	01	Northside	EMERALD RESOURCES	32.10	13,064	150.40	39.30
PA	03	Northside	EMERALD RESOURCES	14.70	12,778	145.80	37.26
PA	05	Northside	RAG	16.10	13,134	145.80	38.30
PA	05	Northside	RAG	14.60	13,142	145.80	38.32
PA	06	Northside	RAG	13.60	13,002	143.80	37.39
PA	06	Northside	RAG	15.50	13,099	141.70	37.12
PA	07	Northside	RAG	13.80	13,064	144.30	37.70
PA	07	Northside	RAG	13.80	13,040	146.80	38.29
PA	08	Northside	RAG	14.70	13,240	145.20	38.45
PA	08	Northside	RAG	14.70	12,896	145.40	37.50
PA	09	Northside	RAG	14.70	12,889	139.40	35.93
PA	10	Northside	RAG	13.70	13,030	145.30	37.87
PA	10	Northside	RAG	13.60	12,913	145.40	37.55
PA	11	Northside	RAG	13.60	12,968	145.80	37.87
PA	12	Northside	RAG	13.50	12,905	145.50	37.55
PA	12	Northside	RAG	14.00	12,802	182.30	46.68
PA	12	Northside	RAG	20.20	13,017	182.50	47.51
PA Total (Average)				**267.30**	**221,003**	**149.45**	**38.85**
DOMESTIC Total (Average)				**1,320.89**	**384,806**	**154.18**	**39.54**

IMPORTED SHIPMENTS

State	Month	Plant	Source	Tons (000)	BTU Content	Cost (¢/mBtu)	$/Short Ton
IM	01	St Johns River	EL CERREJON (COLOMBIA)	205.68	11,818	148.40	35.08
IM	02	St Johns River	EL CERREJON (COLOMBIA)	158.39	11,628	148.20	35.06
IM	04	St Johns River	EL CERREJON (COLOMBIA)	145.15	11,835	149.30	35.34
IM	05	St Johns River	EL CERREJON (COLOMBIA)	192.62	11,857	151.40	35.90
IM	06	St Johns River	EL CERREJON (COLOMBIA)	94.17	11,810	152.00	35.90
IM	06	St Johns River	GUASARE (COLOMBIA)	58.70	13,065	139.60	36.48
IM	07	St Johns River	EL CERREJON (COLOMBIA)	234.89	11,830	149.90	35.47
IM	08	St Johns River	EL CERREJON (COLOMBIA)	191.77	11,816	148.90	35.19
IM	09	St Johns River	CERREJON NORTE (COLOMBIA)	12.60	11,875	178.90	42.49
IM	09	St Johns River	EL CERREJON (COLOMBIA)	190.26	11,807	149.00	35.18
IM	10	St Johns River	EL CERREJON (COLOMBIA)	97.17	11,868	148.70	35.30
IM	11	St Johns River	EL CERREJON (COLOMBIA)	194.40	11,854	149.20	35.37
IM	11	St Johns River	GUASARE (COLOMBIA)	59.81	12,870	139.20	35.83
IM	12	St Johns River	EL CERREJON (COLOMBIA)	144.22	11,717	151.00	35.39
IMPORTED Total (Average)				**1,979.83**	**167,850**	**150.12**	**36.00**



CONFIDENTIAL

(PMG-1)	**CONFIDENTIAL,** Exhibit to the Rebuttal Testimony of Paula M. Guletsky (Rebuttal)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 61
COMPANY/ TECO
WITNESS: PMG-1
DATE: 05/27-28/04

CONFIDENTIAL

(FJM-1)	**CONFIDENTIAL,** Exhibit to the Rebuttal Testimony of Frederick J. Murrell (Rebuttal)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 62
COMPANY/ TECO
WITNESS: FJM-1
DATE: 05/27-28/04

Exhibit No. 63
Tampa Electric Company
Docket No. 031033-EI

Dibner Comments on Platts

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 63
COMPANY/ OPC
WITNESS: Dibner Comments on Platt
DATE: 05/27-28/04

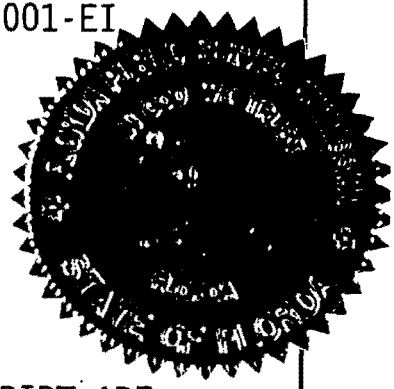
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 030001-EI

In the Matter of

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.

_____/



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DEPOSITION OF:	JOANN T. WEHLE BRENT DIBNER
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Gunter Building Conference Room 309 2540 Shumard Oak Boulevard Tallahassee, Florida
TIME:	Commenced at 9:00 a.m. Concluded at 4:47 p.m.
DATE:	Monday, October 20, 2003
REPORTED BY:	JANE FAUROT, RPR Chief, Office of Hearing Reporter Services FPSC Division of Commission Clerk and Administrative Services (850) 413-6732

FLORIDA PUBLIC SERVICE COMMISSION

those problems mitigated somewhat merely because the chain is provided?

A It certainly is possible that over time there would be efficient enforcement of the rules of the game, but I can tell you that there are hundreds of millions of dollars of demurrage claims washing around the shipping industry that are so huge that there are people who make a business of trying to clear them, and exchange them, and factor them. So, things can get very ugly, or let's say very costly over time.

Q Exactly.

A I'm not saying it has to happen, but it does happen sometimes.

Q And it would also be true that these claims don't magically go away with one provider, either?

A No, but if there is one party that is accountable -- there really is no recourse to the customer and that is what this is about. So the party, or the general contractor, let's suppose that someone had stepped forward, supposing that could be the case. The general contractor might have to make a tremendous effort for their own account. Let's suppose Tampa Electric doesn't even know that they are at each other's throats, or that somebody is, but the issue is the customer, the customer is Tampa Electric.

Q Are you familiar with Platts coal website?

A I have seen it from time to time. I don't subscribe

to it.

MR. VANDIVER: Okay. I want to show you an exhibit. I would like to have it marked for the deposition. It is hiding here somewhere. Hold on one second.

(Exhibit 3 marked for identification.)

BY MR. VANDIVER:

Q And this is from Platts coal website. It is July 7th. It appeared several days on Platts. The first page is simply a synopsis of it. The second page is the actual posting on the website. And I will give you a second to take a look at that.

A (By Mr. Dibner) Yes, I have seen this actually.

Q Have you seen that? You saw the posting contemporaneously at the time?

A I didn't see it on screen, it was something that I did get.

Q It was provided to you, and you are familiar with it, then?

A Correct.

Q Very well, sir. My question to you is this: Is the perception in the marketplace important in the RFP process?

A As Ms. Wehle explained, the perceptions are important, but they can be spoiled by any number of parties unknown to me or to Tampa Electric. Whenever you have journalists in an industry who typically do not -- they are not

business people by their basic orientation and are looking for interesting impactful news, whether it is legitimate or not, my concern -- you know, my answer to your question is sure, it's important, but it is also very possible to color or depict something with a few casual statements from some unknown party that costs nothing to a website, and frankly nothing to an industry journal. And I have seen it happen, you know, a number of times. It happens to me. People are looking for controversy. People are trying to jockey. Nothing perhaps was better for some than to detract from this whole thing.

It is no secret that anyone familiar with the coal industry knows that there are relationships between certain carriers and certain utilities. To get things like this, you are asking me does it color things? Sure. It makes people afraid. So does the interest of perhaps a Public Service Commission. So does the prospect of being somehow encumbered by it. And, frankly, I saw this, I read it, I understood where they are coming from, but it doesn't -- we don't know whether this is -- this is not -- this colored things, it damaged things. It created a basis, in my humble opinion, to declare the contest dead. You know, it's skewed, it's screwed up, it's going to go to TECO anyway.

My own view is if there were people who had 300 barges that were doing nothing and who wanted to be on the lower Mississippi and run that river, this is a tough highly

competitive business. I think you have my report, you know what is happening to the rates. I don't care whether there are two competitors or five, they are beating the hell out of each other. And so my own view is if they wanted to be here, they would be here, this website notwithstanding, okay?

Q Okay.

A And one of them was there and put in a series of rates where we found no anomalies when we looked ourselves. So people, you know, this hurts. It hurts. My opinion, it hurts the process. It serves people's needs. It may have been planted by an outsider. Who knows where it came from.

Q Right. And I guess that is my thing, where you have an unattributed source like this and it gets out and it is early in the process, this was dated July 7th, and I don't recall when this came onto the website. Again, I was trying to monitor this process, and the RFP was issued, I believe, June 24th, but this was --

A (By Ms. Wehle) In that neighborhood.

Q And so this was well -- this was right mid in the bidding process. This was when you were out there soliciting bids. This is not good for this process, is it?

A (By Mr. Dibner) Right.

Q And my question to you was you had said earlier that this was not in magazines and so forth, but isn't the web now kind of the lingua franca of our society, or can you enlighten

me as to who reads what in --

A No. Let me put it this way.

Q Okay.

A If I'm running a barge line, and I look at this piece of business in my portfolio, and as I said I think more than once today, this is a big unique piece of business that takes you as far down the road as you can go. If you want it, you don't care what is the on the web. If you want it, you know full well that Midsouth Towing Company and TECO Transport are let us call it the incumbent. But, people have bid. People bid last time. They weren't cavalier bids, and they weren't devious low bids, and they weren't absurd high bids.

That suggests to me that the industry looks at the business in the time in which the opportunity comes up. They don't care what anybody says. Individually they make their decisions. I don't think this had -- even if you and I understand the cynicism that this reflects, I don't think it sways the president of Ingram Barge Line, or the president of ACBL, or the president of -- well, if there was another, or of AEP. They are going to do what they want to do. They don't care what, with all due respect, is on a website. They don't care what is in a journal. They are big people and they know what they want to do.

Now, I went through the five, and I think I reduced it, you know, to one. And I said, that is really not too bad

because we might have had two, but the one that didn't bid is very busy and very happy up on the Ohio using its density to beat up its competitors in a fiercely competitive business. And so, the fact that they didn't come isn't reflective of this. They want to be pursuing something else where they can make an extra X dollars per barge day of contribution. And believe me, they may have seen this, but it is like reading the National Inquirer. They don't care.

Q In the responses to the RF --

A Yes.

Q -- and I want to be careful on the confidential nature of what was said. Was there one response that had a similar vein, and I am going from memory here, but there was one letter.

A (By Ms. Wehle) I think there might have been one, sort of cavalier comment.

Q And I'm going from memory, but it seems to me there was one letter.

A (By Mr. Dibner) I understand. I recall something to that effect, too. That shouldn't surprise us.

Q Okay.

A Again, I think I have said, you have a big powerful fleet.

Q Is it sour grapes?

A You have a well depreciated fleet that knows what it

is doing. You have people with scale, they are formidable, and I'm talking about the incumbent. If I were in the busy, I would grouse, too. But it is a grousing that isn't based on, necessarily, anything other than the frustration that there is somebody out there who does have a system that was dedicated to meeting the needs of this constituency.

Q So if I were to go back, that gentleman would not be among those, that number who had the wherewithal to actually do the business?

A Right. And I think, and I said this again in the report, the bigger utility, the bigger barge lines makes it awfully hard for little people with 100 opens to mobilize and demobilize when a huge utility, I don't care if it is energy, or anybody comes out with a bid, you know, it's hard. But this is a tough business. That is why the biggest is in Chapter 11, to a degree.

Q I'm going to harken back just briefly to 1997. You mentioned the River Transport News, it is one of these rags, and --

A Actually, it's not a rag. It's a publication, it is very focused. As rags go, it is a very standard, tries very hard, so let's not call it a rag. But then, again, controversy sells sometimes, but there is not much of it in RTN.

Q Something very similar to this appeared in 1997 in the River Transport News.

A Right.

Q Is it the same genre as this in relation to the same bid, or to the TECO Transport bid in '97?

A First of all, I have to take your word for it that it did appear.

Q It did. I don't have it with me, I apologize. I represent that, and it's in the same --

A I would argue that the same person --

Q And it was anonymous again, I will tell you that?

A Said the same mean thing, or the same thing, let's call it the same true thing, but everybody knows all over again just to -- and you know something, the industry was different then, people were in Chapter 11, people were this, there were more carriers, and there were more bids. So it didn't scare the people who really cared. They came in and, frankly, my fingers at the beginning, they came in this time, it is just that it is a different industry and a hurting business.

Q We are on Ms. Wehle's testimony now. In the new TECO Transport contract.

A (By Ms. Wehle) Are we in direct or supplemental

Q Good question. We are in 9/12, Page 18. The new TECO Transport contract, is there a right of first refusal?

A That is confidential information.

Q You say at Page 18, I think this is confidential, yes it is. Well, you discuss how it -- can we go off the record

Exhibit No. 64
Tampa Electric Company
Docket No. 031033-EI

Dibner No Marginal Backhaul

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 64
COMPANY/ OPC
WITNESS: Dibner No Marginal Backhaul
DATE 05/27-28/04

27. Referring to Bates Stamp 134, 135 and 136, does the fuel cost included in this estimate include the total cost of fuel for the return voyage to Davant? Likewise, do the fixed and variable costs include an assumption that the total costs of ocean transport vessels shall be recovered from ratepayers with no allocation of expenses or revenues as a result of backhaul? Please discuss the reasons why no allocation of backhaul expenses or revenues is appropriate in this instance.

A. Tampa Electric understands that the aforementioned Bates stamp pages refers to Mr. Dibner's testimony and exhibit and therefore answers as such. Yes, fuel cost for a return to Davant is included in Mr. Dibner's model. Mr. Dibner estimated the costs for voyages that will be required to serve Tampa Electric's volume and type of transportation needs. He based his calculation on the estimated average cost of service for the core fleet that serves Tampa Electric, without allocation for backhaul revenues or expenses. Mr. Dibner determined that there is no marginal backhaul business. Therefore, backhaul does not affect the market for transportation services, and it would not be appropriate to include backhaul in setting rates.

Exhibit No. 65
Tampa Electric Company
Docket No. 031033-EI

Progress Terminal Rates

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 65
COMPANY/ OPC
WITNESS: Progress Terminal Rates
DATE: 05/27-28/04

Progress Energy

JAMES A. McGEE
ASSOCIATE GENERAL COUNSEL
PROGRESS ENERGY SERVICE COMPANY, LLC

April 12, 2004

VIA OVERNIGHT DELIVERY

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 031057-EI; **Notice of Intent to Request Confidential Classification.**

Dear Ms. Bayó:

Enclosed for filing in the subject docket on behalf of Progress Energy Florida, Inc. are an original and seven copies of its Notice of Intent to Request Confidential Classification. Also enclosed is a sealed envelope containing the document subject to the Notice, with the confidential information highlighted. **This document should be held as Confidential Information in accordance with Rule 25-22.006, F.A.C.** A public copy of the document in which the confidential information has been redacted is attached to each filed copy of the Notice.

Please acknowledge your receipt of the above filing on the enclosed copy of this letter and return to the undersigned. A 3½ inch diskette containing the above-referenced Notice in Word format is also enclosed. Thank you for your assistance in this matter.

Very truly yours,

James A. McGee

JAM/scc
Enclosures

cc: Parties of record

100 Central Avenue (33701) • Post Office Box 14042 (33733) • St. Petersburg, Florida
Phone: 727.820.5184 • Fax: 727.820.5519 • Email: james.mcgee@pgnmail.com

DOCUMENT NUMBER-DATE
04471 APR 13 ß
FPSC-COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Progress Energy Florida's benchmark for Waterborne Transportation Transactions with Progress Fuels.	Docket No. 031057-EI Submitted for filing: April 13, 2004

NOTICE OF INTENT TO REQUEST CONFIDENTIAL CLASSIFICATION

Progress Energy Florida, Inc. (Progress Energy or the Company), pursuant to pursuant to Section 366.093, F.S., and Rule 25-22.006, F.A.C., hereby files this notice of its intent to request Confidential Classification of the highlighted portions of its response to the Staff audit report of Progress Energy's 2003 waterborne transportation costs (the Response) contained in the sealed envelope enclosed with this Notice. The audit report, Audit Control No. 04-082-2-1, was filed by Staff on April 1, 2004 as a confidential document and was designated DN 04160-04. A copy of a public version of the Response, with the confidential information redacted, is attached to each filed copy of this Notice. Accordingly, Progress Energy hereby submits the following:

1. A separate, sealed envelope containing one copy of the Response, with the information for which Progress Energy intends to request confidential classification highlighted. **This information should be accorded confidential treatment pending the filing of Progress Energy's request and a decision thereon by the Commission.**

2. As an attachment to each copy of this Notice, a copy of the Response with the information for which Progress Energy intends to request confidential classification redacted.

Respectfully submitted,

James A. McGee
Associate General Counsel
Progress Energy Service Company, LLC
Post Office Box 14042
St. Petersburg, Florida 33733-4042
Telephone: 727-820-5184
Facsimile: 727-820-5519
Email: james.mcgee@pgnmail.com

Attorney for
PROGRESS ENERGY FLORIDA, INC.

PROGRESS ENERGY FLORIDA

DOCKET NO. 031057-EI

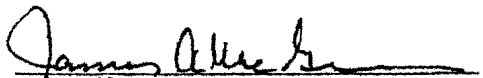
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing has been furnished to the following individuals by regular U.S. Mail this 12th day of April, 2004.

Wm. Cochran Keating, IV, Esquire
Office of the General Counsel
Economic Regulation Section
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Robert Vandiver, Esquire
Office of the Public Counsel
c/o The Florida Legislature
111 West Madison St., Room 812
Tallahassee, FL 32399-1400

Vicki Gordon Kaufman, Esquire
117 S. Gadsden Street
Tallahassee, FL 32301



Attorney

Progress Energy Florida's Response to
Staff's Waterborne Transportation Audit Report
(twelve months ended December 31, 2003)

Response to Disclosure No. 1

Under the "Auditor Opinion" paragraph at the conclusion of Disclosure No. 1, the audit report states:

> "We determined the average cost of waterborne transportation for Progress Fuels Corporation [PFC] for 2003 was $16.52 per ton based on company records."

As explained below, the audit report's calculation of this average cost is erroneous. When correctly calculated, PFC's average contractual cost for 2003 is $[redacted] per ton. As is also explained below, PFC incurred non-contractual costs in 2003 of $[redacted] per ton, for total 2003 waterborne transportation costs of $[redacted] per ton.

The audit report's calculation is wrong because it simply divided PFC's total 2003 waterborne transportation costs by the tonnage of coal purchased by PFC in 2003. This ignored the fact that these costs were actually incurred in distinct waterborne transportation segments (upriver, river barge, Gulf terminal and cross-Gulf) in which the tonnage varies significantly from segment to segment. For this reason, the only way PFC's costs can be accurately expressed on a per ton basis is to perform the calculation for each segment separately, and then total the unit costs of each segment. The problem with the audit report's calculation can be see by reference to the table included with the report as Attachment A, which shows the proper calculation of PFC's 2003 contractual costs on a segment-by-segment basis. The same table is also attached to this response, with one additional column on the far right to illustrate the flaw in the audit report's calculation.

The audit report's cost of $16.52 per ton was calculated by dividing PFC's total costs on Attachment A of $[redacted] by [redacted] As can be seen in the right-hand column added to Attachment A, the audit report's [redacted] seriously distorted the cost per ton calculated for these segments and, as a result, the total cost per ton for PFC's overall waterborne transportation system.

In addition, PFC's contractual costs of $[redacted] per ton do not include other significant non-contractual costs incurred by PFC for the cross-Gulf segment, such as a utility return on barge investment and major maintenance capital costs and expenses. When these non-contractual costs of $[redacted] per ton are added to PFC's contractual costs, total 2003 waterborne transportation costs are $[redacted] per ton, rather than the audit report's erroneously calculated $16.52 figure.

---

[1] The slight difference of just over 10,000 tons is due to the net effect of purchases made near the end of 2002 that were received at the Gulf terminal in early 2003, and purchases made near the end of 2003 that were received at the Gulf terminal in early 2004.

[2] The "Upriver" tonnage shown on Attachment A includes only FOB Mine purchases, which require short-haul transportation and storage and/or transloading at the upriver terminal. Attachment A's "River Barge" tonnage includes most FOB Mine purchases (except those in upriver storage at the end of 2003) and all FOB Barge purchases, but none of the foreign purchases included in the total tonnage figure used in the audit report's calculation. The "Cross-Gulf" tonnage on Attachment A reflects all shipments from the Gulf terminal to Crystal River, which includes both 2003 purchases and pre-2003 purchases shipped from the Gulf terminal's inventory.

Response to Disclosure No. 2

Several points in audit Disclosure No. 2, which addresses the commodity price of PFC's coal purchases in 2003, require clarification if they are to be properly understood.

First, the opening paragraph in the Statement of Fact states that coal commodity prices for 2003 purchases

> "ranged from $[redacted] per ton for coal from Alliance Coal Sales Corp. (MC Mining), a non affiliate, to $[redacted] per ton for synfuel from Riverside Synfuel LLC, an affiliated company."

As a point of clarification, while Riverside Synfuel is, in fact, an affiliated company, it's capacity in this particular purchase was only as an agent for RC Synfuel, a non-affiliated company which actually manufactured and supplied the synfuel purchased by PFC. With respect to the audit report's comparison between the price of this purchase and the lowest price of any PFC purchase in 2003, it is important to note that the contract for the Alliance purchase was executed in March, 2001, when market prices were significantly lower than they were when the contract for the synfuel purchase was executed two year later, in March, 2003. At the time the synfuel contract was signed, the price was fully competitive with then-current market prices and $2 lower than the price of comparable coal.

The next paragraph states: "The contracts reviewed for waterborne transported fuel were FOB dock [*i.e.*, barge]." In point of fact, the auditor was provided with a contract between PFC and Massey Coal Sales Company for the purchase of a significant quantity of coal, which clearly stated that the price was FOB mine. The majority of the coal purchased under this contract was sold and repurchased by PFC at an FOB barge price after conversion to synfuel, with upriver transportation costs from the mine included in the commodity purchase price. However, these upriver costs were excluded from the commodity price charged to PEF, so that the synfuel was effectively repurchased on an FOB mine basis at a price that was $2 per ton less than the original Massey purchase.

Finally, the concluding "Auditor Opinion" paragraph states:

> "The average delivered price, including transportation, to PEF in 2003 was $58.06 per ton for coal and $70.10 per ton for synfuel."

While the statement is true on its face, it presents an apples-to-oranges comparison. The price of $58.06 is the average of all 2003 coal deliveries to the Crystal River plant site; both compliance and non-compliance coal, delivered by both water and rail. Compliance coal is more costly than non-compliance coal, and waterborne deliveries in 2003 were more costly than rail deliveries. Synfuel is both compliance coal and was delivered entirely by water. For this reason alone, it was a mathematical certainty that the delivered price of synfuel would be greater than the average delivered price of all coal, as would be the case with any other compliance coal delivered by water. In addition, the audit report's price comparison does not account for differences between the vintage of the contracts under which the synfuel deliveries were purchased and the average vintage of the contracts under which all deliveries were purchased. Of the total 5.5 million tons of coal delivered to Crystal River in 2003, synfuel accounted for only just over 400,000 tons. All of this synfuel was purchased under more recent contracts entered into when the market price of coal was relatively high, such as the Riverside and Massey contracts discussed above. Nonetheless, these synfuel contracts were based on then-current market conditions and were priced at $2 per ton below the price of comparable coal.

Public Version Attachment A

Progress Energy Florida
Response to FPSC Waterborne Coal Transportation System Audit Report - Disclosure No. 1
Docket No. 031057

Progress Fuels Weighted Average Contractual Cost per Ton
Coal Shipped by Water from Mine to Crystal River

	2003			Audit Calculation
	Tons	Dollars	$/Ton	$/Ton*
Contract Rate	21,127.31	[redacted]		
Contract Rate	164,480.41			
Contract Rate	20,222.45			
Contract Rate	301,819.51			
Contract Rate	166,349.72			
1) TOTAL UPRIVER	673,999.40			2.60
Contract Rate	1,092,150.69	[redacted]		
Contract Rate	20,222.45			
Demurrage				
2) TOTAL RIVER BARGE	1,112,373.14			5.79
Contract Rate - Direct	816,849.33	[redacted]		
Contract Rate - Storage	332,216.55			
Contract Rate - Foreign	146,317.94			
Contract Rate	131,174.48			
Contract Rate - Foreign	250,536.88			
Port Fees				
Line Handling				
Dockage				
3) TOTAL GULF TERMINAL	1,677,095.18			1.97
Contract Rate	2,080,494.84	[redacted]		
Demurrage				
Port Fees				
Insurance/Labor				
Customs				
4) TOTAL CROSS-GULF	2,080,494.84			6.05
Dixie Rebel	2,080,494.85	[redacted]		
5) TOTAL OTHER	2,080,494.85			0.11
TOTAL CONTRACTUAL COSTS			[redacted]	$16.52

* Costs divided by tons, per audit calculation

CONFIDENTIAL

Document Number: 00094-04
Order Number:
Fine/Settlement: N
Pages: 0
Suffix: EI
Co. Name: Tampa Electric Company

Filing Date: 01/05/2004
Is/Was Confidential: Y
Type: (•) Other
( ) Motion
( ) Order

DESCRIPTION

TECO (Beasley) - (CONFIDENTIAL) Portions of answers to OPC's 1st set of interrogatories (Nos. 4-5). [See DN 00169-04]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 66
COMPANY/ OPC
WITNESS: TECO Resp. to OPC 1st Interr. #5
DATE: 05/27-28/04

CONFIDENTIAL

Docket No.: 031033-EI
Wells Exhibit No. _____, (HGW-4)
Letter from Ingram to TECO

INGRAM BARGE COMPANY

THOMAS R. VORHOLT
VICE PRESIDENT, UTILITY SALES
E-MAIL: vorholtt@ingrambarge.com

ONE BELLE MEADE PLACE
2400 HARDING ROAD
NASHVILLE, TENNESSEE 37205-2290
TEL: 615-298-8214 FAX: 615-298-8213

July 30, 2003

Mr. Martin Duff
Fuel Strategist
Tampa Electric Company
P. O. Box 111
Tampa, FL 33601-0111

Dear Martin:

After serious consideration and deliberation, Ingram Barge Company has elected not to provide rates in response to your Request for Waterborne Transportation Services Proposals WB-2004.

I can assure you that if TECO had proceeded to divest itself of the barge line, our response would be different. However, our impression from bidding on this business in the past is that our response, along with others', does nothing more than establish the rate structure at which your in-house carrier will continue to move your tonnage.

We appreciate the opportunity to look at your RFP's for barging services, and it is our sincere hope that at some point in the future our respective companies will have the opportunity to conduct business together.

Sincerely,

Thomas R. Vorholt

Thomas R. Vorholt

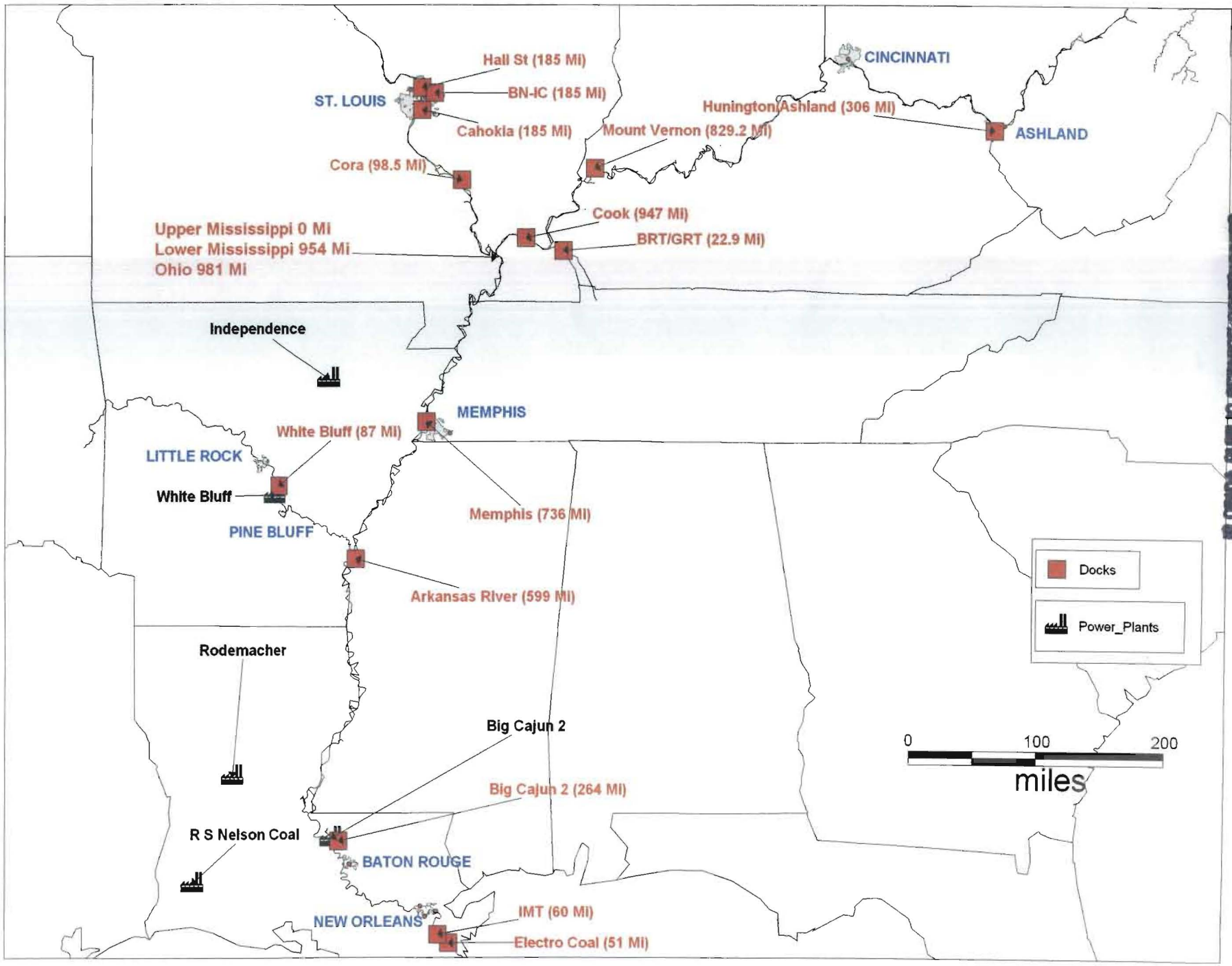
TRV/tas:TECO Bid Response

NHP 11.26.05
DECLASSIFIED
CONFIDENTIAL

declas 11-26-05
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 67
COMPANY/ WITNESS: FIPUG
DATE: 5/27-28/04 + 6/10/04

DOCUMENT NUMBER-DATE
06644 JUN 16 04
FPSC-COMMISSION CLERK

An American Chemistry Council Responsible Care ® Partner



PSC Docket No. 031033-EI
In Re: TECO Coal Transportation
Exhibit 68
Ohio and Mississippi River Distance

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 68
COMPANY/ CSX
WITNESS. Map of River Distances
DATE: 05/20-28/04

Document Number: 06645-04
Order Number:
Fine/Settlement: N
Pages: 0
Suffix: EI
Co. Name: Tampa Electric Company

Filing Date: 06/16/2004
Is/Was Confidential: Y
Type: (•) Other
( ) Motion
( ) Order

CONFIDENTIAL

DESCRIPTION

(CONFIDENTIAL) Hearing Exhibit No. 69 (Letter dated 9/25/03, from TECO to TECO Transport) from 5/27-28/04 and 6/10/04.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 69
COMPANY/ CSX
WITNESS: Letter From TECO to TECO Transport
DATE: 05/27-28/04

CONFIDENTIAL

Document Number: 06646-04
Order Number:
Fine/Settlement: N
Pages: 0
Suffix: EI
Co. Name: Tampa Electric Company

Filing Date: 06/16/2004
Is/Was Confidential: Y
Type: (•) Other
( ) Motion
( ) Order

DESCRIPTION

(CONFIDENTIAL) Hearing Exhibit No. 70 (Barge loading logs) from 5/27-28/04 and 6/10/04 hearing.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 70
COMPANY/ CSX
WITNESS: Barge Loading Logs
DATE: 05/27-28/04

EXHIBIT NO. 71

DOCKET NO: 031033-EI

WITNESS: JOANN WEHLE

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT OF GULF POWER COMPANY'S FPSC FORM 423:

1. JANUARY 2001, PAGE 6 OF 19
2. FEBRUARY 2001, PAGE 4 OF 19
3. MARCH 2001, PAGE 4 OF 19
4. APRIL 2001, PAGE 4 OF 19
5. JANUARY 2004, PAGE 4 OF 19

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 71
COMPANY/ FPSC Staff
WITNESS: Composite of Gulf Power's form 423 FPSC
DATE: 05/27-28/04

COMMISSIONERS:
BRAULIO L. BAEZ, CHAIRMAN
J. TERRY DEASON
LILA A. JABER
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

STATE OF FLORIDA

DIVISION OF THE COMMISSION CLERK &
ADMINISTRATIVE SERVICES
BLANCA S. BAYÓ
DIRECTOR
(850) 413-6770 (CLERK)
(850) 413-6330 (ADMIN)

Public Service Commission

CERTIFICATE

I, BLANCA S. BAYÓ, Director of the Commission Clerk and Administrative Services, Florida Public Service Commission, do certify that I am the duly appointed custodian of the official records of said Commission and, in that capacity, do certify that the attached pages (listed and described below) are true and correct copies of certain pages of Gulf Power Company's FPSC Form 423, as shown in the records of the Commission.

Description

1. DN.03481-01 - Gulf Power Company's January 2001, FPSC Form 423, page 6 of 19
2. DN.04627-01 - Gulf Power Company's February 2001, FPSC Form 423, page 4 of 19
3. DN.06036-01 - Gulf Power Company's March 2001, FPSC Form 423, page 4 of 19
4. DN.07592-01 - Gulf Power Company's April 2001, FPSC Form 423, page 4 of 19
5. DN.03684-04 - Gulf Power Company's January 2004, FPSC Form 423, page 4 of 19

WITNESS my hand and the seal of the Florida Public Service Commission this 25th day of May, 2004.

BLANCA S. BAYÓ

By: Kay Flynn

Kay Flynn, Chief, Bureau of Records

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: JANUARY Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: March 16, 2001

Line No.	Supplier Name	Mine Location			Shipping Point	Transport Mode	Tons	Effective Purchase Price ($/Ton)	Additional Shorthaul & Loading Charges ($/Ton)	Rail Charges: Rail Rate ($/Ton)	Rail Charges: Other Rail Charges ($/Ton)	Waterborne Charges: River Barge Rate ($/Ton)	Waterborne Charges: Trans-loading Rate ($/Ton)	Waterborne Charges: Ocean Barge Rate ($/Ton)	Waterborne Charges: Other Water Charges ($/Ton)	Other Related Charges ($/Ton)	Total Transpor-tation charges ($/Ton)	FOB Plant Price ($/Ton)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	MCDUFFIE TERMINAL	RB	27,765.58	34.983	-	-	-	2.30	-	-	-	-	2.30	37.283
2	AMERICAN COAL	10	IL	165	MCDUFFIE TERMINAL	RB	11,587.61	33.276	-	-	-	2.30	-	-	-	-	2.30	35.576
3	TAFT COAL	13	AL	127	MCDUFFIE TERMINAL	RB	2,575.71	30.770	-	-	-	12.97	-	-	-	-	12.97	43.740
4	PEABODY COALSALES-COOK	10	IL	165	COOK TERMINAL	RB	119,767.00	28.781	-	-	-	8.77	-	-	-	-	8.77	37.551
5	CONSOLIDATION COAL	10	IL	81	MOUND CITY	RB	24,805.08	21.883	-	-	-	9.00	-	-	-	-	9.00	30.883
6	PEABODY COALTRADE	10	IL	165	COOK TERMINAL	RB	1,551.00	27.933	-	-	-	8.77	-	-	-	-	8.77	36.703
7	AMERICAN COAL	10	IL	165	COOK TERMINAL	RB	11,166.00	28.041	-	-	-	8.77	-	-	-	-	8.77	36.811
8	EMERALD INTERNATIONAL	8	KY	233	INT MARINE TERM	RB	13,466.07	39.819	-	-	-	5.17	-	-	-	-	5.17	44.989
9																		
10																		
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13																		
14																		
15																		

*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
ORIGIN, TONNAGE, DELIVERED PRICE, AND AS RECEIVED QUALITY

1. Reporting Month: FEBRUARY Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: April 10, 2001

Line No. (a)	Supplier Name (b)	Mine Location (c)			Purchase Type (d)	Transport Mode (e)	Tons (f)	Purchase Price ($/Ton) (g)	Effective Transport Charges ($/Ton) (h)	Total FOB Plant Price ($/Ton) (i)	Sulfur Content (%) (j)	Btu Content (Btu/lb) (k)	Ash Content (%) (l)	Moisture Content (%) (m)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	C	RB	18,229.64	35.414	2.30	37.714	0.99	12,121	6.10	11.67
2	AMERICAN COAL	10	IL	165	S	RB	3,624.83	33.426	2.30	35.726	1.32	12,192	6.30	11.11
3	TAFT COAL SALES	13	AL	127	S	RB	805.73	30.920	12.97	43.890	0.99	11,810	14.04	6.16
4	PEABODY COALSALES	10	IL	165	S	RB	60,843.00	29.011	8.77	37.781	1.01	12,113	5.92	11.99
5	CONSOLIDATION COAL	10	IL	81	S	RB	34,316.44	22.231	9.00	31.231	1.42	12,156	6.27	10.77
6	AMERICAN COAL	10	IL	165	S	RB	19,596.00	27.289	8.77	36.059	1.04	12,169	6.65	10.30
7	PEABODY COALSALES	7	WV	39	S	RB	10,884.14	38.399	15.17	53.569	0.73	13,165	8.05	5.48
8	OXBOW CARBON & MINERAL	17	CO	51	S	RB	11,963.80	21.719	26.95	48.669	0.48	11,755	8.55	9.14
9	EMERALD INTERNATIONAL	8	KY	233	S	RB	28,829.44	39.615	5.17	44.785	1.49	11,587	13.74	8.45
10	OXBOW CARBON & MINERAL	17	CO	51	S	RB	8,982.99	20.446	22.98	43.426	0.50	11,685	8.64	9.22
11	OXBOW CARBON & MINERAL	17	CO	51	S	RB	10,846.40	22.729	26.95	49.679	0.61	12,331	10.74	6.21
12														
13														
14														
15														

*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: MARCH Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: May 10, 2001

Line No.	Supplier Name	Mine Location			Shipping Point	Transport Mode	Tons	Effective Purchase Price ($/Ton)	Additional Shorthaul & Loading Charges ($/Ton)	Rail Charges			Waterborne Charges			Other Related Charges ($/Ton)	Total Transportation charges ($/Ton)	FOB Plant Price ($/Ton)
										Rail Rate ($/Ton)	Other Rail Charges ($/Ton)	River Barge Rate ($/Ton)	Trans-loading Rate ($/Ton)	Ocean Barge Rate ($/Ton)	Other Water Charges ($/Ton)			
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	MCDUFFIE TERMINAL	RB	38,274.00	35.480	-	-	-	2.30	-	-	-	-	2.30	37.780
2	AMERICAN COAL	10	IL	165	MCDUFFIE TERMINAL	RB	1,251.40	33.426	-	-	-	2.30	-	-	-	-	2.30	35.726
3	PEABODY COALSALES	10	IL	165	COOK TERMINAL	RB	58,787.00	28.901	-	-	-	8.77	-	-	-	-	8.77	37.671
4	CONSOLIDATION COAL	10	IL	81	MOUND CITY	RB	17,433.28	21.949	-	-	-	9.00	-	-	-	-	9.00	30.949
5	AMERICAN COAL	10	IL	165	COOK TERMINAL	RB	23,946.00	27.289	-	-	-	8.77	-	-	-	-	8.77	36.059
6	PEABODY COALSALES	7	WV	39	MARMET POOL	RB	12,626.79	38.189	-	-	-	15.17	-	-	-	-	15.17	53.359
7	OXBOW CARBON & MINERAL	17	CO	29	CAHOKIA DOCK	RB	10,515.37	20.547	-	-	-	23.29	-	-	-	-	23.29	43.837
8	OXBOW CARBON & MINERAL	17	CO	51	CAHOKIA DOCK	RB	10,819.44	21.691	-	-	-	22.98	-	-	-	-	22.98	44.671
9	SSM PETCOKE	17	CO	29	IMT	RB	11,786.19	49.346	-	-	-	5.17	-	-	-	-	5.17	54.516
10	OXBOW CARBON & MINERAL	17	CO	51	CAHOKIA DOCK	RB	1,491.00	20.446	-	-	-	22.98	-	-	-	-	22.98	43.426
11	OXBOW CARBON & MINERAL	17	CO	29	CAHOKIA DOCK	RB	4,744.34	15.959	-	-	-	22.98	-	-	-	-	22.98	38.939
12	PEABODY COALTRADE	10	IL	165	COOK TERMINAL	RB	13,073.00	28.139	-	-	-	8.77	-	-	-	-	8.77	36.909
13																		
14																		
15																		

*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: APRIL Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: June 14, 2001

Line No.	Supplier Name	Mine Location			Shipping Point	Transport Mode	Tons	Effective Purchase Price ($/Ton)	Additional Shorthaul & Loading Charges ($/Ton)	Rail Charges			Waterborne Charges			Other Related Charges ($/Ton)	Total Transportation charges ($/Ton)	FOB Plant Price ($/Ton)
										Rail Rate ($/Ton)	Other Rail Charges ($/Ton)	River Barge Rate ($/Ton)	Trans-loading Rate ($/Ton)	Ocean Barge Rate ($/Ton)	Other Water Charges ($/Ton)			
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	MCDUFFIE TERMINAL	RB	21,977.72	35.601	-	-	-	2.27	-	-	-	-	2.27	37.871
2	AMERICAN COAL	10	IL	165	MCDUFFIE TERMINAL	RB	5,691.94	33.656	-	-	-	2.27	-	-	-	-	2.27	35.926
3	EMERALD COAL	10	IL	165	MCDUFFIE TERMINAL	RB	1,952.54	35.435	-	-	-	2.27	-	-	-	-	2.27	37.705
4	PBDY COAL SALES-COOK	10	IL	165	COOK TERMINAL	RB	50,229.00	29.122	-	-	-	8.49	-	-	-	-	8.49	37.612
5	CONSOLIDATION COAL	10	IL	81	MOUND CITY	RB	52,543.39	21.839	-	-	-	6.71	-	-	-	-	6.71	30.549
6	AMERICAN COAL	10	IL	165	COOK TERMINAL	RB	8,614.00	27.193	-	-	-	8.49	-	-	-	-	8.49	35.683
7	PEABODY COALTRADE	10	IL	165	COOK TERMINAL	RB	6,156.00	28.113	-	-	-	8.49	-	-	-	-	8.49	36.603
8	PEABODY COALSALES	7	WV	39	MARMET POOL	RB	23,997.43	38.379	-	-	-	14.68	-	-	-	-	14.68	53.059
9	OXBOW CARBON & MINERAL	17	CO	29	CAHOKIA	RB	9,557.86	20.998	-	-	-	23.29	-	-	-	-	23.29	44.288
10	OXBOW CARBON & MINERAL	17	CO	51	CAHOKIA	RB	10,896.02	21.691	-	-	-	22.98	-	-	-	-	22.98	44.671
11	SSM PETCOKE	17	CO	29	IMT	RB	8,228.65	49.346	-	-	-	5.10	-	-	-	-	5.10	54.446
12	OXBOW CARBON & MINERAL	17	CO	51	CAHOKIA	RB	11,542.52	20.472	-	-	-	22.98	-	-	-	-	22.98	43.452
13																		
14																		
15																		

*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
ORIGIN, TONNAGE, DELIVERED PRICE, AND AS RECEIVED QUALITY

1. Reporting Month: JANUARY Year: 2004
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: March 12, 2004

Line No.	Supplier Name	Mine Location			Purchase Type	Transport Mode	Tons	Purchase Price ($/Ton)	Effective Transport Charges ($/Ton)	Total FOB Plant Price ($/Ton)	Sulfur Content (%)	Btu Content (Btu/lb)	Ash Content (%)	Moisture Content (%)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	PEABODY COAL SALES	10	IL	165	C	RB	88,582.13	35.143	2.40	37.543	1.04	12,105	6.39	11.57
2	PEABODY COALSALES	45	IM	999	C	RB	19,950.69	34.124	2.40	36.524	0.50	11,771	4.05	12.00
3	INTEROCEAN COAL SALES	45	IM	999	S	RB	32,659.27	33.643	2.40	36.043	0.46	11,736	4.67	12.11
4	ALABAMA POWER CO.	45	IM	999	S	RB	6,478.81	31.636	2.40	34.036	0.44	11,445	4.94	13.46
5	PEABODY COAL SALES	45	IM	999	S	RB	20,637.05	41.225	2.40	43.625	0.47	11,782	4.19	11.84
6	INTEROCEAN COAL SALES	45	IM	999	S	RB	14,310.91	41.545	2.40	43.945	0.39	11,874	4.35	10.95
7	PEABODY COAL SALES	10	IL	165	C	RB	1,559.00	28.540	9.24	37.780	1.09	12,063	6.90	11.08
8														
9														
10														
11														
12														
13														
14														
15														

(use continuation sheet if necessary)

EXHIBIT NO. 72-Conf

DOCKET NO: 031033-EI

WITNESS: BRENT DIBNER

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: DOCUMENT NO. 01500-04

PROFERRED BY: STAFF

11.26.05 (entire DN)

CONFIDENTIAL

DECLASSIFIED

DOCUMENT NUMBER-DATE

06647 JUN 16 ⁰⁶

FPSC-COMMISSION CLERK

dlclas 11-26-05

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 031033-EI EXHIBIT NO. 72

COMPANY/ WITNESS: Staff

DATE: 5(27-28)/04 - 6/10/04

AUSLEY & MCMULLEN
ATTORNEYS AND COUNSELORS AT LAW
227 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

ORIGINAL

February 2, 2004

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

RECEIVED-FPSC
04 FEB -2 PM 4:53
COMMISSION
CLERK

Re: Review of Tampa Electric Company's waterborne transportation contract with TECO Transport and associated benchmark; FPSC Docket No. 031033-EI

TRANSMITTAL OF CONFIDENTIAL INFORMATION

Dear Ms. Bayo:

Pursuant to a Request for Specified Confidential Treatment Tampa Electric is simultaneously filing with your office, we enclose a single confidential version of six pages of output from Mr. Brent Dibner's computer models requested by Staff. The confidential information contained in this filing is printed on yellow stock paper and stamped "CONFIDENTIAL." We would appreciate your maintaining confidential treatment of the enclosed materials.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

RECEIVED & FILED
FPSC-BUREAU OF RECORDS

James D. Beasley

JDB/pp
Enclosure

cc: Wm. Cochran Keating IV (w/o enc.)
Todd Bohrmann (w/o enc.)
Bill McNulty (w/o enc.)

CONFIDENTIAL

DOCUMENT NUMBER-DATE
01500 FEB-2 04
FPSC-COMMISSION CLERK

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TECO OCEAN BARGE RATE MODEL

INPUT

	Current Value	Revised Value
Cost per crew day		
ITB	350	350
Tug Barge	325	325

Operating Parameters		
Load rate (tons per hour)	1,250	1,250
Shifting Time at Big Bend (days)	0.0	-
Channel Maneuvering/Docking/Undocki	0.5	0.5
Delay as % of Voyage Time at Sea	15%	15%

Cost of Capital Calculation	Current Value				Revised Value			
	Pct of Capital	Return	Tax	Capital Cost (Wtd)	Pct of Capital	Return	Tax	Capital Cost (Wtd)
Equity	50%	18%	0%	9%	50%	18%	0%	9%
Debt	50%	8%	35%	3%	50%	8%	35%	3%
	100%			12%	100%			12%

Daily Operating Costs

Current Values	Peggy Palmer	Gayle Eustace	Dons Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	66	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	569	422	423	364
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

CONFIDENTIAL

DOCUMENT NUMBER-DATE
01500 FEB-2 05
FPSC-COMMISSION CLERK

INPUT

	Current Value	Revised Value					
Revised Values							
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	66	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

OUTPUT

← **To obtain the correct results, click the 'Order Barges' button to the left each time changes are made to input values!**

Rate Build-Up and Composition

Barge	Est Rate	Capacity r (000 tons)	Tons/Yr (000)	Cum Tons (000)	Cum Cost ($000)	Ave Rate	Rate to Ave
Peggy Palmer	7.47	1,111	1,111	1,111	8,293	7.47	0.54
Gayle Eustace	7.66	1,447	1,447	2,558	19,376	7.57	0.35
Doris Guenther	8.05	877	877	3,435	26,441	7.70	(0.04)
Mary Turner	8.09	1,024	1,024	4,459	34,727	7.79	(0.08)
D Ludwig	8.73	756	756	5,215	41,321	7.92	(0.72)
Diana T	9.58	560	285	5,500	44,053	8.01	(1.58)
Barbara Vaught	11.35	585	-	5,500	44,053	8.01	(3.34)

Composition Per Ton

	Fuel	Fixed	Variable	Total
Peggy Palmer	0.99	3.72	2.75	7.47
Gayle Eustace	0.67	4.25	2.74	7.66
Doris Guenther	0.86	3.85	3.34	8.05
Mary Turner	1.05	3.66	3.38	8.09
D Ludwig	1.14	4.14	3.44	8.73
Diana T	1.59	3.01	4.98	9.58
Barbara Vaught	1.20	5.75	4.39	11.35
Weighted Avg.	**0.95**	**3.89**	**3.17**	**8.01**
Component Share	**12%**	**49%**	**40%**	**100%**

Per Diem Rates

Bareboat Hire	TECO TC	Preference TC Rate	AverageTC Rate
7,551	15,846	25,000	20,423
21,875	32,694	25,000	28,847
6,820	14,819	21,000	17,909
9,346	18,733	22,000	20,367
3,471	10,603	22,000	16,301
5,517	13,133	12,000	12,566
6,771	13,797	20,000	16,898

Vessel Value

Tug Value	Barge Value	Total Value
4,308,698	10,738,845	15,047,543
11,504,321	27,416,679	38,921,000
6,739,656	8,860,069	15,599,725
7,074,302	12,868,890	19,943,192
3,901,914	876,960	4,778,874
3,952,545	5,222,250	9,174,795
2,565,108	756,000	3,321,108

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Tug		Naida Ramil	Barbara Kessel	Sharon DeHart	Beverly Anderson	Ellena Hicks	Debbie Rankin	Lisa W.	3 Barges	4 barges
Barge/Ship		Peggy Palmer	Clayle Eustace	Doris Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught	**Somerset Class**	**Dixie Fuels Class**
Linkage			Artubar	Artubar						
Type		No Gear TB	Geared ITB	No Gear ITB	Geared TB	No Gear TB	Self Unload TB	No Gear TB	No Gear ATB	No Gear ATB
Am. Bureau of Shipping Classification						In Class Til 6 2003				
Total Time		10.35	7.54	8.36	9.33	9.93	9.74	10.76	10.22	10.27
Voyage Rate Assessment		At Average Rate	At Average Rate	At Average Rate	At Average Rate	At Average Rate	At Average Rate	At Average Rate	At Average Rate	At Average Rate
Total Time Charter Expense		211,303	217,489	149,642	189,953	161,815	122,433	182,221	145,746	149,230
Fuel at Sea		31,674	19,251	17,026	28,236	23,357	24,160	20,588	14,932	19,328
Tug Generating Fuel		1,201	1,751	1,067	722	1,268	754	1,043	1,583	1,589
Barge Fuel		585	426	472	527	561	551	610	578	580
Lube Oil		1,584	963	851	1,412	1,168	1,208	1,029	747	966
Tug Assist at Davant		500	500	500	500	500	500	500	500	500
Tug Assist at Big Bend		1,000	1,000	1,000	1,000	1,000	1,000	1,999	1,000	1,000
Misc. Port Expenses		3,770	3,669	2,545	4,280	2,300	2,750	1,920	1,470	1,730
Total Cost Per Voyage		251,617	245,048	173,104	226,629	191,968	153,356	209,911	166,556	174,924
Per Short Ton - Big Bend		**7.47**	**7.66**	**8.05**	**8.09**	**8.73**	**9.58**	**11.35**	**11.49**	**10.29**
Annual Voyages and Maximum Delivery										
Voyages Per Year		32.96	45.23	40.81	36.56	34.35	35.00	31.62	33.36	33.21
Tons Per Year		1,110,694	1,447,331	877,440	1,023,731	755,757	560,000	585,023	483,661	564,577
Fuel Prices										
Fuel Price Per Ton-IFO Del. New Orlns		135	135	135	135	135	135	135	135	135
Fuel Price Per Ton-No. 2 Diesel New Orlns		212	212	212	212	212	212	212	212	212
Fuel Price - Coal										
Fuel Adder for Delivery to Vessel/Per Ton		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Capital Cost Analysis										
Tug Rep Value Per HP		1150	1650	1650	1350	1350	1350	1350	1400	1100
Barge Rep Value Per DWT		633	633	633	633	633	633	633	633	633
Tug DRV at 50 Yr Useful Life		4,308,698	11,504,321	6,739,656	7,074,302	3,901,914	3,952,545	2,565,108	3,362,477	3,682,713
Barge DRV at 35 Yr Useful Life $		10,738,845	17,416,679	8,860,069	12,868,890	-	5,222,250	-	6,280,943	5,201,678
Tug Rehab Credit										
Barge Scrap Credit						876,960		756,000		
Barge Jumboization/Enlargement and Life			10,000,000						1,000,000	1,000,000
Barge Undr Value at $ 250 per DWT										
Ship DRV at $ 1600 per DWT										
Int! Bulker Value										
Wreck Act Reconstruction										
US Flag Reflag Addl Cost										
Market Scale Value										
Total		15,047,543	38,921,000	15,599,725	19,943,192	4,778,874	9,174,795	3,321,108	10,643,420	9,884,390
Amortization of Capital										
Tug Amortization of Value		$796,395	$2,379,022	$1,011,732	$1,120,965	$721,207	$755,867	$837,418	$602,413	$659,786
Barge/Ship Amortization of Value		$1,778,590	$5,080,285	$1,313,780	$2,065,913	$462,518	$1,125,295	$1,471,632	$979,380	$995,589
Bareboat as pct of value		17%	19%	15%	16%	25%	21%	70%	15%	17%
Days in Service/Year		341	341	341	341	341	341	341	341	341
Time Charter Array and Averaging										
Operating Expenses		$ 8,294	$ 10,819	$ 7,999	$ 9,388	$ 7,131	$ 7,616	$ 7,025	$ 5,875	$ 6,213
Bareboat/Day		$7,551	$21,875	$6,820	$9,346	$3,471	$5,517	$6,771	$4,639	$4,854
Total TC Requirement		15,846	32,694	14,819	18,733	10,603	13,133	13,797	10,513	11,067
Preference TC Rate (From Parabolic Curve Fit)		25,000	25,000	21,000	22,000	22,000	12,000	20,000	18,000	18,000
Average/Used TC Rate		20,423	28,847	17,909	20,367	16,301	12,566	16,898	14,247	14,534
Implicit Daily Bareboat/Capital Component		12,128	18,028	9,910	10,979	9,170	4,950	9,873	8,382	$ 6,213
Components of Costs										
Fuel		0.99	0.67	0.86	1.05	1.14	1.59	1.20	1.18	1.26
Fixed		3.72	4.25	3.85	3.66	4.14	3.01	5.75	5.91	3.75
Variable		2.75	2.74	3.34	3.38	3.44	4.98	4.39	4.40	5.27
Tonnage Required for 5.5mm		7.47	7.66	8.05	8.09	8.73	9.58	11.35		
Percentages of Costs										
Fuel		13.3%	8.7%	10.7%	13.0%	13.1%	16.6%	10.6%	10.3%	12.3%
Fixed		49.9%	55.5%	47.8%	45.2%	47.4%	31.4%	50.7%	51.4%	36.5%
Variable		36.8%	35.8%	41.4%	41.8%	39.5%	51.9%	38.7%	38.3%	51.2%
	TC Cost Base	15,846	32,694	14,819	18,733	10,603	13,133	13,797		
	Preference TC	25,000	25,000	21,000	22,000	22,000	12,000	20,000		
	Average TC Used	20,423	28,847	17,909	20,367	16,301	12,566	16,898		
Tug Value		4,308,698	11,504,321	6,739,656	7,074,302	3,901,914	3,952,545	2,565,108		
Barge Value		10,738,845	27,416,679	8,860,069	12,868,890	876,960	5,222,250	756,000		

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Tug		Naida Ramil	Barbara Kessel	Sharon DeHart	Beverly Anderson	Elena Hicks	Debbie Rankin	Lisa W.		3 Barges	4 barges
Barge/Ship		Peggy Palmer	Gayle Estrade	Doris Gustafson	Mary Turner	Diane Ludwig	Diane T	Barbara Vaught		Somerset Class	Dixie Fuels Class
Linkage			Artubar	Artubar							
Type		No Gear TB	Geared ITB	No Gear ITB	Geared TB	No Gear TB	Self Unload TB	No Gear TB		No Gear ATB	No Gear ATB
Am. Bureau of Shipping Classification						In Class Til 6 2003					
Tug Built		1976	1966	1972	1982	1976	1975	1966		1982	1982
Barge/Ship Built		1981	1977	1985	1982	1967	1975	1964		1990	1982
Barge/Ship Rebuilt			1998	1985							
Tug Acquired		1986	1966	1981			1975	1966		1982	1982
Barge Acquired				1981		1967		1964		1990	1982
Tug former name		Frances S			April T Becker	Alice St Philip					
Barge/Ship former name		Oceanport	CF-1	Thunder/USL 502	Erol Becker	Pearll Jahn	Faustina				
DWT Short Tons		37,700	36,686	25,449	42,800	23,000	27,500	19,200		14,700	17,300
Hold capacity ft3		1,392,000	1,128,984	866,000	1,077,455	945,000	625,000	812,116			
Tons to Big Bend at 33 feet ST - Actual Delivery		33,700	32,000	21,500	28,000	22,000	16,000	18,500		14,500	17,000
Gross tons		14,379	16,728	10,434	16,728	9,542	16,528	7,998		7,438	10,000
LOA		550.0	640.0	548.0	610.0	420.0	495.0	420.0		419.0	462.0
Beam		78.0	75.3	76.2	78.1	80.0	85.0	80.0		75.0	82.0
Draft Full, ft		34.7	35.9	28.1	36.7	29.1	34.2	25.2		20.4	22.0
Draft Light, ft		5.5	6.5	5.5	5.1	5.8	7.0	5.0		5.0	4.8
Feet of Cargo		29.2	29.4	22.6	31.6	23.3	27.2	20.2			
TPI estimated (ST)		108	104	94	115	84		81		85	83
TPI overall (ST)		108	104	94	113	82	84	79		80	84
FT3/GT		97	67	83	64	99	38	102		0	0
Speed, knots		6.5	11	9	7.5	6.8	7.0	6.0		6.5	7
Horsepower		7,000	7,200	5,210	7,200	5,400	5,750	4,200		3300	4,600
Fuel		DO	DO	DO	DO	DI	DO	DO		DO	DO
HP/DWT ST		0.21	0.23	0.24	0.26	0.25	0.36	0.23		0.23	0.27
Fuel Burn at 90% HP (gals/hr)		315	324	234.45	324	243	258.75	189		148.5	207
Tons Per Day		26	26	19	26	19	21	15		12	17
Tug KW generating - Installed		300	600	330	200	330	200	250		400	400
Gen Tons/Day		0.5	1.1	0.6	0.4	0.6	0.4	0.5		0.7	0.7
Speed/L^.33*DWT/HP		3.90	5.80	4.63	3.51	3.77	2.51	3.60		3.89	3.42
Tug Age, Gross or Since Rebuild		27	5	18	21	27	28	37		21	21
Barge Age, Gross or Since Rebuild		22	5	18	21	36	28	39		13	21
Ultimate Tug Life		45	20	45	45	45	45	45		45	45
Ultimate Barge/Ship Life		40	20	40	40	40	40	40		40	40
Tug Years Remaining (Financed if new)		18	15	27	24	18	17	8		19	19
Barge/Ship Years Remaining (Financed if new)		18	15	22	19	4	12	1		27	19
Financed Life Tug		9.0	7.5	13.5	12.0	9.0	8.5	4.0		9.5	9.5
Financed Life Ship/Barge		9.0	7.5	11.0	9.5	2.0	6.0	0.5		13.5	9.5
Daily Operating Costs											
Crew Size		9	10	9	10	8	8	8		7	8
Cost/Crew-day		325	350	350	325	325	325	325		325	325
Tug/Ship Crew Cost		2,925	3,500	3,150	3,250	2,600	2,600	2,600		2,275	2,600
Tug/Ship Stores, Supplies, Lube Oil		288	320	288	320	256	256	256		224	256
Tug/Ship Machinery Overhaul		75	76	64	76	66	68	58		51	60
Tug Yard Accrual		538	737	617	418	538	558	737		418	418
Tug Voyage Repairs		222	228	165	228	171	182	133		105	146
Tug Insurance		472	744	568	589	422	423	384		368	459
Barge Op Stores and Supplies		224	218	151	254	137	163	114		87	103
Barge/Ship Yard Accrual - Hull		972	1,117	537	1,053	970	902	877		224	426
Barge Self-Unloading M&R Accrual		-	303		403	-	303	-			
Barge Insurance		636	1,645	659	843	202	388	140		450	42
Barge/Ship Voyage Repairs		444	432	299	504	271	324	226		173	204
Management Cost		1,500	1,500	1,500	1,450	1,500	1,450	1,500		1,500	1,500
Total		8,294	10,819	7,999	9,388	7,131	7,616	7,025		5,875	6,213
Tug Cash Operating		5,269	6,355	5,603	5,606	4,802	4,812	4,918		4,191	4,689
Load rate	1,250			tons per hour							
	456			Distance in nautical miles							
Big Bend Delivery Analysis at Minimum Capital											
Time											
Voyage Time at Sea		5.8	3.5	4.2	5.1	5.6	5.4	6.3		5.8	5.43
Big Bend Unload in Free Days		2.00	2.00	2.00	2.00	2.00	2.00	2.00		2.00	2.00
Load Rate as above		1.12	1.07	1.00	1.00	1.00	1.00	1.00		1.00	1.00
Shifting Time at Big Bend		0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00
Channel Maneuvering/Docking/Undocking		0.50	0.50	0.50	0.50	0.50	0.50	0.50		0.50	0.50
Delay at 15% of Voyage Time at Sea	15%	0.68	0.52	0.63	0.76	0.84	0.81	0.95		0.88	1.34

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Tug					
Barge/Ship					
Linkage					
Type					
Am. Bureau of Shipping Classification					
Fuel					
Fixed	***Cost of Capital Calculation***				
Variable		**Pct of**	**Return**	**Tax**	**Capital**
	Equity	50%	18%	0%	9%
	Debt	50%	8%	35%	3%
		100%	0%	0%	**12%**

EXHIBIT NO. 73 - Conf.

DOCKET NO: 031033-EI

WITNESS: BRENT DIBNER

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: TAMPA ELECTRIC COMPANY'S RESPONSE TO STAFF'S 4TH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 28-33)

PROFERRED BY: STAFF

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DECLASSIFIED
NH 11.26.05 (entire DN)

DOCUMENT NUMBER-DATE
06648 JUN 16 04
FPSC-COMMISSION CLERK

declas 11-26-05
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 73
COMPANY/ WITNESS: Staff
DATE: 5/27-28/04 + 6/10/04

AUSLEY & MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

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TALLAHASSEE, FLORIDA 32301
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April 8, 2004

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Review of Tampa Electric Company's waterborne transportation contract with TECO Transport and associated benchmark; FPSC Docket No. 031033-EI

TRANSMITTAL OF CONFIDENTIAL INFORMATION

Dear Ms. Bayo:

Pursuant to a Notice of Intent to Seek Confidential Classification Tampa Electric is simultaneously filing with your office, we enclose a single unredacted confidential version of Tampa Electric's responses to Staff's Fourth Request for Production of Documents (Nos. 28-33). The confidential information contained in this filing is highlighted in yellow or printed on yellow paper stock and stamped "CONFIDENTIAL." We would appreciate your maintaining confidential treatment of the enclosed materials.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter. AHK 11.26.05 (entire DN)

Sincerely,

DECLASSIFIED
CONFIDENTIAL

James D. Beasley

JDB/pp
Enclosures

cc: Wm. Cochran Keating IV
All Parties of Record

This docketed notice of intent was filed with Confidential Document No. 04417-04. The document has been placed in confidential storage pending timely receipt of a request for confidentiality.

RECEIVED & FILED
FPSC-BUREAU OF RECORDS

DOCUMENT NUMBER-DATE
04417 APR-8 04
FPSC-COMMISSION CLERK

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Tampa Electric Company's 2004-2008 Waterborne Transportation Contract with TECO Transport and Associated Benchmark.	)))))	DOCKET NO. 031033-EI FILED: APRIL 8, 2004

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TAMPA ELECTRIC COMPANY'S

ANSWERS TO FOURTH REQUEST FOR

PRODUCTION OF DOCUMENTS (NOS. 28 - 33)

OF

THE FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Production of Documents (Nos. 28 - 33) propounded and served on March 24, 2004, by Florida Public Service Commission Staff.

DOCUMENT NUMBER-DATE
04417 APR-8 04
FPSC-COMMISSION CLERK

TAMPA ELECTRIC COMPANY

DOCKET NO. 031033-EI

INDEX TO STAFF'S FOURTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 28-33)

Number	Sponsor	Subject	Page Number
28	Dibner	In its response to Staff's Second Set of Interrogatories, No. 12, Tarnpa Electric stated that "Mr. Dibner focused on the costs of capital that would be used by a bidder on this contract." Please provide all source documents (reports, analyses, studies, etc.) that Mr. Dibner relied upon to estirnate the cost of capital used in developing the cost of capital incorporated into the "all-in barge hire rate" used in the Inland River Model.	1
29	Dibner	In its response to Staff's Second Set of Interrogatories, No. 12, Tampa Electric stated that "Mr. Dibner focused on the costs of capital that would be used by a bidder on this contract." Please provide all source documents (reports, analyses, studies, etc.) that Mr. Dibner relied upon to estimate the cost of capital used in developing the cost of capital inputs used in the Ocean Model.	2
30	Dibner	In its response to Staff's Second Set of Interrogatories, No. 12, Tampa Electric stated that "Mr. Dibner based the costs of capital used in his models on the typical objectives and financing positions of the industry and the costs of capital that are incurred and expected by cornpanies that would bid on the contract." Please provide all source documents (reports, analyses, studies, etc.) that Mr. Dibner relied upon to determine the "typical objectives and financing positions of the industry" in general and "the companies that would bid on the contract" in particular.	3
31	Dibner	In its response to Staff's Second Set of Interrogatories, No. 12, Tampa Electric stated that "Mr. Dibner based the costs of capital used in his models on the typical objectives and financing positions of the industry and the costs of capital that are incurred and expected by companies that would bid on the contract." Please provide all source documents (reports, analyses, studies, etc.) that Mr. Dibner relied upon to determine "the costs of capital that are incurred and expected by companies that would bid on the contract."	4
32	Dibner	Please provide all source documents (reports, analyses, studies, etc.) relied upon in the	19

		determination of the average cost of capital included in Tampa Electric's response to Staff's Second Set of Interrogatories, No. 36.	
33	Dibner	Please provide all source documents (reports, analyses, studies, etc.) relied upon in the determination of the cost of equity, cost of debt, capital structure, and overall cost of capital indicated in Tampa Electric's response to Staff's Second Set of Interrogatories, No. 38.	20

Brent Dibner, President
Dibner Maritime Associates, LLC
151 Laurel Road
Chestnut Hill, Massachusetts 02467

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FOURTH REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 28
BATES STAMPED PAGE: 1
FILED: APRIL 8, 2004

28. In its response to Staff's Second Set of Interrogatories, No. 12, Tampa Electric stated that "Mr. Dibner focused on the costs of capital that would be used by a bidder on this contract." Please provide all source documents (reports, analyses, studies, etc.) that Mr. Dibner relied upon to estimate the cost of capital used in developing the cost of capital incorporated into the "all-in barge hire rate" used in the Inland River Model.

A. As discussed in Mr. Dibner's report at pages 20 and 75, during his October 20, 2003 deposition and in Tampa Electric's responses to Staff's Second Set of Interrogatories, No. 36 and 37, the portion of the inland river barge daily rate that covers capital cost was derived from estimated prevailing open hopper barge time charter rates. Thus the barge hire rate is not derived from cost of capital analysis. The documents relied upon were previously provided in Tampa Electric's response to Staff's First Request for Production of Documents, No. 10.

Mr. Dibner has used cost of capital concepts with respect to inland barge hire solely to respond to questions asked by Staff or the parties to this proceeding during his deposition or in interrogatory responses. In answering these questions, Mr. Dibner linked the daily time charter rate to an amount of monies that would be generated annually. He then used assumptions to explain how one might translate the daily time charter rate into an approximate barge value and related this barge value to new construction costs. This was done only by way of example to illustrate the reasonableness of the capital component amount in response to deposition questions and interrogatories.

29. In its response to Staff's Second Set of Interrogatories, No. 12, Tampa Electric stated that "Mr. Dibner focused on the costs of capital that would be used by a bidder on this contract." Please provide all source documents (reports, analyses, studies, etc.) that Mr. Dibner relied upon to estimate the cost of capital used in developing the cost of capital inputs used in the Ocean Model.

A. See the response to Request for Production of Documents No. 31.

30. In its response to Staff's Second Set of Interrogatories, No. 12, Tampa Electric stated that "Mr. Dibner based the costs of capital used in his models on the typical objectives and financing positions of the industry and the costs of capital that are incurred and expected by companies that would bid on the contract." Please provide all source documents (reports, analyses, studies, etc.) that Mr. Dibner relied upon to determine the "typical objectives and financing positions of the industry" in general and "the companies that would bid on the contract" in particular.

A. See the responses to Request for Production of Documents, No. 28 and 31.

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FOURTH REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 31
BATES STAMPED PAGES: 4 - 18
FILED: APRIL 8, 2004

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31. In its response to Staff's Second Set of Interrogatories, No. 12, Tampa Electric stated that "Mr. Dibner based the costs of capital used in his models on the typical objectives and financing positions of the industry and the costs of capital that are incurred and expected by companies that would bid on the contract." Please provide all source documents (reports, analyses, studies, etc.) that Mr. Dibner relied upon to determine "the costs of capital that are incurred and expected by companies that would bid on the contract."

A. The cost of capital calculations used by Mr. Dibner pertain exclusively to the ocean model, and the portion of the time charter determinations that relate to the market-based costs of the towing and transportation industry. This was averaged with the observed time charter rates in the preference trade. The analysis was guided by the insights drawn from exposure to many private shipping companies, as well as the relevant public information described below.

With respect to the ocean model, Mr. Dibner considered financing of vessels on a project basis, with the 50 percent debt and 50 percent equity "advance rate" as being typical of financing available to operators of equipment that is not recently constructed. In U.S. experience, the overall availability of long term debt is generally limited by the banks, particularly if a long term and full-use commitment for the loan duration is not provided. Data sources that support this type of financing include the attached *Marine Money* article on the Royal Bank of Scotland and its reference to U.S. marine finance

The RMA (formerly Robert Morris Associates) report on SIC Code 4449, "Water Transportation of Freight, NEC," also supports the debt-equity ratio used by Mr. Dibner. RMA found that, for the larger companies with approximately $10 to 50 million in revenues, long term debt due beyond one year amounted to 46 percent of total assets and that long term debt due within one year amounts to about four to five percent of total assets. This totals 50 percent. The equity component is also evident at 33 percent, with an additional amount of net working capital of current assets less current liabilities (excluding current portion of long term debt) of 13.5 percent. Thus equity plus net working capital represents 46.5 percent of total assets. This suggests that shareholder equity and working capital are approximately equal to long term debt. The RMA data is both attached and summarized on the following page.

RMA Analysis of Larger Carriers in SIC 4449, 2002
All Ratios are as Percent of Total Assets (or Total Liabilities)

	Equity		Debt	Total
Raw Ratio				
Equity	0.326	Long Term Debt	0.46	0.786
Percent	41%		59%	100%
Adjusted Ratio				
Current Assets	0.255			
Current Liabilities	0.169			
Net Capital	0.086			
Plus Current Long Term Debt	0.049	Current Long Term Debt	0.049	
Net Capital	0.135			
Total	0.461		0.509	0.97
Percent	**48%**		**52%**	**100%**

Source: DMA Analysis

Note: Equity is shown at cost, while valuation of equity at market and earnings raises equity weighting.

Crowley Maritime Corporation financial data also supports the debt-equity ratio used by Mr. Dibner. The financial data of Crowley Maritime, one of the nation's largest tug-barge companies, are available although the company is privately-owned and financially healthy and mature, *i.e.*, not highly leveraged through an initial public offering. This company is diversified with various tug-barge operations. It does not have ocean-going dry bulk tug-barge units, but it does operate tank-barge units. The financial data is both attached and summarized on the following page.

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Crowley Maritime Corporation
All figures are in millions as of September 30th, 2003

	Equity		Debt	Total
Raw Ratio				
Equity	292.3	Long Term Debt	298.4	590.7
Percent	49%		51%	100%
Adjusted Ratio				
Current Assets	240.5			
Current Liabilities	188.3			
Net Capital	52.2			
Plus Current Long Term Debt	28.8	Current Long Term Debt	29.8	
Net Capital	81			
Total	373.3		328.2	701.5
Percent	**53%**		**47%**	**100%**

Source: DMA Analysis

The 10 percent interest rate used in Mr. Dibner's ocean model is supported by data from *Marine Money*. The "blue page" transaction watch for July/August 2003, attached, shows typical high yield rates applicable to U.S. marine companies engaged in towing and coastal/ dry bulk barging operations. These are indicative of the types of financing that might be secured for coastal tug-barge units of the types and ages that would compete for the Tampa Electric business. Both current and issue coupon yields have some relevance. Both are summarized below.

American High Yield Shipping Bonds

	Coupon	Yield to Maturity
American Commercial Lines	11.250	Not reported
American Commercial Lines	9.750	Not reported
Great Lakes Dredge	11.250	9.770
Hornbeck Offshore	10.625	8.980
Oglebay Norton	10.000	Not reported
Seabulk International	9.500	9.740
Average Above	10.396	9.497

Source: Marine Money "blue pages," September 2003, page XIV, in percent

The 18 percent equity return used in Mr. Dibner's ocean model is based on the targeted return in the tug and barge industry that is used by investors who are acquiring companies or equipment. In determining the appropriate return on equity for the ocean model, Mr. Dibner relied upon his experience with numerous client projects. The attached pages pertaining to Return on Equity targets depict

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the targeted rates of return that investors seek. In general, target equity IRR's are in the 18 percent range on an after tax free cash flow basis, which is equivalent to the return used in Mr. Dibner's model. Many acquisitions of equipment seek even higher returns. Recently, a client advised Mr. Dibner that "returns of (only) 43 percent targeted equity IRR are the ones that get us into trouble." The cost of equity is also set forth in the attached table from *Marine Money* titled "Sources of Capital for Shipping", which shows that private equity targets 20 to 30 percent returns.

The historical realization of equity returns is shown in the table below. Private equity in total has consistently received 13 to 14 percent returns.

Performance of private equity vs. public equity
Period ending December 31, 2003

Asset Class	Index/Proxy	Annualized Rate of Return (%)			
		1 Year	5 Year	10 Year	20 Year
Canadian public equity	S&P TSX Composite	26.72	6.54	8.59	8.79
U.S. public equity	S&P 500	5.26	-3.95	10.79	13.21
	NASDAQ	24.03	-4.94	9.77	10.63
	Russell 3000	7.81	-2.89	10.59	12.84
	Russell 2000	21.14	3.54	9.23	10.42
Private equity*	Buyouts	9.9	1.4	8.1	12.0
	Venture capital	-17.8	25.7	25.4	15.7
	All private equity	1.3	6.7	13.3	13.6

* Venture Economics US Private Equity Performance Index in USD as of September 30, 2003

Source: CPP Website of Canada

A major recent investor in the U.S. maritime industry has been the combined private equity firms of Carlyle and Riverstone. They have invested in U.S. flag marine holdings with the expectation of earning returns consistent with their return targets and past performance. As shown below, returns in the 26 percent to 32 percent range have been achieved.

CARLYLE/RIVERSTONE INVESTMENTS

Seabulk Intl
Ft. Lauderdale, FL

Carlyle/Riverstone Energy

Acquired: September 2002
Status: Unrealized

Seabulk International, Inc. is a leading provider of marine support and transportation services. Seabulk is principally engaged in three main businesses: offshore energy support, marine transportation and towing

Source: Carlyle Website

Fund Description	Vintage Year	Capital Committed	Cash In	Cash Out	Cash Out & Remaining Value	Net IRR	Foot-notes	Investment Multiple
Carlyle Partners II, L.P.	1996	80,000,000	84,587,433	115,764,307	178,794,780	26.39%		2.11x
Carlyle/Riverstone Global Energy & Power II	2003	75,000,000	19,475,611	2,070,979	21,545,272	32.48%	N/M	1.11x

Source: CALPERS Website

N/M: Internal rates of return ("IRR") and multiples are not meaningful in the early years of a fund (those established in or since 1998) nor are they indicative of performance.

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FOURTH REQUEST FOR PODS

The Royal Bank of Scotland plc in Greece

By Kevin Oates

Introduction

Speak to most banks these days involved in ship financing and you definitely get the feeling that plain vanilla is... well...just too plain. The trend is definitely towards bigger, sexier deals which will result in arrangement fees as well as margins, as little perceived risk as possible either by lending on the back of a strong balance sheet or against secure long-term employment and essentially using as minute a portion as possible of their own balance sheet. That is why some of the big boys of shipping finance like Citibank and JP Morgan Chase, and many of the large European lenders, are heard of less these days but are nonetheless participating in the big deals as much as ever. Not so much as prime lender but as prime arranger.

It makes a change therefore that one major shipping bank with a global portfolio of about $4 billion is quite happy continuing to lend on a bilateral basis and surviving basically on margin, fee and direct ancillary business from the lending relationships. Not only that but over 60% of the shipping portfolio concerns Greek related lending. This too is something which is not near the top of the list of most major lenders. Over the years the bank has had various advertising slogans including "The Twenty Year Men" reflecting the fact that a number of the senior shipping executives in the bank have worked within the shipping department for over 20 years, and "The Shipowners Club" giving the impression that membership to the clientele is somewhat restricted. The bank is, of course, The Royal Bank of Scotland.

This article will consider the growth and development of the bank and it's shipping presence in the Greek market and comment on lending strategy now and in the future. Known Greek clients include instantly recognisable names such as Angelopoulos, the Procopiou brothers, the Angelicoussis family, Frangos, Laliotis, Mylonas, Hadjioannou, Kyriakou, Kulukundis, the Lemos family, the Goulandris family, Embiricos and many more.

Not to be forgotten is that the bank is very active in shipping in other geographical markets

RBS in Shipping

In two years the Royal Bank of Scotland (hereafter "RBS") will celebrate 250 years since records suggest it entered into it's first shipping transaction. A long time later, but still a century ago, William Deacon's Bank opened a branch in St Mary Axe close to the Baltic Exchange in the City of London. The proximity to the Exchange led to the Bank starting to handle shipping accounts. This connection was the catalyst which led to the close association with the London Greek and Greek shipping fraternity. By the late 1930's there were 17 Greek shipping agencies in London representing over 45% of the Greek controlled fleet. William Deacon's Bank in St Mary Axe virtually cornered the market and grew strong customer relations at that time which remain loyal today.

In the 1950's and 1960's London and then New York remained the centre of Greek related shipping and William Deacon's Bank continued to actively market these customers. Also in the 1960's the Greek marketing drive was taking senior shipping staff to Piraeus where the domestic Greeks were becoming increasingly active.

RBS in Greece

In the early 1970's more and more Piraeus based Greek ship owners were becoming clients of the bank and it was becoming clear to the bank (then Williams & Glyn's Bnak) that there was considerable potential in Greece not only from lending but also from operational business. Thus, in 1973 a representative office was opened. The success of the office was such

TAMPA ELECTRIC COMPANY
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that in 1974 a branch was opened in Xylas House (still the same location today) with a staff of 25.

After being courted and courting others during the early 1980's The Royal Bank of Scotland merged with Williams & Glyn's Bank in 1985 and the bank in general and the branch in Greece was renamed RBS as it remains today. Since the branch opened some 27 years ago there have been only 6 managers. Prior to the present manager the previous five served an average of five years. The current manager, the first Greek to occupy this post, took office in 1998. Of the staff of 65 at the branch today, eleven joined during the first year of operation.

Growth of the Greek Portfolio

RBS is active in a number of geographical markets but the predominance is Greek related business. Of a total shipping portfolio of about $ 4billion, in the region of $ 2.5 billion is Greek related and about $ 1.2 billion is actively managed from the Piraeus branch. The other markets in which the bank lends are Scandinavia, Italy, being the second most important market in dollar terms after Greece, North America, France and India. Noticeably absent is the Far East where the bank believes it does not have the in situ expertise which other banks have built over the years. Also there is a strong tendency to avoid specialised tonnage. There are few container operators and the vast bulk of the portfolio is standard wet and dry bulk tonnage.

As far as the branch in Greece is concerned there has been over 300% growth in portfolio size since 1994 when about $ 300 million was lent to local customers of the Piraeus branch. The increase to approximately $ 1.2 billion since has been due to a strong focus on younger tonnage to stronger owners thus resulting in bigger loans. The newbuilding spree of the strong Greeks since 1998 has certainly served RBS well in building the portfolio. Not only were the vessels being contracted at historically low prices, but the category of owner being courted by RBS did not require overly high gearing and had cash besides to operate the vessel in a soft market. The fact that during 2001 and through into 2002 many of these committed newbuilds will be delivered into far from perfect market conditions causes no alarm for RBS. When you have lent $15 million on a newbuild panamax bulk carrier to an owner who has been around for a long time with a respected reputation, another dozen or more vessels and plenty spare cash in the kitty, a period of $ 8,000 per day time charter equivalent will not cause sleepness nights.

Back in 1994 the target portfolio for the branch was indeed $ 1 billion. This having been exceeded, a new target has presumably been set but RBS are keeping this close to their chest. Interestingly, and unlike other banks involved in shipping, RBS does not favour syndicated loans, either as lead or as participant. In the Piraeus portfolio there is not a single syndicated loan. Not that that restricts capacity though because RBS is able and willing to accommodate over $100 million to the right client and for the right transaction.

Typical Client : Shipping Policy

RBS has always had a preference for modern vessels and bigger owners in terms of number of vessels. In age terms the cut off for RBS

You can advertise here

was and is 15 years at loan draw-down. Vessels older than this, except for exceptional cases for long trusted clients, are categorised at scrap value. For the Greek market in particular this is quite a drastic evaluation when one considers that a panamax bulk carrier built 1986 is even in today's softening market worth over 4x scrap value. And for tankers the ratio is currently even more than this. But it has worked well for RBS over the years for a number of reasons. Clearly by having strict age restrictions you can by and large weed out the weaker owners who are unable to bridge the financial cost of moving from post 20 year to pre 15 year tonnage. Additionally in the event of a problem the bank has many more options available to it with a younger vessel than with an older vessel. This is especially the case if the problem occurs part way through a weak cycle.

Many RBS clients, including some of the names listed in the first paragraph, took advantage of the historically low newbuilding prices seen for first bulk carriers and subsequently tankers in 1998 through 2000. These owners generally had sizeable fleets and on the whole had substantial cash reserves. RBS was not there to compete on percentage financing but was willing to be competitive with pricing and other terms and many of the owners ordering tonnage at that time financed with the bank. This caused a massive increase in the portfolio in terms of drawn and committed loans from 1998 to 2000.

Typical loan terms include 70% to 75% financing for newbuilds and a touch less for modern vessels up to 10 years old. During the period 1998 to 2000 this percentage financing for low priced newbuilds and to strong credits provided attractive finance opportunities for the bank. The typical RBS client has equity and generally prefers preferential pricing rather than higher gearing. This certainly differentiates from clients of some other banks in the Greek market who push for high gearing with the historically low building prices being the justification. Also RBS have no requirement for term employment. The motto is that if the bank is content with the client and the transaction it is up to the shipowner to run his business in the way he sees fit. Again this is a far cry from some predominantly US based finance providers who require long-term cash flow comfort in order to lend these days.

Clearly RBS in Greece has the benefit, perhaps the luxury, of a large portfolio of well tested clients and also a large database of information from the branch presence over the past 27 years. This permits the relationship factor to be much stronger than for newcomers to the lending market. The current shipping strategy of RBS in Greece has been tried and tested with great success. It is unlikely to be changed and more of the same is projected in the future.

Ancillary Business

Over the years it has been said that RBS can compete on margin because it makes just as much again from the ancillary business provided by both borrowing and non-borrowing clients. Indeed for many a year it was said that RBS had cash on deposit from it's clients as much as it was lending. The bank is unwilling to comment on this but with the recent addition of Coutts & Co after the takeover of National Westminster Bank it can reasonably be assumed that the level of deposit or cash investment by clients of RBS within the umbrella of the RBS group is very substantial.

The bank has a strong treasury capacity and has over the years tried with varying degrees of success to develop hedging products for shipowners which cater for the cyclicality of the business. Despite these more complex products it remains

Want to become a shipping client of RBS???

Have a pedigree background in shipping for 20 years
Have a fleet of over 5 vessels with average age well below 15 years
Having ordered a newbuilding or two would help
Be able to accept gearing of not more than 70%
Have a tidy cash availability and be prepared to show it to the Bank

4449 Water Transportation of Freight. Not Elsewhere Classified

Establishments primarily engaged in the transportation of freight on all inland waterways, including the intracoastal waterways on the Atlantic and Gulf Coasts. Transportation of freight on the Great Lakes and the St. Lawrence Seaway is classified in Industry 4432. Establishments primarily engaged in providing lighterage and towing or tugboat services are classified in Industry Group 449.

- Canal barge operations
- Canal freight transportation
- Intracoastal freight transportation
- Lake freight transportation, except on the Great Lakes
- Log rafting and towing
- River freight transportation, except on the St. Lawrence Seaway
- Transportation of freight on bays and sounds of the oceans

TRANSPORTATION—WATER TRANSPORTATION OF FREIGHT, NEC SIC# 4449 (NAICS 483211)

Current Data Sorted By Assets

0-500M	500M-2MM	2-10MM	10-50MM	50-100MM	100-250MM	
	1	3	4	2	5	Type of Statement Unqualified
	1	1	2			Reviewed
1	2	6	3			Compiled
	3	1				Tax Returns
1	3	6	6	2	2	Other
	7 (4/1-9/30/01)		47 (10/1/01-3/31/02)			
2	9	17	15	4	7	NUMBER OF STATEMENTS
%	%	%	%	%	%	ASSETS
		16.8	9.7			Cash & Equivalents
		20.1	12.2			Trade Receivables (net)
		.2	1.3			Inventory
		2.3	2.4			All Other Current
		39.4	25.5			Total Current
		50.2	67.9			Fixed Assets (net)
		2.8	.6			Intangibles (net)
		7.6	5.9			All Other Non-Current
		100.0	100.0			Total
						LIABILITIES
		3.3	1.4			Notes Payable-Short Term
		5.0	4.9			Cur. Mat.-L/T/D
		12.2	4.1			Trade Payables
		1.6	.1			Income Taxes Payable
		4.4	6.3			All Other Current
		26.5	16.9			Total Current
		19.4	46.0			Long Term Debt
		1.1	1.5			Deferred Taxes
		9.5	3.1			All Other Non-Current
		43.5	32.6			Net Worth
		100.0	100.0			Total Liabilities & Net Worth
						INCOME DATA
		100.0	100.0			Net Sales
						Gross Profit
		85.5	82.4			Operating Expenses
		14.5	17.6			Operating Profit
		1.7	5.8			All Other Expenses (net)
		12.7	11.8			Profit Before Taxes
						RATIOS
		3.0	2.3			
		1.2	1.2			Current
		.7	.8			
		3.0	1.8			
		1.0	1.2			Quick
		.6	.5			
		31 11.9	24 14.9			
		52 7.1	41 8.9			Sales/Receivables
		96 3.8	58 6.5			
						Cost of Sales/Inventory
						Cost of Sales/Payables
		6.0	4.7			
		21.5	40.1			Sales/Working Capital
		-15.0	-24.7			
		35.9	3.5			
		(15) 4.5	(13) 2.3			EBIT/Interest
		1.0	1.8			
						Net Profit + Depr., Dep., Amort./Cur. Mat. L/T/D
		.4	1.3			
		1.4	2.5			Fixed/Worth
		3.2	7.4			
		.5	1.0			
		1.9	1.8			Debt/Worth
		5.1	6.8			
		65.2	44.6			
		23.8	(14) 22.5			% Profit Before Taxes/Tangible Net Worth
		3.9	15.5			
		18.7	12.8			
		11.5	6.5			% Profit Before Taxes/Total Assets
		1.3	3.5			
		7.7	3.8			
		1.3	1.1			Sales/Net Fixed Assets
		.7	.8			
		1.6	1.7			
		.7	.8			Sales/Total Assets
		.5	.6			
		1.7	5.2			
		(14) 7.9	(14) 6.6			% Depr., Dep., Amort./Sales
		30.1	10.1			
						% Officers', Directors', Owners' Comp/Sales
1113M	26904M	137448M	386564M	238493M	1162362M	Net Sales ($)
386M	9964M	97217M	396403M	268991M	1119702M	Total Assets ($)

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M = $ thousand MM = $ million

See Pages 11 through 20 for Explanation of Ratios

<PAGE>

CROWLEY MARITIME CORPORATION AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
AS OF SEPTEMBER 30, 2003 AND DECEMBER 31, 2002
(IN THOUSANDS, EXCEPT SHARE AND PER SHARE AMOUNTS)

<Table>
<Caption>

	SEPTEMBER 30, 2003	DECEMBER 31, 2002
<S>	<C>	<C>
ASSETS		
Cash and cash equivalents	$ 31,707	$ 43,575
Receivables, net	160,564	147,346
Prepaid expenses and other assets	48,213	41,805
TOTAL CURRENT ASSETS	240,484	232,726
Receivable from related party	17,012	16,936
Goodwill	44,786	45,097
Intangibles, net	15,586	14,211
Other assets	35,861	21,429
Property and equipment, net	539,581	552,895
TOTAL ASSETS	$893,310	$883,294
LIABILITIES AND STOCKHOLDERS' EQUITY		
Accounts payable and accrued liabilities	$ 90,419	$102,971
Accrued payroll and related expenses	48,082	38,850
Insurance claims payable	15,332	11,370
Unearned revenue	5,644	9,529
Current portion of long-term debt	28,763	29,357
TOTAL CURRENT LIABILITIES	188,240	192,077
Deferred income taxes	85,578	76,770
Deferred gain	3,348	5,356
Other liabilities	14,021	14,176
Long-term liabilities of discontinued operations	5,875	6,398
Minority interests in consolidated subsidiaries	5,198	4,568
Long-term debt, net of current portion	298,355	296,019
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Preferred class A convertible stock, $100 par value, 315,000 shares issued, authorized and outstanding	31,500	31,500
Common voting stock, $.01 par value, 4,485,000 shares authorized; 89,426 and 89,710 shares issued and outstanding at September 30, 2003 and December 31, 2002, respectively	1	1
Class N common non-voting stock, $.01 par value, 54,500 shares authorized; 46,138 shares outstanding	--	--
Additional paid-in capital	67,354	67,540
Retained earnings	200,239	195,994
Accumulated other comprehensive loss, net of tax benefit of $3,606 and $3,997, respectively	(6,399)	(7,105)
TOTAL STOCKHOLDERS' EQUITY	292,695	287,930
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$893,310	$883,294

Transaction Watch - July/August 2003

High Yield Shipping Bonds (Source: Jefferies & Co)

COMPANY	DESCRIPTION	ISSUE DATE	ISSUE PRICE	COUPON	MATURITY	INDICATED PRICE 7/1/03	INDICATED YIELD TO MATURITY	INDICATED CURRENT YIELD
American Commercial Lines	Sr Notes	6/3/98	100.000	11.250%	1/1/08	11.00	NM	NM
American Commercial Lines	Sr Sub Nts	NA	NA	12.000%	7/1/08	1.00	NM	NM
Cenargo International	1st Mtge Nts	6/12/98	98.450	9.750%	6/15/08	40.00	NM	24.38%
CP Ships	Sr Notes	NA	97.720	10.375%	7/15/12	109.00	8.89%	9.52%
General Maritime	Sr Notes	3/20/03	98.463	10.000%	3/15/13	109.50	8.53%	9.13%
Golden State Petroleum	1st Pfd Mtge Nts	7/23/97	100.000	8.040%	2/1/19	94.00	8.75%	8.55%
Great Lakes Dredge	Sr Sub Notes	8/14/98	100.000	11.250%	8/15/08	105.75	9.77%	10.64%
Gulfmark Offshore	Sr Notes	6/2/98	99.699	8.750%	6/1/08	101.50	8.36%	8.62%
Hornbeck Offshore Services	Sr Notes	7/19/01	98.193	10.625%	8/1/08	106.50	8.98%	9.98%
International Shipholding	Sr Notes	1/14/98	99.490	7.750%	10/15/07	99.00	8.03%	7.83%
MC Shipping	Sr Notes	3/5/98	100.000	11.250%	3/1/08	50.00	33.25%	22.50%
Navigator Gas	1st Mtge Nts	7/31/97	100.000	10.500%	6/30/07	32.00	NM	NM
Navigator Gas	2nd Mtge Nts	7/31/97	100.000	12.000%	6/30/07	1.00	NM	NM
Ogiebay Norton	Sr Sub Notes	1/26/99	100.000	10.000%	2/1/09	25.00	NM	NM
Overseas Shipholding	Sr Notes	12/2/93	99.760	8.000%	12/1/03	101.00	4.78%	7.92%
Overseas Shipholding	Sr Notes	3/4/2003	99.16	8.250%	3/15/13	103.75	7.69%	7.95%
Overseas Shipholding	Sr Debs	12/2/93	99.680	8.750%	12/1/13	107.00	7.75%	8.18%
Sea Bulk	Sr Notes	7/29/03	100.000	9.500%	8/15/13	98.50	9.74%	9.64%
Sea Containers	Sr Notes	2/13/98	100.000	7.875%	2/15/08	81.00	13.63%	9.72%
Sea Containers	Sr Sub Debs	11/13/92	97.000	12.500%	12/1/04	100.50	12.04%	12.44%
Sea Containers	Sr Notes	10/13/99	98.805	10.750%	10/15/06	95.50	12.49%	11.26%
Stena AB	Sr Notes	9/25/97	100.000	8.750%	6/15/07	103.00	7.83%	8.50%
Stena AB	Sr Notes	11/22/02	100.000	9.625%	12/1/12	109.75	8.11%	8.77%
Teekay Shipping	1st Mtge Nts	35083	100.000	8.320%	2/1/08	108.00	6.25%	7.70%
Teekay Shipping	Sr Notes	June 2001	100.000	8.875%	7/15/11	110.00	7.20%	8.07%
Trico Marine Services	Sr Notes	5/23/02	99.196	8.875%	5/15/12	72.00	14.63%	12.33%
Ultrapetrol	1st Mtge Nts	3/24/98	100.000	10.500%	4/1/08	65.00	23.15%	16.15%

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FOURTH REQUEST FOR PODS

Transaction Watch - July/August 2003

Shipping Bond Status

ISSUER	COUPON	OUTSTANDING	DESCRIPTION	ISSUE DATE	SECTOR	DEFAULTED (?)
Alpha Shipping	9.25%	$175	Senior Notes '08	2/11/98	Multiple Sectors (5)	Yes
Amer Reefer Co. Ltd. (AMEREE)	10.25%	$100	First Mortgage Notes '08	2/27/98	Reefers	Yes
American Commercial Lines (VECTUR)	10.25%	$300	Senior Notes '08	6/23/98	Inland Barging	Yes
American President Lines (APS)	8.00%	$150	Senior Notes '24	1/5/94	Container Shipping	No
American President Lines (APS)	7.125%	$150	Senior Notes '03	11/18/93	Container Shipping	No
Cenargo Intl PLC (CENINT)	9.75%	$175	First Mortgage Notes '08	6/12/98	Ferry	Yes
CMA-CGM	10.00%	$100	Senior Notes '10	4/1/03	Container	No
CP Ships	10.38%	$150	Senior Notes '12	7/1/02	Container	No
Eletson Holdings (ELETSN)	9.25%	$140	First Mortgage Notes '03	11/19/93	Tanker	No
Enterprises Shipholding Inc. (ENTSHI)	8.88%	$175	Senior Notes '08	4/22/98	Reefers	Yes
Equimar Shipholdings Ltd. (EQUIMA)	9.88%	$124	First Mortgage Notes '07	6/20/97	Tanker	Yes
Ermis Maritime (ERMIS)	12.50%	$150	First Mortgage Notes '06	3/9/98	Tanker	Yes
Gearbulk Holding (GEAR)	11.25%	$175	Senior Notes '04	11/23/94	Specialized Bulk	No
General Maritime	10.00%	$250	Senior Notes '13	3/1/03	Tanker	No
Global Ocean Carriers (GLO)	10.25%	$126	Senior Notes '07	7/18/97	Dry Bulk, Containerships	Yes
Golden Ocean Group (GOLDOG)	10.00%	$291	Company Guarantee '01	8/26/97	Tankers	Yes
Gulfmark Offshore (GMRK)	8.75%	$130	Senior Notes '08	6/2/98	Offshore Support	No
Hide Marine (HMAR)	8.38%	$300	Senior Notes '08	2/13/98	Offshore Support	Yes
International Shipholding (ISH)	7.75%	$110	Senior Notes '07	3/13/98	Liner, Specialized	No
Kirby Corp.	120bps	$250	Senior Notes '13	3/1/03	Barges	No
MC Shipping (MCX)	11.25%	$85	Senior Notes '08	3/5/98	Gas Carriers	No (buy-back)
Millenium Seacarriers (MILSEA)	12.00%	$100	First Mortgage Notes '05	7/20/98	Drybulk	Yes
Navigator Gas Transport (NAVGAS)	10.50%	$217	First Mortgage Notes '07	7/31/97	Gas Carriers	Yes
Navigator Gas Transport (NAVGAS)	12.00%	$87	Second Priority Notes '07	7/31/97	Gas Carriers	Yes
Overseas Shipholding (OSG)	8.25%	$150	Senior Notes '03	3/1/03	Tankers	No
Pacific & Atlantic (PACATL)	11.50%	$128	First Mortgage Notes '08	5/21/98	Dry Bulk, Multi, Container	Yes
Pan Oceanic	12.00%	$100	First Mortgaine Notes '07	1997	Dry Bulk	Yes
Pegasus Shipping (PEGSHP)	11.88%	$150	First Mortgage Notes '04	11/19/97	Tankers	Yes
Premier Cruises (CRUISE)	11.00%	$160	Senior Notes '08	3/6/98	Cruise	Yes
Seabulk (SBLK)	9.50%	$150	Senior Notes '13	8/5/03	Offshore/Tanker	No
Sea Containers (SCR)	7.88%	$150	Senior Notes '08	2/13/98	Container Leasing	No
Sea Containers (SCR)	12.50%	$100	Senior Sub Notes '04	11/13/92	Container Leasing	No
Stena AB (STENA)	8.75%	$175	Senior Notes '07	9/25/97	Tankers, Rigs, Other	No
Stena AB (STENA)	10.50%	$175	Senior Notes '05	12/13/95	Tankers, Rigs, Other	No
Stena Line AB (STENA)	10.63%	$300	Senior Notes '08	5/28/98	Tankers, Rigs, Other	No
TBS Shipping (TBSSHP)	10.00%	$110	First Mortgage Notes '05	4/29/98	Breakbulk	Yes
Teekay Shipping Corp. (TK)	8.32%	$225	First Mortgage Notes '08	1/11/96	Tankers	No
Teekay Shipping Corp. (TK)	8.88%	$200	Senior Notes '11	6/1/01	Tankers	No
Transportacion Maritima Mexicana (TMM)	10.00%	$200	Senior Notes '06	11/21/96	Diversified/Container	No
Transportacion Maritima Mexicana (TMM)	8.50%	$142	Senior Notes '00	10/6/93	Diversified/Container	No
Trico Marine (TMAR)	8.50%	$280	Senior Notes '05	7/16/97	Offshore	No
Ultrapetrol (Bahamas) (ULTRAP)	10.50%	$135	First Mortgage Notes '08	1998	Tankers	No

70% leverage available for a new foreign-built vessel (see Royal Bank of Scotland article)

The Other 30%

By Matt McCleery

First mortgage financing will always account for 70% of the capital formation in the shipping industry. And why shouldn't it? It's dirt cheap, it's flexible and it's abundant. But in our view, financing the other 30% is where the business gets fun. Optimizing the other 30% allows for more leverage, higher returns on equity, lower operating break-even and frees up buying power to do more deals. The other 30% can transform a shipbroker into a shipowner, a spectator into a principal and, in the eyes of a banker, a toad into a prince. Put another way, the other 30% is what has attracted many of us to this industry.

In this September issue of Marine Money, we celebrate the unofficial beginning of the new business year by looking at the various ways the other 30% can be financed. Urs Dur begins the issue with a look at Seaspan which achieved relatively unique junior mezzanine for which Fortis created an investment grade commercial paper product. Nicolai Heidenreich analyzes the American Bulker KS transaction completed by Lasco a few months ago, and explores the depth and breadth of liquidity for the other 30% in the Norwegian KS market. Kevin Oates provides insight into the Royal Bank of Scotland, one of the most reliable mortgage lenders in the business. Finally, Geoff Ullmark presents a case why we think Japan is the land of opportunity for ship financiers and shipowners.

While it is tempting to assume that the other 30% is just another way of saying "renting equity," we beg to differ: the other 30% is anything junior to senior debt and its sources are limited only by the imaginations of the dealmakers. In the olden days, shipping entrepreneurs sold cargo space before they had ships and used the cash as the other 30%. Aristotle Onassis obviated the need for the other 30% by arranging long-term, full payout charters with credit worthy counter parties – a practice now known as project finance. Clever, but now disreputable, financier Bjorn Aaserod and his Cambridge Partners built a machine that recycled address commissions and other fees into the other 30%. Peter Georgiopoulos of General Maritime charmed US hedge funds like Wexford to contribute the other 30% he needed. Alf Aanonsen of Sea Oil secured his other 30% from BT Shipping when he bought their panamax tankers with seller's credit – a variation on a reliable source of the other 30%, vendor financing. Most of the Hong Kong Chinese owners built their other 30% by participating in long-term Shikemusen deals and ending up with residual values in excess of balloon repayments. And, sadly, as we saw in the high yield market, some owners were able to fabricate their other 30% by getting shipbrokers to give appraisals that were, you guessed it, 30% higher than they should rightfully have been. Today, the half dozen banks and financial advisors included in Figure Two have increased their product offerings to include the other 30%. While most banks have always had subordinated funds available for good clients, they are now becoming more open about it. The most recent example of this is DVB Nedship's hiring of Bote de Vries away from NIB Capital to run its mezzanine efforts. We think that in five years time every one of the major ship mortgage players will have in-house mezzanine capability,

Shipping Investment Funds

Fund Name	Bank Affiliation	Fund Size	Ideal Rate of Return	Ideal Deal Size	Status
AMA Shipping Fund I	NIB/GATX	$150m	25%	$12	Open!
AMA Shipping Fund II (distress oriented)	NIB/GATX				Fundraising
DVB Nedship	DVB Nedship				Open!
Northern Navigation	None				Open!
Mes Capital	Fortis	$80m+	15-20%	$17	Open!
OPIC	None	$700m	25%	$15-$30m	Fundraising

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FOURTH REQUEST FOR PODS

Sources of Capital for Shipping

Type Senior and Secured	Arrangement Fees	Cost of Funds	Upside	Downside	Finance Provider Profile	Market	Recent Deal
Bilaterals	30-100bps	Depends	Cheap	Conservative	Mortgage Banks	Open	Countless
Syndicated Loans	50-100bps	LIBOR	Open	Less Flexible	Mortgage Banks & Money Centers	Open	OMI
High Yield	3-4%	10-20%	Non-amortizing, unsecured, aggressive	Expensive	Funds	Open	Hornbeck Leevac
Investment Grade Bonds	2.50%	Treasuries +	Cheap?	Investment grade guarantor	Insurance Co.'s, Funds	Open	Teekay
Private Placements	25-75bps	5-7%	Liquid	Need NAIC Rating	Insurance Co.'s, etc	Open	Stolt Nielsen ('98)
Government Guaranteed	Depends	Depends	Cheap	Headache	Usually govt. guaranteed bonds	Anemic	American Classic Voyages
Private Equity	7%	20-30% all-in return	Increased leverage, risk sharing	Hard to get, demanding investors	Hedge funds	Open	Pan Ocean
Commercial Paper	?	6%	Less expensive, unsecured	Need Investment Grade	Insurance cos.	Open	Seaspan
Mezzanine	5%	12-25%	Higher leverage	Expensive, short-term, hard to find	Banks/Hedge Funds	Open	Skaugen
Public Equity	7%	Falling cost	No debt service	Expensive/Dilutive	Individuals/funds	Closed	General Maritime
German KGs	Back end loaded	12.15%	100% financing/no residual value exposure	More expensive than bank debt	German investors	Open	Far East Silo
Norwegian KGs	1%	Depends	Off balance sheet deal	Lose control of residual value (unless purchase option)	Norwegian investors	Open	American Bulk KS
SMI	LIBOR + 150bps all-in		Deal lubricant	Need good charter	Chubb	Anemic	
Leasing	1%	Attractive	High leverage, no residual value risk	Need long charter with good credit	Leasing companies	Open	NYK tax carrier

or at the very least, formal relationships with providers of unsecured capital. One reason for this is that advance rates are dropping and mezzanine funds will be there to make up the difference. Another reason is that even the largest corporate credits want the highest possible leverage to maximize their margins. Mezzanine is also a profit center for banks on deals for which they already have credit comfort. Perhaps the most significant aspect of this trend is that commercial bankers are starting to think in terms of upside, rather than just downside.

In reality, offering the other 30% (and charging a 20% return for it) and finding the right deals to invest in are different things altogether. That shipping is considered among the worst of the asset classes is proven by Marine Money's database, which indicates that the

32. Please provide all source documents (reports, analyses, studies, etc.) relied upon in the determination of the average cost of capital included in Tampa Electric's response to Staff's Second Set of Interrogatories, No. 36.

A. See the responses to Request for Production of Documents, No. 28 and 31.

33. Please provide all source documents (reports, analyses, studies, etc.) relied upon in the determination of the cost of equity, cost of debt, capital structure, and overall cost of capital indicated in Tampa Electric's response to Staff's Second Set of Interrogatories, No. 38.

A. See the response to Request for Production of Documents, No. 31.

EXHIBIT NO. 74-Conf.

DOCKET NO: 031033-EI

WITNESS: BRENT DIBNER

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: DOCUMENT NO. 05241-04

PROFERRED BY: STAFF

11-26-05 (entire DN)

DECLASSIFIED

CONFIDENTIAL

DOCUMENT NUMBER-DATE

06949 JUN 16

FPSC-COMMISSION CLERK

declas 11-26-05

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 031033-EI EXHIBIT NO. 74

COMPANY/ WITNESS: Staff

DATE: 5/(27-28)/04 + 6/10/04

ORIGINAL

AUSLEY & MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

227 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

May 5, 2004

HAND DELIVERED

RECEIVED-FPSC
04 MAY -5 PM 2:48
COMMISSION CLERK

Ms. Blanca S. Bayo, Director
Division of Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Review of Tampa Electric Company's waterborne transportation contract with TECO Transport and associated benchmark; FPSC Docket No. 031033-EI

TRANSMITTAL OF CONFIDENTIAL INFORMATION

Dear Ms. Bayo:

Pursuant to a Request for Specified Confidential Treatment Tampa Electric is simultaneously filing with your office, we enclose a single confidential version of 21 pages of output from Mr. Brent Dibner's computer models requested by Staff. For tracking purposes, we have paginated these pages as "1 of 21" through "21 of 21" beneath today's date, May 5, 2004, at the bottom of each page. The confidential information contained in this filing is printed on yellow stock paper and stamped "CONFIDENTIAL." We would appreciate your maintaining confidential treatment of the enclosed materials.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

11-26-05 (entire DN) DECLASSIFIED

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JDB/pp
Enclosures

cc: Wm. Cochran Keating IV
All Parties of Record

RECEIVED & FILED

FPSC-BUREAU OF RECORDS

DOCUMENT NUMBER-DATE
05241 MAY-5 04
FPSC-COMMISSION CLERK

ORIGINAL

AUSLEY & MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

227 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

May 5, 2004

HAND DELIVERED

RECEIVED-FPSC
04 MAY -5 PM 2:48
COMMISSION CLERK

Ms. Blanca S. Bayo, Director
Division of Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

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Sincerely,

James D. Beasley

JDB/pp
Enclosures

CONFIDENTIAL

cc: Wm. Cochran Keating IV
All Parties of Record

RECEIVED & FILED

FPSC-BUREAU OF RECORDS

DOCUMENT NUMBER-DATE
05241 MAY-5 04
FPSC-COMMISSION CLERK

INPUT

	Current Value	Revised Value
Cost per crew day		
ITB	350	350
Tug Barge	325	325

Operating Parameters		
Load rate (tons per hour)	1,250	1,250
Shifting Time at Big Bend (days)	0.0	-
Channel Maneuvering/Docking/Undocki	0.5	0.5
Delay as % of Voyage Time at Sea	15%	15%

Cost of Capital Calculation	Current Value				Revised Value			
	Pct of Capital	Return	Tax	Capital Cost (Wtd)	Pct of Capital	Return	Tax	Capital Cost (Wtd)
Equity	50%	18%	0%	9%	50%	18%	0%	9%
Debt	50%	6%	35%	3%	50%	6%	35%	3%
	100%			12%	100%			12%

Daily Operating Costs Current Values	Peggy Palmer	Gayle Eustace	Doris Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	84	76	66	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

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	Current Value	Revised Value					
Revised Values							
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	66	88	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

OUTPUT

← To obtain the correct results, click the 'Order Barges' button to the left each time changes are made to input values!

Rate Build-Up and Composition

Barge	Est Rate	Capacity/Yr (000 tons)	Tons/Yr (000)	Cum Tons (000)	Cum Cost ($000)	Ave Rate	Rate to Ave
Peggy Palmer	7.47	1,111	1,111	1,111	8,293	7.47	0.54
Gayle Eustace	7.66	1,447	1,447	2,558	19,376	7.57	0.35
Doris Guenther	8.05	877	877	3,435	26,441	7.70	(0.04)
Mary Turner	8.09	1,024	1,024	4,459	34,727	7.79	(0.08)
D Ludwig	8.73	756	756	5,215	41,321	7.92	(0.72)
Diana T	9.58	560	285	5,500	44,053	8.01	(1.58)
Barbara Vaught	11.35	585	-	5,500	44,053	8.01	(3.34)

Composition Per Ton

	Fuel	Fixed	Variable	Total
Peggy Palmer	0.99	3.72	2.75	7.47
Gayle Eustace	0.67	4.25	2.74	7.66
Doris Guenther	0.86	3.85	3.34	8.05
Mary Turner	1.05	3.66	3.38	8.09
D Ludwig	1.14	4.14	3.44	8.73
Diana T	1.59	3.01	4.98	9.58
Barbara Vaught	1.20	5.75	4.39	11.35
Weighted Avg.	**0.95**	**3.89**	**3.17**	**8.01**
Component Share	**12%**	**49%**	**40%**	**100%**

Per Diem Rates

Bareboat Hire	TECO TC	Preference TC Rate	AverageTC Rate
7,551	15,846	25,000	20,423
21,875	32,694	25,000	28,847
6,820	14,819	21,000	17,909
9,346	18,733	22,000	20,367
3,471	10,603	22,000	16,301
5,517	13,133	12,000	12,566
6,771	13,797	20,000	16,898

Vessel Value

Tug Value	Barge Value	Total Value
4,308,698	10,738,845	15,047,543
11,504,321	27,416,679	38,921,000
6,739,656	8,860,069	15,599,725
7,074,302	12,868,890	19,943,192
3,901,914	876,960	4,778,874
3,952,545	5,222,250	9,174,795
2,565,108	756,000	3,321,108

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INPUT

	Current Value	Revised Value
Cost per crew day		
ITB	350	350
Tug Barge	325	325

Operating Parameters		
Load rate (tons per hour)	1,250	1,250
Shifting Time at Big Bend (days)	0.0	-
Channel Maneuvering/Docking/Undocki	0.5	0.5
Delay as % of Voyage Time at Sea	15%	15%

Cost of Capital Calculation	Current Value				Revised Value			
	Pct of Capital	Return	Tax	Capital Cost (Wtd)	Pct of Capital	Return	Tax	Capital Cost (Wtd)
Equity	50%	18%	0%	9%	30%	18%	0%	5%
Debt	50%	8%	35%	3%	70%	8%	35%	4%
	100%			12%	100%			9%

Daily Operating Costs

Current Values	Peggy Palmer	Gayle Eustace	Doris Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	66	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	368	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

INPUT

	Current Value	Revised Value					
Revised Values							
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	78	64	76	68	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

OUTPUT

← To obtain the correct results, click the 'Order Barges' button to the left each time changes are made to input values!

Rate Build-Up and Composition

Barge	Est Rate	Capacity/Yr (000 tons)	Tons/Yr (000)	Cum Tons (000)	Cum Cost ($000)	Ave Rate	Rate to Ave
Peggy Palmer	7.37	1,111	1,111	1,111	8,188	7.37	0.51
Gayle Eustace	7.48	1,447	1,447	2,558	19,011	7.43	0.40
Doris Guenther	7.91	877	877	3,435	25,953	7.55	(0.03)
Mary Turner	7.95	1,024	1,024	4,459	34,092	7.65	(0.07)
D Ludwig	8.68	756	756	5,215	40,650	7.79	(0.79)
Diana T	9.47	560	285	5,500	43,350	7.88	(1.59)
Barbara Vaught	11.32	585	-	5,500	43,350	7.88	(3.43)

Composition Per Ton

	Fuel	Fixed	Variable	Total
Peggy Palmer	0.99	3.63	2.75	7.37
Gayle Eustace	0.67	4.07	2.74	7.48
Doris Guenther	0.86	3.71	3.34	7.91
Mary Turner	1.05	3.51	3.38	7.95
D Ludwig	1.14	4.09	3.44	8.68
Diana T	1.59	2.90	4.98	9.47
Barbara Vaught	1.20	5.72	4.39	11.32
Weighted Avg.	**0.95**	**3.76**	**3.17**	**7.88**
Component Share	**12%**	**48%**	**40%**	**100%**

Per Diem Rates

Bareboat Hire	TECO TC	Preference TC Rate	AverageTC Rate
6,936	15,231	25,000	20,115
20,348	31,167	25,000	28,083
6,101	14,100	21,000	17,550
8,485	17,872	22,000	19,936
3,253	10,384	22,000	16,192
5,147	12,763	12,000	12,381
6,664	13,689	20,000	16,845

Vessel Value

Tug Value	Barge Value	Total Value
4,308,698	10,738,845	15,047,543
11,504,321	27,416,679	38,921,000
6,739,656	8,860,069	15,599,725
7,074,302	12,868,890	19,943,192
3,901,914	876,960	4,778,874
3,952,545	5,222,250	9,174,795
2,565,108	756,000	3,321,108

INPUT

	Current Value	Revised Value
Cost per crew day		
ITB	350	350
Tug Barge	325	325

Operating Parameters		
Load rate (tons per hour)	1,250	1,250
Shifting Time at Big Bend (days)	0.0	-
Channel Maneuvering/Docking/Undocki	0.5	0.5
Delay as % of Voyage Time at Sea	15%	15%

Cost of Capital Calculation	Current Value				Revised Value			
	Pct of Capital	Return	Tax	Capital Cost (Wtd)	Pct of Capital	Return	Tax	Capital Cost (Wtd)
Equity	50%	18%	0%	9%	38%	18%	0%	7%
Debt	50%	8%	35%	3%	62%	8%	35%	3%
	100%			12%	100%			10%

Daily Operating Costs **Current Values**	Peggy Palmer	Gayle Eustace	Doris Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	66	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

INPUT

	Current Value	Revised Value					
Revised Values							
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	75	64	76	86	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

OUTPUT

← To obtain the correct results, click the 'Order Barges' button to the left each time changes are made to input values!

Rate Build-Up and Composition

Barge	Est Rate	Capacity/Yr (000 tons)	Tons/Yr (000)	Cum Tons (000)	Cum Cost ($000)	Ave Rate	Rate to Ave
Peggy Palmer	7.41	1,111	1,111	1,111	8,230	7.41	0.52
Gayle Eustace	7.55	1,447	1,447	2,558	19,156	7.49	0.38
Doris Guenther	7.97	877	877	3,435	26,147	7.61	(0.03)
Mary Turner	8.01	1,024	1,024	4,459	34,344	7.70	(0.07)
D Ludwig	8.70	756	756	5,215	40,916	7.85	(0.76)
Diana T	9.52	560	285	5,500	43,629	7.93	(1.58)
Barbara Vaught	11.33	585	-	5,500	43,629	7.93	(3.40)

Composition Per Ton

	Fuel	Fixed	Variable	Total
Peggy Palmer	0.99	3.67	2.75	7.41
Gayle Eustace	0.67	4.14	2.74	7.55
Doris Guenther	0.86	3.77	3.34	7.97
Mary Turner	1.05	3.57	3.38	8.01
D Ludwig	1.14	4.11	3.44	8.70
Diana T	1.59	2.95	4.98	9.52
Barbara Vaught	1.20	5.74	4.39	11.33
Weighted Avg.	**0.95**	**3.81**	**3.17**	**7.93**
Component Share	**12%**	**48%**	**40%**	**100%**

Per Diem Rates

Bareboat Hire	TECO TC	Preference TC Rate	AverageTC Rate
7,181	15,475	25,000	20,237
20,955	31,774	25,000	28,387
6,385	14,384	21,000	17,692
8,826	18,214	22,000	20,107
3,339	10,471	22,000	16,235
5,294	12,910	12,000	12,455
6,707	13,732	20,000	16,866

Vessel Value

Tug Value	Barge Value	Total Value
4,308,698	10,738,845	15,047,543
11,504,321	27,416,679	38,921,000
6,739,656	8,860,069	15,599,725
7,074,302	12,868,890	19,943,192
3,901,914	876,960	4,778,874
3,952,545	5,222,250	9,174,795
2,565,108	756,000	3,321,108

INPUT

	Current Value	Revised Value
Cost per crew day		
ITB	350	350
Tug Barge	325	325

Operating Parameters		
Load rate (tons per hour)	1,250	1,250
Shifting Time at Big Bend (days)	0.0	-
Channel Maneuvering/Docking/Undocki	0.5	0.5
Delay as % of Voyage Time at Sea	15%	15%

Cost of Capital Calculation	Current Value				Revised Value			
	Pct of Capital	Return	Tax	Capital Cost (Wtd)	Pct of Capital	Return	Tax	Capital Cost (Wtd)
Equity	50%	18%	0%	9%	25%	10%	0%	2%
Debt	50%	6%	35%	3%	75%	8%	35%	4%
	100%			12%	100%			6%

Daily Operating Costs

Current Values	Peggy Palmer	Gayle Eustace	Doris Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught
Tug/Ship Stores, Supplies, Lube Oil	268	320	266	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	68	68	58
Tug Yard Accrual	538	737	617	418	538	556	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	588	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

INPUT

	Current Value	Revised Value					
Revised Values							
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	66	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

OUTPUT

← To obtain the correct results, click the 'Order Barges' button to the left each time changes are made to input values!

Rate Build-Up and Composition

Barge	Est Rate	Capacity/Yr (000 tons)	Tons/Yr (000)	Cum Tons (000)	Cum Cost ($000)	Ave Rate	Rate to Ave
Peggy Palmer	7.27	1,111	1,111	1,111	8,078	7.27	0.48
Gayle Eustace	7.29	1,447	1,447	2,558	18,626	7.28	0.46
Doris Guenther	7.77	877	877	3,435	25,442	7.41	(0.02)
Mary Turner	7.80	1,024	1,024	4,459	33,429	7.50	(0.05)
D Ludwig	8.63	756	756	5,215	39,948	7.66	(0.88)
Diana T	9.35	560	285	5,500	42,614	7.75	(1.61)
Barbara Vaught	11.28	585	-	5,500	42,614	7.75	(3.53)

Composition Per Ton

	Fuel	Fixed	Variable	Total
Peggy Palmer	0.99	3.53	2.75	7.27
Gayle Eustace	0.67	3.88	2.74	7.29
Doris Guenther	0.86	3.57	3.34	7.77
Mary Turner	1.05	3.36	3.38	7.80
D Ludwig	1.14	4.04	3.44	8.63
Diana T	1.59	2.78	4.98	9.35
Barbara Vaught	1.20	5.69	4.39	11.28
Weighted Avg.	**0.95**	**3.63**	**3.17**	**7.75**
Component Share	**12%**	**47%**	**41%**	**100%**

Per Diem Rates

Bareboat Hire	TECO TC	Preference TC Rate	AverageTC Rate
6,291	14,586	25,000	19,793
18,736	29,556	25,000	27,278
5,360	13,359	21,000	17,179
7,590	16,978	22,000	19,489
3,028	10,160	22,000	16,080
4,758	12,374	12,000	12,187
6,553	13,578	20,000	16,789

Vessel Value

Tug Value	Barge Value	Total Value
4,308,698	10,738,845	15,047,543
11,504,321	27,416,679	38,921,000
6,739,656	8,860,069	15,599,725
7,074,302	12,868,890	19,943,192
3,901,914	876,960	4,778,874
3,952,545	5,222,250	9,174,795
2,565,108	756,000	3,321,108

INPUT

	Current Value	Revised Value
Cost per crew day		
ITB	350	350
Tug Barge	325	325

Operating Parameters		
Load rate (tons per hour)	1,250	1,250
Shifting Time at Big Bend (days)	0.0	-
Channel Maneuvering/Docking/Undocki	0.5	0.5
Delay as % of Voyage Time at Sea	15%	15%

Cost of Capital Calculation	Current Value				Revised Value			
	Pct of Capital	Return	Tax	Capital Cost (Wtd)	Pct of Capital	Return	Tax	Capital Cost (Wtd)
Equity	50%	18%	0%	9%	50%	12%	0%	6%
Debt	50%	8%	35%	3%	50%	7%	35%	2%
	100%			12%	100%			8%

Daily Operating Costs Current Values	Peggy Palmer	Gayle Eustace	Doris Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	66	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	677
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	836	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

INPUT

	Current Value	Revised Value					
Revised Values							
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	66	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

OUTPUT

← To obtain the correct results, click the 'Order Barges' button to the left each time changes are made to input values!

Rate Build-Up and Composition

Barge	Est Rate	Capacity/Yr (000 tons)	Tons/Yr (000)	Cum Tons (000)	Cum Cost ($000)	Ave Rate	Rate to Ave
Peggy Palmer	7.34	1,111	1,111	1,111	8,149	7.34	0.50
Gayle Eustace	7.41	1,447	1,447	2,558	18,874	7.38	0.42
Doris Guenther	7.86	877	877	3,435	25,771	7.50	(0.03)
Mary Turner	7.90	1,024	1,024	4,459	33,856	7.59	(0.06)
D Ludwig	8.66	756	756	5,215	40,399	7.75	(0.82)
Diana T	9.43	560	285	5,500	43,087	7.83	(1.60)
Barbara Vaught	11.30	585	-	5,500	43,087	7.83	(3.47)

Composition Per Ton

	Fuel	Fixed	Variable	Total
Peggy Palmer	0.99	3.59	2.75	7.34
Gayle Eustace	0.67	4.00	2.74	7.41
Doris Guenther	0.86	3.66	3.34	7.86
Mary Turner	1.05	3.46	3.38	7.90
D Ludwig	1.14	4.07	3.44	8.66
Diana T	1.59	2.86	4.98	9.43
Barbara Vaught	1.20	5.71	4.39	11.30
Weighted Avg.	**0.95**	**3.71**	**3.17**	**7.83**
Component Share	**12%**	**47%**	**40%**	**100%**

Per Diem Rates

Bareboat Hire	TECO TC	Preference TC Rate	AverageTC Rate
6,707	15,001	25,000	20,000
19,775	30,595	25,000	27,797
5,835	13,834	21,000	17,417
8,165	17,553	22,000	19,776
3,173	10,304	22,000	16,152
5,008	12,625	12,000	12,312
6,624	13,650	20,000	16,825

Vessel Value

Tug Value	Barge Value	Total Value
4,308,698	10,738,845	15,047,543
11,504,321	27,416,679	38,921,000
6,739,656	8,860,069	15,599,725
7,074,302	12,868,890	19,943,192
3,901,914	876,960	4,778,874
3,952,545	5,222,250	9,174,795
2,565,108	756,000	3,321,108

INPUT

	Current Value	Revised Value
Cost per crew day		
ITB	350	350
Tug Barge	325	325

Operating Parameters		
Load rate (tons per hour)	1,250	1,250
Shifting Time at Big Bend (days)	0.0	-
Channel Maneuvering/Docking/Undocki	0.5	0.5
Delay as % of Voyage Time at Sea	15%	15%

Cost of Capital Calculation	Current Value				Revised Value			
	Pct of Capital	Return	Tax	Capital Cost (Wtd)	Pct of Capital	Return	Tax	Capital Cost (Wtd)
Equity	50%	18%	0%	9%	25%	10%	0%	2%
Debt	50%	6%	35%	3%	75%	10%	35%	5%
	100%			12%	100%			7%

Daily Operating Costs

Current Values	Peggy Palmer	Gayle Eustace	Doris Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	68	68	58
Tug Yard Accrual	538	737	817	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
Barge Op Stores and Supplies	224	218	151	254	137	163	114
Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

INPUT

	Current Value	Revised Value					
Revised Values							
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	66	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	165	228	171	162	133
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Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

OUTPUT

← To obtain the correct results, click the 'Order Barges' button to the left each time changes are made to input values!

Rate Build-Up and Composition

Barge	Est Rate	Capacity/Yr (000 tons)	Tons/Yr (000)	Cum Tons (000)	Cum Cost ($000)	Ave Rate	Rate to Ave
Peggy Palmer	7.31	1,111	1,111	1,111	8,117	7.31	0.49
Gayle Eustace	7.35	1,447	1,447	2,558	18,761	7.33	0.44
Doris Guenther	7.82	877	877	3,435	25,621	7.46	(0.02)
Mary Turner	7.85	1,024	1,024	4,459	33,661	7.55	(0.06)
D Ludwig	8.64	756	756	5,215	40,193	7.71	(0.85)
Diana T	9.40	560	285	5,500	42,871	7.79	(1.60)
Barbara Vaught	11.29	585	-	5,500	42,871	7.79	(3.50)

Composition Per Ton

	Fuel	Fixed	Variable	Total
Peggy Palmer	0.99	3.56	2.75	7.31
Gayle Eustace	0.67	3.94	2.74	7.35
Doris Guenther	0.86	3.62	3.34	7.82
Mary Turner	1.05	3.42	3.38	7.85
D Ludwig	1.14	4.06	3.44	8.64
Diana T	1.59	2.82	4.98	9.40
Barbara Vaught	1.20	5.70	4.39	11.29
Weighted Avg.	**0.95**	**3.67**	**3.17**	**7.79**
Component Share	**12%**	**47%**	**41%**	**100%**

Per Diem Rates

Bareboat Hire	TECO TC	Preference TC Rate	AveregeTC Rate
6,517	14,812	25,000	19,906
19,302	30,122	25,000	27,561
5,618	13,617	21,000	17,308
7,903	17,290	22,000	19,645
3,107	10,238	22,000	16,119
4,894	12,511	12,000	12,255
6,592	13,617	20,000	16,808

Vessel Value

Tug Value	Barge Value	Total Value
4,308,698	10,738,845	15,047,543
11,504,321	27,416,679	38,921,000
6,739,656	8,860,069	15,599,725
7,074,302	12,868,890	19,943,192
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3,952,545	5,222,250	9,174,795
2,565,108	756,000	3,321,108

INPUT

	Current Value	Revised Value
Cost per crew day		
ITB	350	350
Tug Barge	325	325

Operating Parameters		
Load rate (tons per hour)	1,250	1,250
Shifting Time at Big Bend (days)	0.0	-
Channel Maneuvering/Docking/Undocki	0.5	0.5
Delay as % of Voyage Time at Sea	15%	15%

Cost of Capital Calculation	Current Value				Revised Value			
	Pct of Capital	Return	Tax	Capital Cost (Wtd)	Pct of Capital	Return	Tax	Capital Cost (Wtd)
Equity	50%	18%	0%	9%	0%	10%	0%	0%
Debt	50%	8%	35%	3%	100%	12%	35%	8%
	100%			12%	100%			8%

Daily Operating Costs

Current Values	Peggy Palmer	Gayle Eustace	Doris Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	66	68	58
Tug Yard Accrual	538	737	617	418	538	558	737
Tug Voyage Repairs	222	228	185	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
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Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

INPUT

	Current Value	Revised Value					
Revised Values							
Tug/Ship Stores, Supplies, Lube Oil	288	320	288	320	256	256	256
Tug/Ship Machinery Overhaul	75	76	64	76	66	68	58
Tug Yard Accrual	538	737	617	418	538	556	737
Tug Voyage Repairs	222	228	165	228	171	182	133
Tug Insurance	472	744	568	589	422	423	384
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Barge/Ship Yard Accrual - Hull	972	1,117	537	1,053	970	902	877
Barge Self-Unloading M&R Accrual	-	303	-	403	-	303	-
Barge Insurance	636	1,645	659	843	202	388	140
Barge/Ship Voyage Repairs	444	432	299	504	271	324	226
Management Cost	1,500	1,500	1,500	1,450	1,500	1,450	1,500

OUTPUT

← **To obtain the correct results, click the 'Order Barges' button to the left each time changes are made to input values!**

Rate Build-Up and Composition

Barge	Est Rate	r (000 tons)	Tons/Yr (000)	Cum Tons (000)	Cum Cost ($000)	Ave Rate	Rate to Ave
Peggy Palmer	7.33	1,111	1,111	1,111	8,138	7.33	0.49
Gayle Eustace	7.39	1,447	1,447	2,558	18,837	7.36	0.43
Doris Guenther	7.85	877	877	3,435	25,721	7.49	(0.03)
Mary Turner	7.88	1,024	1,024	4,459	33,791	7.58	(0.06)
D Ludwig	8.65	756	756	5,215	40,331	7.73	(0.83)
Diana T	9.42	560	285	5,500	43,015	7.82	(1.60)
Barbara Vaught	11.30	585	-	5,500	43,015	7.82	(3.48)

Composition Per Ton

	Fuel	Fixed	Variable	Total
Peggy Palmer	0.99	3.58	2.75	7.33
Gayle Eustace	0.67	3.98	2.74	7.39
Doris Guenther	0.86	3.65	3.34	7.85
Mary Turner	1.05	3.45	3.38	7.88
D Ludwig	1.14	4.07	3.44	8.65
Diana T	1.59	2.85	4.98	9.42
Barbara Vaught	1.20	5.71	4.39	11.30
Weighted Avg.	**0.95**	**3.70**	**3.17**	**7.82**
Component Share	**12%**	**47%**	**41%**	**100%**

Per Diem Rates

Bareboat Hire	TECO TC	Preference TC Rate	AverageTC Rate
6,644	14,938	25,000	19,969
19,618	30,437	25,000	27,719
5,763	13,762	21,000	17,381
8,078	17,465	22,000	19,733
3,151	10,282	22,000	16,141
4,970	12,587	12,000	12,293
6,613	13,639	20,000	16,819

Vessel Value

Tug Value	Barge Value	Total Value
4,308,698	10,738,845	15,047,543
11,504,321	27,416,679	38,921,000
6,739,656	8,860,069	15,599,725
7,074,302	12,868,890	19,943,192
3,901,914	876,960	4,778,874
3,952,545	5,222,250	9,174,795
2,565,108	756,000	3,321,108

Exhibit No. 75
Tampa Electric Company
Docket No. 031033-EI

Whele $10 - $12 Million Dead Freight

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 75
COMPANY/ OPC
WITNESS: Wehle, Dead Freight Exhibit
DATE: 05/27-28/04

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 031033-EI

In the Matter of

REVIEW OF TAMPA ELECTRIC COMPANY'S 2004-2008 WATERBORNE TRANSPORTATION CONTRACT WITH TECO TRANSPORT AND ASSOCIATED BENCHMARK.

_____/

CONFIDENTIAL DECLASSIFIED 4-20-06 (entire DN)

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CONFIDENTIAL

VOLUME 2

Pages 102 through 265

DEPOSITION OF:	JOANN T. WEHLE
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Ausley & McMullen Law Firm Main Building, Downstairs Conference Room 227 South Calhoun Street Tallahassee, Florida
TIME:	Commenced at 9:00 a.m. Concluded at 8:05 p.m.
DATE:	Wednesday, May 12, 2004
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732

(portions of Depo. identified as Wg Exh's. 75 & 76)

DOCUMENT NUMBER-DATE
05745 MAY 19 05
FPSC-COMMISSION CLERK

CONFIDENTIAL

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 031033-EI

In the Matter of

CONFIDENTIAL

REVIEW OF TAMPA ELECTRIC COMPANY'S 2004-2008 WATERBORNE TRANSPORTATION CONTRACT WITH TECO TRANSPORT AND ASSOCIATED BENCHMARK.

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REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732

DOCUMENT NUMBER-DATE
05745 MAY 19 04

to a rail head.

MR. BEASLEY: I would like to have this marked as a deposition exhibit.

(Confidential Exhibit 6 marked for identification.)

BY MR. BEASLEY:

Q Ms. Wehle, you were asked some questions about the effect of the Gannon shutdown and the potential for dead freight charges that Tampa Electric would have to pay to TECO Transport in connection with that event. Do you recall those?

A Yes.

Q Is it your understanding that Tampa Electric was obligated to pay dead freight to TECO Transport?

A Yes.

Q Do you recall the amount that was discussed earlier?

A I believe it was in the neighborhood of 10 to 12 million, that was my recollection at the time.

Q And what occurred with respect to that obligation?

A TECO Transport actually waived that particular obligation. But had they -- I believe what would have occurred is if we had entered, possibly entered into an agreement with someone else, another supplier let's say, they probably would not have waived that particular obligation and it would have been borne by the ratepayers.

Q Does the relationship between Tampa Electric and its affiliate pay off for the ratepayers where it might not be if

it were a third party you were dealing with in that circumstance?

A Absolutely.

Q You were asked some questions about back in the fall of 2002 when CSXT approached Tampa Electric regarding the potential for rail service to one or both of Tampa Electric Company's generating stations. Do you recall that?

A Yes.

Q Were there any particular factors, constraints, or concerns at that time that affected Tampa Electric and its ability to consider entering into proposals of that nature?

A Yes. We had a lot of uncertainty that was facing us, much of which I touch on in my testimony. The Gannon Station shutdown that we had to comply with in the consent decree by December 31, 2004; further consent decree requirements related to Big Bend and how, and if -- how we were going to be complying with those were really two big uncertainties at the time.

Q I believe Mr. Wright asked you a question concerning whether working capital cost recovery is recovered through the cost-recovery clause with respect to an inventory cost component. Do you recall that question?

A Yes.

Q Do you wish to correct your answer?

A I do. After further consultation with Mr. Aldazabal,

Exhibit No. 76
Tampa Electric Company
Docket No. 031033-EI

Whele No Quid Pro Quo

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 76
COMPANY/ OPC
WITNESS. Whele No Quid Pro Quo
DATE: 05/27-28/04

CONFIDENTIAL

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 031033-EI

In the Matter of

CONFIDENTIAL

REVIEW OF TAMPA ELECTRIC COMPANY'S 2004-2008 WATERBORNE TRANSPORTATION CONTRACT WITH TECO TRANSPORT AND ASSOCIATED BENCHMARK.

_____/

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VOLUME 2

Pages 102 through 265

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TIME:	Commenced at 9:00 a.m. Concluded at 8:05 p.m.
DATE:	Wednesday, May 12, 2004
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732

DOCUMENT NUMBER-DATE
05745 MAY 19 04

A CSXT is a competitor in the marketplace, and as such the associated cost-of-service hypothetical scenario should not be applied because there is a relevant market for the ocean component.

Q Is this proposal and the conclusion upon which it is based, that there is no market for the ocean barge service, refuted by Mr. Dibner's testimony?

A Yes, it is.

Q Do you believe that this approach would be consistent with the observations in Order Number 20298 regarding the difficulties associated with administering a cost-of-service based method of regulation?

A No, I do not think that.

MR. BEASLEY: Thank you.

MR. VANDIVER: Jim, could I ask one or two quick questions? I have heard something new that I haven't heard before. It will just take a second.

MR. BEASLEY: Sure.

RECROSS EXAMINATION

BY MR. VANDIVER:

Q Ms. Wehle, is it your testimony that -- did I understand you to say that had Tampa Electric changed suppliers, TECO Transport would not have forgiven the dead freight issue for the Gannon?

A I believe that would have been the case.

Q And what do you base that belief on?

A They are no longer servicing our needs. They were contractually due those monies.

Q And so your belief is that -- I thought that debt was forgiven in January 2004?

A That's correct, after the contract was signed and after we knew exactly what the dead freight would have been calculated to be. It was forgiven after the dead freight liability was actually established.

MR. BEASLEY: So it was really forgiven.

BY MR. VANDIVER:

Q So the contract -- when was the freight contract signed?

A October 6th, 2003.

Q Was there an explicit quid pro quo?

A No, there was not an explicit quid pro quo.

Q And it never came up in conversation?

A Oh, it came up in conversation quite a bit, quite a bit. We were constantly reminded of the fact that there was dead freight liability established.

Q Who specifically mentioned it for TECO Transport?

A I have heard that term and those numbers used by the president.

Q Mr. Rankin.

A Mr. Rankin. Their CFO, Mr. Bresnahan, and others in

the organization.

Q And did that affect your decision to award the contract to TECO Transport?

A Not at all.

MR. VANDIVER: That's all the questions I have. Thank you.

MR. BEASLEY: We would like to read and sign.

MR. WRIGHT: I have recross, I'm sorry, but you raised something new.

RECROSS EXAMINATION

BY MR. WRIGHT:

Q This relates to your goals.

A Yes.

Q Do those goals exist in writing?

A Yes.

MR. WRIGHT: May we have those as a late-filed deposition exit, please.

(Late-filed Exhibit Number 7 marked for identification.)

BY MR. WRIGHT:

Q I have a couple of questions about Deposition Exhibit 6.

MR. BEASLEY: It would be cost-recovery reduction goals.

MR. WRIGHT: I want to see her total, the goals for

Exhibit No. 77
Tampa Electric Company
Docket No. 031033-EI

Whele Dead Freight 10/20/03

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 77
COMPANY/ OPC
WITNESS: Whele Dead Freight 10/20/03
DATE 03/22-28/04

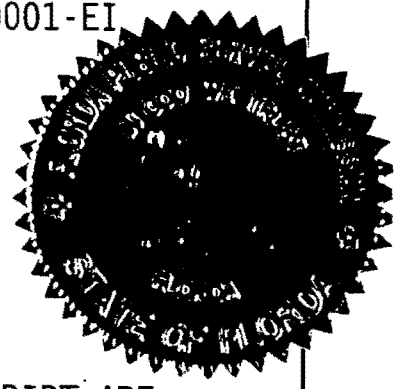
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 030001-EI

In the Matter of

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.

_____/



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DEPOSITION OF:	JOANN T. WEHLE BRENT DIBNER
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Gunter Building Conference Room 309 2540 Shumard Oak Boulevard Tallahassee, Florida
TIME:	Commenced at 9:00 a.m. Concluded at 4:47 p.m.
DATE:	Monday, October 20, 2003
REPORTED BY:	JANE FAUROT, RPR Chief, Office of Hearing Reporter Services FPSC Division of Commission Clerk and Administrative Services (850) 413-6732

be competitive in that world as well as in this one, in the electric world.

I don't think we can think of it as just, you know, they sort of went off away from the utility business and, you know, they will come back. Some of that equipment is completely focused elsewhere.

Q Ms. Wehle, I'm on Page 30 of your direct. In your negotiations, how much dead freight cost was negotiated?

A (By Ms. Wehle) It's not a particular cost, per se. It's a calculation.

Q Can I get a late-filed exhibit for that?

A I think that is confidential information. You are talking about --

Q Would it be the calculation that was done, it would be something less than was calculated in scenario five on Page 1187, is that right, because those, those numbers, as you recall, were calculated on a March 15th --

A I'm not sure which dead freight calculation you are talking about. I know what this is.

Q That is a dead freight number, but that is calculated as a closure date of September 1, and I believe the Gannon Units are now running through October 15th, and so I think the dead freight number would be less now?

A Okay. Now I understand what you are talking about. I thought you were talking about the contractual calculation of

how dead freight is arrived at. We have determined that we will not be incurring any dead freight associated with the Gannon Station.

Q Right. And what I'm trying to get at is when you all went and negotiated with TECO Transport there was a number there that lessened this contract price with TECO Transport, right, it was a negotiated number that lessened the contract price with TECO Transport because you gave something up.

In other words there is a number there on that page there was a liability to --

A Under the contract that expires at the end of this year, okay.

Q Right. And now that is not being claimed by TECO Transport against Tampa Electric?

A That is correct.

Q And somehow that came out in the wash when the contract was signed, is that correct?

A Which contract?

Q The new contract.

A No, it did not.

Q Explain to me what happened on the dead freight?

A The dead freight is no longer an issue, there is no liability.

Q Okay. How is there no liability?

A The companies agreed that there would not be a

liability for the Gannon Station closure.

Q Okay. And that was just simply -- that's wonderful for ratepayers, I'm thrilled to death. It just was negotiated away?

A It was discussed, and it was determined that that was not, there should not be a liability for that between the two parties.

Q And was that any part of the contractual negotiations in signing the new contract?

A No, it was not. There is no carry-over from the existing agreement to the new agreement.

Q And was there any consideration paid for giving up the contractual claim for the dead freight?

A No, there was no consideration paid.

Q None whatsoever?

A No, sir.

Q Okay. Back to Mr. Dibner. If we go to your market study, I'm on Bate-stamped Page 30, but I got it from Mr. Willis, so I'm not certain out that.

A The page that starts with --

Q Future fuel requirements.

A Okay.

Q How much of TECO Transport's investments have already been recovered through depreciation?

A I don't have that number offhand. Obviously the

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 031033-EI EXHIBIT NO. 78
COMPANY/ FIPUG
WITNESS. Waterborne Transportation Process
DATE 05/27-28/04

Exh. 78

TECO TAMPA ELECTRIC

Waterborne Transportation Process 2003

Timeline

Early 2003 Tampa Electric was notified by TECO Transport that an auditor from the FPSC was making unsolicited telephone calls to a competitor seeking their interest in transporting coal for Tampa Electric beginning in 2004. Mark Laux made Bill McNulty and Todd Bohrmann aware of this inappropriate activity and, to the company's knowledge, it ceased.

Summer 2003 Tampa Electric was again notified by TECO Transport that Bernard Windham from the FPSC was making unsolicited telephone calls to a competitor seeking their interest in transporting coal for Tampa Electric beginning in 2004. Mark Laux made Bill McNulty and Todd Bohrmann aware of this inappropriate activity and, to the company's knowledge, it ceased.

June 2 Informal meeting with Staff and company held in Tallahassee to discuss fuel related matters. Staff expressed concerns in not knowing when and what Tampa Electric expects to do related to its waterborne transportation contract that is set to expire December 31, 2003. It also provided suggestions that it believed an RFP was the appropriate means to procure services and they provided some terms and conditions they felt were appropriate.

June 7-11 Attended SEARUC meeting in Pinehurst, North Carolina. Commissioner Baez re-emphasized Staff's concerns and asked that the company stay in contact with Staff to keep them apprised of decision.

June 17 Received telephone call from Jorge Chamizo informing me that Staff was prepared to issue a recommendation by noon on June 19 if the company was not prepared to issue an RFP for transportation services beginning in 2004. Denise called Bill M. to inform him of the senior leadership's upcoming meeting to decide on the RFP.

June 18 Informed that Tampa Electric had decided to issue an RFP for waterborne transportation services beginning in 2004. I notified Jorge and Denise notified Bill M. of the company's decision. We both asked that the recommendation be pulled.

June 19 Again Denise and I updated Commissioner Baez's office and Staff of the company's decision and committed to keep them updated as the process progressed. No recommendation was issued.

June 27 RFP was issued to potential bidders and Staff was provided a courtesy copy hand-delivered by Mark. Mark offered to answer questions that Bill M. had. The company also advertised the RFP in industry publications.

July 1 Informal meeting with Staff and company held in Tallahassee to discuss fuel related matters. Staff expressed concerns that it had not been given an opportunity to provide the company with input into terms and conditions of the RFP. Staff discussed items that they believed should have been included in the RFP. They also believed that if they were not included, potential bidders could be misled. Although the company walked through the concerns with Staff and explained why their issues were either immaterial or inappropriate for the RFP, Staff remained

TECO TAMPA ELECTRIC

Waterborne Transportation Process
2003

unconvinced and agreed to prepare a complete list of suggested changes for the company to consider.

July 2 — Tampa Electric notified the Staff that it did not intend to make any changes to the RFP and that it would respond to potential bidders as questions arose.

Postmark from Tallahassee of first set of materials and memo sent to Bernie Windham.

July 11 — Received letter from Tim Devlin memorializing discussions held during the July 1 informal meeting with Staff along with indicating six items that Staff recommended be included in the RFP to help ensure it is fair to all potential bidders. The memo included Staff's points along with a timeline Tampa Electric shared with Staff during the meeting but had no intention of publicizing competitively sensitive dates.

July 15 — Notified by Lou Hau, St. Petersburg times, and questioned about the Devlin letter. Informs Ross Bannister that Joe Jenkins made statements alleging the RFP is designed to favor TECO Transport.

July 16 — Sent a letter to Tim Devlin responding to his memorandum explaining the company's position and its confidence in the process the company planned to follow in awarding transportation services.

Discussed with Will Rodgers, Tampa Tribune, Tampa Electric's position. Ross Bannister was again told that Joe had made statements alleging the RFP is designed to favor TECO Transport.

July 17 — Discovery served on Tampa Electric from Staff.

July 18 — Dee Brown and Mark Laux met with Jorge to discuss concerns about Staff's approach to date and the company's concern about having a fair process during the fuel hearing. He reassured us that the process would be fair and told us that he would follow up with Staff to ensure they handle the process fairly.

July 26-30 — Attended NARUC meeting in Denver, Colorado. Updated Jorge about the RFP process. Reviewed two more articles with derogatory comments regarding the RFP by FPSC Spokesperson, Kevin Bloom.

July 31 — Received fax from Todd of anonymous letter sent to Governor Bush alleging inappropriate activities between TECO Energy, Tampa Electric and TECO Transport. The letter is postmarked Tallahassee, Florida on July 25.

Staff has anonymous letter included in the fuel docket and posted on the FPSC website.

TECO TAMPA ELECTRIC

Waterborne Transportation Process
2003

August 1 Informal meeting with Staff and company held in Tallahassee to discuss fuel related matters. Received inquiry from Staff regarding bid responses. No material information was provided. Staff presented the materials mailed to Bernie on or around July 2. They linked the anonymous letter to the materials they had received.

Anonymous letter removed from website.

Received inquiry from Lou regarding bid responses. No information was provided.

August 4 Mark received inquiry from Todd regarding bid responses. No information was provided.

Received inquiry from Lou regarding bid responses. No information was provided.

August 5 Denise received inquiry via voicemail from Tim regarding bid responses.

August 6 Jim Beasley informed Cochran Keating that Tampa Electric would only update Staff on bid responses through related formal discovery requests that had been served on the company on July 17.

TECO
TAMPA ELECTRIC

Waterbourne Transportation Contract
Florida Public Service Commission
Calendar of Events

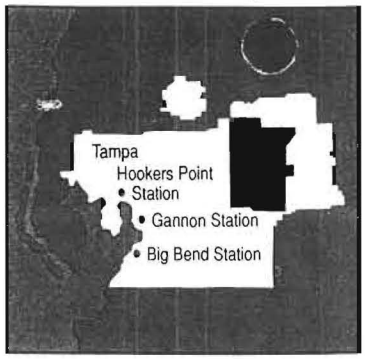
Key Dates:

• Deadline to submit sealed proposals	August 1, 2003	
• Complete evaluation of proposals	August 11, 2003	*
• Notification of winner/Begin contract negotiations	August 18, 2003	*
• Begin direct testimony preparation/Review	August 25, 2003	*
• Direct testimony filed with FPSC	September 12, 2003	* *
• Review of intervenor testimony, if any	October 2, 2003	* *
• Complete contract negotiations	October 6, 2003	*
• Review of FPSC staff testimony, if any	October 9, 2003	* *
• Begin rebuttal testimony preparation/Review if necessary	October 13, 2003	*
• Notify unsuccessful bidders	October 13, 2003	*
• Rebuttal testimony filed with FPSC, if any	October 16, 2003	* *
• Begin witness preparation	October 20, 2003	*
• Prehearing (issues for hearing finalized)	October 23, 2003	* *
• Complete witness preparation	November 3, 2003	*
• Hearing in Tallahassee, Florida	November 13-14	* *

* Tampa Electric target date for completion during the week indicated
* * FPSC Case Management/Docket date

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 031033-EI EXHIBIT NO. 79
COMPANY/ FIPUG
WITNESS. Waterbourne Transport Contract Calendar
DATE 05/27-28/04

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 80
COMPANY/ CSX
WITNESS. Big Bend Station Brochure
DATE: 05/27-28/04



About Tampa Electric

Tampa Electric has been supplying the Tampa area with electricity since the late 1800s. Its West Central Florida service area covers 2,000 square miles. More than 450,000 commercial, residential and industrial Customers depend on Tampa Electric for power. In 1989, about 99 percent of the electricity generated by the company was produced by coal-burning plants. In addition to the Big Bend Station, Tampa Electric's other generating facilities are Gannon Station and Hookers Point Station, both located just a few miles north on Tampa Bay.

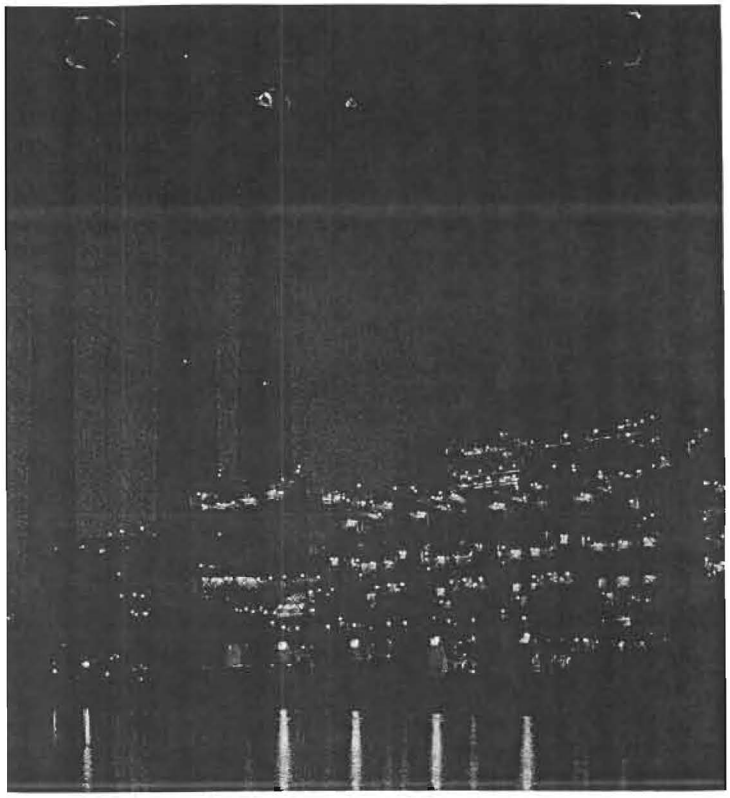
About TECO Energy, Inc.

TECO Energy, Inc. is an investor-owned holding company, organized in 1981. In addition to Tampa Electric, its largest subsidiary, TECO Energy companies include:

- **TECO Diversified**, the umbrella organization under which most of the non-utility companies are managed.
  - **TECO Transport & Trade**, the bulk commodity arm of the corporation. An efficient network of river and ocean shipping, ground storage and transloading operations.
  - **TECO Coal**, owns and operates coal mines: Gatliff Coal, in Williamsburg, Kentucky, Elkhorn Mining in eastern Kentucky and Rich Mountain Coal in Tennessee.
  - **TECO Coalbed Methane**, an energy-related diversified company that taps naturally occurring methane gas from cracks in coal beds near Birmingham, Alabama.
  - **TECO Properties**, invests in a diversified portfolio of high-end real estate.
- **TECO Power Services**, specializes in the wholesale of power generation and sale of electricity to utility companies.
- **TECO Investments**, handles specialized investments for the holding company.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

886.135 12/90



Big Bend Station operates around the clock to provide Tampa Electric Customers with reliable electric service.

Tampa Electric

Big Bend Station

People managing growth

PSC Docket No. 031033-EI
In Re: TECO Coal Transportation
Exhibit _____
Big Bend Station Brochure

A Guide to Big Bend Station

1 Boiler Structure—Boilers convert water into steam, burning about 14,000 tons of coal per day.

2 Turbine Building—Each of Big Bend's four generating units uses steam to turn a turbine, which turns the generator rotor, producing electricity at 22,000 volts.

3 Electrostatic Precipitator—More than 99 percent of the fly ash created when coal is burned is collected on electrically charged plates.

4 Flue-gas Desulfurization (FGD)—After leaving the precipitator, flue gas passes through a water-limestone spray that removes sulfur dioxide.

5 Generator Step-up Transformers—22,000-volt output of generators is increased to 230,000 volts for delivery to the electrical transmission and distribution system.

6 Coal Unloading Facility—About 15 ocean barges per month carry bituminous coal, mined in Kentucky, across the Gulf of Mexico from a New Orleans-area coal terminal.

7 Coal Field—Coal storage capacity is about 700,000 tons, about a 45-50 day supply.

8 Coal Stacking and Reclaiming—Massive machines shape coal storage piles and remove coal for burning.

9 Crusher—After coals of varying sulfur content are blended into a mix best suited for combustion and environmental considerations, the blend is reduced to uniform size and grade.

10 Limestone Unloading Building—Some 625 tons of limestone—about 25 truckloads—are needed each day for the FGD process.

11 Limestone Storage Building—This 55,000-sq.-ft. structure, operated by one person, stores as much as 37,000 tons of limestone.

12 Limestone Preparation Building—Grading mills grind the limestone and add water to form a slurry.

13 Organism Return Discharge—Marine organisms collected from the fine mesh screens at the water inlet point are deposited back into Tampa Bay.

14 Gypsum Handling Building—Forty-five tons of gypsum per hour are extracted from gypsum slurry produced by the FGD system.

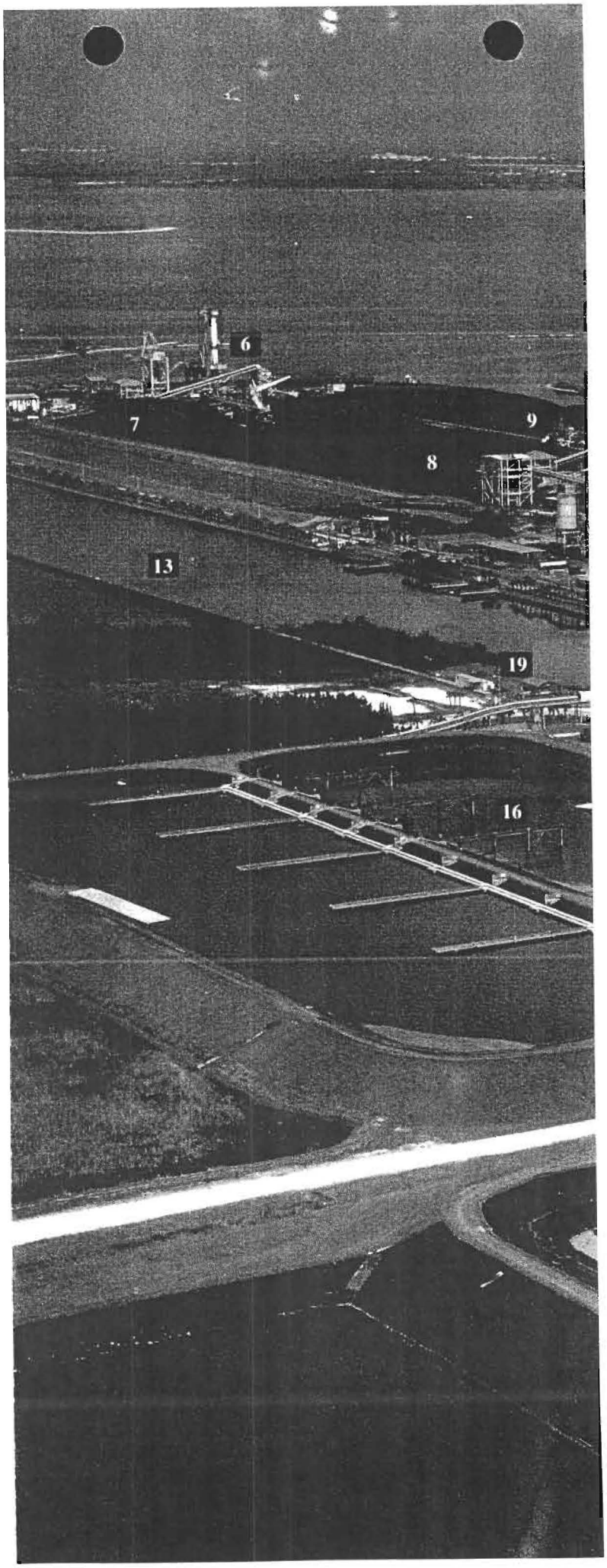
15 Gypsum Conveyor—Gypsum byproduct from the handling building is carried to outside storage area.

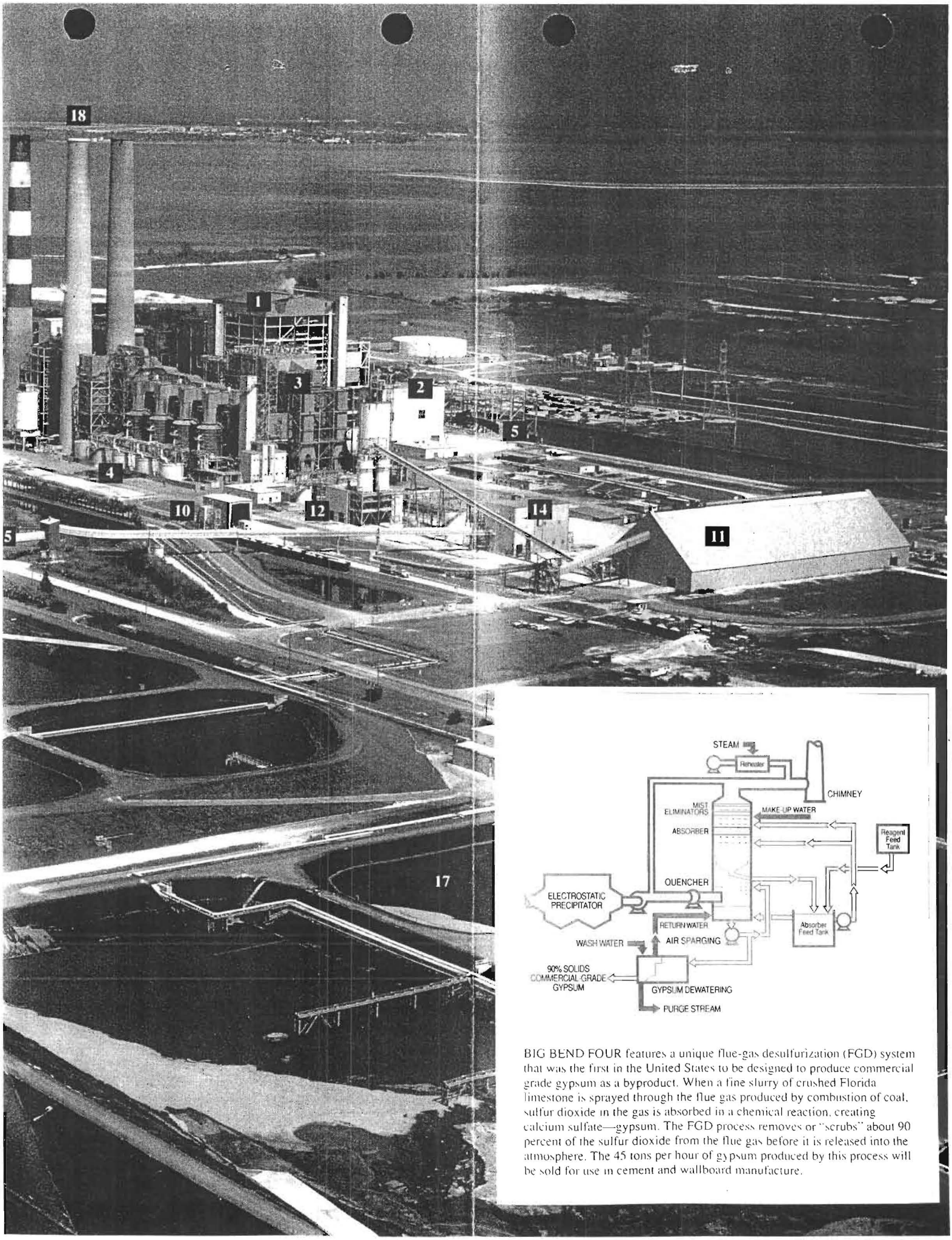
16 Bottom Ash Settling Ponds—Bottom ash from the combustion process is hydraulically transported to these ponds, which are lined with an 80-mil polyethylene liner. The ash settles out and the water is recycled for future use. The bottom ash will be reclaimed and sold for cement manufacture.

17 Fly Ash Settling Ponds—Fly ash settles out of a water mixture for reclaiming.

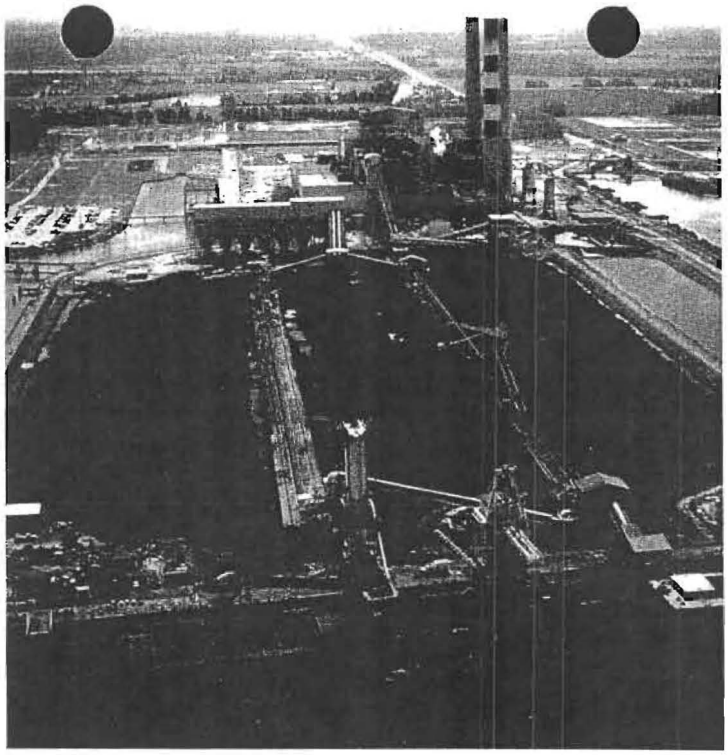
18 Stacks—Big Bend Units 1 and 2 share the westernmost (striped) stack, Unit 3 uses the northeast (unpainted) stack and Unit 4 uses the southeast (unpainted) stack. Water vapor emitted from Unit 4's stack results from the FGD process.

19 Big Bend Manatee Viewing Center—Opened in the fall of 1986 and attracted more than 200,000 visitors in its first five seasons.

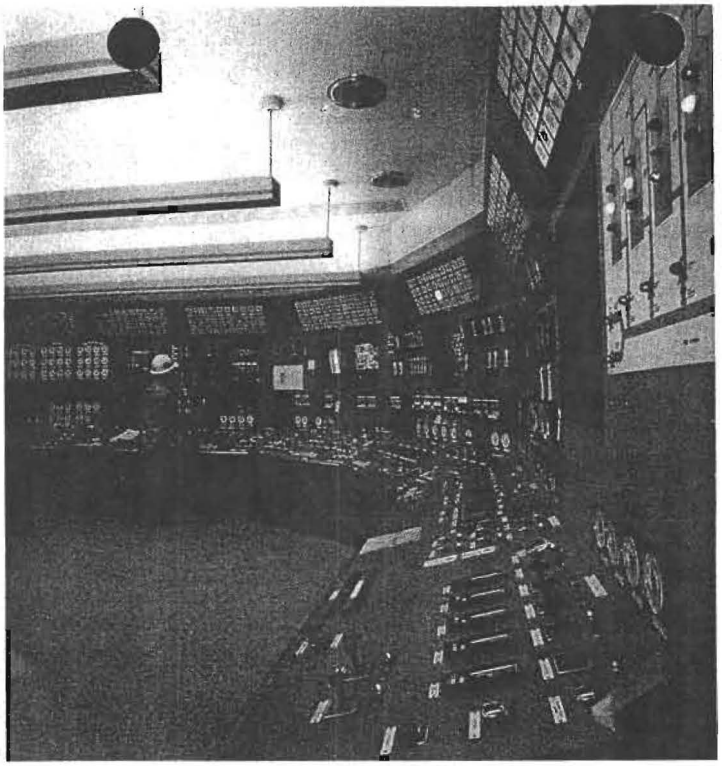




BIG BEND FOUR features a unique flue-gas desulfurization (FGD) system that was the first in the United States to be designed to produce commercial grade gypsum as a byproduct. When a fine slurry of crushed Florida limestone is sprayed through the flue gas produced by combustion of coal, sulfur dioxide in the gas is absorbed in a chemical reaction, creating calcium sulfate—gypsum. The FGD process removes or "scrubs" about 90 percent of the sulfur dioxide from the flue gas before it is released into the atmosphere. The 45 tons per hour of gypsum produced by this process will be sold for use in cement and wallboard manufacture.

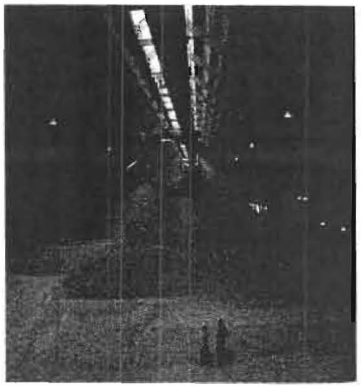


Big Bend Station is the destination for ocean-going barges carrying midwestern coal from a terminal on the Mississippi.

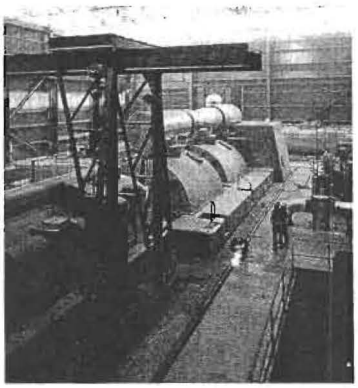


Computerized control room monitors critical temperatures, pressures, flow rates, and vibration to assure maximum system performance.

Stacker unloads 4,000 tons of coal per hour into piles as high as 50 feet.



Huge storage building holds 70-day supply of limestone for use in FGD process.



Each of the four turbine-generator combinations can produce more than 400 megawatts of electricity.

Big Bend Four's FGD system yields commercial grade gypsum at the rate of 45 tons hourly.

People managing growth at Big Bend Station

Tampa Electric's Big Bend Station on Tampa Bay is the largest of the company's power plants. With the addition in February 1985 of 427-megawatt Big Bend Four, the station's four coal-fired units have a combined output of more than 1,500 megawatts—more than half of Tampa Electric's total generating capability.

Located on a 1,492-acre site in southeastern Hillsborough County near Apollo Beach, Big Bend Station has expanded to meet the demands of rapid growth within Tampa Electric's compact and economically diverse service area. The first unit at Big Bend began service in 1970. The second and third generating units were added in 1973 and 1976.

With Big Bend Four, Tampa Electric has sufficient capacity to meet the area's electric power needs—without new plant construction—into the 1990s.

Anticipating the electric power needs of the communities it serves reflects the company's strategy of growth management. This strategy helped postpone construction, and the costs, of Big Bend Four for six years. Key elements in this strategy are energy conservation, load management and cogeneration programs. A new plant will be built only when we need it to serve our Customers.

Tampa Electric's growth management approach works in tandem with on-going operational efficiencies implemented by a skilled staff of utility-industry professionals. The combination of planning and action will enable Customers to continue to receive reliable electric service in the years ahead.

Although Big Bend Four has about the same power output as each of its three companion units, it also meets strict environmental regulations through use of a flue-gas desulfurization (FGD) system, or "scrubber," that removes sulfur dioxide produced when the naturally occurring sulfur in the coal is burned. The scrubber and other environmental protection equipment account for about $275 million of the $591 million cost of Big Bend Four.

CONFIDENTIAL

Document Number: 06650-04
Order Number:
Fine/Settlement: N
Pages: 0
Suffix: EI
Co. Name: Tampa Electric Company

Filing Date: 06/16/2004
Is/Was Confidential: Y
Type: (•) Other
( ) Motion
( ) Order

DESCRIPTION

(CONFIDENTIAL) Hearing Exhibit No. 81 (CSX Gannon Rail contracts) from 5/27-28/04 and 6/10/04 hearing.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 81
COMPANY/ CSX
WITNESS: CSX Gannon Rail Contracts
DATE: 05/27-28/04

93. After meeting with CSX Transportation on October 23, 2002 and March 12, 2003, for the purpose of re-establishing a business relationship, why did not further activity related to these discussions occur?

A. Although CSXT's offer was made at a time that was appropriate for its own business needs and direction, its needs did not correspond with Tampa Electric's business needs. At the time CSXT made its unsolicited offer, the company was in a period of transition and was in the process of conducting various evaluations of its generation resources and needs.

Among other things, Tampa Electric was in the process of making significant decisions about the most prudent means to comply with the U.S. Environmental Protection Agency ("EPA") and the Florida Department of Environmental Protection consent decrees. One key decision that was being evaluated in late 2002 through early 2003 was how much longer its coal-fired Gannon Station could continue to operate safely and reliably given the environmental requirements that Gannon Station terminate its coal operations by December 31, 2004. Depending on the timing of closure and the conditions of its existing coal transportation contract with TECO Transport which had been entered into before the consent decrees existed, the company was facing potential dead freight impacts totaling over $15 million. Dead freight is a term used to indicate minimum tonnage that is "take or pay" in nature. Tampa Electric was focused on reducing or eliminating this exposure and potential negative customer impact.

Another important issue under consideration in late 2002 through early 2004 was the future of burning coal at Big Bend Station, again based on federal and state environmental requirements. According to the consent decrees, Tampa Electric is required to advise the EPA by May 1, 2005 regarding its plan for Big Bend Unit 4 and by May 1, 2007 with respect to Big Bend units 1, 2 and 3 whether each unit will i) be shut down, ii) be repowered with natural gas as its primary fuel, or iii) continue to be fired by coal.

While these issues were under consideration, the company was seriously considering simply extending the terms of the transportation contract for two or three years to meet the committed tonnages for delivery and to gain a better understanding of its future fuel mix and transportation needs. It was not practical nor was it prudent for the company to enter into any type of serious discussions with CSXT in October and November 2002.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 82
COMPANY/ CSX
WITNESS: TECO's Answers to Staff's Ints. #93+94
DATE: 05/27-28/04

PSC Docket No. 031033-EI
In Re: TECO Coal Transportation
Exhibit 82
TECO's Answers to Staff's
Interrogatories No. 93 & 94

94. Please refer to page 15, lines 14-15 of Robert F. White's March 30, 2004, direct testimony, witness for CSX Transportation. Please respond to the following:

A. What actions did Tampa Electric need to undertake in order to "digest the proposal" after meeting with CSX Transportation on March 12, 2003?
B. Which actions were completed?
C. Which actions were not completed?
D. How did Tampa Electric respond to CSX Transportation's letters to Joanne Wehle of March 21, 2003, June 13, 2003, and July 16, 2003?

A. A. Please see the response to Interrogatory Number 93.
B. The decision was made to retire Gannon Station in 2003. Decisions were made concerning the sale of the Polk gasifier. The decision was made to issue an RFP for waterborne transportation services.
C. Tampa Electric is still evaluating its strategy for complying with the Consent Decree.
D. Joann Wehle responded via telephone as acknowledged in Mike Bullock's letters to Joann Wehle

CONFIDENTIAL

Document Number: 06651-04
Order Number:
Fine/Settlement: N
Pages: 0
Suffix: EI
Co. Name: Tampa Electric Company

Filing Date: 06/16/2004
Is/Was Confidential: Y
Type: (•) Other
( ) Motion
( ) Order

DESCRIPTION

(CONFIDENTIAL) Hearing Exhibit No. 83 (Wehle deposition Exh. 6) from 5/27-28/04 and 6/10/04 hearing. [See DNs 06009-04 and 06488-04]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 83
COMPANY/ CSX
WITNESS: Wehle Depo. Exh. #6
DATE: 05/27-28/04

Comparison of Adjusted Rail Bid Rates and Waterborne Transportation Contract Rates ($/Ton)

CONFIDENTIAL

CONFIDENTIAL

			Original						
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Source	Pool	River Dock	TT River	TT Terminal	TT Ocean	TT Total	Rail Bidder Rate	TT Less Rail Rate	Initial Recov. Cost
C, R	Lock 53 Pool Ohio River	Cook	5.98	2.45	7.98	16.41	17.70	(1.29)	15.55
C, R	Smithland Pool Ohio River	Hamilton	6.90	2.45	7.98	17.33	15.62	1.71	16.42
C, R	Smithland Pool Ohio River	Caseyville	6.74	2.45	7.98	17.17	15.62	1.55	16.27
C, R	Uniontown Pool Ohio River	Overland	6.97	2.45	7.98	17.40	15.98	1.42	16.49
C, R	Smithland Pool Ohio River	Rigsby & Barnard	6.69	2.45	7.98	17.12	15.98	1.14	16.22
C, R	Uniontown Pool Ohio River	Mount Vernon	7.04	2.45	7.98	17.47	15.98	1.49	16.55
C, R	Lock 53 Pool Ohio River	Mound City	5.98	2.45	7.98	16.39	17.70	(1.31)	15.53
C, R	Uniontown Pool Ohio River	Southern Indiana	7.21	2.45	7.98	17.64	15.98	1.66	16.71
C		*New Hope*	7.53	2.45	7.98	17.96	16.06	1.90	17.02
C, R	Smithland Pool Ohio River	Empire Dock	6.65	2.45	7.98	17.08	15.62	1.46	16.18
C, R	Newburgh Pool Ohio River	Yankeetown	7.34	2.45	7.98	17.77	16.06	1.71	16.84
C		Owensboro	7.45	2.45	7.98	17.88	16.06	1.82	16.94
C, R	Green River	Ken Mine	8.99	2.45	7.98	19.42	N/A	N/A	18.40
C, R	Green River	Pyramid	8.95	2.45	7.98	19.38	N/A	N/A	18.36
C, R	Green River	Green Coal	8.01	2.45	7.98	18.44	N/A	N/A	17.47
C, R	Green River	Patriot	8.24	2.45	7.98	18.67	N/A	N/A	17.69
C, R	Green River	Sebree	8.37	2.45	7.98	18.80	N/A	N/A	17.81
C	Meldahl Pool Ohio River	TTI	9.20	2.45	7.98	19.63	N/A	N/A	18.60
C, R	Cannelton Pool Ohio River	Jefferson River Port	8.13	2.45	7.98	18.56	N/A	N/A	17.59
C, R	Tennessee River	Kentucky Lake Dock	7.16	2.45	7.98	17.59	N/A	N/A	16.67
C		GRT	7.16	2.45	7.98	17.59	N/A	N/A	16.67
C, R	Upper Mississippi	Cora	7.12	2.45	7.98	17.55	19.00	(1.45)	16.63
C		Dekoven	6.75	2.45	7.98	17.18	N/A	N/A	16.28
C		Powhatan	10.65	2.45	7.98	21.08	N/A	N/A	19.97
C		Shawneetown	6.81	2.45	7.98	17.24	N/A	N/A	16.33
C		Refineries Petcoke	2.53	2.45	7.98	12.96	N/A	N/A	12.28
C, R	Tennessee River	BRT	7.16	2.45	7.98	17.59	N/A	N/A	16.67
C	Upper Mississippi	Cahokia	N/A	N/A	N/A	N/A	N/A	N/A	
C	Upper Mississippi	Kellogg	N/A	N/A	N/A	N/A	N/A	N/A	
R	Smithland Pool Ohio River	Kanipe Enterprises	N/A	N/A	N/A	N/A	N/A	N/A	
		Average for All Docks on Contract	7.33	2.45	7.98	17.76	N/A		
		Average for Docks Common to TT and Rail Bid				17.32	16.41		
		Weighted Average Rate							
		Weighted Average for Docks Common to TT and Rail Bid							

					Adjusted					
$(H)_1$	$(H)_2$	$(H)_3$	$(H)_4$	$(H)_{TOTAL}$	(J)	(K)	(L)	(M)	(N)	(O)
Bidder's Fuel Surcharge (Note 1)	Bidder's Synfuel Adder	Demurrage Rate (Note 2)	Incr. Cost to Polk Station (Note 3)	Adj. Total Rail Bidder Rate	Difference: TT Less Adj. Total Bid Rate	2004 Tons	TT Trans. Cost	*Rail Bid* Trans. Cost	Difference: *TT Less* Adj. Rail Bid	Notes
0.64	0.00	0.06	0.14	18.54	(2.13)	400,000	6,564,000	7,414,880		(4, 5)
0.56	0.00	0.06	0.14	16.36	0.95	N/A	N/A	N/A		
0.56	0.00	0.06	0.14	16.36	0.79	N/A	N/A	N/A		
0.56	0.00	0.06	0.14	16.76	0.64	N/A	N/A	N/A		
0.56	0.00	0.06	0.14	16.76	0.36	N/A	N/A	N/A		
0.56	0.00	0.06	0.14	17.01	0.46	N/A	N/A	N/A		
0.64	0.00	0.06	0.14	18.54	(2.15)	N/A	N/A	N/A		
0.58	0.00	0.06	0.14	16.78	0.88	N/A	N/A	N/A		
0.58	0.00	0.06	0.14	16.84	1.12	N/A	N/A	N/A		
0.56	0.25	0.06	0.14	16.36	0.70	1,000,000	17,080,000	16,382,320		(4, 5)
0.56	0.00	0.06	0.14	16.84	0.93	N/A	N/A	N/A		
0.58	0.00	0.06	0.14	16.84	1.04	N/A	N/A	N/A		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
0.68	0.00	0.06	0.14	19.88	(2.33)	1,050,000	18,427,500	20,878,200		(4, 5)
N/A	N/A	N/A	N/A	N/A	N/A	750,000	12,685,000	N/A		(4)
N/A	N/A	N/A	N/A	N/A	N/A	400,000	8,432,000	N/A		(4)
N/A	N/A	N/A	N/A	N/A	N/A	300,000	5,172,000	N/A		(4)
N/A	N/A	N/A	N/A	N/A	N/A	300,000	3,888,000	N/A		(4)
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
				N/A						
				17.22	0.10					
							17.25			
							17.17	18.23	(1.06)	

DECLASSIFIED
CONFIDENTIAL
MH 4-20-06

Notes:
1. Current fuel surcharge rate is 3.6 percent, applicable to all rail bid rates.
2. Weighted average demurrage rate, per bid specifications and estimated unloading time. $0.06 = $330,000 / 5.5 million
   Assumptions: 5.5 million tons total annually; 550 trains per year; 6 hours unloading time per train. Bid rates allow 4 hours for unloading. 2 hours at $300.00 per hour for each train = $330,000
3. Weighted average incremental cost for transportation to Polk Station from Big Bend Station based on current trucking rate and rail proposal rate. $0.14 = (673,000*$1.17) / 5.5 million
   Assumptions: 5.5 million tons total annually; 673,000 tons transferred to Polk Station annually; current trucking rate is $3.33; short haul rail rate is $4.50; difference is $1.17 per ton.
4. Based on Tampa Electric's 2004 coal purchase agreements, the company expects to receive coal at these river docks.
5. Based on Mr. McNulty's analysis, only rates for Cook, Empire Dock and Cora were provided. Therefore, the weighted average rate is calculated using the rates for only the aforementioned river docks.

Calculations:
Column A - J: Exhibit WBM-1
Column H_1: Rail proposal and Tariff 8200
Column H_2: Rail proposal
Column H_3: Calculated weighted average rate. See note 2.
Column H_4: Calculated weighted average rate. See note 3.
Column $H_{TOTAL} = (H) + (H_1) + (H_2) + (H_3) + (H_4)$
Column $J = (G) - (H_{TOTAL})$
Column K = Tampa Electric
Column $L = (G) * (K)$
Column $M = (H_{TOTAL}) * (K)$
Column N = (L) - (M)

Sources:
C = Contract
R = Request For Proposal

declas 4-20-06
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 83
COMPANY/ WITNESS. CSX
DATE: 5/27-28/04 + 10/10/04

PSC Docket No. 031033-EI
In Re: TECO Coal Transportation
Exhibit _____
Wehle - Deposition Exhibit 6

DEPOSITION EXHIBIT 6

DOCUMENT NUMBER-DATE
06651 JUN 15
FPSC-COMMISSION CLERK

CONFIDENTIAL

Document Number: 06652-04
Order Number:
Fine/Settlement: N
Pages: 0
Suffix: EI
Co. Name: Tampa Electric Company

Filing Date: 06/16/2004
Is/Was Confidential: Y
Type: (•) Other
( ) Motion
( ) Order

DESCRIPTION

(CONFIDENTIAL) Hearing Exhibit No. 84 (TECO fuels department prices 3rd quarter - 2003) from 5/27-28/04 and 6/10/04 hearing.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 84
COMPANY/ WITNESS: CSX TECO's Fuel dept. prices 3rd qtr/2003
DATE: 05/27-28/04

CONFIDENTIAL

Tampa Electric Company
Docket No. 031033-EI
Late Filed Hearing Exhibit of
Joann T. Wehle
No. 85
Page 1 of 9

"Update of Index on Footnote to Butterfly Exhibit"

3-20-06
DECLASSIFIED
CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI late-filed EXHIBIT NO: 85
COMPANY/ WITNESS: Wehle
DATE: 5(27-28)04

(Pt 1 of 2)
3-20-06
dlcles
DOCUMENT NUMBER-DATE
06483 JUN 10 04
FPSC-COMMISSION CLERK

CONFIDENTIAL

[redacted]

TO: MARTY DUFF
TAMPA ELECTRIC COMPANY
TAMPA, FLORIDA 33601
FUELS DEPARTMENT

DATE: April 2, 2004

RE: **RATE ADJUSTMENT**

In accordance with section 6.4 of the Coal Transportation Agreement between Teco Transport and Tampa Electric Company, the following revised rate adjustments, effective April 1, 2004 are proposed for your approval. The fuel adjustment is based on the average low price rate of No. 2 Diesel fuel at New Orleans for the average of December 2003, January 2004 and February 2004. The variable component for all rates has been adjusted based on the CPI and PPI rates for the average of December 2003, January and February 2004.

All changes effected in the contract amendment have been adjusted to reflect those changes.

If you have any questions concerning the attached rates please do not hesitate to call.

Sincerely,

Cherie L. Lukcic
Budget & Financial Manager

cc: Joann Wehle
Karen Bramley

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TAMPA ELECTRIC COMPANY
April 2, 2004
PAGE TWO

Adjustment Factors:
FUEL ADJUSTMENT

Price per gallon per contract (Base) 0.7000
Platts Average December 2003, January & February 2004 0.8891

Calculation of adjustment rate: $\frac{0.8891}{0.7000} = 1.27014$

VARIABLE COMPONENT ADJUSTMENT

	CPI	PPI
September, 2003	191.0	145.0
October, 2003	191.7	145.9
November, 2003	191.6	146.1
December, 2003	191.5	146.2
January, 2004	191.9	147.1
February, 2004	192.7	148.2

$$\frac{\text{CPI Average Dec, Jan \& Feb}}{3} = \frac{191.0 + 191.7 + 191.6}{3} = 191.4$$

$$\frac{\text{PPI Average Dec, Jan, \& Feb}}{3} = \frac{145.0 + 145.9 + 146.1}{3} = 145.7$$

$$\frac{\text{Base Quarterly Index Average}}{2} = \frac{\text{AVERAGE CPI + AVERAGE PPI}}{2} = \frac{191.4 + 145.7}{2} = 168.6$$

Quarterly Index Average

$$\text{CPI 12/03, 01/04 \& 02/04 CPI Ave} = \frac{191.5 + 191.9 + 192.7}{3} = 192.0$$

$$\text{PPI 12/03, 01/04 \& 02/04 Average} = \frac{146.2 + 147.1 + 148.2}{3} = 147.2$$

$$\frac{\text{Average CPI + Average PPI}}{2} = \frac{192.0 + 147.2}{2} = 169.6$$

Calculation of adjustment rate: $\frac{169.6}{168.6} = 1.00593$

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TAMPA ELECTRIC COMPANY
April 2, 2004
PAGE THREE

TECO BULK TERMINAL	BASE RATE	ADJUSTMENT FACTOR	OTHER ADJUSTMENT	RATE EFFECTIVE 04/01/04
TRANSFER RATE DOMESTIC	2.45	1.00000	0.00	2.45
TRANSFER RATE IMPORT	4.00	1.00000	0.00	4.00
TECO OCEAN SHIPPING				
FUEL	0.86	1.27014	0.00	1.09
VARIABLE	4.32	1.00593	0.00	4.35
OTHER	2.80	1.00000	0.00	2.80
TOTAL	7.98			8.24
TECO OCEAN SHIPPING - PETCOKE				
FUEL	1.52	1.27014	0.00	1.93
VARIABLE	5.19	1.00593	0.00	5.22
OTHER	4.17	1.00000	0.00	4.17
TOTAL	10.88			11.32

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INCREMENTAL RATES

GREEN 11 - GR11				
FUEL	$1.99	1.27014	$0.00	$2.53
VARIABLE	4.89	1.00593	0.00	4.92
OTHER	1.13	1.00000	0.00	1.13
TOTAL	$8.01			$8.58
PATRIOT - GR32				
FUEL	$2.09	1.27014	0.00	$2.65
VARIABLE	5.01	1.00593	0.00	5.04
OTHER	1.14	1.00000	0.00	1.14
TOTAL	$8.24			$8.83
SEBREE - GR43				
FUEL	$2.14	1.27014	0.00	$2.72
VARIABLE	5.08	1.00593	0.00	5.11
OTHER	1.15	1.00000	0.00	1.15
TOTAL	$8.37			$8.98
PYRAMID - GR94				
FUEL	$2.39	1.27014	0.00	$3.04
VARIABLE	5.36	1.00593	0.00	5.39
OTHER	1.20	1.00000	0.00	1.20
TOTAL	$8.95			$9.63
KEN MINE - GR 98				
FUEL	$2.41	1.27014	0.00	$3.06
VARIABLE	5.38	1.00593	0.00	5.41
OTHER	1.20	1.00000	0.00	1.20
TOTAL	$8.99			$9.67
POWHATTAN POINT - OR110.8				
FUEL	$3.24	1.27014	0.00	$4.12
VARIABLE	6.10	1.00593	0.00	6.14
OTHER	1.31	1.00000	0.00	1.31
TOTAL	$10.65			$11.57

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TTI - OR 406

FUEL	$2.81	1.27014	0.00	$3.57
VARIABLE	5.21	1.00593	0.00	5.24
OTHER	1.18	1.00000	0.00	1.18
TOTAL	$9.20			$9.99

JEFFERSON RIVER PORT - OR618

FUEL	$2.50	1.27014	0.00	$3.18
VARIABLE	4.55	1.00593	0.00	4.58
OTHER	1.08	1.00000	0.00	1.08
TOTAL	$8.13			$8.83

NEW HOPE - OR734

FUEL	$2.32	1.27014	0.00	$2.95
VARIABLE	4.18	1.00593	0.00	4.20
OTHER	1.03	1.00000	0.00	1.03
TOTAL	$7.53			$8.18

OWENSBORO

FUEL	2.30	1.27014	0.00	$2.92
VARIABLE	4.13	1.00593	0.00	4.15
OTHER	1.02	1.00000	0.00	1.02
TOTAL	$7.45			$8.10

YANKEETOWN - OR773

FUEL	2.27	1.27014	0.00	$2.88
VARIABLE	4.06	1.00593	0.00	4.08
OTHER	1.01	1.00000	0.00	1.01
TOTAL	$7.34			$7.98

SOUTHERN INDIANA - OR794

FUEL	2.23	1.27014	0.00	$2.83
VARIABLE	3.98	1.00593	0.00	4.00
OTHER	1.00	1.00000	0.00	1.00
TOTAL	$7.21			$7.84

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MT VERNON

FUEL	$2.18	1.27014	0.00	$2.77
VARIABLE	3.87	1.00593	0.00	3.89
OTHER	0.99	1.00000	0.00	0.99
TOTAL	$7.04			$7.65

OVERLAND - OR842

FUEL	$2.16	1.27014	0.00	$2.74
VARIABLE	3.83	1.00593	0.00	3.85
OTHER	0.98	1.00000	0.00	0.98
TOTAL	$6.97			$7.58

HAMILTON - OR852

FUEL	$2.13	1.27014	0.00	$2.71
VARIABLE	3.80	1.00593	0.00	3.82
OTHER	0.97	1.00000	0.00	0.97
TOTAL	$6.90			$7.50

SHAWNEETOWN - OR858

FUEL	$2.12	1.27014	0.00	$2.69
VARIABLE	3.75	1.00593	0.00	3.77
OTHER	0.94	1.00000	0.00	0.94
TOTAL	$6.81			$7.40

DEKOVEN - OR869

FUEL	$2.11	1.27014	0.00	$2.68
VARIABLE	3.70	1.00593	0.00	3.72
OTHER	0.94	1.00000	0.00	0.94
TOTAL	$6.75			$7.34

CASEYVILLE - OR872

FUEL	$2.11	1.27014	0.00	$2.68
VARIABLE	3.70	1.00593	0.00	3.72
OTHER	0.93	1.00000	0.00	0.93
TOTAL	$6.74			$7.33

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RIGSBY & BARNARD - OR881

FUEL	$2.09	1.27014	0.00	$2.65
VARIABLE	3.67	1.00593	0.00	3.69
OTHER	0.93	1.00000	0.00	0.93
TOTAL	$6.69			$7.28

EMPIRE - OR896

FUEL	$2.08	1.27014	0.00	$2.64
VARIABLE	3.64	1.00593	0.00	3.66
OTHER	0.93	1.00000	0.00	0.93
TOTAL	$6.65			$7.23

COOK - OR948

FUEL	$1.86	1.27014	0.00	$2.36
VARIABLE	3.26	1.00593	0.00	3.28
OTHER	0.86	1.00000	0.00	0.86
TOTAL	$5.98			$6.50

MOUND CITY - OR976

FUEL	$1.86	1.27014	0.00	$2.36
VARIABLE	3.24	1.00593	0.00	3.26
OTHER	0.86	1.00000	0.00	0.86
TOTAL	$5.96			$6.48

GRT - TR23

FUEL	$1.98	1.27014	0.00	$2.51
VARIABLE	4.13	1.00593	0.00	4.15
OTHER	1.05	1.00000	0.00	1.05
TOTAL	$7.16			$7.72

KENTUCKY LAKES DOCK - TR24

FUEL	$1.98	1.27014	0.00	$2.51
VARIABLE	4.13	1.00593	0.00	4.15
OTHER	1.05	1.00000	0.00	1.05
TOTAL	$7.16			$7.72

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CORA - UM98

FUEL	$2.32	1.27014	0.00	$2.95
VARIABLE	3.82	1.00593	0.00	3.84
OTHER	0.98	1.00000	0.00	0.98
TOTAL	$7.12			$7.77

REFINERIES, PET COKE M.P. 1
LOWER MISSISSIPPI RIVER

FUEL	$0.77	1.27014	0.00	$0.98
VARIABLE	1.39	1.00593	0.00	1.40
OTHER	0.37	1.00000	0.00	0.37
TOTAL	$2.53			$2.75

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ORIGINAL

AUSLEY & MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

227 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

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June 10, 2004

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Review of Tampa Electric Company's waterborne transportation contract with TECO Transport and associated benchmark; FPSC Docket No. 031033-EI

TRANSMITTAL OF CONFIDENTIAL INFORMATION

Dear Ms. Bayo:

Pursuant to a Request for Specified Confidential Treatment Tampa Electric is simultaneously filing with your office, we enclose a single confidential version of the Late Filed Hearing Exhibits Nos. 85 and 87 of Tampa Electric's witness Joann T. Wehle. The confidential information contained in this filing is highlighted in yellow and stamped "CONFIDENTIAL." We would appreciate your maintaining confidential treatment of the enclosed materials.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley (pp)

James D. Beasley

JDB/pp
Enclosures

cc: Wm. Cochran Keating IV
All Parties of Record

3.20.06
DECLASSIFIED

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DOCUMENT NUMBER-DATE
06483 JUN 10 04
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TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
FIPUG'S 1st REQUEST FOR POD

JK MD 7/24/03

TO: MARTY DUFF
TAMPA ELECTRIC COMPANY
TAMPA, FLORIDA 33601
FUELS DEPARTMENT

DATE: July 21, 2003

RE: RATE ADJUSTMENT

In accordance with section 6.4 of the Coal Transportation Agreement between Teco Transport and Tampa Electric Company, the following revised rate adjustments, effective July 1, 2003 are proposed for your approval. The fuel adjustment is based on the average low price rate of No. 2 Diesel fuel at New Orleans for the 2nd quarter of 2003. The variable component for all rates has been adjusted based on the CPI and PPI rates for the 2nd quarter of 2003.

All changes effected in the contract amendment have been adjusted to reflect those changes.

If you have any questions concerning the attached rates please do not hesitate to call.

AUS 11.26.05 (entire DN)
CONFIDENTIAL DECLASSIFIED

Sincerely,

Cherie L. Lukcic
Budget & Financial Manager

cc: Carey McBride
Joann Wehle
Karen Bramley
Ellen Campbell

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 86
COMPANY/ WITNESS
DATE: 5|27|28|04 + 6|10|04

DOCUMENT NUMBER-DATE
06672 JUN 16 04
declas 11-28-05
FPSC-COMMISSION CLERK

"Performance You Can Count On"

TECO TRANSPORT CORPORATION
702 N. FRANKLIN STREET, PLAZA 9 P.O. BOX 22048 TAMPA, FLORIDA, USA 33622-2048
(813) 209-4200 FAX (813) 273-0248 WWW.TECOTRANSPORT.COM
TECO BARGE LINE TECO BULK TERMINAL TECO OCEAN SHIPPING
AN EQUAL OPPORTUNITY COMPANY

PSC Docket No. 031033-EI
In Re: TECO Coal Transportation
Exhibit CSX
TECO Transport Letter to TECO Re:
Rate Adjustments, 7/21/2003

CONFIDENTIAL

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
FIPUG'S 1st REQUEST FOR POD

TAMPA ELECTRIC COMPANY
July 21, 2003
PAGE TWO

Adjustment Factors:
FUEL ADJUSTMENT

Price per gallon per contract (Base) 0.3587
Average est price per gallon at 06/30/03 0.7333

Calculation of adjustment rate: $\frac{0.7333}{0.3587} = 2.04433$

VARIABLE COMPONENT ADJUSTMENT

	CPI	PPI
October, 1998	172.2	138.6
November, 1998	172.3	138.4
December, 1998	172.3	138.7
April, 2003	190.2	144.9
May, 2003	190.3	144.8
June, 2003	190.3	144.8

$$\frac{\text{CPI 4th Quarter 1998 Average}}{} = \frac{172.2 + 172.3 + 172.3}{3} = 172.3$$

$$\frac{\text{PPI 4th Quarter 1998 Average}}{} = \frac{138.6 + 138.4 + 138.7}{3} = 138.6$$

$$\frac{\text{Base Quarterly Index Average}}{} = \frac{\text{AVERAGE CPI + AVERAGE PPI}}{2} = \frac{172.3 + 138.6}{2} = 155.5$$

$$\frac{\text{Quarterly Index Average}}{}$$

$$\text{CPI 2nd Quarter 2003 Average} = \frac{190.2 + 190.3 + 190.3}{3} = 190.3$$

$$\text{PPI 2nd Quarter 2003 Average} = \frac{144.9 + 144.8 + 144.8}{3} = 144.8$$

$$\frac{\text{Average CPI + Average PPI}}{2} = \frac{190.3 + 144.8}{2} = 167.6$$

Calculation of adjustment rate: $\frac{167.6}{155.5} = 1.07781$

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TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
FIPUG'S 1st REQUEST FOR POD

TAMPA ELECTRIC COMPANY
July 21, 2003
PAGE THREE

TECO BULK TERMINAL	BASE RATE	ADJUSTMENT FACTOR	OTHER ADJUSTMENT	RATE EFFECTIVE 07/01/03
DIRECT	1.75	1.00000	0.00	1.75
STORAGE	2.69	1.00000	0.00	2.69
IMPORT	4.25	1.00000	0.00	4.25
TECO OCEAN SHIPPING				
FUEL	0.98	2.04433	0.00	2.00
VARIABLE	3.85	1.07781	0.00	4.15
OTHER	2.17	1.00000	0.00	2.17
TOTAL	7.00			8.32
TECO OCEAN SHIPPING - PETCOKE				
FUEL	0.98	2.04433	0.00	2.00
VARIABLE	5.60	1.07781	0.00	6.04
OTHER	2.17	1.00000	0.00	2.17
TOTAL	8.75			10.21

Gulf Coast #1

GIBRALTER M.P. 86				
FUEL	$1.95	2.04433	$0.00	$3.99
VARIABLE	4.69	1.07781	0.00	5.05
OTHER	1.17	1.00000	0.00	1.17
TOTAL	$7.81			$10.21
HAMILTON M.P. 852				
FUEL	$1.55	2.04433	0.00	$3.17
VARIABLE	3.73	1.07781	0.00	4.02
OTHER	0.93	1.00000	0.00	0.93
TOTAL	$6.21			$8.12
CASEYVILLE M.P. 872				
FUEL	$1.44	2.04433	0.00	$2.94
VARIABLE	3.44	1.07781	0.00	3.71
OTHER	0.86	1.00000	0.00	0.86
TOTAL	$5.74			$7.51
OVERLAND TERMINAL (CONSOL) M.P. 841.5				
FUEL	$1.50	2.04433	0.00	$3.07
VARIABLE	3.60	1.07781	0.00	3.88
OTHER	0.90	1.00000	0.00	0.90
TOTAL	$6.00			$7.85
MT. VERNON M.P. 829				
FUEL	$1.50	2.04433	0.00	$3.07
VARIABLE	3.60	1.07781	0.00	3.88
OTHER	0.90	1.00000	0.00	0.90
TOTAL	$6.00			$7.85
BIG SANDY				
FUEL	$1.82	2.04433	0.00	$3.72
VARIABLE	4.38	1.07781	0.00	4.72
OTHER	1.09	1.00000	0.00	1.09
TOTAL	$7.29			$9.53

CONFIDENTIAL

TAMPA ELECTRIC COMPANY
July 21, 2003
PAGE FIVE

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
FIPUG'S 1st REQUEST FOR POD

PYRAMID / DEMAO (PATRIOT) M.P. GR 32				
FUEL	$1.82	2.04433	0.00	$3.72
VARIABLE	4.38	1.07781	0.00	4.72
OTHER	1.09	1.00000	0.00	1.09
TOTAL	$7.29			$9.53
PYRAMID M.P. 94				
FUEL	$1.95	2.04433	0.00	$3.99
VARIABLE	4.69	1.07781	0.00	5.05
OTHER	1.17	1.00000	0.00	1.17
TOTAL	$7.81			$10.21
BRT M.P. 23				
FUEL	$1.50	2.04433	0.00	$3.07
VARIABLE	3.60	1.07781	0.00	3.88
OTHER	0.90	1.00000	0.00	0.90
TOTAL	$6.00			$7.85
YANKEETOWN M.P. OR 773				
FUEL	1.56	2.04433	0.00	$3.19
VARIABLE	3.76	1.07781	0.00	4.05
OTHER	0.94	1.00000	0.00	0.94
TOTAL	$6.26			$8.18
SOUTHERN IN. M.P. 784				
FUEL	1.54	2.04433	0.00	$3.15
VARIABLE	3.70	1.07781	0.00	3.99
OTHER	0.92	1.00000	0.00	0.92
TOTAL	$6.16			$8.06
NEW HOPE M.P. 734				
FUEL	1.60	2.04433	0.00	$3.27
VARIABLE	3.85	1.07781	0.00	4.15
OTHER	0.96	1.00000	0.00	0.96
TOTAL	$6.41			$8.38

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INLAND (OWENSBORO)				
FUEL	$1.60	2.04433	0.00	$3.27
VARIABLE	3.85	1.07781	0.00	4.15
OTHER	0.96	1.00000	0.00	0.96
TOTAL	$6.41			$8.38
JEFFERSON RIVERPORT-MP 618				
FUEL	$1.63	2.04433	0.00	$3.33
VARIABLE	3.91	1.07781	0.00	4.21
OTHER	0.98	1.00000	0.00	0.98
TOTAL	$6.52			$8.52
EMPIRE DOCK M.P. 896				
FUEL	$1.44	2.04433	0.00	$2.94
VARIABLE	3.44	1.07781	0.00	3.71
OTHER	0.86	1.00000	0.00	0.86
TOTAL	$5.74			$7.51
CAHOKIA MARINE M.P. 178				
FUEL	$1.67	2.04433	0.00	$3.41
VARIABLE	4.02	1.07781	0.00	4.33
OTHER	1.00	1.00000	0.00	1.00
TOTAL	$6.69			$8.74
COOK COAL TERMINAL M.P. 948				
FUEL	$1.09	2.04433	0.00	$2.23
VARIABLE	2.63	1.07781	0.00	2.83
OTHER	0.66	1.00000	0.00	0.66
TOTAL	$4.38			$5.72
RIGSBY - BARNARD (ARCLAR) M.P. 881				
FUEL	$1.44	2.04433	0.00	$2.94
VARIABLE	3.44	1.07781	0.00	3.71
OTHER	0.86	1.00000	0.00	0.86
TOTAL	$5.74			$7.51

CONFIDENTIAL

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
FIPUG'S 1st REQUEST FOR POD

TAMPA ELECTRIC COMPANY
July 21, 2003
PAGE EIGHT

MOUND CITY M.P. 976				
FUEL	$1.31	2.04433	0.00	$2.68
VARIABLE	3.14	1.07781	0.00	3.38
OTHER	0.78	1.00000	0.00	0.78
TOTAL	$5.23			$6.84
SEBREE, KY M.P. 43				
FUEL	$1.82	2.04433	0.00	$3.72
VARIABLE	4.38	1.07781	0.00	4.72
OTHER	1.09	1.00000	0.00	1.09
TOTAL	$7.29			$9.53

"Updated Rate Adjustment Letter"

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI late-filed EXHIBIT NO. 87
COMPANY/ WITNESS: Wehle
DATE: 5(27-28)04

3-20-06
DECLASSIFIED

(Pt 2 of 2)
DN
06483-04
6·10.04

[redacted]

CONFIDENTIAL

TO: MARTY DUFF
TAMPA ELECTRIC COMPANY
TAMPA, FLORIDA 33601
FUELS DEPARTMENT

DATE: April 2, 2004

RE: **RATE ADJUSTMENT**

In accordance with section 6.4 of the Coal Transportation Agreement between Teco Transport and Tampa Electric Company, the following revised rate adjustments, effective April 1, 2004 are proposed for your approval. The fuel adjustment is based on the average low price rate of No. 2 Diesel fuel at New Orleans for the average of December 2003, January 2004 and February 2004. The variable component for all rates has been adjusted based on the CPI and PPI rates for the average of December 2003, January and February 2004.

All changes effected in the contract amendment have been adjusted to reflect those changes.

If you have any questions concerning the attached rates please do not hesitate to call.

Sincerely,

Cherie L. Lukcic
Budget & Financial Manager

cc: Joann Wehle
Karen Bramley

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TAMPA ELECTRIC COMPANY
April 2, 2004
PAGE TWO

Adjustment Factors:
FUEL ADJUSTMENT

Price per gallon per contract (Base) 0.7000
Platts Average December 2003, January & February 2004 0.8891

Calculation of adjustment rate: 0.8891 / 0.7000 = 1.27014

VARIABLE COMPONENT ADJUSTMENT

	CPI	PPI
September, 2003	191.0	145.0
October, 2003	191.7	145.9
November, 2003	191.6	146.1
December, 2003	191.5	146.2
January, 2004	191.9	147.1
February, 2004	192.7	148.2

CPI Average Dec, Jan & Feb = (191.0 + 191.7 + 191.6) / 3 = 191.4

PPI Average Dec, Jan, & Feb = (145.0 + 145.9 + 146.1) / 3 = 145.7

Base Quarterly Index Average = (AVERAGE CPI + AVERAGE PPI) / 2 = (191.4 + 145.7) / 2 = 168.6

Quarterly Index Average

CPI 12/03, 01/04 & 02/04 CPI Ave = (191.5 + 191.9 + 192.7) / 3 = 192.0

PPI 12/03, 01/04 & 02/04 Average = (146.2 + 147.1 + 148.2) / 3 = 147.2

Average CPI + Average PPI / 2 = (192.0 + 147.2) / 2 = 169.6

Calculation of adjustment rate: 169.6 / 168.6 = 1.00593

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TECO BULK TERMINAL	BASE RATE	ADJUSTMENT FACTOR	OTHER ADJUSTMENT	RATE EFFECTIVE 04/01/04
TRANSFER RATE DOMESTIC	2.45	1.00000	0.00	2.45
TRANSFER RATE IMPORT	4.00	1.00000	0.00	4.00
TECO OCEAN SHIPPING				
FUEL	0.86	1.27014	0.00	1.09
VARIABLE	4.32	1.00593	0.00	4.35
OTHER	2.80	1.00000	0.00	2.80
TOTAL	7.98			8.24
TECO OCEAN SHIPPING - PETCOKE				
FUEL	1.52	1.27014	0.00	1.93
VARIABLE	5.19	1.00593	0.00	5.22
OTHER	4.17	1.00000	0.00	4.17
TOTAL	10.88			11.32

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INCREMENTAL RATES

GREEN 11 - GR11				
FUEL	$1.99	1.27014	$0.00	$2.53
VARIABLE	4.89	1.00593	0.00	4.92
OTHER	1.13	1.00000	0.00	1.13
TOTAL	$8.01			$8.58
PATRIOT - GR32				
FUEL	$2.09	1.27014	0.00	$2.65
VARIABLE	5.01	1.00593	0.00	5.04
OTHER	1.14	1.00000	0.00	1.14
TOTAL	$8.24			$8.83
SEBREE - GR43				
FUEL	$2.14	1.27014	0.00	$2.72
VARIABLE	5.08	1.00593	0.00	5.11
OTHER	1.15	1.00000	0.00	1.15
TOTAL	$8.37			$8.98
PYRAMID - GR94				
FUEL	$2.39	1.27014	0.00	$3.04
VARIABLE	5.36	1.00593	0.00	5.39
OTHER	1.20	1.00000	0.00	1.20
TOTAL	$8.95			$9.63
KEN MINE - GR 98				
FUEL	$2.41	1.27014	0.00	$3.06
VARIABLE	5.38	1.00593	0.00	5.41
OTHER	1.20	1.00000	0.00	1.20
TOTAL	$8.99			$9.67
POWHATTAN POINT - OR110.8				
FUEL	$3.24	1.27014	0.00	$4.12
VARIABLE	6.10	1.00593	0.00	6.14
OTHER	1.31	1.00000	0.00	1.31
TOTAL	$10.65			$11.57

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TTI - OR 406				
FUEL	$2.81	1.27014	0.00	$3.57
VARIABLE	5.21	1.00593	0.00	5.24
OTHER	1.18	1.00000	0.00	1.18
TOTAL	$9.20			$9.99
JEFFERSON RIVER PORT - OR618				
FUEL	$2.50	1.27014	0.00	$3.18
VARIABLE	4.55	1.00593	0.00	4.58
OTHER	1.08	1.00000	0.00	1.08
TOTAL	$8.13			$8.83
NEW HOPE - OR734				
FUEL	$2.32	1.27014	0.00	$2.95
VARIABLE	4.18	1.00593	0.00	4.20
OTHER	1.03	1.00000	0.00	1.03
TOTAL	$7.53			$8.18
OWENSBORO				
FUEL	2.30	1.27014	0.00	$2.92
VARIABLE	4.13	1.00593	0.00	4.15
OTHER	1.02	1.00000	0.00	1.02
TOTAL	$7.45			$8.10
YANKEETOWN - OR773				
FUEL	2.27	1.27014	0.00	$2.88
VARIABLE	4.06	1.00593	0.00	4.08
OTHER	1.01	1.00000	0.00	1.01
TOTAL	$7.34			$7.98
SOUTHERN INDIANA - OR794				
FUEL	2.23	1.27014	0.00	$2.83
VARIABLE	3.98	1.00593	0.00	4.00
OTHER	1.00	1.00000	0.00	1.00
TOTAL	$7.21			$7.84

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TAMPA ELECTRIC COMPANY
April 2, 2004
PAGE SIX

MT VERNON				
FUEL	$2.18	1.27014	0.00	$2.77
VARIABLE	3.87	1.00593	0.00	3.89
OTHER	0.99	1.00000	0.00	0.99
TOTAL	$7.04			$7.65
OVERLAND - OR842				
FUEL	$2.16	1.27014	0.00	$2.74
VARIABLE	3.83	1.00593	0.00	3.85
OTHER	0.98	1.00000	0.00	0.98
TOTAL	$6.97			$7.58
HAMILTON - OR852				
FUEL	$2.13	1.27014	0.00	$2.71
VARIABLE	3.80	1.00593	0.00	3.82
OTHER	0.97	1.00000	0.00	0.97
TOTAL	$6.90			$7.50
SHAWNEETOWN - OR858				
FUEL	$2.12	1.27014	0.00	$2.69
VARIABLE	3.75	1.00593	0.00	3.77
OTHER	0.94	1.00000	0.00	0.94
TOTAL	$6.81			$7.40
DEKOVEN - OR869				
FUEL	$2.11	1.27014	0.00	$2.68
VARIABLE	3.70	1.00593	0.00	3.72
OTHER	0.94	1.00000	0.00	0.94
TOTAL	$6.75			$7.34
CASEYVILLE - OR872				
FUEL	$2.11	1.27014	0.00	$2.68
VARIABLE	3.70	1.00593	0.00	3.72
OTHER	0.93	1.00000	0.00	0.93
TOTAL	$6.74			$7.33

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RIGSBY & BARNARD - OR881

FUEL	$2.09	1.27014	0.00	$2.65
VARIABLE	3.67	1.00593	0.00	3.69
OTHER	0.93	1.00000	0.00	0.93
TOTAL	$6.69			$7.28

EMPIRE - OR896

FUEL	$2.08	1.27014	0.00	$2.64
VARIABLE	3.64	1.00593	0.00	3.66
OTHER	0.93	1.00000	0.00	0.93
TOTAL	$6.65			$7.23

COOK - OR948

FUEL	$1.86	1.27014	0.00	$2.36
VARIABLE	3.26	1.00593	0.00	3.28
OTHER	0.86	1.00000	0.00	0.86
TOTAL	$5.98			$6.50

MOUND CITY - OR976

FUEL	$1.86	1.27014	0.00	$2.36
VARIABLE	3.24	1.00593	0.00	3.26
OTHER	0.86	1.00000	0.00	0.86
TOTAL	$5.96			$6.48

GRT - TR23

FUEL	$1.98	1.27014	0.00	$2.51
VARIABLE	4.13	1.00593	0.00	4.15
OTHER	1.05	1.00000	0.00	1.05
TOTAL	$7.16			$7.72

KENTUCKY LAKES DOCK - TR24

FUEL	$1.98	1.27014	0.00	$2.51
VARIABLE	4.13	1.00593	0.00	4.15
OTHER	1.05	1.00000	0.00	1.05
TOTAL	$7.16			$7.72

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CORA - UM98

FUEL	$2.32	1.27014	0.00	$2.95
VARIABLE	3.82	1.00593	0.00	3.84
OTHER	0.98	1.00000	0.00	0.98
TOTAL	$7.12			$7.77

REFINERIES, PET COKE M.P. 1
LOWER MISSISSIPPI RIVER

FUEL	$0.77	1.27014	0.00	$0.98
VARIABLE	1.39	1.00593	0.00	1.40
OTHER	0.37	1.00000	0.00	0.37
TOTAL	$2.53			$2.75

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TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIRST REQUEST FOR PRODUCTION
OF DOCUMENTS
DOCUMENT NO. 13
BATES STAMPED PAGES: 31 - 47
FILED: MARCH 3, 2004

13. Please provide all documents prepared by of [sic] for Tampa Electric regarding the cost effectiveness of contracting for the delivery of foreign coal from a ship with an adequate draft to approach, dock, and unload coal at Tampa Electric's generating stations.

A. The requested documents are attached.

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11.26.05 (entire DN)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 88
COMPANY/ WITNESS. CSX
DATE: 5|27-28|04 + 6|10|04

declas 11-26-05
DOCUMENT NUMBER-DATE
06653 JUN 16 04
FPSC-COMMISSION CLERK

Supplier Name	Bid #	Conforming	Reason
Black Beauty (Somerville)	4B-GEN-2005	yes	
Interocean Coal Sales, LDC	7B-GEN-2005	Yes	missing information
Interocean Coal Sales, LDC	7A-GEN-2005	Yes	missing information
Black Beauty (Willow Lake)	4A-GEN-2005	yes	
Black Beauty (Willow Lake)	4A-GEN-2005	yes	
Pact Resources, LLC #1	10A-GEN-2005	Yes	
Alliance Coal, LLC	1-GEN-2005	Yes	
Pact Resources, LLC #3	10C-GEN-2005	Yes	
Lafayette Coal, Co. (Jader)	8A-GEN-2005	Yes	

Supplier Name	Bid #	Conforming	Reason
S Coal Company	12-GEN-2005	No	Tons
MacEachern Energy & Transportation	9-GEN-2005	No	Tons and Term

Supplier Name	Bid #	Conforming	Reason
American Innovative Group, LLC*	3-GEN-2005	No	Sulfur, tons, term
Freeman United **(Snyfuel)**	6C-GEN-2005	No	Moisture
Pact Resources, LLC #2	10B-GEN-2005	No	Ash
Pigman Sales Company	11B-GEN-2005	No	Chlorine
CMC	14-GEN-2005	No	Tons, ash fusion
American Coal Company	2-GEN-2005	No	Sulfur
Consol Energy	5-GEN-2005	No	Sulfur
Lafayette Coal, Co.	8B-GEN-2005	No	Moisture
Freeman United	6B-GEN-2005	No	Moisture
Solar Sources	13-GEN-2005	No	Moisture
Freeman United	6A-GEN-2005	No	Moisture
Pigman Sales Company	11A-GEN-2005	No	Chlorine

Supplier Name	Term	$/Ton FOB Point
Black Beauty (Somerville)	2005 to 2014	$24.40
Interocean Coal Sales, LDC	2005 to 2014	$39.70
Interocean Coal Sales, LDC	2005 to 2014	$41.35
Black Beauty (Willow Lake)	2005 to 2014	$28.85
Black Beauty (Willow Lake)	2005 to 2014	$28.85
Pact Resources, LLC #1	2005 to 2014	$24.41
Alliance Coal, LLC	2005 to 2014	$28.00
Pact Resources, LLC #3	2005 to 2014	$28.08
Lafayette Coal, Co. (Jader)	2005 to 2014	$30.75

Supplier Name	Term	$/Ton FOB Point
S Coal Company	2005 to 2014	$25.29
MacEachern Energy & Transportation	2004 to 2013	$29.50

Supplier Name	Term	$/Ton FOB Point
American Innovative Group, LLC*	2004 to June 2005	$24.54
Freeman United **(Snyfuel)**	2005 to 2014	$24.10
Pact Resources, LLC #2	2005 to 2014	$22.57
Pigman Sales Company	2005 to 2014	$30.31
CMC	2005 to 2014	$30.91
American Coal Company	2005 to 2014	$28.71
Consol Energy	2005 to 2014	$27.00
Lafayette Coal, Co.	2005 to 2014	$24.00
Freeman United	2005 to 2014	$27.10
Solar Sources	2005 to 2007	$24.50
Freeman United	2005 to 2014	$27.25
Pigman Sales Company	2005 to 2014	$34.00

Supplier Name	Escalation	Rail Rate to Mt. Vernon	Railcar lease & Transfer fee
Black Beauty (Somerville)	2% per year in 06; reopener		
Interocean Coal Sales, LDC	2% per year; silent on reopener		
Interocean Coal Sales, LDC	2% per year; silent on reopener		
Black Beauty (Willow Lake)	2% per year in 06; reopener		
Black Beauty (Willow Lake)	2% per year in 06; reopener		
Pact Resources, LLC #1	3% per year; silient on reopener		
Alliance Coal, LLC	Silent on commodity; wants transloading esclation		
Pact Resources, LLC #3	3% per year; silient on reopener		
Lafayette Coal, Co. (Jader)	2% per year		

Supplier Name	Escalation	Rail Rate to Mt. Vernon	Railcar lease & Transfer fee
S Coal Company	mentions, but does not define esclation		
MacEachern Energy & Transportation	1.5% per year		

Supplier Name	Escalation	Rail Rate to Mt. Vernon	Railcar lease & Transfer fee
American Innovative Group, LLC*			
Freeman United **(Snyfuel)**	silent on escalation and reopener		
Pact Resources, LLC #2	3% per year; silient on reopener		
Pigman Sales Company	1.93 % per year		
CMC	proposes CPI or PPI		
American Coal Company			
Consol Energy	3.7% escalation		
Lafayette Coal, Co.	2% per year	$3.60	$1.40
Freeman United	silent on escalation and reopener		
Solar Sources		$3.60	
Freeman United	silent on escalation and reopener		
Pigman Sales Company	silent on escalation		

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Supplier Name	Dock	River Barge Rate	TBT/TOS Rate	Total Del'd price/ton	Total Del'd c/MMBTU
Black Beauty (Somerville)	Evansville	$7.21	$10.43	$42.04	185.198
Interocean Coal Sales, LDC	Marigold Land (POT)	$1.65	$0.00	$41.35	187.955
Interocean Coal Sales, LDC	Big Bend	$0.00	$0.00	$41.35	187.955
Black Beauty (Willow Lake)	Shawneetown	$6.81	$10.43	$46.09	190.455
Black Beauty (Willow Lake)	Shawneetown	$6.81	$10.43	$46.09	190.455
Pact Resources, LLC #1	Green River	$8.37	$10.43	$43.21	191.195
Alliance Coal, LLC	Mt. Vernon	$7.04	$10.43	$45.47	192.669
Pact Resources, LLC #3	Green River	$8.37	$10.43	$46.88	198.644
Lafayette Coal, Co. (Jader)	Empire	$6.65	$10.43	$47.83	199.292
				$3.43	

Supplier Name	Dock	River Barge Rate	TBT/TOS Rate	Total Del'd price/ton	Total Del'd c/MMBTU
S Coal Company	Gorham (85.6)	$7.12	$10.43	$42.84	178.500
MacEachern Energy & Transportation	Guanta Port		$16.00	$45.50	192.797

Supplier Name	Dock	River Barge Rate	TBT/TOS Rate	Total Del'd price/ton	Total Del'd c/MMBTU
American Innovative Group, LLC*	Dekovan	$6.75	$10.43	$41.72	176.780
Freeman United **(Snyfuel)**	Cook	$5.98	$10.43	$40.51	189.299
Pact Resources, LLC #2	Green River	$8.37	$10.43	$41.37	190.645
Pigman Sales Company	Dekoven	$6.75	$10.43	$47.49	191.492
CMC	Puerto Bolivar, Columbia	$12.00		$42.91	198.657
American Coal Company	Powhattan	$10.65	$10.43	$49.79	199.160
Consol Energy	Shoemaker (Ohio 93.7)	$11.00	$10.43	$48.43	200.954
Lafayette Coal, Co.	Mt. Vernon	$7.04	$10.43	$46.47	202.043
Freeman United	Cook	$5.98	$10.43	$43.51	203.318
Solar Sources	Rail (Wheatland Siding (176.2))	$7.04	$10.43	$45.57	203.438
Freeman United	Cook	$5.98	$10.43	$43.66	204.019
Pigman Sales Company	Dekoven	$6.75	$10.43	$51.18	209.325

Bid Specification Monthly

Supplier Name	Bid #	Conforming	Reason
Alliance Coal, LLC	1-GEN-2005	Yes	
American Coal Company	2-GEN-2005	No	Sulfur
American Innovative Group, LLC	3-GEN-2005	No	Tons and Term
Black Beauty (Willow Lake)	4A-GEN-2005	No	Chlorine
Black Beauty (Somerville)	4B-GEN-2005	yes	
Consol Energy	5-GEN-2005	No	Sulfur
Freeman United	6A-GEN-2005	No	Moisture
Freeman United	6B-GEN-2005	No	Moisture
Freeman United	6C-GEN-2005	No	Moisture
Interocean Coal Sales, LDC	7A-GEN-2005	no	missing information
Interocean Coal Sales, LDC	7B-GEN-2005	no	missing information
Lafayette Coal, Co. (Jader)	8A-GEN-2005	Yes	
Lafayette Coal, Co.	8B-GEN-2005	No	Moisture
MacEachern Energy & Transportation	9-GEN-2005	No	Tons and Term
Pact Resources, LLC	10A-GEN-2005	Yes	
Pact Resources, LLC	10B-GEN-2005	No	Ash
Pact Resources, LLC	10C-GEN-2005	Yes	
Pigman Sales Company	11A-GEN-2005	No	Tons in 2005
Pigman Sales Company	11B-GEN-2005	No	Chlorine
S Coal Company	12-GEN-2005	No	Tons
Solar Sources	13-GEN-2005	No	Rail and Tons

Bid Specification Monthly

Supplier Name	Bid #	Term	$/Ton FOB Point
Alliance Coal, LLC	1-GEN-2005	2005 to 2014	$28.00
American Coal Company	2-GEN-2005	2005 to 2014	$28.71
American Innovative Group, LLC	3-GEN-2005	2004 to June 2005	$23.07
Black Beauty (Willow Lake)	4A-GEN-2005	2005 to 2014	$28.85
Black Beauty (Somerville)	4B-GEN-2005	2005 to 2014	$24.40
Consol Energy	5-GEN-2005	2005 to 2014	$27.00
Freeman United	6A-GEN-2005	2005 to 2014	$27.25
Freeman United	6B-GEN-2005	2005 to 2014	$27.10
Freeman United	6C-GEN-2005	2005 to 2014	$24.10
Interocean Coal Sales, LDC	7A-GEN-2005	2005 to 2014	$41.35
Interocean Coal Sales, LDC	7B-GEN-2005	2005 to 2014	$39.70
Lafayette Coal, Co. (Jader)	8A-GEN-2005	2005 to 2014	$30.75
Lafayette Coal, Co.	8B-GEN-2005	2005 to 2014	$24.00
MacEachern Energy & Transportation	9-GEN-2005	2004 to 2013	$29.50
Pact Resources, LLC	10A-GEN-2005	2005 to 2014	$24.41
Pact Resources, LLC	10B-GEN-2005	2005 to 2014	$22.57
Pact Resources, LLC	10C-GEN-2005	2005 to 2014	$28.08
Pigman Sales Company	11A-GEN-2005	2005 to 2014	$34.00
Pigman Sales Company	11B-GEN-2005	2005 to 2014	$30.31
S Coal Company	12-GEN-2005	2005 to 2014	$25.29
Solar Sources	13-GEN-2005	2005 to 2007	$24.50

Bid Specification Monthly

Supplier Name	Bid #	Escalation	Rail Rate to Mt. Vernon	Railcar lease & Transfer fee
Alliance Coal, LLC	1-GEN-2005	Silent on commodity; wants transloading esclation		
American Coal Company	2-GEN-2005			
American Innovative Group, LLC	3-GEN-2005			
Black Beauty (Willow Lake)	4A-GEN-2005	2% per year in 06; reopener		
Black Beauty (Somerville)	4B-GEN-2005	2% per year in 06; reopener		
Consol Energy	5-GEN-2005	3.7% escalation		
Freeman United	6A-GEN-2005	silent on escalation and reopener		
Freeman United	6B-GEN-2005	silent on escalation and reopener		
Freeman United	6C-GEN-2005	silent on escalation and reopener		
Interocean Coal Sales, LDC	7A-GEN-2005	2% per year; silent on reopener		
Interocean Coal Sales, LDC	7B-GEN-2005	2% per year; silent on reopener		
Lafayette Coal, Co. (Jader)	8A-GEN-2005	2% per year		
Lafayette Coal, Co.	8B-GEN-2005	2% per year	$3.60	$1.40
MacEachern Energy & Transportation	9-GEN-2005	1.5% per year		
Pact Resources, LLC	10A-GEN-2005	3% per year; silient on reopener		
Pact Resources, LLC	10B-GEN-2005	3% per year; silient on reopener		
Pact Resources, LLC	10C-GEN-2005	3% per year; silient on reopener		
Pigman Sales Company	11A-GEN-2005	silent on escalation		
Pigman Sales Company	11B-GEN-2005	1.93 % per year		
S Coal Company	12-GEN-2005	mentions, but does not define esclation		
Solar Sources	13-GEN-2005			

Bid Solicitation Evalı
Received: Decembe
Tonnage Required: 8

Bid Specification Monthly

Supplier Name	Bid #	Dock	River Barge Rate	TBT/TOS Rate	Total Del'd price/ton
Alliance Coal, LLC	1-GEN-2005	Mt. Vernon	$7.04	$10.43	$45.47
American Coal Company	2-GEN-2005	Powhattan	$10.65	$10.43	$49.79
American Innovative Group, LLC	3-GEN-2005	Dekovan	$6.75	$10.43	$40.25
Black Beauty (Willow Lake)	4A-GEN-2005	Shawneetown	$6.81	$10.43	$46.09
Black Beauty (Somerville)	4B-GEN-2005	Evansville	$7.21	$10.43	$42.04
Consol Energy	5-GEN-2005	Shoemaker (Ohio 93.7)	$11.00	$10.43	$48.43
Freeman United	6A-GEN-2005	Cook	$5.98	$10.43	$43.66
Freeman United	6B-GEN-2005	Cook	$5.98	$10.43	$43.51
Freeman United	6C-GEN-2005	Cook	$5.98	$10.43	$40.51
Interocean Coal Sales, LDC	7A-GEN-2005	Big Bend	$0.00	$0.00	$41.35
Interocean Coal Sales, LDC	7B-GEN-2005	Marigold Land (POT)	$0.00	$0.00	$39.70
Lafayette Coal, Co. (Jader)	8A-GEN-2005	Empire	$6.65	$10.43	$47.83
Lafayette Coal, Co.	8B-GEN-2005	Mt. Vernon	$7.04	$10.43	$46.47
MacEachern Energy & Transportation	9-GEN-2005	Guanta Port		$12.00	$41.50
Pact Resources, LLC	10A-GEN-2005	Green River	$8.37	$10.43	$43.21
Pact Resources, LLC	10B-GEN-2005	Green River	$8.37	$10.43	$41.37
Pact Resources, LLC	10C-GEN-2005	Green River	$8.37	$10.43	$46.88
Pigman Sales Company	11A-GEN-2005	Dekoven	$6.75	$10.43	$51.18
Pigman Sales Company	11B-GEN-2005	Dekoven	$6.75	$10.43	$47.49
S Coal Company	12-GEN-2005	Gorham (85.6)	$7.12	$10.43	$42.84
Solar Sources	13-GEN-2005	Rail (Wheatland Siding (176.2))			$24.50

ıation: Gen 2005
· 19, 2003
50,000

	Bid Specification Monthly			14.50%	12.00%	10,700
Supplier Name	**Bid #**	**Total Del'd c/MMBTU**	**Tonnage offered**	**% Moisture**	**% Ash**	**Btu**
Alliance Coal, LLC	1-GEN-2005	192.669	850,000	12.00%	7.00%	11,800
American Coal Company	2-GEN-2005	199.160	850,000	7.00%	9.75%	12,500
American Innovative Group, LLC	3-GEN-2005	179.688	360,000	12.00%	12.00%	11,200
Black Beauty (Willow Lake)	4A-GEN-2005	190.455	850,000	14.50%	12.00%	12,100
Black Beauty (Somerville)	4B-GEN-2005	185.198	850,000	14.50%	10.50%	11,350
Consol Energy	5-GEN-2005	200.954	850,000	7.50%	10.30%	12,050
Freeman United	6A-GEN-2005	204.019	500,000	16.00%	9.00%	10,700
Freeman United	6B-GEN-2005	203.318	850,000	16.00%	9.00%	10,700
Freeman United	6C-GEN-2005	189.299	850,000	16.00%	9.00%	10,700
Interocean Coal Sales, LDC	7A-GEN-2005	187.955	850,000	14.50%	12.00%	11,000
Interocean Coal Sales, LDC	7B-GEN-2005	180.455	850,000	14.50%	12.00%	11,000
Lafayette Coal, Co. (Jader)	8A-GEN-2005	199.292	850,000	8.00%	10.00%	12,000
Lafayette Coal, Co.	8B-GEN-2005	202.043	850,000	16.00%	7.50%	11,500
MacEachern Energy & Transportation	9-GEN-2005	175.847	250,000 to 300,000	8.00%	8.00%	11,800
Pact Resources, LLC	10A-GEN-2005	191.195	850,000	12.00%	12.00%	11,300
Pact Resources, LLC	10B-GEN-2005	190.645	850,000	12.00%	14.00%	10,850
Pact Resources, LLC	10C-GEN-2005	198.644	850,000	10.00%	10.00%	11,800
Pigman Sales Company	11A-GEN-2005	209.325	350,000	10.22%	10.50%	12,225
Pigman Sales Company	11B-GEN-2005	191.492	850,000	10.22%	8.80%	12,400
S Coal Company	12-GEN-2005	178.500	500,000	9.00%	10.00%	12,000
Solar Sources	13-GEN-2005	109.375	500,000	17.00%	10.00%	11,200

	Bid Specification Monthly	3.50%	0.20%	2300	47	36.00%	43.00%
Supplier Name	**Bid #**	**% Sulfur**	**Chlorine**	**Ash Softening Temp (H=W)**	**Grind (HGI)**	**Volatile Matter**	**Fixed Carbon**
Alliance Coal, LLC	1-GEN-2005	3.20%	0.20%	2040	50	36%	43%
American Coal Company	2-GEN-2005	4.56%	0.04%	2190	50	39%	45%
American Innovative Group, LLC	3-GEN-2005	4.00%	0.15%	2040	50	38%	44%
Black Beauty (Willow Lake)	4A-GEN-2005	3.50%	0.24%	2050	54	34%	45%
Black Beauty (Somerville)	4B-GEN-2005	3.55%	0.04%	2085	52	34%	43%
Consol Energy	5-GEN-2005	4.40%	0.07%	2055	52	36%	46%
Freeman United	6A-GEN-2005	3.50%	0.20%	2040	55	35%	42%
Freeman United	6B-GEN-2005	3.50%	0.20%	2040	55	35%	42%
Freeman United	6C-GEN-2005	3.50%	0.20%	2040	55	35%	42%
Interocean Coal Sales, LDC	7A-GEN-2005	1.00%	0.10%	2300	47	34-37%	40-45%
Interocean Coal Sales, LDC	7B-GEN-2005	1.00%	0.10%	2300	47	34-37%	40-45%
Lafayette Coal, Co. (Jader)	8A-GEN-2005	3.00%	0.20%	2200	58	34%	51%
Lafayette Coal, Co.	8B-GEN-2005	2.40%	0.02%	2170	55	34%	46%
MacEachern Energy & Transportation	9-GEN-2005	1.50%	0.03%	2300	45-48	40-41%	45-48%
Pact Resources, LLC	10A-GEN-2005	3.50%	0.15%	2054	50	38%	43%
Pact Resources, LLC	10B-GEN-2005	3.50%	0.15%	2054	50	38%	43%
Pact Resources, LLC	10C-GEN-2005	3.20%	0.15%	2089	50	38%	45%
Pigman Sales Company	11A-GEN-2005	3.50%	0.22%	2025	50	30%	40%
Pigman Sales Company	11B-GEN-2005	?		?	?	?	?
S Coal Company	12-GEN-2005	2.50%	0.09%	2160	54	39%	51%
Solar Sources	13-GEN-2005	2.50%	0.05%	2300	50	34%	44%

Bid Specification Monthly

Supplier Name	Bid #	Conforming	Reason
Solar Sources	13-GEN-2005	No	Rail and Tons
MacEachern Energy & Transportation	9-GEN-2005	No	Tons and Term
S Coal Company	12-GEN-2005	No	Tons
American Innovative Group, LLC	3-GEN-2005	No	Tons and Term
Interocean Coal Sales, LDC	7B-GEN-2005	Yes	
Black Beauty (Somerville)	4B-GEN-2005	No	Sulfur
Interocean Coal Sales, LDC	7A-GEN-2005	Yes	
Freeman United	6C-GEN-2005	No	Moisture
Black Beauty (Willow Lake)	4A-GEN-2005	No	Chlorine
Pact Resources, LLC	10B-GEN-2005	No	Ash
Pact Resources, LLC	10A-GEN-2005	Yes	
Pigman Sales Company	11B-GEN-2005	No	Chlorine
Alliance Coal, LLC	1-GEN-2005	Yes	
Pact Resources, LLC	10C-GEN-2005	Yes	
American Coal Company	2-GEN-2005	No	Sulfur
Lafayette Coal, Co. (Jader)	8A-GEN-2005	Yes	
Consol Energy	5-GEN-2005	No	Sulfur
Lafayette Coal, Co.	8B-GEN-2005	No	Moisture
Freeman United	6B-GEN-2005	No	Moisture
Freeman United	6A-GEN-2005	No	Moisture
Pigman Sales Company	11A-GEN-2005	No	Tons in 2005

Bid Specification Monthly

Supplier Name	Bid #	Term	$/Ton FOB Point
Solar Sources	13-GEN-2005	2005 to 2007	$24.50
MacEachern Energy & Transportation	9-GEN-2005	2004 to 2013	$29.50
S Coal Company	12-GEN-2005	2005 to 2014	$25.29
American Innovative Group, LLC	3-GEN-2005	2004 to June 2005	$23.07
Interocean Coal Sales, LDC	7B-GEN-2005	2005 to 2014	$39.70
Black Beauty (Somerville)	4B-GEN-2005	2005 to 2014	$24.40
Interocean Coal Sales, LDC	7A-GEN-2005	2005 to 2014	$41.35
Freeman United	6C-GEN-2005	2005 to 2014	$24.10
Black Beauty (Willow Lake)	4A-GEN-2005	2005 to 2014	$28.85
Pact Resources, LLC	10B-GEN-2005	2005 to 2014	$22.57
Pact Resources, LLC	10A-GEN-2005	2005 to 2014	$24.41
Pigman Sales Company	11B-GEN-2005	2005 to 2014	$30.31
Alliance Coal, LLC	1-GEN-2005	2005 to 2014	$28.00
Pact Resources, LLC	10C-GEN-2005	2005 to 2014	$28.08
American Coal Company	2-GEN-2005	2005 to 2014	$28.71
Lafayette Coal, Co. (Jader)	8A-GEN-2005	2005 to 2014	$30.75
Consol Energy	5-GEN-2005	2005 to 2014	$27.00
Lafayette Coal, Co.	8B-GEN-2005	2005 to 2014	$24.00
Freeman United	6B-GEN-2005	2005 to 2014	$27.10
Freeman United	6A-GEN-2005	2005 to 2014	$27.25
Pigman Sales Company	11A-GEN-2005	2005 to 2014	$34.00

Bid Specification Monthly

Supplier Name	Bid #	Escalation	Rail Rate to Mt. Vernon	Railcar lease & Transfer fee
Solar Sources	13-GEN-2005			
MacEachern Energy & Transportation	9-GEN-2005	1.5% per year		
S Coal Company	12-GEN-2005	mentions, but does not define esclation		
American Innovative Group, LLC	3-GEN-2005			
Interocean Coal Sales, LDC	7B-GEN-2005	2% per year; silent on reopener		
Black Beauty (Somerville)	4B-GEN-2005	2% per year in 06; reopener		
Interocean Coal Sales, LDC	7A-GEN-2005	2% per year; silent on reopener		
Freeman United	6C-GEN-2005	silent on escalation and reopener		
Black Beauty (Willow Lake)	4A-GEN-2005	2% per year in 06; reopener		
Pact Resources, LLC	10B-GEN-2005	3% per year; silient on reopener		
Pact Resources, LLC	10A-GEN-2005	3% per year; silient on reopener		
Pigman Sales Company	11B-GEN-2005	1.93 % per year		
Alliance Coal, LLC	1-GEN-2005	Silent on commodity; wants transloading esclation		
Pact Resources, LLC	10C-GEN-2005	3% per year; silient on reopener		
American Coal Company	2-GEN-2005			
Lafayette Coal, Co. (Jader)	8A-GEN-2005	2% per year		
Consol Energy	5-GEN-2005	3.7% escalation		
Lafayette Coal, Co.	8B-GEN-2005	2% per year	$3.60	$1.40
Freeman United	6B-GEN-2005	silent on escalation and reopener		
Freeman United	6A-GEN-2005	silent on escalation and reopener		
Pigman Sales Company	11A-GEN-2005	silent on escalation		

CONFIDENTIAL

Bid Solicitation Evalu
Received: Decembe
Tonnage Required: 8

Bid Specification Monthly

Supplier Name	Bid #	Dock	River Barge Rate	TBT/TOS Rate	Total Del'd price/ton
Solar Sources	13-GEN-2005	Rail (Wheatland Siding (176.2))			
MacEachern Energy & Transportation	9-GEN-2005	Guanta Port		$12.00	$41.50
S Coal Company	12-GEN-2005	Gorham (85.6)	$7.12	$10.43	$42.84
American Innovative Group, LLC	3-GEN-2005	Dekovan	$6.75	$10.43	$40.25
Interocean Coal Sales, LDC	7B-GEN-2005	Marigold Land (POT)	$0.00	$0.00	$39.70
Black Beauty (Somerville)	4B-GEN-2005	Evansville	$7.21	$10.43	$42.04
Interocean Coal Sales, LDC	7A-GEN-2005	Big Bend	$0.00	$0.00	$41.35
Freeman United	6C-GEN-2005	Cook	$5.98	$10.43	$40.51
Black Beauty (Willow Lake)	4A-GEN-2005	Shawneetown	$6.81	$10.43	$46.09
Pact Resources, LLC	10B-GEN-2005	Green River	$8.37	$10.43	$41.37
Pact Resources, LLC	10A-GEN-2005	Green River	$8.37	$10.43	$43.21
Pigman Sales Company	11B-GEN-2005	Dekoven	$6.75	$10.43	$47.49
Alliance Coal, LLC	1-GEN-2005	Mt. Vernon	$7.04	$10.43	$45.47
Pact Resources, LLC	10C-GEN-2005	Green River	$8.37	$10.43	$46.88
American Coal Company	2-GEN-2005	Powhattan	$10.65	$10.43	$49.79
Lafayette Coal, Co. (Jader)	8A-GEN-2005	Empire	$6.65	$10.43	$47.83
Consol Energy	5-GEN-2005	Shoemaker (Ohio 93.7)	$11.00	$10.43	$48.43
Lafayette Coal, Co.	8B-GEN-2005	Mt. Vernon	$7.04	$10.43	$46.47
Freeman United	6B-GEN-2005	Cook	$5.98	$10.43	$43.51
Freeman United	6A-GEN-2005	Cook	$5.98	$10.43	$43.66
Pigman Sales Company	11A-GEN-2005	Dekoven	$6.75	$10.43	$51.18

ıation: Gen 2005
· 19, 2003
50,000

	Bid Specification Monthly			14.50%	12.00%	10,700
Supplier Name	**Bid #**	**Total Del'd c/MMBTU**	**Tonnage offered**	**% Moisture**	**% Ash**	**Btu**
Solar Sources	13-GEN-2005	0.000	500,000	17.00%	10.00%	11,200
MacEachern Energy & Transportation	9-GEN-2005	175.847	250,000 to 300,000	8.00%	8.00%	11,800
S Coal Company	12-GEN-2005	178.500	500,000	9.00%	10.00%	12,000
American Innovative Group, LLC	3-GEN-2005	179.688	360,000	12.00%	12.00%	11,200
Interocean Coal Sales, LDC	7B-GEN-2005	180.455	850,000	14.50%	12.00%	11,000
Black Beauty (Somerville)	4B-GEN-2005	185.198	850,000	14.50%	10.50%	11,350
Interocean Coal Sales, LDC	7A-GEN-2005	187.955	850,000	14.50%	12.00%	11,000
Freeman United	6C-GEN-2005	189.299	850,000	16.00%	9.00%	10,700
Black Beauty (Willow Lake)	4A-GEN-2005	190.455	850,000	14.50%	12.00%	12,100
Pact Resources, LLC	10B-GEN-2005	190.645	850,000	12.00%	14.00%	10,850
Pact Resources, LLC	10A-GEN-2005	191.195	850,000	12.00%	12.00%	11,300
Pigman Sales Company	11B-GEN-2005	191.492	850,000	10.22%	8.80%	12,400
Alliance Coal, LLC	1-GEN-2005	192.669	850,000	12.00%	7.00%	11,800
Pact Resources, LLC	10C-GEN-2005	198.644	850,000	10.00%	10.00%	11,800
American Coal Company	2-GEN-2005	199.160	850,000	7.00%	9.75%	12,500
Lafayette Coal, Co. (Jader)	8A-GEN-2005	199.292	850,000	8.00%	10.00%	12,000
Consol Energy	5-GEN-2005	200.954	850,000	7.50%	10.30%	12,050
Lafayette Coal, Co.	8B-GEN-2005	202.043	850,000	16.00%	7.50%	11,500
Freeman United	6B-GEN-2005	203.318	850,000	16.00%	9.00%	10,700
Freeman United	6A-GEN-2005	204.019	500,000	16.00%	9.00%	10,700
Pigman Sales Company	11A-GEN-2005	209.325	350,000	10.22%	10.50%	12,225

CONFIDENTIAL

	Bid Specification Monthly	3.50%	0.20%	2300	47	36.00%	43.00%
Supplier Name	**Bid #**	**% Sulfur**	**Chlorine**	**Ash Softening Temp (H=W)**	**Grind (HGI)**	**Volatile Matter**	**Fixed Carbon**
Solar Sources	13-GEN-2005	2.50%	0.05%	2300	50	34%	44%
MacEachern Energy & Transportation	9-GEN-2005	1.50%	0.03%	2300	45-48	40-41%	45-48%
S Coal Company	12-GEN-2005	2.50%	0.09%	2160	54	39%	51%
American Innovative Group, LLC	3-GEN-2005	4.00%	0.15%	2040	50	38%	44%
Interocean Coal Sales, LDC	7B-GEN-2005	1.00%	0.10%	2300	47	34-37%	40-45%
Black Beauty (Somerville)	4B-GEN-2005	3.55%	0.04%	2085	52	34%	43%
Interocean Coal Sales, LDC	7A-GEN-2005	1.00%	0.10%	2300	47	34-37%	40-45%
Freeman United	6C-GEN-2005	3.50%	0.20%	2040	55	35%	42%
Black Beauty (Willow Lake)	4A-GEN-2005	3.50%	0.24%	2050	54	34%	45%
Pact Resources, LLC	10B-GEN-2005	3.50%	0.15%	2054	50	38%	43%
Pact Resources, LLC	10A-GEN-2005	3.50%	0.15%	2054	50	38%	43%
Pigman Sales Company	11B-GEN-2005	?		?	?	?	?
Alliance Coal, LLC	1-GEN-2005	3.20%	0.20%	2040	50	36%	43%
Pact Resources, LLC	10C-GEN-2005	3.20%	0.15%	2089	50	38%	45%
American Coal Company	2-GEN-2005	4.56%	0.04%	2190	50	39%	45%
Lafayette Coal, Co. (Jader)	8A-GEN-2005	3.00%	0.20%	2200	58	34%	51%
Consol Energy	5-GEN-2005	4.40%	0.07%	2055	52	36%	46%
Lafayette Coal, Co.	8B-GEN-2005	2.40%	0.02%	2170	55	34%	46%
Freeman United	6B-GEN-2005	3.50%	0.20%	2040	55	35%	42%
Freeman United	6A-GEN-2005	3.50%	0.20%	2040	55	35%	42%
Pigman Sales Company	11A-GEN-2005	3.50%	0.22%	2025	50	30%	40%

No Exh. 89

"Performance Goals" (Cost Recovery Reduction Based Goals)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 90
COMPANY/ CSX
WITNESS: Wehle Performance Goals
DATE: 05/27-28/04

Joann T. Wehle
Director, Wholesale Marketing and Fuels
2004 Goals

		Weight
Goal #1:	Meet or exceed TECO Energy's EPS/ROE relative goal As measured against the designate group of utilities	5%
Goal #2:	Meet or exceed TECO Energy's Net Income Other Cash Generation (Absolute) Goal	10%
Goal #3:	Meet or exceed Tampa Electric's & PGS' net income / ROE goal	25%
Goal #4:	Achieve Tampa Electric's Success Sharing goals of: • Safety – Company target: 116 accidents max • Customer favorability: target 94% • Environmental – Company target: 0 preventable • Achieve total cost recovery clause cost of $41.51/MWH or less • Maintain annual cash flow of $81.4 M • Net income: targets up to $165.9 M	10%
Goal #5:	Leadership goal • AA/Diversity: Supporting the company's diversity initiatives and Affirmative Action program through training and recruitment • Succession planning – work with team to identify succession plan and develop course of action • Developing people – Annual DEPs, identify cross training opportunities • Eliminate single points of failure	10%
Goal # 6:	Individual Goal – Wholesale Power • Complete Tampa Electric's 2005 power RFP process by successfully negotiating terms and conditions that meet the needs of both the company and its customers • Optimize the company's wholesale power portfolio • Create new opportunities for wholesale power sales including new customers and new structures • Establish clear front/middle/back offices procedures and policies • Achieve the non-separated sales goal threshold margin • Improve communication with all related departments • Achieve cost recovery goal noted above	20%

Goal #7: Individual Goal – Fuels 20%

- Optimize coal and petroleum coke portfolio
- Successfully execute Tampa Electric's hedging strategy
- Establish clear front/middle/back offices procedures and policies
- Improve communication with all related departments
- Achieve cost recovery goal noted above

Critical Success Factors

1. Achieve the 2004 Business Plan
2. Strengthen credibility with all constituencies (internal and external)
3. Identify and implement best practices throughout the organization
4. Drive toward strategies that position the company for successful growth
5. Finalize the long-term strategy for Big Bend Station
6. Provide open and proactive communication to employees
7. Maintain our reliability levels relative to the other Florida investor-owned utilities

LIFE RUNS ON ENERGY.

Vision

A culture of speed, leadership and integrity powering an integrated business.

252.491 CorpComm 3.8M 2/04 RN

the TECO edge

SHARING IN OUR SUCCESS

TECO TAMPA ELECTRIC

2004 Goals

tampaelectric.com

Values

In conducting our business and interacting with fellow employees, customers, investors and communities, we value the following:

- Resourcefulness
- Ethical behavior
- Safety
- Personal accountability & commitment
- Embracing diversity
- Communicating openly & proactively
- Trust

the TECO edge

Tampa Electric Company 2004 Success Sharing Goals/Savings Plan Match

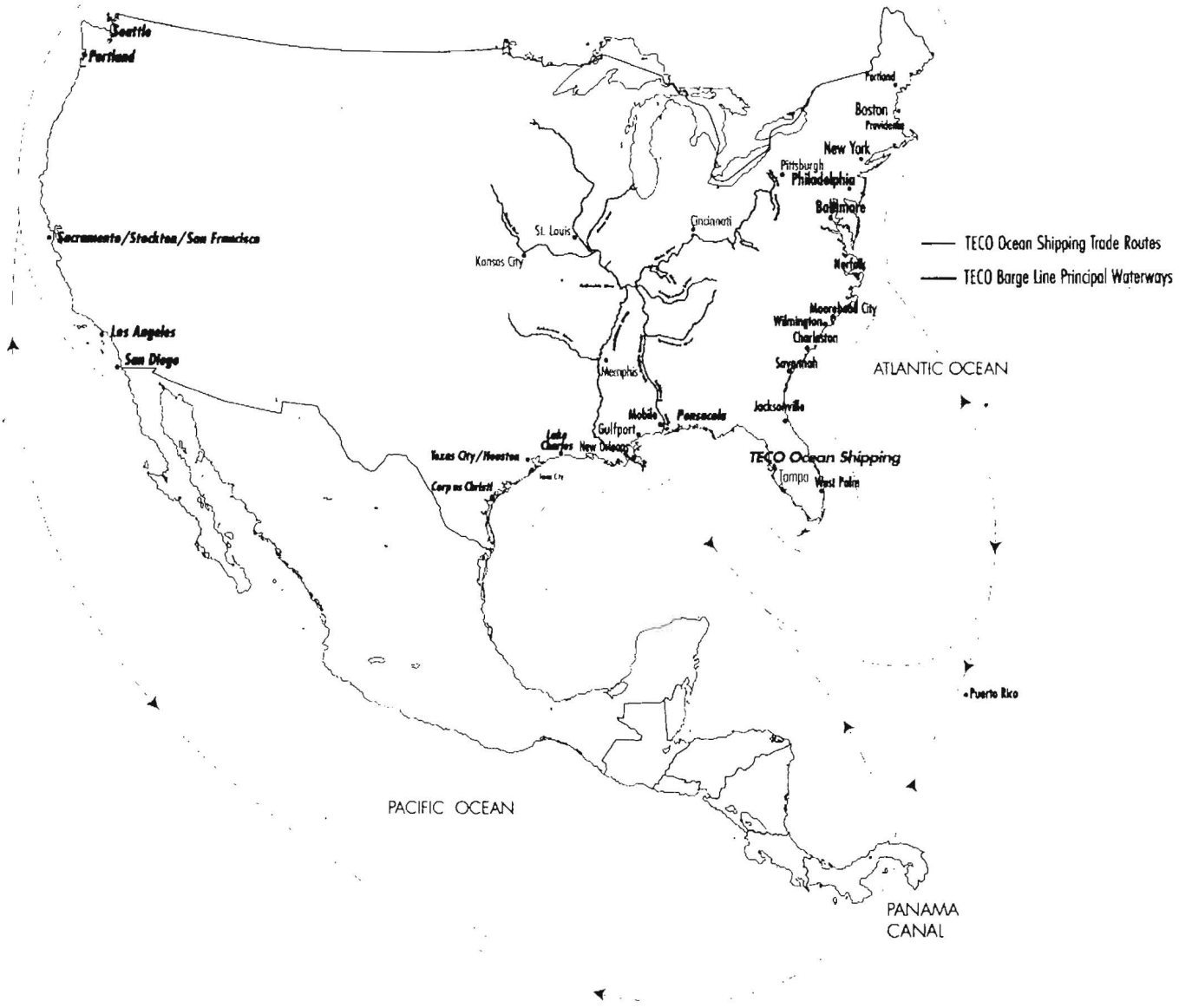
SUCCESS SHARING GOALS	POTENTIAL PAYOUT
Safety[1] – Participate in proactive safety activity. Achieve individual goal of zero personal injuries and zero preventable accidents.	Designated Operating Employees – 2% All Other Employees – 1%
Environmental[2] – Limit preventable environmental events to zero in each quarter.	0.5%
Customer Favorability – Achieve a yearly average favorable rating of 94 percent or better.	0.5%
Reliability[3] – Limit average annual outage time to no more than 67 minutes, and the average annual number of momentary interruptions to no more than 34 occurrences.	0.5%
Cost Recovery Clauses[4] – Achieve total recovery clauses cost of $41.53/megawatt hour or less.	0.5%
Cash Flow – Achieve annual cash flow of $81.4 million.	Designated Operating Employees – 1% All Other Employees – 2%
Net Income[5] – Achieve annual net income of:	
$154.1 million – $158.5 million	Up to 3%
$158.6 million – $162.3 million	Up to 2%
$162.4 million – $165.9 million	Up to 2%
Maximum Success Sharing Payout Percentage	**12%**

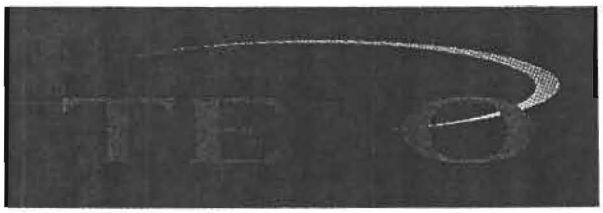
SAVINGS PLAN TARGETS	MATCH
Fixed Company Match	$0.30
Net Income[5] – Achieve annual net income of:	
$130.9 million – $154.0 million	Up to $0.20
$154.1 million – $158.5 million	Up to $0.20
$158.6 million – $162.3 million	Up to $0.20
$162.4 million – $165.9 million	Up to $0.10
Performance Match	Up to $0.70
Maximum Savings Plan Match	**$1.00**

1. *Success Sharing Safety goal is an individual goal and paid out quarterly.*
2. *In each quarter, there will be a 1/4 reduction in Success Sharing payout for each preventable environmental event. Results will be calculated quarterly and paid out annually.*
3. *Payout is based 50% on outage time and 50% on number of interruptions.*
4. *Actual monthly $/megawatt hour will be adjusted to account for gas price fluctuation.*
5. *Savings Plan Performance Match and Success Sharing Net Income payout are directly tied to the achievement of the Net Income targets, and will be prorated accordingly and paid annually.*

YOUR DRY BULK TRAIN LOAD ALTERNATIVE

SERVING ALL MAJOR U.S. PORTS





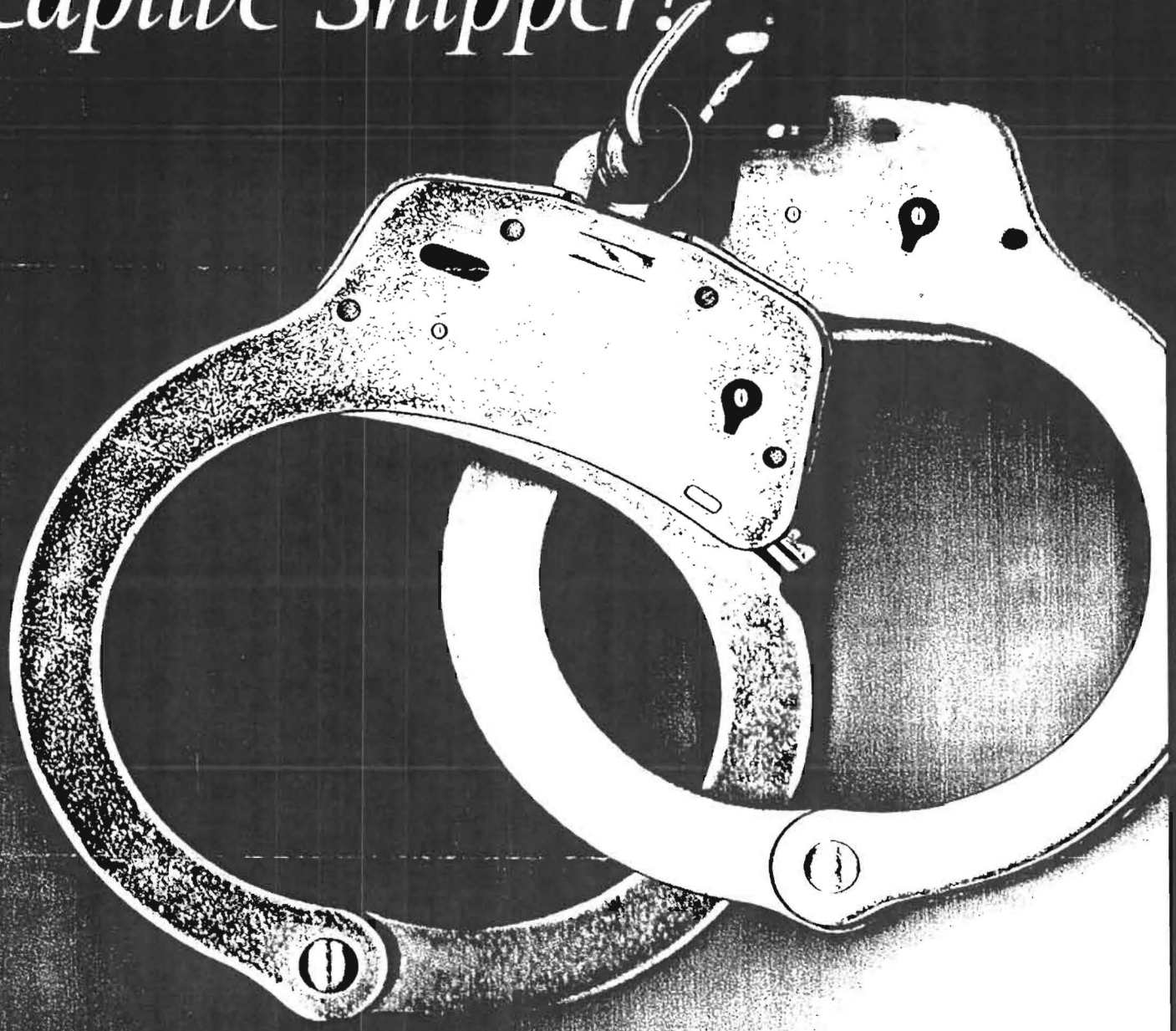
OCEAN SHIPPING

TECO Ocean Shipping Co.
2101 GATX Drive
Tampa, FL 33602
Phone: 813-209-4204
FAX: 813-677-5514
www.tecooceanshipping.com

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 91
COMPANY/ CSX
WITNESS. TECO ocean Shipping Flyer
DATE: 05/22-28/07

PSC Docket No. 031033-EI
In Re: TECO Coal Transportation
Exhibit 91
TECO Ocean Shipping
"Captive Shipper" Flyer

Feel like a *Captive Shipper?*



ere's some good news: you are not locked in to shipping dry bulk goods by rail. Because you can ship with TECO Ocean Shipping instead. TECO owns and operates 12 U.S. flag vessels with a total capacity of over 400,000 DWT. In conjunction with our sister companies, TECO Barge Line and TECO Bulk Terminal, our extensive water transportation network often proves to be more efficient and economical than overland shipping, and our field expertise is second to none. So take a long, hard look at the numbers. You may just begin to consider TECO as your handy "Get Out of Jail Free" card.

TECO

OCEAN SHIPPING

WWW.TECOOCEANSHIPPING.COM

EXHIBIT NO. 92

DOCKET: 031033-EI

WITNESS: JOANN T. WEHLE

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT OF GULF POWER COMPANY'S FPSC 423 FORM PAGES FOR CRIST FACILITY:
JAN 2001, SCHEDULES 423-2, 2(a) AND 2(b)
FEB 2001, SCHEDULES 423-2, 2(a) AND 2(b)
MAR 2001, SCHEDULES 423-2, 2(a) AND 2(b)
APR 2001, SCHEDULES 423-2, 2(a) AND 2(b
JAN 2004, SCHEDULES 423-2, 2(a) AND 2(b

PROFFERED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 92
COMPANY/ FPSC Staff
WITNESS: Revised Gulf Power form 423
DATE: 05/27-28/04

COMMISSIONERS:
BRAULIO L. BAEZ, CHAIRMAN
J. TERRY DEASON
LILA A. JABER
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

STATE OF FLORIDA

DIVISION OF THE COMMISSION CLERK &
ADMINISTRATIVE SERVICES
BLANCA S. BAYÓ
DIRECTOR
(850) 413-6770 (CLERK)
(850) 413-6330 (ADMIN)

Public Service Commission

CERTIFICATE

I, BLANCA S. BAYÓ, Director of the Commission Clerk and Administrative Services, Florida Public Service Commission, do certify that I am the duly appointed custodian of the official records of said Commission and, in that capacity, do certify that the attached pages (listed and described below) are true and correct copies of certain schedules from Gulf Power Company's FPSC Forms 423, as shown in the records of the Commission.

Description

1. Gulf Power Company's January 2001 FPSC Forms 423-2, 2(a), and 2(b).
2. Gulf Power Company's February 2001 FPSC Forms 423-2, 2(a), and 2(b).
3. Gulf Power Company's March 2001 FPSC Forms 423-2, 2(a), and 2(b).
4. Gulf Power Company's April 2001 FPSC Forms 423-2, 2(a), and 2(b).
5. Gulf Power Company's January 2004 FPSC Forms 423-2, 2(a), and 2(b).

WITNESS my hand and the seal of the Florida Public Service Commission this 28th day of May, 2004.

BLANCA S. BAYÓ

By: _____
Kay Flynn, Chief
Bureau of Records

(SEAL)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
ORIGIN, TONNAGE, DELIVERED PRICE, AND AS RECEIVED QUALITY

1. Reporting Month: JANUARY Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: March 16, 2001

Line No.	Supplier Name	Mine Location			Purchase Type	Transport Mode	Tons	Purchase Price ($/Ton)	Effective Transport Charges ($/Ton)	Total FOB Plant Price ($/Ton)	Sulfur Content (%)	Btu Content (Btu/lb)	Ash Content (%)	Moisture Content (%)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	C	RB	27,765.58	34.983	2.30	37.283	1.06	12,070	5.84	12.29
2	AMERICAN COAL	10	IL	165	S	RB	11,587.61	33.276	2.30	35.576	1.32	12,192	6.30	11.11
3	TAFT COAL	13	AL	127	S	RB	2,575.71	30.770	12.97	43.740	0.99	11,810	14.04	6.16
4	PEABODY COALSALES-COOK	10	IL	165	C	RB	119,767.00	28.781	8.77	37.551	1.06	12,076	5.94	12.18
5	CONSOLIDATION COAL	10	IL	81	S	RB	24,805.08	21.883	9.00	30.883	1.33	12,101	6.28	10.89
6	PEABODY COALTRADE	10	IL	165	S	RB	1,551.00	27.933	8.77	36.703	0.97	12,101	5.71	12.49
7	AMERICAN COAL	10	IL	165	S	RB	11,166.00	28.041	8.77	36.811	1.56	12,135	6.21	11.35
8	EMERALD INTERNATIONAL	8	KY	233	S	RB	13,466.07	39.819	5.17	44.989	1.34	11,647	13.18	8.32
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

FPSC Form No. 423-2(a)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
DETAILED PURCHASED COAL INVOICE INFORMATION

1. Reporting Month: JANUARY Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: March 16, 2001

Line No.	Supplier Name	Mine Location			Purchase Type	Tons	FOB Mine Price ($/Ton)	Shorthaul & Loading Charges ($/Ton)	Original Invoice Price ($/Ton)	Retroactive Price increases ($/Ton)	Base Price ($/Ton)	Quality Adjustments ($/Ton)	Effective Purchase Price ($/Ton)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	C	27,765.58	33.000	-	33.000	-	33.000	0.193	34.983
2	AMERICAN COAL	10	IL	165	S	11,587.61	30.990	-	30.990	-	30.990	0.496	33.276
3	TAFT COAL	13	AL	127	S	2,575.71	29.220	-	29.220	-	29.220	(0.700)	30.770
4	PEABODY COALSALES-COOK	10	IL	165	C	119,767.00	28.600	-	28.600	-	28.600	0.181	28.781
5	CONSOLIDATION COAL	10	IL	81	S	24,805.08	21.700	-	21.700	-	21.700	0.183	21.883
6	PEABODY COALTRADE	10	IL	165	S	1,551.00	27.700	-	27.700	-	27.700	0.233	27.933
7	AMERICAN COAL	10	IL	165	S	11,166.00	27.960	-	27.960	-	27.960	0.081	28.041
8	EMERALD INTERNATIONAL	8	KY	233	S	13,466.07	40.000	-	40.000	-	40.000	(0.181)	39.819
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: JANUARY Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: March 16, 2001

Line No.	Supplier Name	Mine Location			Shipping Point	Transport Mode	Tons	Effective Purchase Price ($/Ton)	Additional Shorthaul & Loading Charges ($/Ton)	Rail Charges: Rail Rate ($/Ton)	Rail Charges: Other Rail Charges ($/Ton)	Waterborne Charges: River Barge Rate ($/Ton)	Waterborne Charges: Trans-loading Rate ($/Ton)	Waterborne Charges: Ocean Barge Rate ($/Ton)	Waterborne Charges: Other Water Charges ($/Ton)	Other Related Charges ($/Ton)	Total Transportation charges ($/Ton)	FOB Plant Price ($/Ton)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	MCDUFFIE TERMINAL	RB	27,765.58	34.983	-	-	-	2.30	-	-	-	-	2.30	37.283
2	AMERICAN COAL	10	IL	165	MCDUFFIE TERMINAL	RB	11,587.81	33.276	-	-	-	2.30	-	-	-	-	2.30	35.576
3	TAFT COAL	13	AL	127	MCDUFFIE TERMINAL	RB	2,575.71	30.770	-	-	-	12.97	-	-	-	-	12.97	43.740
4	PEABODY COALSALES-COOK	10	IL	165	COOK TERMINAL	RB	119,767.00	28.781	-	-	-	8.77	-	-	-	-	8.77	37.551
5	CONSOLIDATION COAL	10	IL	81	MOUND CITY	RB	24,805.08	21.883	-	-	-	9.00	-	-	-	-	9.00	30.883
6	PEABODY COALTRADE	10	IL	165	COOK TERMINAL	RB	1,551.00	27.933	-	-	-	8.77	-	-	-	-	8.77	36.703
7	AMERICAN COAL	10	IL	165	COOK TERMINAL	RB	11,166.00	28.041	-	-	-	8.77	-	-	-	-	8.77	36.811
8	EMERALD INTERNATIONAL	8	KY	233	INT MARINE TERM	RB	13,466.07	39.819	-	-	-	5.17	-	-	-	-	5.17	44.989
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13																		
14																		
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
ORIGIN, TONNAGE, DELIVERED PRICE, AND AS RECEIVED QUALITY

1. Reporting Month: FEBRUARY Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: April 10, 2001

Line No.	Supplier Name	Mine Location			Purchase Type	Transport Mode	Tons	Purchase Price ($/Ton)	Effective Transport Charges ($/Ton)	Total FOB Plant Price ($/Ton)	Sulfur Content (%)	Btu Content (Btu/lb)	Ash Content (%)	Moisture Content (%)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	C	RB	18,229.64	35.414	2.30	37.714	0.99	12,121	6.10	11.67
2	AMERICAN COAL	10	IL	165	S	RB	3,624.83	33.426	2.30	35.726	1.32	12,192	6.30	11.11
3	TAFT COAL SALES	13	AL	127	S	RB	805.73	30.920	12.97	43.890	0.99	11,810	14.04	6.16
4	PEABODY COALSALES	10	IL	165	S	RB	60,843.00	29.011	8.77	37.781	1.01	12,113	5.92	11.99
5	CONSOLIDATION COAL	10	IL	81	S	RB	34,316.44	22.231	9.00	31.231	1.42	12,156	6.27	10.77
6	AMERICAN COAL	10	IL	165	S	RB	19,596.00	27.289	8.77	36.059	1.04	12,169	6.65	10.30
7	PEABODY COALSALES	7	WV	39	S	RB	10,884.14	38.399	15.17	53.569	0.73	13,165	8.05	5.48
8	OXBOW CARBON & MINERAL	17	CO	51	S	RB	11,963.80	21.719	26.95	48.669	0.48	11,755	8.55	9.14
9	EMERALD INTERNATIONAL	8	KY	233	S	RB	28,829.44	39.615	5.17	44.785	1.49	11,587	13.74	8.45
10	OXBOW CARBON & MINERAL	17	CO	51	S	RB	8,982.99	20.446	22.98	43.426	0.50	11,685	8.64	9.22
11	OXBOW CARBON & MINERAL	17	CO	51	S	RB	10,846.40	22.729	26.95	49.679	0.61	12,331	10.74	6.21
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
DETAILED PURCHASED COAL INVOICE INFORMATION

1. Reporting Month: FEBRUARY Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: April 10, 2001

Line No.	Supplier Name	Mine Location			Purchase Type	Tons	FOB Mine Price ($/Ton)	Shorthaul & Loading Charges ($/Ton)	Original Invoice Price ($/Ton)	Retroactive Price increases ($/Ton)	Base Price ($/Ton)	Quality Adjustments ($/Ton)	Effective Purchase Price ($/Ton)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	C	18,229.64	33.140	-	33.140	-	33.140	0.334	35.414
2	AMERICAN COAL	10	IL	165	S	3,624.83	30.990	-	30.990	-	30.990	0.496	33.426
3	TAFT COAL SALES	13	AL	127	S	805.73	29.220	-	29.220	-	29.220	(0.700)	30.920
4	PEABODY COALSALES	10	IL	165	S	60,843.00	28.740	-	28.740	-	28.740	0.271	29.011
5	CONSOLIDATION COAL	10	IL	81	S	34,316.44	21.700	-	21.700	-	21.700	0.281	22.231
6	AMERICAN COAL	10	IL	165	S	19,596.00	26.910	-	26.910	-	26.910	0.379	27.289
7	PEABODY COALSALES	7	WV	39	S	10,884.14	38.500	-	38.500	-	38.500	(0.101)	38.399
8	OXBOW CARBON & MINERAL	17	CO	51	S	11,963.80	20.560	-	20.560	-	20.560	0.009	21.719
9	EMERALD INTERNATIONAL	8	KY	233	S	28,829.44	40.000	-	40.000	-	40.000	(0.385)	39.615
10	OXBOW CARBON & MINERAL	17	CO	51	S	8,982.99	20.560	-	20.560	-	20.560	(0.114)	20.446
11	OXBOW CARBON & MINERAL	17	CO	51	S	10,846.40	21.000	-	21.000	-	21.000	0.579	22.729
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: FEBRUARY Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)-444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: April 10, 2001

Line No.	Supplier Name	Mine Location			Shipping Point	Transport Mode	Tons	Effective Purchase Price ($/Ton)	Additional Shorthaul & Loading Charges ($/Ton)	Rail Charges: Rail Rate ($/Ton)	Rail Charges: Other Rail Charges ($/Ton)	Waterborne Charges: River Barge Rate ($/Ton)	Waterborne Charges: Trans-loading Rate ($/Ton)	Waterborne Charges: Ocean Barge Rate ($/Ton)	Waterborne Charges: Other Water Charges ($/Ton)	Other Related Charges ($/Ton)	Total Transportation charges ($/Ton)	FOB Plant Price ($/Ton)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	MCDUFFIE TERMINAL	RB	18,229.64	35.414	-	-	-	2.30	-	-	-	-	2.30	37.714
2	AMERICAN COAL	10	IL	165	MCDUFFIE TERMINAL	RB	3,624.83	33.426	-	-	-	2.30	-	-	-	-	2.30	35.726
3	TAFT COAL SALES	13	AL	127	MCDUFFIE TERMINAL	RB	805.73	30.920	-	-	-	12.97	-	-	-	-	12.97	43.890
4	PEABODY COALSALES	10	IL	165	COOK TERMINAL	RB	60,843.00	29.011	-	-	-	8.77	-	-	-	-	8.77	37.781
5	CONSOLIDATION COAL	10	IL	81	MOUND CITY	RB	34,316.44	22.231	-	-	-	9.00	-	-	-	-	9.00	31.231
6	AMERICAN COAL	10	IL	165	COOK TERMINAL	RB	19,596.00	27.289	-	-	-	8.77	-	-	-	-	8.77	36.059
7	PEABODY COALSALES	7	WV	39	MARMET POOL	RB	10,884.14	38.399	-	-	-	15.17	-	-	-	-	15.17	53.569
8	OXBOW CARBON & MINERAL	17	CO	51	ICR DOCK	RB	11,963.80	21.719	-	-	-	26.95	-	-	-	-	26.95	48.669
9	EMERALD INTERNATIONAL	8	KY	233	INT MARINE TERMINAL	RB	28,829.44	39.615	-	-	-	5.17	-	-	-	-	5.17	44.785
10	OXBOW CARBON & MINERAL	17	CO	51	CAHOKIA DOCK	RB	8,982.99	20.446	-	-	-	22.98	-	-	-	-	22.98	43.426
11	OXBOW CARBON & MINERAL	17	CO	51	ICR DOCK	RB	10,846.40	22.729	-	-	-	26.95	-	-	-	-	26.95	49.679
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
ORIGIN, TONNAGE, DELIVERED PRICE, AND AS RECEIVED QUALITY

1. Reporting Month: MARCH Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: May 10, 2001

Line No.	Supplier Name	Mine Location			Purchase Type	Transport Mode	Tons	Purchase Price ($/Ton)	Effective Transport Charges ($/Ton)	Total FOB Plant Price ($/Ton)	Sulfur Content (%)	Btu Content (Btu/lb)	Ash Content (%)	Moisture Content (%)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	C	RB	38,274.00	35.480	2.30	37.780	1.10	12,145	5.74	11.94
2	AMERICAN COAL	10	IL	165	S	RB	1,251.40	33.426	2.30	35.726	1.32	12,192	6.30	11.11
3	PEABODY COALSALES	10	IL	165	C	RB	58,787.00	28.901	8.77	37.671	1.06	12,067	5.64	12.61
4	CONSOLIDATION COAL	10	IL	81	S	RB	17,433.28	21.949	9.00	30.949	1.49	11,999	6.68	11.37
5	AMERICAN COAL	10	IL	165	S	RB	23,946.00	27.289	8.77	36.059	1.04	12,169	6.65	10.30
6	PEABODY COALSALES	7	WV	39	S	RB	12,626.79	38.189	15.17	53.359	0.70	13,093	7.78	6.14
7	OXBOW CARBON & MINERAL	17	CO	29	S	RB	10,515.37	20.547	23.29	43.837	0.41	11,741	10.34	8.27
8	OXBOW CARBON & MINERAL	17	CO	51	S	RB	10,819.44	21.691	22.98	44.671	0.62	12,395	11.26	5.77
9	SSM PETCOKE	17	CO	29	S	RB	11,786.19	49.346	5.17	54.516	0.38	11,843	7.51	10.02
10	OXBOW CARBON & MINERAL	17	CO	51	S	RB	1,491.00	20.446	22.98	43.426	0.50	11,685	8.64	9.22
11	OXBOW CARBON & MINERAL	17	CO	29	S	RB	4,744.34	15.959	22.98	38.939	0.36	11,969	7.66	9.18
12	PEABODY COALTRADE	10	IL	165	S	RB	13,073.00	28.139	8.77	36.909	1.00	12,190	5.83	11.34
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
DETAILED PURCHASED COAL INVOICE INFORMATION

1. Reporting Month: MARCH Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: May 10, 2001

Line No.	Supplier Name	Mine Location			Purchase Type	Tons	FOB Mine Price ($/Ton)	Shorthaul & Loading Charges ($/Ton)	Original Invoice Price ($/Ton)	Retroactive Price increases ($/Ton)	Base Price ($/Ton)	Quality Adjustments ($/Ton)	Effective Purchase Price ($/Ton)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	C	38,274.00	33.140	-	33.140	-	33.140	0.400	35.480
2	AMERICAN COAL	10	IL	165	S	1,251.40	30.990	-	30.990	-	30.990	0.496	33.426
3	PEABODY COALSALES	10	IL	165	C	58,787.00	28.740	-	28.740	-	28.740	0.161	28.901
4	CONSOLIDATION COAL	10	IL	81	S	17,433.28	21.700	-	21.700	-	21.700	(0.001)	21.949
5	AMERICAN COAL	10	IL	165	S	23,946.00	26.910	-	26.910	-	26.910	0.379	27.289
6	PEABODY COALSALES	7	WV	39	S	12,626.79	38.500	-	38.500	-	38.500	(0.311)	38.189
7	OXBOW CARBON & MINERAL	17	CO	29	S	10,515.37	21.000	-	21.000	-	21.000	(0.453)	20.547
8	OXBOW CARBON & MINERAL	17	CO	51	S	10,819.44	21.000	-	21.000	-	21.000	0.691	21.691
9	SSM PETCOKE	17	CO	29	S	11,786.19	50.000	-	50.000	-	50.000	(0.654)	49.346
10	OXBOW CARBON & MINERAL	17	CO	51	S	1,491.00	20.560	-	20.560	-	20.560	(0.114)	20.446
11	OXBOW CARBON & MINERAL	17	CO	29	S	4,744.34	16.000	-	16.000	-	16.000	(0.041)	15.959
12	PEABODY COALTRADE	10	IL	165	S	13,073.00	27.700	-	27.700	-	27.700	0.439	28.139
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: MARCH Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: May 10, 2001

Line No.	Supplier Name	Mine Location			Shipping Point	Transport Mode	Tons	Effective Purchase Price ($/Ton)	Additional Shorthaul & Loading Charges ($/Ton)	Rail Charges: Rail Rate ($/Ton)	Rail Charges: Other Rail Charges ($/Ton)	Waterborne Charges: River Barge Rate ($/Ton)	Waterborne Charges: Trans-loading Rate ($/Ton)	Waterborne Charges: Ocean Barge Rate ($/Ton)	Waterborne Charges: Other Water Charges ($/Ton)	Other Related Charges ($/Ton)	Total Transpor-tation charges ($/Ton)	FOB Plant Price ($/Ton)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	MCDUFFIE TERMINAL	RB	38,274.00	35.480	-	-	-	2.30	-	-	-	-	2.30	37.780
2	AMERICAN COAL	10	IL	165	MCDUFFIE TERMINAL	RB	1,251.40	33.426	-	-	-	2.30	-	-	-	-	2.30	35.726
3	PEABODY COALSALES	10	IL	165	COOK TERMINAL	RB	58,787.00	28.901	-	-	-	8.77	-	-	-	-	8.77	37.671
4	CONSOLIDATION COAL	10	IL	81	MOUND CITY	RB	17,433.28	21.949	-	-	-	9.00	-	-	-	-	9.00	30.949
5	AMERICAN COAL	10	IL	165	COOK TERMINAL	RB	23,946.00	27.289	-	-	-	8.77	-	-	-	-	8.77	36.059
6	PEABODY COALSALES	7	WV	39	MARMET POOL	RB	12,626.79	38.189	-	-	-	15.17	-	-	-	-	15.17	53.359
7	OXBOW CARBON & MINERAL	17	CO	29	CAHOKIA DOCK	RB	10,515.37	20.547	-	-	-	23.29	-	-	-	-	23.29	43.837
8	OXBOW CARBON & MINERAL	17	CO	51	CAHOKIA DOCK	RB	10,819.44	21.691	-	-	-	22.98	-	-	-	-	22.98	44.671
9	SSM PETCOKE	17	CO	29	IMT	RB	11,786.19	49.346	-	-	-	5.17	-	-	-	-	5.17	54.516
10	OXBOW CARBON & MINERAL	17	CO	51	CAHOKIA DOCK	RB	1,491.00	20.446	-	-	-	22.98	-	-	-	-	22.98	43.426
11	OXBOW CARBON & MINERAL	17	CO	29	CAHOKIA DOCK	RB	4,744.34	15.959	-	-	-	22.98	-	-	-	-	22.98	38.939
12	PEABODY COALTRADE	10	IL	165	COOK TERMINAL	RB	13,073.00	28.139	-	-	-	8.77	-	-	-	-	8.77	36.909
13																		
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
ORIGIN, TONNAGE, DELIVERED PRICE, AND AS RECEIVED QUALITY

1. Reporting Month: APRIL Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: June 14, 2001

Line No.	Supplier Name	Mine Location			Purchase Type	Transport Mode	Tons	Purchase Price ($/Ton)	Effective Transport Charges ($/Ton)	Total FOB Plant Price ($/Ton)	Sulfur Content (%)	Btu Content (Btu/lb)	Ash Content (%)	Moisture Content (%)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	C	RB	21,977.72	35.601	2.27	37.871	1.05	12,072	6.28	11.91
2	AMERICAN COAL	10	IL	165	S	RB	5,691.94	33.656	2.27	35.926	1.50	12,191	6.73	10.56
3	EMERALD COAL	10	IL	165	S	RB	1,952.54	35.435	2.27	37.705	1.26	12,031	6.58	11.74
4	PBDY COAL SALES-COOK	10	IL	165	C	RB	50,229.00	29.122	8.49	37.612	1.06	12,067	5.64	12.61
5	CONSOLIDATION COAL	10	IL	81	S	RB	52,543.39	21.839	8.71	30.549	1.51	12,077	6.58	10.85
6	AMERICAN COAL	10	IL	165	S	RB	6,614.00	27.193	8.49	35.683	1.51	12,227	6.79	10.40
7	PEABODY COALTRADE	10	IL	165	S	RB	6,156.00	28.113	8.49	36.603	1.05	12,179	6.51	10.34
8	PEABODY COALSALES	7	WV	39	S	RB	23,997.43	38.379	14.68	53.059	0.66	13,158	7.59	5.93
9	OXBOW CARBON & MINERAL	17	CO	29	S	RB	9,557.86	20.998	23.29	44.288	0.38	11,999	8.20	8.75
10	OXBOW CARBON & MINERAL	17	CO	51	S	RB	10,896.02	21.691	22.98	44.671	0.62	12,395	11.26	5.77
11	SSM PETCOKE	17	CO	29	S	RB	8,228.65	49.346	5.10	54.446	0.38	11,843	7.51	10.02
12	OXBOW CARBON & MINERAL	17	CO	51	S	RB	11,542.52	20.472	22.98	43.452	0.49	11,700	9.03	9.00
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
DETAILED PURCHASED COAL INVOICE INFORMATION

1. Reporting Month: APRIL Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: June 14, 2001

Line No.	Supplier Name	Mine Location			Purchase Type	Tons	FOB Mine Price ($/Ton)	Shorthaul & Loading Charges ($/Ton)	Original Invoice Price ($/Ton)	Retroactive Price increases ($/Ton)	Base Price ($/Ton)	Quality Adjustments ($/Ton)	Effective Purchase Price ($/Ton)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	C	21,977.72	33.460	-	33.460	-	33.460	0.201	35.601
2	AMERICAN COAL	10	IL	165	S	5,691.94	31.480	-	31.480	-	31.480	0.236	33.656
3	EMERALD COAL	10	IL	165	S	1,952.54	33.130	-	33.130	-	33.130	0.365	35.435
4	PBDY COAL SALES-COOK	10	IL	165	C	50,229.00	28.960	-	28.960	-	28.960	0.162	29.122
5	CONSOLIDATION COAL	10	IL	81	S	52,543.39	21.700	-	21.700	-	21.700	0.139	21.839
6	AMERICAN COAL	10	IL	165	S	6,614.00	26.910	-	26.910	-	26.910	0.283	27.193
7	PEABODY COALTRADE	10	IL	165	S	6,156.00	27.700	-	27.700	-	27.700	0.413	28.113
8	PEABODY COALSALES	7	WV	39	S	23,997.43	38.500	-	38.500	-	38.500	(0.121)	38.379
9	OXBOW CARBON & MINERAL	17	CO	29	S	9,557.86	21.000	-	21.000	-	21.000	(0.002)	20.998
10	OXBOW CARBON & MINERAL	17	CO	51	S	10,896.02	21.000	-	21.000	-	21.000	0.691	21.691
11	SSM PETCOKE	17	CO	29	S	8,228.65	50.000	-	50.000	-	50.000	(0.654)	49.346
12	OXBOW CARBON & MINERAL	17	CO	51	S	11,542.52	20.560	-	20.560	-	20.560	(0.088)	20.472
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF FUEL OIL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: APRIL Year: 2001
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: June 14, 2001

Line No.	Supplier Name	Mine Location			Shipping Point	Transport Mode	Tons	Effective Purchase Price ($/Ton)	Additional Shorthaul & Loading Charges ($/Ton)	Rail Charges: Rail Rate ($/Ton)	Rail Charges: Other Rail Charges ($/Ton)	Waterborne Charges: River Barge Rate ($/Ton)	Waterborne Charges: Trans-loading Rate ($/Ton)	Waterborne Charges: Ocean Barge Rate ($/Ton)	Waterborne Charges: Other Water Charges ($/Ton)	Other Related Charges ($/Ton)	Total Transportation charges ($/Ton)	FOB Plant Price ($/Ton)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	PBDY COAL SALES-MCDUFF2	10	IL	165	MCDUFFIE TERMINAL	RB	21,977.72	35.601	-	-	-	2.27	-	-	-	-	2.27	37.871
2	AMERICAN COAL	10	IL	165	MCDUFFIE TERMINAL	RB	5,691.94	33.656	-	-	-	2.27	-	-	-	-	2.27	35.926
3	EMERALD COAL	10	IL	165	MCDUFFIE TERMINAL	RB	1,952.54	35.435	-	-	-	2.27	-	-	-	-	2.27	37.705
4	PBDY COAL SALES-COOK	10	IL	165	COOK TERMINAL	RB	50,229.00	29.122	-	-	-	8.49	-	-	-	-	8.49	37.612
5	CONSOLIDATION COAL	10	IL	81	MOUND CITY	RB	52,543.39	21.839	-	-	-	8.71	-	-	-	-	8.71	30.549
6	AMERICAN COAL	10	IL	165	COOK TERMINAL	RB	6,614.00	27.193	-	-	-	8.49	-	-	-	-	8.49	35.683
7	PEABODY COALTRADE	10	IL	165	COOK TERMINAL	RB	6,156.00	28.113	-	-	-	8.49	-	-	-	-	8.49	36.603
8	PEABODY COALSALES	7	WV	39	MARMET POOL	RB	23,997.43	38.379	-	-	-	14.68	-	-	-	-	14.68	53.059
9	OXBOW CARBON & MINERAL	17	CO	29	CAHOKIA	RB	9,557.86	20.998	-	-	-	23.29	-	-	-	-	23.29	44.288
10	OXBOW CARBON & MINERAL	17	CO	51	CAHOKIA	RB	10,896.02	21.691	-	-	-	22.98	-	-	-	-	22.98	44.671
11	SSM PETCOKE	17	CO	29	IMT	RB	8,228.65	49.346	-	-	-	5.10	-	-	-	-	5.10	54.446
12	OXBOW CARBON & MINERAL	17	CO	51	CAHOKIA	RB	11,542.52	20.472	-	-	-	22.98	-	-	-	-	22.98	43.452
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*Buyout cost previously approved by FPSC included.

(use continuation sheet if necessary)

FPSC Form No. 423-2

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
ORIGIN, TONNAGE, DELIVERED PRICE, AND AS RECEIVED QUALITY

1. Reporting Month: JANUARY Year: 2004
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: March 12, 2004

Line No.	Supplier Name	Mine Location			Purchase Type	Transport Mode	Tons	Purchase Price ($/Ton)	Effective Transport Charges ($/Ton)	Total FOB Plant Price ($/Ton)	Sulfur Content (%)	Btu Content (Btu/lb)	Ash Content (%)	Moisture Content (%)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	PEABODY COAL SALES	10	IL	165	C	RB	88,582.13	35.143	2.40	37.543	1.04	12,105	6.39	11.57
2	PEABODY COALSALES	45	IM	999	C	RB	19,950.69	34.124	2.40	36.524	0.50	11,771	4.05	12.00
3	INTEROCEAN COAL SALES	45	IM	999	S	RB	32,659.27	33.643	2.40	36.043	0.46	11,736	4.67	12.11
4	ALABAMA POWER CO.	45	IM	999	S	RB	6,478.81	31.636	2.40	34.036	0.44	11,445	4.94	13.46
5	PEABODY COAL SALES	45	IM	999	S	RB	20,637.05	41.225	2.40	43.625	0.47	11,782	4.19	11.84
6	INTEROCEAN COAL SALES	45	IM	999	S	RB	14,310.91	41.545	2.40	43.945	0.39	11,874	4.35	10.95
7	PEABODY COAL SALES	10	IL	165	C	RB	1,559.00	28.540	9.24	37.780	1.09	12,063	6.90	11.08
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(use continuation sheet if necessary)

FPSC Form No. 423-2(a)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAILED PURCHASED COAL INVOICE INFORMATION

1. Reporting Month: JANUARY Year: 2004
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: March 12, 2004

Line No.	Supplier Name	Mine Location			Purchase Type	Tons	FOB Mine Price ($/Ton)	Shorthaul & Loading Charges ($/Ton)	Original Invoice Price ($/Ton)	Retroactive Price Increases ($/Ton)	Base Price ($/Ton)	Quality Adjustments ($/Ton)	Effective Purchase Price ($/Ton)
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	PEABODY COAL SALES	10	IL	165	C	88,582.13	34.550	-	34.550	-	34.550	0.303	35.143
2	PEABODY COALSALES	45	IM	999	C	19,950.69	33.630	-	33.630	-	33.630	0.204	34.124
3	INTEROCEAN COAL SALES	45	IM	999	S	32,659.27	33.250	-	33.250	-	33.250	0.103	33.643
4	ALABAMA POWER CO.	45	IM	999	S	6,478.81	32.340	-	32.340	-	32.340	(0.704)	31.636
5	PEABODY COAL SALES	45	IM	999	S	20,637.05	40.650	-	40.650	-	40.650	0.285	41.225
6	INTEROCEAN COAL SALES	45	IM	999	S	14,310.91	40.650	-	40.650	-	40.650	0.605	41.545
7	PEABODY COAL SALES	10	IL	165	C	1,559.00	28.390	-	28.390	-	28.390	0.150	28.540
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(use continuation sheet if necessary)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: JANUARY Year: 2004
2. Reporting Company: Gulf Power Company
3. Plant Name: Crist Electric Generating Plant
4. Name, Title, & Telephone Number of Contact Person Concerning Data Submitted on this Form: Ms. J.P. Peters, Fuels Analyst (850)- 444-6332
5. Signature of Official Submitting Report: Jocelyn P. Peters
6. Date Completed: March 12, 2004

Line No.	Supplier Name	Mine Location			Shipping Point	Transport Mode	Tons	Effective Purchase Price ($/Ton)	Additional Shorthaul & Loading Charges ($/Ton)	Rail Charges			Waterborne Charges			Other Related Charges ($/Ton)	Total Transportation charges ($/Ton)	FOB Plant Price ($/Ton)
										Rail Rate ($/Ton)	Other Rail Charges ($/Ton)	River Barge Rate ($/Ton)	Trans-loading Rate ($/Ton)	Ocean Barge Rate ($/Ton)	Other Water Charges ($/Ton)			
(a)	(b)	(c)			(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	PEABODY COAL SALES	10	IL	165	MCDUFFIE TERMINAL	RB	88,582.13	35.143	-	-	-	2.40	-	-	-	-	2.40	37.543
2	PEABODY COAL SALES	45	IM	999	MCDUFFIE TERMINAL	RB	19,950.69	34.124	-	-	-	2.40	-	-	-	-	2.40	36.524
3	INTEROCEAN COAL SALES	45	IM	999	MCDUFFIE TERMINAL	RB	32,659.27	33.643	-	-	-	2.40	-	-	-	-	2.40	36.043
4	ALABAMA POWER CO.	45	IM	999	MCDUFFIE TERMINAL	RB	6,478.81	31.636	-	-	-	2.40	-	-	-	-	2.40	34.036
5	PEABODY COAL SALES	45	IM	999	MCDUFFIE TERMINAL	RB	20,637.05	41.225	-	-	-	2.40	-	-	-	-	2.40	43.625
6	INTEROCEAN COAL SALES	45	IM	999	MCDUFFIE TERMINAL	RB	14,310.91	41.545	-	-	-	2.40	-	-	-	-	2.40	43.945
7	PEABODY COAL SALES	10	IL	165	COOK TERMINAL	RB	1,559.00	28.540	-	-	-	9.24	-	-	-	-	9.24	37.780
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(use continuation sheet if necessary)

EXHIBIT NO. 93

DOCKET NO: 031033-EI

WITNESS: JOANN WEHLE

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT OF TAMPA ELECTRIC COMPANY'S JUNE 2001, THROUGH SEPTEMBER 2001, SCHEDULE A4, JUNE 2002, THROUGH SEPTEMBER 2002, SCHEDULE A4, AND JUNE 2003, THROUGH SEPTEMBER 2003, SCHEDULE A4

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 93
COMPANY/ FPSC Staff
WITNESS: TECO A Schedule
DATE: 05/27-28/04

SYSTEM NET GENER/ ' AND FUEL COST
TAMPA ELEC1.. COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: JUNE 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	39	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	(266)	0.0	0.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION	**90**	**(266)**	**0.0**	**71.3**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	45,725	55.7	81.3	62.6	11,822	COAL	23,230	23,270,460	540,572.8	965,107	2.11	41.55
GAN.#2	98	44,527	63.1	84.3	72.2	12,664	COAL	28,560	19,744,280	563,896.6	1,186,546	2.66	41.55
GAN.#3	145	65,264	62.5	86.0	65.8	12,618	COAL	41,449	19,868,040	823,510.4	1,722,028	2.64	41.55
GAN.#4	159	28,621	25.0	30.0	68.0	12,984	COAL	18,121	20,508,000	371,625.5	752,850	2.63	41.55
GAN.#5	232	88,720	53.1	63.6	66.4	11,024	COAL	41,969	23,303,360	978,018.7	1,743,632	1.97	41.55
GAN.#6	372	172,202	64.3	76.7	68.9	10,804	COAL	75,870	24,521,260	1,860,428.0	3,152,073	1.83	41.55
GANNON STATION	**1,120**	**445,059**	**55.2**	**69.7**	**67.5**	**11,545**	**COAL**	**229,199**	**22,417,428**	**5,138,052.0**	**9,522,236**	**2.14**	**41.55**
B.B.#1	416	193,665	64.7	74.5	76.0	10,862	COAL	87,070	24,160,400	2,103,646.0	4,414,862	2.28	50.70
B.B.#2	416	204,295	68.2	78.3	74.8	10,731	COAL	91,006	24,088,560	2,192,203.5	4,614,436	2.26	50.70
B.B.#3	433	202,009	64.8	79.7	73.5	10,695	COAL	90,245	23,939,120	2,160,385.9	4,575,850	2.27	50.70
B.B. 1 - 3	1,265	599,969	65.9	77.5	74.7	10,761	COAL	268,321	24,061,611	6,456,235.4	13,605,148	2.27	50.70
B.B.#4	442	243,079	76.4	89.9	83.8	10,384	COAL	112,718	22,394,282	2,524,232.8	5,920,428	2.44	52.52
B.B. STATION	**1,707**	**843,048**	**68.6**	**80.7**	**77.1**	**10,652**	**COAL**	**381,039**	**23,568,386**	**8,980,468.2**	**19,525,576**	**2.32**	**51.24**
SEB-PHIL. #1(HVY OIL)	17	5,032	41.1	100.0	85.9	10,065	HVY.OIL	8,074	6,273,540	50,649.4	234,110	4.65	29.00
SEB-PHIL. #2(HVY OIL)	17	5,663	46.3	100.0	97.6	8,944	HVY.OIL	8,073	6,273,540	50,649.4	234,096	4.13	29.00
SEB-PHILLIPS TOTAL	**34**	**10,695**	**43.7**	**100.0**	**91.8**	**9,472**	**HVY.OIL**	**16,147**	**6,273,540**	**101,298.8**	**468,206**	**4.38**	**29.00**
POLK #1 GASIFIER	250	29,947	16.6	19.3	82.5	10,608	COAL	14,466	21,960,000	317,672.9	708,859	2.37	49.00
POLK #1 CT (OIL)	225	24,271	15.0	95.4	50.5	9,748	LGT.OIL	40,938	5,819,746	236,596.9	1,479,410	6.10	36.14
POLK #1 TOTAL	**250**	**54,218**	**30.1**	**86.9**	**64.2**	**10,223**	**-**	**-**	**-**	**554,269.8**	**2,188,269**	**4.04**	**-**
POLK #2 CT (GAS)	150	43,739	40.5	97.0	77.3	11,650	GAS	524,080	972,290	509,558.0	3,622,952	8.28	6.91
POLK #2 CT (OIL)	150	86	0.1	67.5	32.8	11,237	LGT.OIL	166	5,819,753	966.4	6,001	6.98	36.15
POLK #2 TOTAL	**150**	**43,825**	**40.6**	**97.8**	**77.1**	**11,649**	**-**	**-**	**-**	**510,524.4**	**3,628,953**	**8.28**	**-**
POLK STATION TOTAL	**400**	**98,043**	**34.0**	**91.0**	**69.0**	**10,860**	**-**	**-**	**-**	**1,064,794.2**	**5,817,222**	**5.93**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	190	2.2	96.7	102.3	17,495	LGT.OIL	569	5,846,525	3,324.1	19,485	10.26	34.27
B.B.C.T.#2	66	5,183	10.9	100.0	70.2	15,832	LGT.OIL	14,030	5,848,882	82,058.0	480,883	9.28	34.28
B.B.C.T.#3	66	5,416	11.4	100.0	72.0	15,693	LGT.OIL	14,531	5,848,879	84,991.4	498,055	9.20	34.28
C.T. TOTAL	**144**	**10,789**	**10.4**	**99.7**	**73.7**	**15,791**	**LGT.OIL**	**29,130**	**5,848,834**	**170,373.5**	**998,423**	**9.25**	**34.28**
CITY OF TAMPA	**6**	**1,125**	**0.0**	**0.0**	**0.0**	**11,127**	**GAS**	**12,875**	**972,290**	**12,518.4**	**67,937**	**6.04**	**5.28**
TOT. COAL (GN,BB,POLK)	**3,077**	**1,318,054**	**59.5**	**71.7**	**74.0**	**10,953**	**COAL**	**624,704**	**23,108,864**	**14,436,193.1**	**29,756,671**	**2.26**	**47.63**
SYSTEM	**3,501**	**1,408,493**	**55.9**	**79.0**	**71.0**	**22,109**	**-**	**-**	**-**	**15,467,505.1**	**36,399,600**	**2.58**	**-**

* Hookers Point boiler limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT B.B. = BIG BEND

GAN. = GANNON C.T. = COMBUSTION TURBINE

SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JULY 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	39	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-260	0.0	0.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-260**	**0.0**	**71.3**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	52,446	61.8	89.8	63.3	12,217	COAL	27,548	23,258,000	640,711.4	1,128,663	2.15	40.97
GAN.#2	98	31,941	43.8	62.5	63.5	13,143	COAL	21,533	19,496,000	419,807.4	882,224	2.76	40.97
GAN.#3	145	35,731	33.1	45.5	59.6	12,634	COAL	22,960	19,662,000	451,439.5	940,689	2.63	40.97
GAN.#4	159	57,706	48.8	67.7	56.8	13,383	COAL	38,243	20,194,000	772,279.1	1,566,846	2.72	40.97
GAN.#5	232	72,497	42.0	55.0	67.6	10,478	COAL	33,732	22,520,000	759,644.6	1,382,027	1.91	40.97
GAN.#6	372	192,029	69.4	83.9	69.4	10,705	COAL	84,583	24,304,000	2,055,705.2	3,465,433	1.80	40.97
GANNON STATION	**1,120**	**442,350**	**53.1**	**69.4**	**64.8**	**11,526**	**COAL**	**228,599**	**22,308,003**	**5,099,587.2**	**9,365,882**	**2.12**	**40.97**
B.B.#1	416	198,827	64.2	78.5	69.2	11,220	COAL	94,529	23,599,940	2,230,878.7	4,561,636	2.29	48.26
B.B.#2	416	211,189	68.2	82.8	76.0	10,695	COAL	95,766	23,584,920	2,258,633.4	4,621,330	2.19	48.26
B.B.#3	433	177,818	55.2	68.4	74.5	10,352	COAL	78,239	23,526,640	1,840,700.8	3,775,538	2.12	48.26
B.B. 1 - 3	1,265	587,834	62.5	76.5	73.3	10,769	COAL	268,534	23,573,227	6,330,212.9	12,958,504	2.20	48.26
B.B.#4	442	274,132	83.4	96.3	83.4	10,414	COAL	126,600	22,549,298	2,854,752.9	5,999,832	2.19	47.39
B.B. STATION	**1,707**	**861,966**	**67.9**	**82.1**	**75.9**	**10,656**	**COAL**	**395,134**	**23,245,162**	**9,184,965.8**	**18,958,336**	**2.20**	**47.98**
SEB-PHIL. #1(HVY OIL)	17	3,820	30.2	98.5	69.2	11,071	HVY.OIL	6,741	6,273,540	42,290.8	196,805	5.15	29.20
SEB-PHIL. #2(HVY OIL)	17	5,007	39.6	99.1	95.6	8,446	HVY.OIL	6,741	6,273,540	42,290.8	196,804	3.93	29.20
SEB-PHILLIPS TOTAL	**34**	**8,827**	**34.9**	**98.8**	**82.4**	**9,582**	**HVY.OIL**	**13,482**	**6,273,540**	**84,581.6**	**393,609**	**4.46**	**29.20**
POLK #1 GASIFIER	250	148,315	79.7	85.2	89.3	10,775	COAL	68,604	23,295,040	1,598,132.0	3,101,381	2.09	45.21
POLK #1 CT (OIL)	225	10,372	6.2	99.2	65.8	8,350	LGT.OIL	15,061	5,810,731	86,606.8	541,483	5.22	35.95
POLK #1 TOTAL	**250**	**158,687**	**85.3**	**94.1**	**87.3**	**10,617**	**-**	**-**	**-**	**1,684,738.8**	**3,642,864**	**2.30**	**-**
POLK #2 CT (GAS)	150	26,237	23.5	82.6	79.1	11,750	GAS	327,711	972,290	308,289.0	183,494	0.70	0.56
POLK #2 CT (OIL)	150	11	0.0	77.2	22.0	15,092	LGT.OIL	29	5,810,641	166.0	1,027	9.34	35.41
POLK #2 TOTAL	**150**	**26,248**	**23.5**	**87.8**	**79.1**	**11,752**	**-**	**-**	**-**	**308,455.0**	**184,521**	**0.70**	**-**
POLK STATION TOTAL	**400**	**184,935**	**62.1**	**91.7**	**84.2**	**10,778**	**-**	**-**	**-**	**1,993,193.8**	**3,827,385**	**2.07**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	0	0.0	99.1	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	66	1,848	3.8	100.0	66.7	16,483	LGT.OIL	5,220	5,834,944	30,460.1	175,301	9.49	33.58
B.B.C.T.#3	66	1,690	3.4	100.0	65.7	15,973	LGT.OIL	4,626	5,834,949	26,993.7	155,353	9.19	33.58
C.T. TOTAL	**144**	**3,538**	**3.3**	**99.9**	**60.7**	**16,239**	**LGT.OIL**	**9,846**	**5,834,946**	**57,453.8**	**330,654**	**9.35**	**33.58**
CITY OF TAMPA	**6**	**1,086**	**0.0**	**0.0**	**0.0**	**9,329**	**GAS**	**10,770**	**940,734**	**10,131.7**	**107,325**	**9.88**	**9.97**
TOT. COAL (GN,BB,POLK)	**3,077**	**1,452,631**	**63.5**	**77.7**	**72.9**	**10,934**	**COAL**	**692,337**	**22,940,669**	**15,882,685.0**	**31,425,599**	**2.16**	**45.39**
SYSTEM	**3,501**	**1,502,442**	**57.7**	**79.6**	**70.7**	**10,935**	**-**	**-**	**-**	**16,429,913.9**	**32,983,191**	**2.20**	**-**

* Hookers Point boiler limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT B.B. = BIG BEND
GAN. = GANNON C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELEC COMPANY

ACTUAL FOR MONTH OF: AUGUST 2001

SCHEDULE A4
PAGE 1 OF 1
Revised with Dec. 2001 Filing(column J Phillips Total)

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	39	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-268	0.0	0.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION	**90**	**-268**	**0.0**	**71.3**	**0.0**	**0**	HVY.OIL	**0**	0	0.0	0	0.00	0.00
GAN.#1	114	46,986	55.4	79.4	60.3	12,809	COAL	25,689	23,428,000	601,841.9	1,136,197	2.42	44.23
GAN.#2	98	47,007	64.5	82.4	74.2	12,762	COAL	31,674	18,940,000	599,905.6	1,400,907	2.98	44.23
GAN.#3	145	64,050	59.4	81.3	69.5	12,182	COAL	42,008	18,574,000	780,256.6	1,857,968	2.90	44.23
GAN.#4	159	64,501	54.5	64.9	68.5	13,121	COAL	45,578	18,568,000	846,292.3	2,015,866	3.13	44.23
GAN.#5	232	116,138	67.3	85.6	75.5	10,531	COAL	52,790	23,168,000	1,223,038.7	2,334,845	2.01	44.23
GAN.#6	372	189,873	68.6	81.4	78.9	10,524	COAL	83,487	23,934,000	1,998,177.9	3,692,540	1.94	44.23
GANNON STATION	**1,120**	**528,555**	**63.4**	**79.8**	**73.2**	**11,445**	COAL	**281,226**	**21,511,215**	**6,049,513.0**	**12,438,323**	**2.35**	**44.23**
B.B.#1	416	219,246	70.8	82.0	76.2	11,215	COAL	103,506	23,755,520	2,458,838.9	4,691,040	2.14	45.32
B.B.#2	416	229,872	74.3	87.7	77.6	10,622	COAL	102,932	23,720,720	2,441,621.2	4,665,025	2.03	45.32
B.B.#3	433	219,766	68.2	79.4	75.7	10,669	COAL	98,602	23,779,240	2,344,691.6	4,468,783	2.03	45.32
B.B. 1 - 3	1,265	668,884	71.1	83.0	76.5	10,832	COAL	305,040	23,751,445	7,245,151.7	13,824,848	2.07	45.32
B.B.#4	442	239,172	72.7	82.1	86.8	10,488	COAL	112,805	22,237,150	2,508,456.4	5,760,557	2.41	51.07
B.B. STATION	**1,707**	**908,056**	**71.5**	**82.8**	**79.2**	**10,741**	COAL	**417,845**	**23,342,634**	**9,753,608.1**	**19,585,405**	**2.16**	**46.87**
SEB-PHIL. #1(HVY OIL)	17	5,083	40.2	97.9	86.2	10,118	HVY.OIL	8,197	6,273,540	51,428.7	228,615	4.50	27.89
SEB-PHIL. #2(HVY OIL)	17	5,593	44.2	92.1	98.0	9,195	HVY.OIL	8,198	6,273,540	51,428.8	228,643	4.09	27.89
SEB-PHILLIPS TOTAL	**34**	**10,676**	**42.2**	**95.0**	**92.1**	**9,634**	HVY.OIL	**16,395**	**6,273,540**	**102,857.5**	**457,258**	**4.28**	**27.89**
POLK #1 GASIFIER	250	102,661	55.2	59.9	77.9	11,409	COAL	52,990	22,104,000	1,171,294.1	2,362,338	2.30	44.58
POLK #1 CT (OIL)	225	16,947	10.1	94.0	68.2	8,703	LGT.OIL	26,578	5,612,666	147,483.3	916,906	5.41	34.50
POLK #1 TOTAL	**250**	**119,608**	**64.3**	**80.7**	**76.3**	**11,026**	-	-	-	**1,318,777.4**	**3,279,244**	**2.74**	-
POLK #2 CT (GAS)	150	36,630	32.8	89.4	77.7	11,013	GAS	380,928	972,290	403,402.9	1,701,503	4.65	4.47
POLK #2 CT (OIL)	150	1,800	1.6	97.3	68.6	14,220	LGT.OIL	4,403	5,812,685	25,595.2	151,909	8.44	34.50
POLK #2 TOTAL	**150**	**38,430**	**34.4**	**97.3**	**77.2**	**11,163**	-	-	-	**428,998.1**	**1,853,412**	**4.82**	-
POLK STATION TOTAL	**400**	**158,038**	**53.1**	**86.9**	**76.6**	**11,059**	-	-	-	**1,747,775.5**	**5,132,656**	**3.25**	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	244	2.7	84.3	101.7	17,616	LGT.OIL	737	5,830,993	4,298.2	24,322	9.97	33.00
B.B.C.T.#2	66	4,802	9.8	100.0	68.8	15,969	LGT.OIL	13,180	5,818,330	76,684.6	434,955	9.06	33.00
B.B.C.T.#3	66	420	0.9	24.2	63.6	15,797	LGT.OIL	1,140	5,818,316	6,634.8	37,621	8.96	33.00
C.T. TOTAL	**144**	**5,466**	**5.1**	**64.0**	**69.1**	**16,030**	LGT.OIL	**15,057**	**5,818,949**	**87,617.6**	**496,898**	**9.09**	**33.00**
CITY OF TAMPA	**6**	**1,417**	**0.0**	**0.0**	**0.0**	**10,564**	**GAS**	**14,135**	**972,290**	**14,969.0**	**56,909**	**4.02**	**4.03**
TOT. COAL (GN,BB,POLK)	**3,077**	**1,539,272**	**67.2**	**79.8**	**76.9**	**11,028**	**COAL**	**752,061**	**22,570,519**	**16,974,415.2**	**34,386,066**	**2.23**	**45.72**
SYSTEM	**3,501**	**1,611,940**	**61.9**	**81.2**	**74.5**	**11,016**	-	-	-	**17,756,340.7**	**38,167,449**	**2.37**	-

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT B.B. = BIG BEND
GAN. = GANNON C.T. = COMBUSTION TURBINE

REVISED 12/01

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: SEPTEMBER 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	39	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-240	0.0	0.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-240**	**0.0**	**71.3**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	50,370	61.4	87.2	62.7	11,566	COAL	25,387	22,948,000	582,580.9	1,181,653	2.35	46.55
GAN.#2	98	42,859	60.7	77.1	66.1	14,332	COAL	33,114	18,550,000	614,264.7	1,541,311	3.60	46.55
GAN.#3	145	56,930	54.5	70.6	60.2	12,597	COAL	39,557	18,130,000	717,168.4	1,841,204	3.23	46.55
GAN.#4	159	58,265	50.9	62.3	65.7	13,243	COAL	42,022	18,362,000	771,608.0	1,955,939	3.36	46.55
GAN.#5	232	46,405	27.8	35.5	59.0	11,786	COAL	23,899	22,886,000	546,952.5	1,112,393	2.40	46.55
GAN.#6	372	120,661	45.0	55.1	58.1	12,450	COAL	55,282	27,174,000	1,502,233.1	2,573,133	2.13	46.55
GANNON STATION	**1,120**	**375,490**	**46.6**	**59.3**	**60.8**	**12,610**	**COAL**	**219,261**	**21,594,390**	**4,734,807.6**	**10,205,633**	**2.72**	**46.55**
B.B.#1	416	173,580	58.0	68.1	64.3	11,291	COAL	82,519	23,749,820	1,959,811.4	3,740,551	2.15	45.33
B.B.#2	416	195,788	65.4	74.9	70.6	10,532	COAL	87,299	23,620,400	2,062,037.3	3,957,227	2.02	45.33
B.B.#3	433	152,682	49.0	56.8	76.7	10,493	COAL	68,806	23,283,940	1,602,073.6	3,118,947	2.04	45.33
B.B. 1 - 3	1,265	522,050	57.3	66.5	70.6	10,773	COAL	238,624	23,568,138	5,623,922.3	10,816,725	2.07	45.33
B.B.#4	442	196,803	61.8	72.7	79.9	10,558	COAL	95,593	21,735,450	2,077,749.3	5,098,932	2.59	53.34
B.B. STATION	**1,707**	**718,853**	**58.5**	**68.1**	**73.0**	**10,714**	**COAL**	**334,217**	**23,043,953**	**7,701,671.6**	**15,915,657**	**2.21**	**47.62**
SEB-PHIL. #1(HVY OIL)	17	4,110	33.6	91.0	84.5	9,475	HVY.OIL	6,207	6,273,540	38,941.2	171,394	4.17	27.61
SEB-PHIL. #2(HVY OIL)	17	4,964	40.6	99.0	97.4	9,475	HVY.OIL	7,497	6,273,540	47,032.6	207,015	4.17	27.61
SEB-PHILLIPS TOTAL	**34**	**9,074**	**37.1**	**95.0**	**91.0**	**9,475**	**HVY.OIL**	**13,704**	**6,273,540**	**85,973.8**	**378,409**	**4.17**	**27.61**
POLK #1 GASIFIER	250	85,045	47.2	49.4	80.8	11,497	COAL	44,841	21,805,340	977,781.5	1,989,507	2.34	44.37
POLK #1 CT (OIL)	225	16,340	10.1	91.0	67.1	8,874	LGT.OIL	25,570	5,770,348	145,002.3	695,458	5.48	35.02
POLK #1 TOTAL	**250**	**101,385**	**56.3**	**78.6**	**78.2**	**11,074**	**-**	**-**	**-**	**1,122,783.8**	**2,884,965**	**2.85**	**-**
POLK #2 CT (GAS)	150	44,460	41.2	98.0	81.1	11,368	GAS	478,602	972,290	505,404.0	1,451,345	3.26	3.03
POLK #2 CT (OIL)	150	1,725	1.6	62.6	102.7	11,974	LGT.OIL	3,580	5,770,348	20,656.0	125,362	7.27	35.02
POLK #2 TOTAL	**150**	**46,185**	**42.8**	**98.0**	**81.7**	**11,390**	**-**	**-**	**-**	**526,060.0**	**1,576,707**	**3.41**	**-**
POLK STATION TOTAL	**400**	**147,570**	**51.2**	**85.9**	**79.5**	**11,173**	**-**	**-**	**-**	**1,648,843.8**	**4,461,672**	**3.02**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	102	1.2	100.0	111.1	17,062	LGT.OIL	299	5,819,623	1,740.3	9,942	9.75	33.25
B.B.C.T.#2	66	2,212	4.7	100.0	64.5	16,413	LGT.OIL	6,255	5,804,098	36,306.2	207,977	9.40	33.25
B.B.C.T.#3	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**144**	**2,314**	**2.2**	**54.2**	**38.8**	**16,442**	**LGT.OIL**	**6,554**	**5,804,806**	**38,046.5**	**217,919**	**9.42**	**33.25**
CITY OF TAMPA	**6**	**1,463**	**0.0**	**0.0**	**0.0**	**10,426**	**GAS**	**14,444**	**972,290**	**15,252.9**	**107,301**	**7.33**	**7.43**
TOT. COAL (GN,BB,POLK)	**3,077**	**1,179,388**	**53.2**	**63.4**	**69.2**	**11,374**	**COAL**	**598,319**	**22,419,915**	**13,414,260.7**	**28,110,797**	**2.38**	**46.98**
SYSTEM	**3,501**	**1,254,524**	**49.8**	**67.0**	**66.6**	**11,339**	**-**	**-**	**-**	**14,224,596.2**	**31,286,591**	**2.49**	**-**

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT B.B. = BIG BEND

GAN. = GANNON C.T. = COMBUSTION TURBINE

SYSTEM NET GENERA. AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: JUNE 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	(175)	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**(175)**	**—**	**—**	**—**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	42,306	51.5	70.8	69.0	11,437	COAL	20,366	23,758,000	483,855.4	854,508	2.02	41.96
GAN.#2	98	41,350	58.6	68.5	93.1	11,661	COAL	20,059	24,038,000	482,178.2	841,627	2.04	41.98
GAN.#3	145	17,829	17.1	21.6	76.8	12,697	COAL	12,372	18,298,000	226,382.9	519,099	2.91	41.96
GAN.#4	159	67,869	59.3	73.3	75.6	12,907	COAL	43,919	19,946,000	876,008.4	1,842,736	2.72	41.96
GAN.#5	217	110,417	70.7	81.5	85.6	10,272	COAL	47,836	23,710,000	1,134,191.6	2,007,084	1.82	41.96
GAN.#6	372	171,501	64.0	75.6	81.5	10,342	COAL	74,445	23,824,000	1,773,577.7	3,123,533	1.82	41.96
GANNON STATION	**1,105**	**451,272**	**56.7**	**68.2**	**79.7**	**11,027**	**COAL**	**218,997**	**22,722,659**	**4,976,194.2**	**9,188,587**	**2.04**	**41.96**
B.B.#1	416	164,010	54.8	63.8	70.2	10,936	COAL	75,140	23,870,040	1,793,594.8	3,356,650	2.05	44.67
B.B.#2	416	188,592	63.0	69.2	66.4	11,157	COAL	88,412	23,799,940	2,104,202.9	3,949,537	2.09	44.67
B.B.#3	433	137,274	44.0	51.1	75.3	10,467	COAL	59,195	24,272,520	1,436,807.7	2,644,356	1.93	44.67
B.B. 1 - 3	1,265	489,876	53.8	61.2	70.7	**10,890**	COAL	222,747	23,949,175	5,334,605.4	9,950,543	2.03	44.67
B.B.#4	442	254,361	79.9	90.8	79.9	10,466	COAL	123,663	21,527,900	2,662,206.2	6,875,514	2.70	55.60
B.B. STATION	**1,707**	**744,237**	**60.8**	**68.9**	**73.1**	**10,745**	**COAL**	**346,410**	**23,084,817**	**7,996,811.6**	**16,826,057**	**2.26**	**48.57**
SEB-PHIL. #1(HVY OIL)	17	1,785	14.6	53.1	71.1	9,860	HVY.OIL	2,805	6,273,540	17,599.3	86,291	4.83	30.76
SEB-PHIL. #2(HVY OIL)	17	4,600	37.6	96.5	82.9	9,860	HVY.OIL	7,229	6,273,540	45,353.9	222,388	4.83	30.76
SEB-PHILLIPS TOTAL	**34**	**6,385**	**26.1**	**74.8**	**77.0**	**9,860**	**HVY.OIL**	**10,034**	**6,273,540**	**62,953.2**	**308,679**	**4.83**	**30.76**
POLK #1 GASIFIER	250	133,659	74.3	84.2	81.2	11,957	COAL	59,233	26,980,000	1,598,113.4	2,184,329	1.63	36.88
POLK #1 CT (OIL)	225	17,456	10.8	99.3	120.2	7,654	LGT.OIL	22,928	5,827,534	133,612.3	722,948	4.14	31.53
POLK #1 TOTAL	**250**	**151,115**	**84.0**	**91.2**	**84.4**	**11,460**	**-**	**-**	**-**	**1,731,725.7**	**2,907,277**	**1.92**	**-**
POLK #2 CT (GAS)	150	21,565	20.0	98.8	77.6	11,425	GAS	234,876	972,290	246,385.0	1,257,177	5.83	5.35
POLK #2 CT (OIL)	160	2,787	2.4	98.8	79.2	11,700	LGT.OIL	5,595	5,827,528	32,607.0	176,430	6.33	31.53
POLK #2 TOTAL	**155**	**24,352**	**21.8**	**98.8**	**77.7**	**11,457**	**-**	**-**	**-**	**278,992.0**	**1,433,607**	**5.89**	**-**
POLK #3 CT (GAS)	150	36,541	33.8	98.7	77.6	11,070	GAS	385,597	972,290	404,491.0	2,142,690	5.86	5.56
POLK #3 CT (OIL)	160	1	0.0	98.7	1.2	399,600	LGT.OIL	69	5,827,621	399.6	2,162	216.20	31.33
POLK #3 TOTAL	**155**	**36,542**	**32.7**	**98.8**	**77.4**	**11,080**	**-**	**-**	**-**	**404,890.6**	**2,144,852**	**5.87**	**-**
POLK STATION TOTAL	**560**	**212,009**	**52.6**	**95.4**	**58.5**	**11,394**	**-**	**-**	**-**	**2,415,608.3**	**6,485,736**	**3.06**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	21	0.2	100.0	87.5	18,238	LGT.OIL	66	5,828,641	383.0	1,955	9.31	29.62
B.B.C.T.#2	66	1,681	3.5	97.9	65.3	17,000	LGT.OIL	4,879	5,856,684	28,576.4	144,490	8.60	29.61
B.B.C.T.#3	66	0	0.0	7.6	0.0	0	LGT.OIL	75	0	0.0	2,221	0.00	29.61
C.T. TOTAL	**144**	**1,702**	**1.6**	**56.7**	**37.2**	**17,015**	**LGT.OIL**	**5,020**	**5,768,816**	**28,959.4**	**148,666**	**8.73**	**29.61**
CITY OF TAMPA	**6**	**2,028**	**0.0**	**0.0**	**0.0**	**10,254**	**GAS**	**19,823**	**972,290**	**20,794.3**	**127,437**	**6.28**	**6.43**
TOT. COAL (GN,BB,POLK)	**3,062**	**1,329,168**	**60.3**	**69.9**	**76.1**	**10,963**	**COAL**	**624,640**	**23,327,217**	**14,571,119.2**	**28,198,973**	**2.12**	**45.14**
SYSTEM	**3,556**	**1,417,458**	**55.5**	**72.4**	**71.4**	**10,935**	**-**	**-**	**-**	**15,501,321.0**	**33,085,162**	**2.33**	**-**

* Hookers Point boiler limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE

SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JULY 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	-178	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-178**	---	---	---	**0**	HVY.OIL	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	53,279	62.8	88.0	68.5	12,972	COAL	28,926	23,894,000	691,157.8	1,214,260	2.28	41.98
GAN.#2	98	48,092	66.0	78.3	81.6	13,675	COAL	28,006	23,482,000	657,636.9	1,175,641	2.44	41.98
GAN.#3	145	83,695	77.6	73.2	77.6	12,842	COAL	56,320	19,084,000	1,074,810.9	2,364,210	2.82	41.98
GAN.#4	159	75,796	64.1	82.3	70.0	13,625	COAL	55,026	18,768,000	1,032,728.0	2,309,891	3.05	41.98
GAN.#5	217	94,688	58.6	74.1	78.5	11,648	COAL	46,481	23,728,000	1,102,901.2	1,951,187	2.06	41.98
GAN.#6	372	154,914	56.0	65.0	81.6	11,343	COAL	73,356	23,954,000	1,757,169.6	3,079,350	1.99	41.98
GANNON STATION	**1,105**	**510,464**	**62.1**	**76.5**	**77.4**	**12,374**	**COAL**	**288,115**	**21,923,206**	**6,316,404.4**	**12,094,539**	**2.37**	**41.98**
B.B.#1	416	218,014	70.4	80.9	77.7	10,850	COAL	96,666	24,469,160	2,365,349.0	4,215,299	1.93	43.61
B.B.#2	416	190,833	61.7	67.1	78.0	10,612	COAL	82,611	24,515,080	2,025,209.6	3,600,362	1.89	43.58
B.B.#3	433	112,095	34.8	40.0	72.6	10,606	COAL	48,211	24,660,020	1,188,876.1	2,102,691	1.88	43.61
B.B. 1 - 3	1,265	520,942	55.4	62.4	76.0	10,710	COAL	227,487	24,526,264	5,579,434.7	9,918,352	1.90	43.60
B.B.#4	442	258,189	78.5	89.3	78.7	10,602	COAL	125,167	21,868,830	2,737,261.5	6,534,767	2.53	52.21
B.B. STATION	**1,707**	**779,131**	**61.3**	**69.4**	**76.7**	**10,674**	**COAL**	**352,654**	**23,583,078**	**8,316,696.2**	**16,453,119**	**2.11**	**46.66**
SEB-PHIL. #1(HVY OIL)	17	5,068	40.1	99.6	90.9	9,665	HVY.OIL	7,808	6,273,540	48,981.6	241,517	4.77	30.93
SEB-PHIL. #2(HVY OIL)	17	5,074	40.1	99.6	91.1	9,665	HVY.OIL	7,817	6,273,540	49,039.6	241,795	4.77	30.93
SEB-PHILLIPS TOTAL	**34**	**10,142**	**40.1**	**99.6**	**91.0**	**9,665**	**HVY.OIL**	**15,625**	**6,273,540**	**98,021.2**	**483,312**	**4.77**	**30.93**
POLK #1 GASIFIER	250	130,133	70.0	74.1	83.4	11,695	COAL	56,782	26,802,000	1,521,854.8	2,171,885	1.67	38.25
POLK #1 CT (OIL)	225	10,534	6.3	99.1	70.1	8,089	LGT.OIL	14,640	5,835,965	85,205.9	461,880	4.38	31.55
POLK #1 TOTAL	**250**	**140,667**	**75.6**	**87.7**	**82.2**	**11,425**	-	-	-	**1,607,060.7**	**2,633,765**	**1.87**	-
POLK #2 CT (GAS)	150	20,535	18.4	99.7	78.8	12,223	GAS	237,468	972,290	251,004.0	1,945,831	9.48	8.19
POLK #2 CT (OIL)	160	1,883	1.6	99.7	70.5	13,290	LGT.OIL	4,288	5,835,974	25,026.0	135,285	7.18	31.55
POLK #2 TOTAL	**155**	**22,418**	**19.4**	**99.7**	**78.0**	**12,313**	-	-	-	**276,030.0**	**2,081,116**	**9.28**	-
POLK #3 CT (GAS)	150	27,467	24.6	99.8	76.5	11,131	GAS	289,256	972,290	305,743.0	1,705,983	6.21	5.90
POLK #3 CT (OIL)	160	0	0.0	99.8	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**155**	**27,467**	**23.8**	**99.8**	**76.5**	**11,131**	-	-	-	**305,743.0**	**1,705,983**	**6.21**	-
POLK STATION TOTAL	**560**	**190,552**	**45.7**	**94.4**	**57.6**	**11,487**	-	-	-	**2,188,833.7**	**6,420,864**	**3.37**	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	48	0.5	100.0	100.0	18,038	LGT.OIL	149	5,827,556	865.8	4,421	9.21	29.67
B.B.C.T.#2	66	2,318	4.7	100.0	65.0	16,456	LGT.OIL	6,568	5,807,716	38,145.6	194,874	8.41	29.67
B.B.C.T.#3	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**144**	**2,366**	**2.2**	**54.2**	**38.1**	**16,488**	**LGT.OIL**	**6,717**	**5,808,155**	**39,011.4**	**199,295**	**8.42**	**29.67**
CITY OF TAMPA	**6**	**3,086**	**0.0**	**0.0**	**0.0**	**6,663**	**GAS**	**19,452**	**972,290**	**20,560.8**	**145,524**	**4.72**	**7.48**
TOT. COAL (GN,BB,POLK)	**3,062**	**1,419,728**	**62.3**	**72.3**	**77.5**	**11,379**	**COAL**	**697,552**	**23,159,512**	**16,154,955.4**	**30,719,543**	**2.16**	**44.04**
SYSTEM	**3,556**	**1,495,563**	**56.6**	**75.2**	**72.5**	**11,352**	-	-	-	**16,979,527.7**	**35,796,653**	**2.39**	-

* Hookers Point boiler limited to 90 MW

LEGEND:
H.P. = HOOKERS POINT
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
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ACTUAL FOR MONTH OF: AUGUST 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	-171	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-171**	—	—	—	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	44,015	51.9	79.2	61.1	12,810	COAL	24,297	23,206,320	563,844.0	935,610	2.13	38.51
GAN.#2	98	44,741	61.4	75.3	78.4	13,021	COAL	25,372	22,960,360	582,550.3	977,005	2.18	38.51
GAN.#3	145	64,750	60.0	78.0	69.2	12,728	COAL	45,797	17,995,780	824,152.7	1,763,515	2.72	38.51
GAN.#4	159	67,872	57.4	71.6	71.8	12,893	COAL	47,448	18,443,360	875,100.5	1,827,091	2.69	38.51
GAN.#5	217	122,031	75.6	95.4	75.6	11,312	COAL	59,355	23,256,380	1,380,382.4	2,285,596	1.87	38.51
GAN.#6	372	179,658	64.9	79.0	77.1	10,994	COAL	84,060	23,497,260	1,975,179.7	3,236,917	1.80	38.51
GANNON STATION	**1,105**	**523,067**	**63.6**	**80.7**	**73.5**	**11,855**	**COAL**	**286,329**	**21,657,637**	**6,201,209.6**	**11,025,734**	**2.11**	**38.51**
B.B.#1	416	156,729	50.6	58.4	73.5	11,291	COAL	72,873	24,282,820	1,769,552.0	3,413,102	2.18	46.84
B.B.#2	416	210,930	68.2	73.2	75.6	11,201	COAL	97,276	24,286,880	2,362,532.0	4,556,049	2.16	46.84
B.B.#3	433	147,523	45.8	55.5	74.8	10,841	COAL	65,412	24,449,000	1,599,266.5	3,063,657	2.08	46.84
B.B. 1 - 3	1,265	515,182	54.7	62.3	74.6	11,125	COAL	235,561	24,330,643	5,731,350.5	11,032,808	2.14	46.84
B.B.#4	442	248,022	75.4	87.2	75.4	10,948	COAL	125,413	21,651,984	2,715,442.7	6,265,540	2.53	49.96
B.B. STATION	**1,707**	**763,204**	**60.1**	**68.7**	**74.8**	**11,068**	**COAL**	**360,974**	**23,399,997**	**8,446,793.2**	**17,298,348**	**2.27**	**47.92**
SEB-PHIL. #1(HVY OIL)	17	5,647	44.6	100.0	91.2	9,615	HVY.OIL	8,654	6,273,540	54,293.6	264,651	4.69	30.58
SEB-PHIL. #2(HVY OIL)	17	5,681	44.9	99.9	91.2	9,615	HVY.OIL	8,706	6,273,540	54,620.5	266,241	4.69	30.58
SEB-PHILLIPS TOTAL	**34**	**11,328**	**44.8**	**100.0**	**91.2**	**9,615**	**HVY.OIL**	**17,360**	**6,273,540**	**108,914.1**	**530,892**	**4.69**	**30.58**
POLK #1 GASIFIER	250	149,858	80.6	85.6	90.8	10,815	COAL	62,074	26,110,000	1,620,757.4	2,394,851	1.60	38.58
POLK #1 CT (OIL)	225	4,726	2.8	98.5	58.0	9,185	LGT.OIL	8,107	5,823,622	43,409.8	252,886	5.35	31.19
POLK #1 TOTAL	**250**	**154,584**	**83.1**	**94.4**	**89.2**	**10,765**	**-**	**-**	**-**	**1,664,167.2**	**2,647,737**	**1.71**	**-**
POLK #2 CT (GAS)	150	14,533	13.0	100.0	77.0	11,118	GAS	152,717	972,290	161,574.0	683,602	4.70	4.48
POLK #2 CT (OIL)	160	-5	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**155**	**14,528**	**12.6**	**100.0**	**76.6**	**11,122**	**-**	**-**	**-**	**161,574.0**	**683,602**	**4.71**	**-**
POLK #3 CT (GAS)	150	37,062	33.2	99.7	76.6	11,914	GAS	417,341	972,290	441,547.0	2,540,661	6.86	6.09
POLK #3 CT (OIL)	160	28	0.0	99.7	22.8	51,557	LGT.OIL	248	5,823,786	1,443.6	7,733	27.62	31.18
POLK #3 TOTAL	**155**	**37,090**	**32.2**	**99.7**	**76.4**	**11,944**	**-**	**-**	**-**	**442,990.6**	**2,548,394**	**6.87**	**-**
POLK STATION TOTAL	**560**	**206,202**	**49.5**	**97.4**	**60.3**	**11,002**	**-**	**-**	**-**	**2,268,731.8**	**5,879,733**	**2.85**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	66	1,697	3.5	100.0	71.4	16,038	LGT.OIL	4,649	5,853,890	27,216.9	138,518	8.16	29.80
B.B.C.T.#3	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**144**	**1,697**	**1.6**	**54.2**	**32.7**	**16,038**	**LGT.OIL**	**4,649**	**5,853,890**	**27,216.9**	**138,518**	**8.16**	**29.80**
CITY OF TAMPA	**6**	**2,077**	**0.0**	**0.0**	**0.0**	**10,368**	**GAS**	**20,353**	**972,290**	**21,533.5**	**29,071**	**1.40**	**1.43**
TOT. COAL (GN,BB,POLK)	**3,062**	**1,436,129**	**63.0**	**74.4**	**75.6**	**11,328**	**COAL**	**709,377**	**22,933,860**	**16,268,760.2**	**30,718,933**	**2.14**	**43.30**
SYSTEM	**3,556**	**1,507,404**	**57.1**	**76.7**	**70.6**	**11,326**	**-**	**-**	**-**	**17,074,399.1**	**34,902,296**	**2.32**	**-**

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: SEPTEMBER 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	-165	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	90	-165	---	---	---	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	40,940	49.9	64.3	74.2	12,129	COAL	22,289	22,278,000	496,554.3	873,248	2.13	39.18
GAN.#2	98	39,108	55.4	62.5	79.4	12,402	COAL	21,371	22,686,000	485,036.2	837,280	2.14	39.18
GAN.#3	145	65,992	63.2	72.2	78.7	12,417	COAL	41,483	19,754,000	819,455.2	1,625,235	2.46	39.18
GAN.#4	159	81,696	54.1	65.7	75.6	13,660	COAL	41,400	20,422,000	845,470.8	1,621,963	2.62	39.18
GAN.#5	217	89,300	57.2	71.6	74.1	11,961	COAL	45,420	23,516,000	1,068,096.7	1,779,480	1.99	39.18
GAN.#6	372	178,356	66.6	79.5	75.3	10,910	COAL	82,742	23,516,000	1,945,926.4	3,241,695	1.82	39.18
GANNON STATION	1,105	475,592	59.8	71.9	75.8	11,902	COAL	254,705	22,223,905	5,660,539.8	9,976,919	2.10	39.18
B.B.#1	416	225,793	75.4	84.3	75.4	11,295	COAL	103,307	24,687,000	2,550,346.8	4,722,152	2.09	45.71
B.B.#2	418	166,375	55.5	59.9	67.9	11,278	COAL	78,415	24,555,720	1,878,418.5	3,492,922	2.10	45.71
B.B.#3	433	194,783	62.5	71.4	71.9	10,722	COAL	86,478	24,150,420	2,088,489.9	3,952,900	2.03	45.71
B.B. 1 - 3	1,265	586,951	64.4	71.8	71.7	11,100	COAL	266,200	24,475,001	6,515,255.2	12,187,974	2.07	45.71
B.B.#4	442	55,348	17.4	22.6	68.7	12,043	COAL	29,315	22,737,953	666,552.4	1,594,959	2.88	54.41
B.B. STATION	1,707	642,299	52.3	59.1	70.9	11,161	COAL	295,515	24,302,689	7,181,807.6	13,782,933	2.14	46.57
SEB-PHIL. #1(HVY OIL)	17	5,561	45.6	94.6	91.3	9,662	HVY.OIL	8,595	6,273,540	53,922.1	265,345	4.75	30.87
SEB-PHIL. #2(HVY OIL)	17	5,729	46.8	100.0	90.0	9,662	HVY.OIL	8,823	6,273,540	55,352.0	272,383	4.75	30.87
SEB-PHILLIPS TOTAL	34	11,310	46.2	97.3	90.6	9,662	HVY.OIL	17,418	6,273,540	109,274.1	537,728	4.75	30.87
POLK #1 GASIFIER	250	120,941	67.2	73.3	84.8	11,150	COAL	51,757	26,054,000	1,348,468.3	2,140,978	1.77	41.37
POLK #1 CT (OIL)	225	11,202	6.9	97.5	74.7	8,312	LGT.OIL	16,562	5,810,967	93,107.9	536,443	4.79	32.39
POLK #1 TOTAL	250	132,143	73.4	89.7	83.8	10,909	-	-	-	1,441,576.2	2,677,421	2.03	-
POLK #2 CT (GAS)	150	23,776	22.0	99.7	98.3	11,164	GAS	252,314	972,290	265,434.0	1,865,814	7.85	7.39
POLK #2 CT (OIL)	160	617	0.5	98.9	48.2	15,412	LGT.OIL	1,636	5,810,942	9,509.2	53,009	8.59	32.40
POLK #2 TOTAL	155	24,393	21.9	100.0	95.8	11,271	-	-	-	274,943.2	1,918,823	7.87	-
POLK #3 CT (GAS)	150	49,434	45.8	100.0	78.4	11,728	GAS	551,107	972,290	579,765.0	2,867,793	5.80	5.20
POLK #3 CT (OIL)	160	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	155	49,434	44.3	100.0	78.4	11,728	-	-	-	579,765.0	2,867,793	5.80	-
POLK STATION TOTAL	560	205,970	51.1	95.4	83.1	11,149	-	-	-	2,296,284.4	7,463,837	3.62	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	48	0.6	100.0	100.0	16,704	LGT.OIL	153	5,855,345	897.8	4,810	9.60	30.13
B.B.C.T.#2	66	1,121	2.4	32.9	70.8	15,047	LGT.OIL	2,881	5,853,913	16,867.7	86,807	7.74	30.13
B.B.C.T.#3	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	144	1,169	1.1	23.4	40.8	15,197	LGT.OIL	3,034	5,853,986	17,765.5	91,417	7.82	30.13
CITY OF TAMPA	6	1,875	0.0	0.0	0.0	10,388	GAS	18,511	972,290	19,473.6	115,203	6.14	6.22
TOT. COAL (GN,BB,POLK)	3,062	1,236,832	56.2	84.9	73.8	11,455	COAL	601,977	23,573,699	14,190,815.5	25,882,830	2.09	43.00
SYSTEM	3,556	1,336,050	52.4	87.7	70.2	11,422	-	-	-	15,285,144.8	31,950,037	2.39	-

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JUNE 2003

SCHEDULE A4
PAGE 1 OF 1
*Revised with July filing

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	75	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	98	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	70,309	65.1	86.9	69.4	12,100	COAL	36,249	23,470,000	850,764.0	1,764,312	2.51	48.67
GAN.#4	164	53,909	45.7	60.5	67.8	12,481	COAL	28,715	23,432,000	672,849.9	1,397,617	2.59	48.67
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	353	70,031	27.6	34.7	57.6	11,738	COAL	34,665	23,714,000	822,045.8	1,687,216	2.41	48.67
GANNON STATION	**840**	**194,249**	**32.1**	**62.5**	**49.8**	**12,076**	**COAL**	**99,629**	**23,543,945**	**2,345,659.7**	**4,849,145**	**2.50**	**48.67**
B.B.#1	421	157,833	52.1	59.1	52.6	11,324	COAL	74,759	23,907,000	1,787,263.4	3,753,959	2.38	50.21
B.B.#2	411	193,418	65.4	75.9	68.0	10,994	COAL	87,730	24,238,380	2,126,433.1	4,405,286	2.28	50.21
B.B.#3	428	189,726	61.6	71.1	67.4	11,023	COAL	85,348	24,502,840	2,091,273.8	4,285,676	2.26	50.21
B.B.#4	452	232,398	71.4	79.6	72.4	10,641	COAL	109,842	22,513,740	2,472,946.3	5,515,622	2.37	50.21
B.B. STATION	**1,712**	**773,375**	**62.7**	**71.5**	**67.7**	**10,962**	**COAL**	**357,679**	**23,702,593**	**8,477,916.6**	**17,960,543**	**2.32**	**50.21**
SEB-PHIL. #1(HVY OIL)	17	4,934	40.3	100.0	90.0	9,743	HVY.OIL	7,662	6,273,540	48,070.4	270,392	5.48	35.29
SEB-PHIL. #2(HVY OIL)	17	4,704	38.4	92.7	90.7	9,743	HVY.OIL	7,305	6,273,540	45,829.6	257,794	5.48	35.29
SEB-PHILLIPS TOTAL	**34**	**9,638**	**39.4**	**96.4**	**90.3**	**9,743**	**HVY.OIL**	**14,967**	**6,273,538**	**93,900.0**	**528,186**	**5.48**	**35.29**
POLK #1 GASIFIER	255	121,785	66.3	70.6	88.4	10,497	COAL	47,899	26,688,000	1,278,318.6	1,986,788	1.63	41.48
POLK #1 CT (OIL)	225	8,909	5.5	90.8	50.6	9,399	LGT.OIL	14,927	5,796,496	83,734.9	570,579	6.40	38.22
POLK #1 TOTAL	**255**	**130,694**	**71.2**	**84.5**	**84.1**	**10,422**	**-**	**-**	**-**	**1,362,053.5**	**2,557,367**	**1.96**	**-**
POLK #2 CT (GAS)	150	17,686	16.4	96.1	79.0	10,597	GAS	176,148	972,290	187,421.0	1,696,302	9.59	9.63
POLK #2 CT (OIL)	160	1,756	1.5	96.5	75.0	13,126	LGT.OIL	3,976	5,796,502	23,049.5	151,999	8.66	38.23
POLK #2 TOTAL	**155**	**19,442**	**17.4**	**96.5**	**78.6**	**10,826**	**-**	**-**	**-**	**210,470.5**	**1,848,301**	**9.51**	**-**
POLK #3 CT (GAS)	150	20,462	18.9	96.5	81.2	11,885	GAS	228,557	972,290	243,185.0	2,202,877	10.77	9.64
POLK #3 CT (OIL)	165	744	0.6	98.3	94.9	11,519	LGT.OIL	1,479	5,796,522	8,570.1	56,515	7.60	38.21
POLK #3 TOTAL	**158**	**21,206**	**18.6**	**98.5**	**81.7**	**11,872**	**-**	**-**	**-**	**251,755.1**	**2,259,392**	**10.65**	**-**
POLK STATION TOTAL	**568**	**171,342**	**41.9**	**91.7**	**81.9**	**10,647**	**-**	**-**	**-**	**1,824,279.1**	**6,665,060**	**3.89**	**-**
B.B.C.T.#1	14	14	0.1	100.0	100.0	19,507	LGT.OIL	48	5,734,985	273.1	1,617	11.55	33.69
B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	21	0.0	100.0	35.0	15,667	LGT.OIL	56	5,828,167	329.0	1,887	8.99	33.70
C.T. TOTAL	**140**	**35**	**0.0**	**100.0**	**25.0**	**17,203**	**LGT.OIL**	**104**	**5,785,529**	**602.1**	**3,504**	**10.01**	**33.69**
CITY OF TAMPA	**6**	**821**	**0.0**	**0.0**	**0.0**	**10,426**	**GAS**	**8,045**	**972,290**	**8,559.9**	**95,891**	**11.68**	**11.92**
BAYSIDE ST 1	246	130,606	73.7	96.4	76.5	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	87,098	81.7	95.7	85.4	11,161	GAS	913,602	972,290	972,072.6	7,711,016	8.85	8.44
BAYSIDE CT1B	148	85,140	79.9	97.2	86.2	11,161	GAS	893,065	972,290	950,220.7	7,537,679	8.85	8.44
BAYSIDE CT1C	148	76,221	71.5	93.3	85.1	11,161	GAS	799,512	972,290	850,680.6	6,748,069	8.85	8.44
BAYSIDE UNIT 1 TOTAL	**690**	**379,065**	**76.3**	**95.8**	**82.3**	**7,315**	**GAS**	**2,606,179**	**972,290**	**2,772,973.9**	**21,996,764**	**5.80**	**8.44**
BAYSIDE UNIT 2 TOTAL	**0**	**(299)**	**-**	**-**	**-**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**378,766**	**76.2**	**95.8**	**82.3**	**7,321**	**GAS**	**2,606,179**	**972,290**	**2,772,973.9**	**21,996,764**	**5.81**	**8.44**
TOT. COAL (GN,BB,POLK)	**2,807**	**1,089,409**	**53.9**	**68.7**	**64.2**	**11,109**	**COAL**	**505,207**	**23,954,353**	**12,101,894.9**	**24,796,476**	**2.28**	**49.08**
SYSTEM	**3,990**	**1,528,226**	**53.2**	**77.9**	**52.9**	**10,158**	**-**	**-**	**-**	**15,523,891.3**	**52,099,093**	**3.41**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

REVISED 7/03

SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JULY 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	75	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	98	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	72,440	64.9	85.5	73.3	12,308	COAL	38,444	23,192,000	891,593.2	1,834,213	2.53	47.71
GAN.#4	164	42,359	34.7	51.7	62.0	13,230	COAL	24,292	23,070,000	560,416.4	1,159,003	2.74	47.71
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	353	133,883	51.0	63.7	64.3	11,985	COAL	67,663	23,714,000	1,604,560.4	3,228,290	2.41	47.71
GANNON STATION	**840**	**248,682**	**39.8**	**72.7**	**52.2**	**12,291**	**COAL**	**130,399**	**23,440,134**	**3,056,570.0**	**6,221,506**	**2.50**	**47.71**
B.B.#1	421	169,176	54.0	58.9	69.4	11,198	COAL	77,772	24,358,120	1,894,379.7	3,818,851	2.26	49.10
B.B.#2	411	213,042	69.7	78.0	69.7	10,873	COAL	94,584	24,489,580	2,316,336.9	4,644,373	2.18	49.10
B.B.#3	428	178,586	56.1	68.5	56.2	11,665	COAL	84,993	24,511,300	2,083,280.8	4,173,425	2.34	49.10
B.B.#4	452	191,005	56.8	66.9	75.7	11,074	COAL	89,739	23,571,140	2,115,252.9	4,406,469	2.31	49.10
B.B. STATION	**1,712**	**751,809**	**59.0**	**68.0**	**67.6**	**11,185**	**COAL**	**347,088**	**24,227,981**	**8,409,250.3**	**17,043,118**	**2.27**	**49.10**
SEB-PHIL. #1(HVY OIL)	17	5,891	46.6	100.0	98.5	9,789	HVY.OIL	9,192	6,273,540	57,668.5	302,584	5.14	32.92
SEB-PHIL. #2(HVY OIL)	17	5,956	47.1	100.0	99.3	9,789	HVY.OIL	9,294	6,273,540	58,304.8	305,941	5.14	32.92
SEB-PHILLIPS TOTAL	**34**	**11,847**	**46.8**	**100.0**	**98.9**	**9,789**	**HVY.OIL**	**18,486**	**6,273,540**	**115,973.3**	**608,525**	**5.14**	**32.92**
POLK #1 GASIFIER	255	155,723	82.1	87.4	83.7	10,845	COAL	66,338	25,458,000	1,688,821.6	2,730,630	1.75	41.16
POLK #1 CT (OIL)	225	2,564	1.5	99.5	77.3	7,341	LGT.OIL	3,283	5,801,362	18,823.1	124,871	4.87	38.03
POLK #1 TOTAL	**255**	**158,287**	**83.4**	**88.7**	**83.6**	**10,788**	**-**	**-**	**-**	**1,707,644.7**	**2,855,501**	**1.80**	**-**
POLK #2 CT (GAS)	150	22,359	20.0	99.2	78.5	10,810	GAS	226,730	972,290	241,694.0	1,764,561	7.89	7.78
POLK #2 CT (OIL)	160	79	0.1	96.9	23.7	64,754	LGT.OIL	882	5,801,381	5,115.6	33,547	42.46	38.04
POLK #2 TOTAL	**155**	**22,438**	**19.5**	**99.4**	**77.8**	**11,000**	**-**	**-**	**-**	**246,809.6**	**1,798,108**	**8.01**	**-**
POLK #3 CT (GAS)	150	31,352	28.1	98.7	79.8	11,900	GAS	349,990	972,290	373,089.0	2,723,674	8.69	7.78
POLK #3 CT (OIL)	165	38	0.0	96.6	13.8	20,155	LGT.OIL	132	5,801,394	765.9	5,023	13.22	38.05
POLK #3 TOTAL	**158**	**31,390**	**26.7**	**99.4**	**79.3**	**11,910**	**-**	**-**	**-**	**373,854.9**	**2,728,697**	**8.69**	**-**
POLK STATION TOTAL	**568**	**212,115**	**50.2**	**94.6**	**80.8**	**10,977**	**-**	**-**	**-**	**2,328,309.2**	**7,382,306**	**3.48**	**-**
B.B.C.T.#1	14	357	3.4	100.0	79.7	18,739	LGT.OIL	1,167	5,734,417	6,690.0	39,341	11.02	33.71
B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	1,499	3.4	100.0	75.7	15,089	LGT.OIL	3,880	5,828,517	22,618.2	130,800	8.73	33.71
C.T. TOTAL	**140**	**1,856**	**1.8**	**100.0**	**40.4**	**15,791**	**LGT.OIL**	**5,047**	**5,806,766**	**29,308.2**	**170,141**	**9.17**	**33.71**
CITY OF TAMPA	**6**	**1,432**	**0.0**	**0.0**	**0.0**	**10,134**	**GAS**	**13,613**	**972,290**	**14,511.5**	**128,884**	**9.00**	**9.47**
BAYSIDE ST 1	246	110,399	60.3	89.2	67.6	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	72,180	65.6	95.5	80.0	11,447	GAS	775,094	972,290	826,249.9	5,595,761	7.75	7.22
BAYSIDE CT1B	148	72,497	65.8	95.3	77.9	11,447	GAS	778,497	972,290	829,878.7	5,620,329	7.75	7.22
BAYSIDE CT1C	148	67,427	61.2	94.9	79.7	11,447	GAS	724,053	972,290	771,840.5	5,227,273	7.75	7.22
BAYSIDE UNIT 1 TOTAL	**690**	**322,503**	**62.8**	**93.1**	**75.1**	**7,529**	**GAS**	**2,277,644**	**972,290**	**2,427,969.1**	**16,443,363**	**5.10**	**7.22**
BAYSIDE UNIT 2 TOTAL	**0**	**(144)**	**-**	**-**	**-**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**322,359**	**62.8**	**93.1**	**75.1**	**7,532**	**GAS**	**2,277,644**	**972,290**	**2,427,969.1**	**16,443,363**	**5.10**	**7.22**
TOT. COAL (GN,BB,POLK)	**2,807**	**1,156,214**	**55.4**	**71.2**	**64.5**	**11,377**	**COAL**	**543,825**	**24,189,112**	**13,154,641.9**	**25,995,254**	**2.25**	**47.80**
SYSTEM	**3,990**	**1,550,100**	**52.2**	**78.5**	**53.8**	**10,568**	**-**	**-**	**-**	**16,381,891.6**	**47,997,843**	**3.10**	**-**

LEGEND:
H.P. = HOOKERS POINT
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SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: AUGUST 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	75	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	98	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	73,428	65.8	87.8	72.3	12,728	COAL	39,690	23,548,000	934,620.1	1,713,520	2.33	43.17
GAN.#4	164	52,344	42.9	85.0	47.2	14,247	COAL	33,023	22,582,000	745,725.4	1,425,689	2.72	43.17
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	353	139,688	53.2	61.1	67.0	11,916	COAL	70,043	23,764,000	1,664,501.9	3,023,938	2.16	43.17
GANNON STATION	**840**	**265,460**	**42.5**	**78.5**	**50.3**	**12,600**	**COAL**	**142,756**	**23,430,521**	**3,344,847.4**	**6,163,147**	**2.32**	**43.17**
B.B.#1	421	162,277	51.8	60.0	62.3	11,436	COAL	76,741	24,183,560	1,855,874.9	3,695,776	2.28	48.16
B.B.#2	411	139,794	45.7	50.6	72.4	11,095	COAL	64,637	23,995,940	1,551,026.3	3,112,859	2.23	48.16
B.B.#3	428	188,794	59.3	68.5	62.9	11,566	COAL	89,154	24,493,260	2,183,670.4	4,293,575	2.27	48.16
B.B.#4	452	275,957	82.1	92.1	82.1	10,872	COAL	133,240	22,517,140	3,000,180.6	6,416,717	2.33	48.16
B.B. STATION	**1,712**	**766,822**	**60.2**	**68.4**	**70.1**	**11,203**	**COAL**	**363,772**	**23,615,760**	**8,590,752.2**	**17,518,927**	**2.28**	**48.16**
SEB-PHIL. #1(HVY OIL)	17	5,705	45.1	100.0	92.2	9,675	HVY.OIL	8,798	6,273,540	55,193.1	302,989	5.31	34.44
SEB-PHIL. #2(HVY OIL)	17	4,935	39.0	87.5	90.4	9,675	HVY.OIL	7,610	6,273,540	47,744.9	262,077	5.31	34.44
SEB-PHILLIPS TOTAL	**34**	**10,640**	**42.1**	**93.8**	**91.3**	**9,675**	**HVY.OIL**	**16,408**	**6,273,540**	**102,938.0**	**565,066**	**5.31**	**34.44**
POLK #1 GASIFIER	255	140,164	73.9	82.7	83.4	11,163	COAL	60,922	25,682,000	1,564,595.7	2,053,853	1.47	33.71
POLK #1 CT (OIL)	225	6,096	3.6	100.0	68.6	8,756	LGT.OIL	9,585	5,795,766	53,377.7	366,389	6.01	38.23
POLK #1 TOTAL	**255**	**146,260**	**77.1**	**92.8**	**82.6**	**11,062**	**-**	**-**	**-**	**1,617,973.4**	**2,420,242**	**1.65**	**-**
POLK #2 CT (GAS)	150	22,175	19.9	97.9	83.2	10,995	GAS	228,505	1,067,000	243,815.0	1,614,089	7.28	7.06
POLK #2 CT (OIL)	160	342	0.3	98.7	47.3	20,535	LGT.OIL	1,211	5,795,768	7,017.7	46,285	13.53	38.22
POLK #2 TOTAL	**155**	**22,517**	**19.5**	**98.7**	**82.3**	**11,140**	**-**	**-**	**-**	**250,832.7**	**1,660,374**	**7.37**	**-**
POLK #3 CT (GAS)	150	24,346	21.8	97.9	79.8	12,619	GAS	287,926	1,067,000	307,217.0	2,037,727	8.37	7.08
POLK #3 CT (OIL)	165	469	0.4	77.8	69.8	11,704	LGT.OIL	946	5,795,767	5,485.5	36,180	7.71	38.25
POLK #3 TOTAL	**158**	**24,815**	**21.1**	**97.9**	**79.5**	**12,601**	**-**	**-**	**-**	**312,702.5**	**2,073,907**	**8.36**	**-**
POLK STATION TOTAL	**568**	**193,592**	**45.8**	**95.8**	**81.7**	**11,269**	**-**	**-**	**-**	**2,181,508.6**	**6,154,523**	**3.18**	**-**
B.B.C.T.#1	14	42	0.4	100.0	75.0	20,062	LGT.OIL	145	5,820,669	842.6	5,151	12.26	35.52
B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**140**	**42**	**0.0**	**100.0**	**7.5**	**20,062**	**LGT.OIL**	**145**	**5,820,669**	**842.6**	**5,151**	**12.26**	**35.52**
CITY OF TAMPA	**6**	**1,199**	**26.9**	**0.0**	**0.0**	**10,236**	**GAS**	**11,502**	**1,067,000**	**12,272.6**	**103,761**	**8.65**	**9.02**
BAYSIDE ST 1	246	116,265	63.5	99.1	64.1	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	73,034	66.3	99.0	82.8	11,368	GAS	778,083	1,067,000	830,215.0	5,296,721	7.25	6.81
BAYSIDE CT1B	148	72,700	66.0	91.3	82.7	11,368	GAS	774,526	1,067,000	826,418.9	5,272,502	7.25	6.81
BAYSIDE CT1C	148	71,004	64.5	95.6	82.3	11,368	GAS	756,455	1,067,000	807,137.1	5,149,485	7.25	6.81
BAYSIDE UNIT 1 TOTAL	**690**	**333,003**	**64.9**	**96.7**	**76.0**	**7,399**	**GAS**	**2,309,064**	**1,067,000**	**2,463,771.0**	**15,718,708**	**4.72**	**6.81**
BAYSIDE UNIT 2 TOTAL	**0**	**(206)**	**-**	**-**	**-**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**332,797**	**64.8**	**96.7**	**76.0**	**7,403**	**GAS**	**2,309,064**	**1,067,000**	**2,463,771.0**	**15,718,708**	**4.72**	**6.81**
TOT. COAL (GN,BB,POLK)	**2,807**	**1,172,446**	**56.1**	**72.7**	**65.4**	**11,515**	**COAL**	**567,450**	**23,790,992**	**13,500,195.3**	**25,735,927**	**2.20**	**45.35**
SYSTEM	**3,990**	**1,570,552**	**52.9**	**80.7**	**66.6**	**10,631**	**-**	**-**	**-**	**16,696,932.4**	**46,229,283**	**2.94**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: SEPTEMBER 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	94	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	100	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	69,015	63.9	78.0	76.2	11,655	COAL	33,101	24,300,000	804,354.3	1,421,797	2.06	42.95
GAN.#4	164	47,735	40.4	80.5	47.7	13,432	COAL	26,524	24,174,000	641,191.2	1,139,294	2.39	42.95
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	353	163,359	64.3	77.8	65.3	11,523	COAL	78,116	24,098,000	1,882,439.4	3,355,340	2.05	42.95
GANNON STATION	**861**	**280,109**	**45.2**	**83.4**	**49.1**	**11,881**	**COAL**	**137,741**	**24,161,179**	**3,327,984.9**	**5,916,431**	**2.11**	**42.95**
B.B.#1	421	183,306	60.5	66.5	62.6	11,478	COAL	89,245	23,574,920	2,103,949.6	4,457,852	2.43	49.95
B.B.#2	411	138,368	46.8	51.4	65.4	10,960	COAL	63,202	23,995,140	1,516,540.8	3,156,986	2.28	49.95
B.B.#3	428	115,134	37.4	41.6	48.9	11,574	COAL	55,445	24,033,960	1,332,559.5	2,769,518	2.41	49.95
B.B.#4	452	262,409	80.6	86.9	81.1	10,842	COAL	126,870	22,425,800	2,845,164.2	6,337,249	2.42	49.95
B.B. STATION	**1,712**	**699,217**	**56.7**	**62.0**	**64.7**	**11,153**	**COAL**	**334,762**	**23,294,784**	**7,798,214.1**	**16,721,605**	**2.39**	**49.95**
SEB-PHIL. #1(HVY OIL)	17	5,922	48.4	100.0	92.8	9,696	HVY.OIL	9,152	6,273,540	57,417.7	306,240	5.17	33.46
SEB-PHIL. #2(HVY OIL)	17	5,775	47.2	98.5	92.8	9,696	HVY.OIL	8,927	6,273,540	56,000.7	298,711	5.17	33.46
SEB-PHILLIPS TOTAL	**34**	**11,697**	**47.8**	**99.3**	**92.8**	**9,696**	**HVY.OIL**	**18,079**	**6,273,541**	**113,418.4**	**604,951**	**5.17**	**33.46**
POLK #1 GASIFIER	255	30,083	16.4	19.7	78.1	12,011	COAL	13,738	26,300,000	361,317.6	567,996	1.89	41.34
POLK #1 CT (OIL)	225	3,612	2.2	23.2	82.8	8,117	LGT.OIL	5,050	5,805,737	29,317.3	190,691	5.28	37.76
POLK #1 TOTAL	**255**	**33,695**	**18.4**	**21.7**	**78.6**	**11,593**	**-**	**-**	**-**	**390,634.9**	**758,687**	**2.25**	**-**
POLK #2 CT (GAS)	150	30,180	27.9	91.6	82.6	11,006	GAS	319,391	1,040,000	332,166.6	2,120,540	7.03	6.64
POLK #2 CT (OIL)	160	78	0.1	82.9	28.9	36,218	LGT.OIL	486	5,805,741	2,819.5	18,339	23.51	37.73
POLK #2 TOTAL	**155**	**30,258**	**27.1**	**91.6**	**82.2**	**11,071**	**-**	**-**	**-**	**334,986.1**	**2,138,879**	**7.07**	**-**
POLK #3 CT (GAS)	150	29,231	27.1	94.5	79.4	12,466	GAS	350,396	1,040,000	364,411.4	2,327,003	7.96	6.64
POLK #3 CT (OIL)	165	32	0.0	94.5	14.7	16,944	LGT.OIL	92	5,805,748	535.3	3,482	10.88	37.85
POLK #3 TOTAL	**158**	**29,263**	**25.7**	**94.5**	**79.0**	**12,471**	**-**	**-**	**-**	**364,946.7**	**2,330,485**	**7.96**	**-**
POLK STATION TOTAL	**568**	**93,216**	**22.8**	**61.0**	**79.7**	**11,699**	**-**	**-**	**-**	**1,090,567.7**	**5,228,051**	**5.61**	**-**
B.B.C.T.#1	14	136	1.3	100.0	81.0	18,913	LGT.OIL	442	5,820,706	2,572.2	15,746	11.58	35.62
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	254	0.6	100.0	60.5	15,806	LGT.OIL	693	5,793,985	4,014.7	24,688	9.72	35.62
C.T. TOTAL	**140**	**390**	**0.4**	**52.9**	**34.0**	**16,889**	**LGT.OIL**	**1,135**	**5,804,408**	**6,586.9**	**40,434**	**10.37**	**35.62**
CITY OF TAMPA	**6**	**1,543**	**35.7**	**0.0**	**0.0**	**10,203**	**GAS**	**15,138**	**1,040,000**	**15,743.5**	**120,597**	**7.82**	**7.97**
BAYSIDE ST 1	246	115,771	65.4	100.0	65.4	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	74,864	70.3	97.4	86.0	11,348	GAS	816,897	1,040,000	849,572.7	5,457,522	7.29	6.68
BAYSIDE CT1B	148	69,237	65.0	96.0	85.7	11,348	GAS	755,496	1,040,000	785,715.9	5,047,317	7.29	6.68
BAYSIDE CT1C	148	75,293	70.7	98.3	85.4	11,348	GAS	821,582	1,040,000	854,445.3	5,488,823	7.29	6.68
BAYSIDE UNIT 1 TOTAL	**690**	**335,165**	**67.5**	**98.2**	**78.4**	**7,428**	**GAS**	**2,393,975**	**1,040,000**	**2,489,733.9**	**15,993,662**	**4.77**	**6.68**
BAYSIDE UNIT 2 TOTAL	**0**	**(589)**	**-**	**-**	**-**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**334,576**	**67.3**	**98.2**	**78.4**	**7,441**	**GAS**	**2,393,975**	**1,040,000**	**2,489,733.9**	**15,993,662**	**4.78**	**6.68**
TOT. COAL (GN,BB,POLK)	**2,828**	**1,009,409**	**49.6**	**64.7**	**61.2**	**11,380**	**COAL**	**486,241**	**23,625,123**	**11,487,516.6**	**23,206,032**	**2.30**	**47.73**
SYSTEM	**4,011**	**1,420,748**	**49.2**	**72.7**	**65.0**	**10,447**	**-**	**-**	**-**	**14,842,249.4**	**44,625,731**	**3.14**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

EXHIBIT NO. 94

DOCKET: 031033-EI

WITNESS: JOANN T. WEHLE

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT OF TAMPA ELECTRIC COMPANY'S MONTHLY SCHEDULE A-4 FOR THE MONTHS OF JANUARY 2001 THROUGH DECEMBER 2003

PROFFERED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 94
COMPANY/ FPSC Staff
WITNESS: TECO A Schedule 1/01 thru 12/03
DATE: 05/27-28/04

COMMISSIONERS:
BRAULIO L. BAEZ, CHAIRMAN
J. TERRY DEASON
LILA A. JABER
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

STATE OF FLORIDA

DIVISION OF THE COMMISSION CLERK &
ADMINISTRATIVE SERVICES
BLANCA S. BAYÓ
DIRECTOR
(850) 413-6770 (CLERK)
(850) 413-6330 (ADMIN)

Public Service Commission

CERTIFICATE

I, BLANCA S. BAYÓ, Director of the Division of the Commission Clerk and Administrative Services, Florida Public Service Commission, do hereby certify that the attached are true and correct copies of Tampa Electric Company's monthly Schedule A-4 for the months of January 2001 through December 2003, as shown in the records of the Commission.

WITNESS my hand and the seal of the Florida Public Service Commission this 28th day of May, 2004.

BLANCA S. BAYÓ

By: Kay Flynn
Kay Flynn, Chief
Bureau of Records

(SEAL)

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: JANUARY 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	34	0.1	100.0	10.1	49,312	HVY.OIL	264	6,359,264	1,676.6	6,958	20.46	26.39
H.P.#2	32	94	0.4	100.0	16.8	48,914	HVY.OIL	723	6,359,264	4,597.9	19,080	20.30	26.39
H.P.#3	32	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	41	227	0.7	100.0	22.7	48,777	HVY.OIL	1,741	6,359,264	11,072.3	45,948	20.24	26.39
H.P.#5	52	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**189**	**355**	**0.3**	**55.6**	**9.5**	**48,864**	**HVY.OIL**	**2,728**	**6,359,264**	**17,346.8**	**71,986**	**20.28**	**26.39**
GAN.#1	114	26,492	31.2	42.9	70.7	11,166	COAL	12,892	22,946,240	295,822.9	544,602	2.06	42.24
GAN.#2	98	46,275	63.5	79.4	77.9	11,542	COAL	23,458	22,769,240	534,120.8	990,946	2.14	42.24
GAN.#3	145	71,952	66.7	83.8	68.6	11,669	COAL	43,125	19,469,920	839,640.3	1,821,747	2.53	42.24
GAN.#4	169	86,030	68.4	87.6	77.6	11,401	COAL	51,234	19,144,460	980,847.3	2,164,299	2.52	42.24
GAN.#5	207	110,880	72.0	84.0	72.0	10,610	COAL	50,184	23,442,620	1,176,444.4	2,119,943	1.91	42.24
GAN.#6	392	163,279	56.0	62.7	77.3	10,119	COAL	70,123	23,562,540	1,652,276.0	2,962,235	1.81	42.24
GANNON STATION	**1,125**	**504,908**	**60.3**	**72.5**	**74.6**	**10,852**	**COAL**	**251,016**	**131,335,020**	**5,479,151.7**	**10,603,772**	**2.10**	**42.24**
B.B.#1	426	218,228	68.9	77.5	80.7	9,970	COAL	91,061	23,893,820	2,175,795.1	3,940,873	1.81	43.28
B.B.#2	426	221,337	69.8	81.0	76.6	9,802	COAL	91,195	23,789,380	2,169,472.5	3,946,672	1.78	43.28
B.B.#3	443	191,398	58.1	71.6	67.8	10,221	COAL	81,511	23,999,380	1,956,213.5	3,527,575	1.84	43.28
B.B. 1 - 3	1,295	630,963	65.5	76.6	74.9	9,987	COAL	263,767	71,682,580	6,301,481.1	11,415,120	1.81	43.28
B.B.#4	447	270,729	81.4	92.2	83.0	9,895	COAL	124,235	21,562,297	2,678,783.5	6,322,483	2.34	50.89
B.B. STATION	**1,742**	**901,692**	**69.6**	**80.6**	**77.0**	**9,959**	**COAL**	**388,002**	**93,244,877**	**8,980,264.6**	**17,737,603**	**1.97**	**45.72**
SEB-PHIL. #1(HVY OIL)	17	3,893	30.8	99.0	64.9	10,569	HVY.OIL	6,558	6,273,540	41,143.8	174,099	4.47	26.55
SEB-PHIL. #2(HVY OIL)	17	4,968	39.3	100.0	83.4	8,282	HVY.OIL	6,558	6,273,540	41,143.8	174,099	3.50	26.55
SEB-PHILLIPS TOTAL	**34**	**8,861**	**35.0**	**99.5**	**74.2**	**9,286**	**HVY.OIL**	**13,116**	**12,547,080**	**82,287.6**	**348,198**	**3.93**	**26.55**
POLK #1 GASIFIER	250	132,961	71.5	75.1	94.7	10,639	COAL	55,755	25,372,000	1,414,616.1	2,758,266	2.07	49.47
POLK #1 CT (OIL)	245	8,148	4.5	92.8	56.9	8,985	LGT.OIL	13,193	5,836,065	73,207.8	516,292	6.34	39.13
POLK #1 TOTAL	**250**	**141,109**	**75.9**	**92.1**	**91.2**	**10,544**	**-**	**-**	**21,783,962**	**1,487,823.9**	**3,274,558**	**2.32**	**-**
POLK #2 CT (GAS)	160	16,577	13.9	88.0	70.8	10,063	GAS	171,562	972,290	166,808.0	1,746,626	10.54	10.18
POLK #2 CT (OIL)	170	2,739	2.2	64.7	51.0	12,705	LGT.OIL	5,963	5,836,065	34,798.2	233,334	8.52	39.13
POLK #2 TOTAL	**165**	**19,316**	**16.2**	**92.8**	**67.1**	**10,437**	**-**	**-**	**1,135,652**	**201,606.2**	**1,979,960**	**10.25**	**-**
POLK STATION TOTAL	**415**	**160,425**	**52.0**	**92.4**	**80.8**	**10,531**	**-**	**-**	**6,872,529**	**1,689,430.1**	**5,254,518**	**3.28**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	17	198	1.6	100.0	38.8	27,794	LGT.OIL	942	5,842,783	5,503.2	34,864	17.61	37.01
B.B.C.T.#2	80	5,083	8.5	100.0	58.3	15,365	LGT.OIL	13,363	5,844,280	78,099.2	494,569	9.73	37.01
B.B.C.T.#3	80	5,427	9.1	100.0	62.2	14,656	LGT.OIL	13,610	5,844,280	79,539.7	503,710	9.28	37.01
C.T. TOTAL	**177**	**10,708**	**8.1**	**100.0**	**58.2**	**15,236**	**LGT.OIL**	**27,915**	**5,844,230**	**163,142.1**	**1,033,143**	**9.65**	**37.01**
TOT. COAL (GN,BB,POLK)	**3,117**	**1,539,561**	**66.4**	**77.3**	**77.6**	**10,311**	**COAL**	**694,773**	**249,951,897**	**15,874,032.4**	**31,099,641**	**2.02**	**44.76**
SYSTEM	**3,682**	**1,586,949**	**57.9**	**79.3**	**72.3**	**10,342**	**-**	**-**	**287,346,891**	**16,411,622.9**	**35,049,220**	**2.21**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: FEBRUARY 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	0	0.0	100.0	0.0	0	HVY.OIL	0	0	0 0	0	0.00	0.00
H.P.#2	32	-6	0.0	100.0	0.0	0	HVY.OIL	103	6,361,613	655.6	2,779	-46.32	26.96
H.P.#3	32	0	0.0	99.0	0.0	0	HVY.OIL	0	0	0 0	0	0.00	0 00
H.P.#4	41	-24	0.0	100.0	0.0	0	HVY.OIL	1,236	6,361,613	7,860.5	33,319	-138.83	26.97
H.P.#5	52	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0 00	0.00
H.P. STATION	189	-30	0.0	72.3	0.0	0	HVY.OIL	1,339	6,361,613	8,516.1	36,098	-120.33	26.97
GAN.#1	114	3,284	4.3	6.0	71.1	11,376	COAL	1,572	23,764,000	37,357.0	62,473	1.90	39.74
GAN.#2	98	29,089	44.2	65.8	66.8	11,801	COAL	14,853	23,110,720	343,263.5	590,274	2.03	39.74
GAN.#3	145	43,356	44.5	65.4	64.7	12,201	COAL	27,590	19,173,820	529,005.7	1,096,456	2.53	39.74
GAN.#4	169	64,561	56.8	82.2	69.1	11,994	COAL	40,253	19,237,120	774,351.8	1,599,697	2.48	39.74
GAN.#5	207	37,685	27.1	36.9	62.2	11,084	COAL	17,810	23,452,260	417,684.8	707,789	1.88	39.74
GAN.#6	392	189,573	72.0	90.0	74.6	10,224	COAL	82,457	23,504,400	1,938,102.3	3,276,930	1.73	39 74
GANNON STATION	1,125	367,548	48.6	65.3	69.2	10,991	COAL	184,535	21,891,593	4,039,765.1	7,333,619	2.00	39.74
B.B.#1	426	199,070	69.5	82.0	78.5	10,664	COAL	84,777	25,040,860	2,122,889.0	4,025,096	2.02	47.48
B.B.#2	426	84,863	29.6	36.3	59.7	10,358	COAL	35,622	24,675,500	878,990.7	1,691,284	1.99	47.48
B.B.#3	443	203,470	68.3	81.5	71.7	10,074	COAL	83,827	24,451,460	2,049,692.5	3,979,991	1.96	47.48
B.B. 1 - 3	1,295	487,403	56.0	66.8	70.0	10,364	COAL	204,226	24,735,206	5,051,572.2	9,696,371	1.99	47.48
B.B.#4	447	206,407	68.7	80.0	81.7	10,371	COAL	94,459	22,662,342	2,140,673.5	4,903,566	2.38	51.91
B.B. STATION	1,742	693,810	59.3	70.2	73.0	10,366	COAL	298,685	24,079,661	7,192,245.7	14,599,937	2.10	48.88
SEB-PHIL. #1(HVY OIL)	17	-77	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	126	-0.16	0.00
SEB-PHIL. #2(HVY OIL)	17	-77	0.0	81.3	0.0	0	HVY.OIL	0	0	0.0	126	-0.16	0.00
SEB-PHILLIPS TOTAL	34	-154	0.0	40.7	0.0	0	HVY.OIL	0	0	0.0	252	-0.16	0.00
POLK #1 GASIFIER	250	150,666	89.7	89.9	98.4	10,294	COAL	61,185	25,347,400	1,550,883.0	2,827,518	1.88	46.21
POLK #1 CT (OIL)	245	5,388	3.3	99.5	66.2	8,947	LGT.OIL	8,298	5,808,770	48,203.5	331,494	6.15	39.95
POLK #1 TOTAL	250	156,054	92.9	98.1	96.7	10,247	-	-	-	1,599,086.5	3,159,012	2.02	-
POLK #2 CT (GAS)	160	6,687	6.2	89.3	67.1	16,014	GAS	110,135	972,290	107,083.0	593,856	8.88	5.39
POLK #2 CT (OIL)	170	626	0.5	91.9	76.5	12,341	LGT.OIL	1,330	5,808,783	7,725.1	53,125	8.49	39.94
POLK #2 TOTAL	165	7,313	6.8	91.9	67.8	15,699	-	-	-	114,808.1	646,981	8.85	-
POLK STATION TOTAL	415	163,367	58.6	95.6	84.4	10,491	-	-	-	1,713,894.6	3,805,993	2.33	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	17	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0 0	0	0.00	0.00
B.B.C.T.#2	80	586	1.1	100.0	56.3	16,130	LGT.OIL	1,619	5,837,023	9,452.3	60,714	10.36	37.50
B.B.C.T.#3	80	704	1.3	100.0	58.7	15,356	LGT.OIL	1,852	5,837,064	10,810.3	69,451	9.87	37.50
C.T. TOTAL	177	1,290	1.1	100.0	52.0	15,707	LGT.OIL	3,471	5,837,045	20,262.6	130,165	10.09	37.50
TOT. COAL (GN,BB,POLK)	3,117	1,212,024	57.9	70.0	73.7	10,547	COAL	544,405	23,480,460	12,782,893.8	24,761,074	2.04	45.48
SYSTEM	3,682	1,225,831	49.5	72.8	67.7	10,584	-	-	-	12,974,684.1	25,906,064	2.11	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: MARCH 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	0	0.0	100.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	32	0	0.0	100.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	32	0	0.0	100.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0 00
H.P.#4	41	0	0.0	100.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	52	-428	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	189	-428	0.0	72.5	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	51,213	60.4	83.0	72.3	11,069	COAL	24,323	23,307,220	566,901.5	972,420	1.90	39.98
GAN.#2	98	23,254	31.9	41.5	74.9	11,485	COAL	11,503	23,217,960	267,076 2	459,883	1.98	39.98
GAN.#3	145	67,695	62.8	84.0	72.0	11,890	COAL	41,621	19,338,040	804,868.6	1,663,984	2.46	39.98
GAN.#4	169	84,290	67.0	90.4	73.7	11,898	COAL	52,477	19,110,860	1,002,880.6	2,098,001	2.49	39.98
GAN.#5	207	0	0.0	0.0	0.0	0	COAL	0	0	0 0	0	0.00	0.00
GAN.#6	392	221,275	75.9	93.7	78.5	10,011	COAL	94,689	23,393,940	2,215,148.8	3,785,612	1.71	39.98
GANNON STATION	1,125	447,727	53.5	69.1	61.6	10,848	COAL	224,613	21,623,306	4,856,875.7	8,979,900	2.01	39.98
B.B.#1	426	71,445	22.5	26.0	78.2	11,009	COAL	32,135	24,476,220	786,543.3	1,555,059	2.18	48.39
B.B.#2	426	109,206	34.5	41.2	73.0	10,529	COAL	46,095	24,945,460	1,149,861.0	2,230,604	2.04	48.39
B.B.#3	443	246,325	74.7	84.7	77.7	10,357	COAL	103,406	24,670,880	2,551,117.0	5,003,965	2.03	48 39
(*) B.B. 1 - 3	1,295	426,976	44.3	51.1	76.3	10,510	COAL	181,636	24,706,123	4,487,521.3	8,789,628	2.06	48.39
B.B.#4	447	271,223	81.6	88.8	85.6	10,391	COAL	126,696	22,244,111	2,818,243.5	6,591,228	2.43	52.02
B.B. STATION	1,742	698,199	53.9	60.8	78.7	10,464	COAL	308,332	23,694,462	7,305,764.8	15,380,856	2.20	49.88
SEB-PHIL. #1(HVY OIL)	17	4,416	34.9	91.4	83.1	9,863	HVY.OIL	6,942	6,273,540	43,552.9	200,210	4.53	28.84
SEB-PHIL. #2(HVY OIL)	17	5,111	40.4	87.5	96.4	8,521	HVY.OIL	6,943	6,273,540	43,552.9	200,240	3.92	28.84
SEB-PHILLIPS TOTAL	34	9,527	37.7	89.5	89.8	9,143	HVY.OIL	13,885	6,273,540	87,105.8	400,450	4.20	28.84
POLK #1 GASIFIER	250	71,082	38.2	40.5	93.6	11,448	COAL	31,122	26,145,660	813,717.5	1,394,239	1.96	44.80
POLK #1 CT (OIL)	245	6,561	3.6	58.2	50.9	10,029	LGT.OIL	12,000	5,824,285	65,799.1	450,895	6.87	37.57
POLK #1 TOTAL	250	77,643	41.7	57.6	87.4	11,328	-	-	-	879,516.6	1,845,134	2.38	-
POLK #2 CT (GAS)	160	33,394	28.1	97.8	131.9	7,124	GAS	244,674	972,290	237,894.0	1,320,650	3.95	5.40
POLK #2 CT (OIL)	170	1,331	1.1	99.9	63.7	12,630	LGT.OIL	2,886	5,824,284	16,810.3	108,450	8.15	37.58
POLK #2 TOTAL	165	34,725	29.2	100.0	126.7	7,335	-	-	-	254,704.3	1,429,100	4.12	-
POLK STATION TOTAL	415	112,368	36.4	74.5	101.5	10,094	-	-	-	1,134,220.9	3,274,234	2.91	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	17	15	0.1	100.0	88.2	17,409	LGT.OIL	45	5,834,004	261.1	1,649	10.99	36.64
B.B.C.T.#2	80	1,586	2.7	100.0	56.6	15,882	LGT.OIL	4,286	5,877,222	25,188.5	157,077	9.90	36.65
B.B.C.T.#3	80	1,464	2.5	100.0	59.0	14,883	LGT.OIL	3,707	5,877,223	21,788.0	135,858	9.28	36.65
C.T. TOTAL	177	3,065	2.3	100.0	60.7	15,412	LGT.OIL	8,038	5,876,982	47,237.6	294,584	9.61	36.65
TOT. COAL (GN,BB,POLK)	3,117	1,217,008	52.5	62.1	73.7	10,663	COAL	564,068	23,004,968	12,976,358.0	25,754,995	2.12	45.66
SYSTEM	3,682	1,270,458	46.4	67.6	71.2	10,572	-	-	-	13,431,204.8	28,330,024	2.23	-

LEGEND:
H.P. = HOOKERS POINT
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: APRIL 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0 00	0 00
H.P.#3	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	39	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0 0	0	0.00	0.00
H.P.#5	52	-317	0.0	0.0	0 0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-317**	**0.0**	**71.3**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	55,258	67.4	90.7	72.7	11,481	COAL	27,074	23,431,740	634,390.9	1,054,299	1.91	38.94
GAN.#2	98	45,994	65.3	78.7	82.5	12,307	COAL	24,287	23,306,780	566,051.8	945,770	2.06	38 94
GAN.#3	145	29,156	28.0	36.1	70.9	12,307	COAL	18,163	19,755,160	358,813.0	707,292	2.43	38.94
GAN.#4	159	72,263	63.2	76 4	80.1	12,265	COAL	44,755	19,803,500	886,305.6	1,742,822	2.41	38.94
GAN.#5	232	70,247	42.1	49.7	71.5	10,105	COAL	30,188	23,513,960	709,839 4	1,175,563	1.67	38.94
GAN.#6	372	5,600	2.1	2.8	54.8	9,986	COAL	2,418	23,128,000	55,923 5	94,160	1.68	38.94
GANNON STATION	**1,120**	**278,518**	**34.6**	**42.9**	**68.2**	**11,530**	**COAL**	**146,885**	**21,862,846**	**3,211,324.2**	**5,719,906**	**2.05**	**38.94**
B.B.#1	416	0	0.0	0.0	0.0	0	COAL	0	0	0 0	0	0.00	0.00
B.B.#2	416	199,716	66.8	75.7	82.8	10,318	COAL	85,681	24,049,920	2,060,621 2	3,982,950	1.99	48 49
B.B.#3	433	201,238	64.6	74.1	77.1	10,240	COAL	85,729	24,037,600	2,060,719 4	3,985,182	1 98	46 49
B.B. 1 - 3	1,265	400,954	44.1	50.3	53.6	10,279	COAL	171,410	24,043,758	4,121,340.6	7,968,132	1.99	46.49
B.B.#4	442	270,664	85.2	97.2	85.2	10,105	COAL	123,038	22,229,711	2,735,099.2	6,296,441	2.33	51.17
B.B. STATION	**1,707**	**671,618**	**54.7**	**62.4**	**61.8**	**10,209**	**COAL**	**294,448**	**23,285,741**	**6,856,439.8**	**14,264,573**	**2.12**	**48.45**
SEB-PHIL #1(HVY OIL)	17	5,967	48.8	98.9	87.9	10,010	HVY.OIL	9,521	6,273,540	59,730.0	255,298	4.28	26.81
SEB-PHIL #2(HVY OIL)	17	6,823	55.8	100.0	98.4	8,754	HVY.OIL	9,521	6,273,540	59,730.0	255,299	3.74	26 81
SEB-PHILLIPS TOTAL	**34**	**12,790**	**52.3**	**99.5**	**93.2**	**9,340**	**HVY.OIL**	**19,042**	**6,273,540**	**119,460.0**	**510,597**	**3.99**	**26.81**
POLK #1 GASIFIER	250	65,966	36.7	40.6	77.2	11,456	COAL	32,661	23,137,700	755,709.9	1,438,955	2.18	44.06
POLK #1 CT (OIL)	225	12,759	7.9	94.4	63.3	9,344	LGT.OIL	21,212	5,826,902	119,223.7	776,108	6 08	36.59
POLK #1 TOTAL	**250**	**78,725**	**43.8**	**82.8**	**74.5**	**11,114**	**-**	**-**	**-**	**874,933.6**	**2,215,063**	**2.81**	**-**
POLK #2 CT (GAS)	150	44,598	41.4	97.7	100.0	11,181	GAS	512,883	972,290	498,671.0	2,688,211	6 03	5 24
POLK #2 CT (OIL)	150	0	0.0	71.2	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**150**	**44,598**	**41.4**	**97.7**	**100.0**	**11,181**	**-**	**-**	**-**	**498,671.0**	**2,688,211**	**6.03**	**-**
POLK STATION TOTAL	**400**	**123,323**	**42.9**	**88.4**	**84.1**	**11,138**	**-**	**-**	**-**	**1,373,604.6**	**4,903,274**	**3.98**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	122	1.4	76.8	92 9	18,886	LGT.OIL	398	5,787,887	2,304.1	14,001	11.48	35.18
B.B.C.T.#2	66	8,149	17.2	100.0	70.9	15,403	LGT.OIL	21,505	5,836,784	125,517.3	756,541	9.28	35.18
B.B.C.T.#3	66	8,527	18.0	100.0	73.9	15,032	LGT.OIL	21,960	5,836,783	128,178.2	772,548	9 06	35.18
C.T. TOTAL	**144**	**16,798**	**16.2**	**98.1**	**74.1**	**15,240**	**LGT.OIL**	**43,863**	**5,836,340**	**255,999.6**	**1,543,090**	**9.19**	**35.18**
TOT. COAL (GN,BB,POLK)	**3,077**	**1,016,102**	**45.9**	**53.5**	**65.4**	**10,652**	**COAL**	**473,994**	**22,834,602**	**10,823,473.9**	**21,423,434**	**2.11**	**45.20**
SYSTEM	**3,495**	**1,102,730**	**43.9**	**61.2**	**65.6**	**10,716**	**-**	**-**	**-**	**11,816,828.2**	**26,941,440**	**2.44**	**-**

* Hookers Point boiler limited to 90MW

LEGEND:

H.P. = HOOKERS POINT B.B. = BIG BEND
GAN. = GANNON C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: MAY 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0.0	100.0	0 0	0	HVY OIL	-	0	0 0	0	0 00	0 00
H.P.#2	30	0	0.0	100.0	0 0	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P.#3	30	0	0.0	100.0	0 0	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H P.#4	39	0	0.0	100 0	0.0	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P.#5	52	-277	0.0	0.0	0.0	0	HVY OIL	-	0	0.0	0	0 00	0 00
H.P. STATION	**90** *	**-277**	**0.0**	**71.3**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	52,831	62 3	88 2	69 3	11,317	COAL	25,560	23,392,000	597,899 5	1,030,470	1 95	40 32
GAN.#2	98	7,358	10.1	11.9	74 8	12,567	COAL	4,682	19,750,000	92,469 5	188,758	2 57	40 32
GAN.#3	145	76,370	70 8	90 2	74 9	12,128	COAL	46,606	19,874,000	928,247 6	1,878,956	2 46	40 32
GAN.#4	159	19,740	16 7	22.9	68 7	12,656	COAL	12,182	20,508,000	249,828.5	491,127	2 49	40 32
GAN.#5	232	88,375	51.2	63 7	72 5	10,604	COAL	40,157	23,336,000	937,103 8	1,618,959	1 83	40 32
GAN.#6	372	226,477	81.8	95 2	81 9	10,115	COAL	93,393	24,528,000	2,290,743 5	3,765,208	1 66	40 32
GANNON STATION	**1,120**	**471,151**	**56.5**	**69.8**	**75.3**	**10,812**	**COAL**	**222,580**	**22,887,467**	**5,094,292.4**	**8,973,478**	**1.90**	**40.32**
B.B.#1	416	169,322	54.7	63.7	77.4	10,541	COAL	74,447	23,973,880	1,784,783.4	3,428,076	2 02	46 05
B.B.#2	416	234,128	75.6	83.7	79 9	10,465	COAL	102,116	23,993,580	2,450,128 4	4,702,157	2.01	46 05
B.B #3	433	199,757	62.0	76.0	71 0	10,257	COAL	84,587	24,223,420	2,048,986.4	3,894,995	1 95	46 05
B.B. 1 - 3	1,265	603,207	64.1	74 5	76.0	10,417	COAL	261,150	24,062,409	6,283,898.2	12,025,228	1 99	46.05
B.B.#4	442	8,297	2.5	3.5	71.7	14,011	COAL	5,075	22,905,582	116,245 6	266,118	3 21	52 44
B.B. STATION	**1,707**	**611,504**	**48.1**	**56.1**	**74.9**	**10,486**	**COAL**	**266,225**	**24,040,357**	**6,400,143.8**	**12,291,346**	**2.01**	**46.17**
SEB-PHIL. #1(HVY OIL)	17	5,145	40.7	100.0	85.9	10,022	HVY.OIL	8,220	6,273,540	51,565.6	236,056	4 59	28 72
SEB-PHIL #2(HVY OIL)	17	5,818	46.0	100.0	97.6	8,863	HVY.OIL	8,219	6,273,540	51,565 6	236,027	4 06	28 72
SEB-PHILLIPS TOTAL	**34**	**10,963**	**43.3**	**100.0**	**91.8**	**9,407**	**HVY.OIL**	**16,439**	**6,273,540**	**103,131.2**	**472,083**	**4.31**	**28.72**
POLK #1 GASIFIER	250	125,867	67.7	69 6	96.0	10,798	COAL	56,601	24,012,000	1,359,092 2	2,564,344	2 04	45.31
POLK #1 CT (OIL)	225	12,702	7.6	95.8	64 8	9,048	LGT.OIL	19,992	5,748,274	114,921 9	730,628	5 75	36 55
POLK #1 TOTAL	**250**	**138,569**	**74.5**	**92.3**	**91.9**	**10,637**	**-**	**-**	**-**	**1,474,014.1**	**3,294,972**	**2.38**	**-**
POLK #2 CT (GAS)	150	30,951	27.7	96.8	88.9	11,085	GAS	352,861	972,290	343,083 0	1,921,935	6.21	5 45
POLK #2 CT (OIL)	150	100	0 1	21.9	29.2	9,747	LGT OIL	168	5,818,350	974 7	6,122	6 12	36 44
POLK #2 TOTAL	**150**	**31,051**	**27.8**	**96.8**	**88.3**	**11,080**	**-**	**-**	**-**	**344,057.7**	**1,928,057**	**6.21**	**-**
POLK STATION TOTAL	**400**	**169,620**	**57.0**	**94.0**	**90.6**	**10,718**	**-**	**-**	**-**	**1,818,071.8**	**5,223,029**	**3.08**	**-**
GAN.C.T #1	0	0	0 0	0 0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
B B.C.T #1	12	30	0.3	100.0	83 3	17,480	LGT.OIL	90	5,796,397	524 4	3,046	10 15	33 84
B.B.C.T #2	66	2,366	4.8	100.0	59.7	17,029	LGT OIL	6,926	5,817,623	40,291 4	234,392	9.91	33 84
B.B.C.T.#3	66	2,321	4.7	100.0	63.9	16,272	LGT.OIL	6,492	5,817,625	37,766 8	219,704	9 47	33 84
C.T. TOTAL	**144**	**4,717**	**4.4**	**100.0**	**63.6**	**16,659**	**LGT.OIL**	**13,508**	**5,817,482**	**78,582.6**	**457,142**	**9.69**	**33.84**
CITY OF TAMPA	**6**	**590**	**-**	**-**	**-**	**6,755**	**GAS**	**4,099**	**972,290**	**3,985.3**	**25,564**	**4.33**	**6.24**
TOT. COAL (GN,BB,POLK)	**3,077**	**1,208,522**	**52.8**	**62.2**	**76.8**	**10,636**	**COAL**	**545,406**	**23,566,920**	**12,853,528.4**	**23,829,168**	**1.97**	**43.69**
SYSTEM	**3,501**	**1,268,268**	**48.7**	**67.3**	**74.5**	**17,398**	**-**	**-**	**-**	**13,498,207.1**	**27,442,642**	**2.16**	**-**

* Hookers Point boiler limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: JUNE 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	39	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	(266)	0.0	0.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION	90	(266)	0.0	71.3	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	45,725	55.7	81.3	62.6	11,822	COAL	23,230	23,270,460	540,572.8	965,107	2.11	41.55
GAN.#2	98	44,527	63.1	84.3	72.2	12,664	COAL	28,560	19,744,280	563,896.6	1,186,546	2 66	41.55
GAN.#3	145	65,264	62.5	86.0	65.8	12,618	COAL	41,449	19,868,040	823,510.4	1,722,028	2.64	41.55
GAN.#4	159	28,621	25.0	30.0	68.0	12,984	COAL	18,121	20,508,000	371,625.5	752,850	2.63	41.55
GAN.#5	232	88,720	53.1	63.6	66.4	11,024	COAL	41,969	23,303,360	978,018.7	1,743,632	1.97	41.55
GAN.#6	372	172,202	64.3	76.7	68.9	10,804	COAL	75,870	24,521,260	1,860,428.0	3,152,073	1.83	41.55
GANNON STATION	1,120	445,059	65.2	69.7	67.5	11,545	COAL	229,199	22,417,428	5,138,052.0	9,522,236	2.14	41.55
B.B.#1	416	193,665	64.7	74.5	76.0	10,862	COAL	87,070	24,160,400	2,103,646.0	4,414,862	2 28	50.70
B.B.#2	416	204,295	68.2	78.3	74.8	10,731	COAL	91,006	24,068,560	2,192,203.5	4,614,436	2.26	50.70
B.B.#3	433	202,009	64.8	79.7	73.5	10,695	COAL	90,245	23,939,120	2,160,385.9	4,575,850	2 27	50.70
B.B. 1 - 3	1,265	599,969	65.9	77.5	74.7	10,761	COAL	268,321	24,061,611	6,456,235.4	13,605,148	2.27	50.70
B.B.#4	442	243,079	76.4	89.9	83.8	10,384	COAL	112,718	22,394,282	2,524,232.8	5,920,428	2.44	52.52
B.B. STATION	1,707	843,048	68.6	80.7	77.1	10,652	COAL	381,039	23,568,386	8,980,468.2	19,525,576	2.32	51.24
SEB-PHIL. #1(HVY OIL)	17	5,032	41.1	100.0	85.9	10,065	HVY.OIL	8,074	6,273,540	50,649.4	234,110	4.65	29.00
SEB-PHIL. #2(HVY OIL)	17	5,663	46.3	100.0	97.6	8,944	HVY.OIL	8,073	6,273,540	50,649.4	234,096	4.13	29.00
SEB-PHILLIPS TOTAL	34	10,695	43.7	100.0	91.8	9,472	HVY.OIL	16,147	6,273,540	101,298.8	468,206	4.38	29.00
POLK #1 GASIFIER	250	29,947	16.6	19.3	82.5	10,608	COAL	14,466	21,960,000	317,672.9	708,859	2.37	49.00
POLK #1 CT (OIL)	225	24,271	15.0	95.4	50.5	9,748	LGT.OIL	40,938	5,819,746	236,596.9	1,479,410	6.10	36.14
POLK #1 TOTAL	250	54,218	30.1	86.9	64.2	10,223	-	-	-	554,269.8	2,188,269	4.04	-
POLK #2 CT (GAS)	150	43,739	40.5	97.0	77.3	11,650	GAS	524,080	972,290	509,558.0	3,622,952	8.28	6.91
POLK #2 CT (OIL)	150	86	0.1	67.5	32.8	11,237	LGT.OIL	166	5,819,753	966.4	6,001	6.98	36.15
POLK #2 TOTAL	150	43,825	40.6	97.8	77.1	11,649	-	-	-	510,524.4	3,628,953	8.28	-
POLK STATION TOTAL	400	98,043	34.0	91.0	69.0	10,860	-	-	-	1,064,794.2	5,817,222	5.93	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	190	2.2	96.7	102.3	17,495	LGT.OIL	569	5,846,525	3,324.1	19,485	10.26	34.27
B.B.C.T.#2	66	5,183	10.9	100.0	70.2	15,832	LGT.OIL	14,030	5,848,882	82,058.0	480,883	9.28	34.28
B.B.C.T.#3	66	5,416	11.4	100.0	72.0	15,693	LGT.OIL	14,531	5,848,879	84,991.4	498,055	9.20	34.28
C.T. TOTAL	144	10,789	10.4	99.7	73.7	15,791	LGT.OIL	29,130	5,848,834	170,373.5	998,423	9.25	34.28
CITY OF TAMPA	6	1,125	0.0	0.0	0.0	11,127	GAS	12,875	972,290	12,518.4	67,937	6.04	5.28
TOT. COAL (GN,BB,POLK)	3,077	1,318,054	59.5	71.7	74.0	10,953	COAL	624,704	23,108,864	14,436,193.1	29,756,671	2.26	47.63
SYSTEM	3,501	1,408,493	55.9	79.0	71.0	22,109	-	-	-	15,467,505.1	36,399,600	2.58	-

* Hookers Point boiler limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JULY 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	39	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-260	0.0	0.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-260**	**0.0**	**71.3**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	52,446	61.8	89.8	63.3	12,217	COAL	27,548	23,258,000	640,711.4	1,128,663	2.15	40.97
GAN.#2	98	31,941	43.8	62.5	63.5	13,143	COAL	21,533	19,496,000	419,807.4	882,224	2.76	40.97
GAN.#3	145	35,731	33.1	45.5	59.6	12,634	COAL	22,960	19,662,000	451,439.5	940,889	2.63	40.97
GAN.#4	159	57,706	48.8	67.7	56.8	13,383	COAL	38,243	20,194,000	772,279.1	1,566,846	2.72	40.97
GAN.#5	232	72,497	42.0	55.0	67.6	10,478	COAL	33,732	22,520,000	759,644.6	1,382,027	1.91	40.97
GAN.#6	372	192,029	69.4	83.9	69.4	10,705	COAL	84,583	24,304,000	2,055,705.2	3,465,433	1.80	40.97
GANNON STATION	**1,120**	**442,350**	**53.1**	**69.4**	**64.8**	**11,528**	**COAL**	**228,599**	**22,308,003**	**5,099,587.2**	**9,365,882**	**2.12**	**40.97**
B.B.#1	416	198,827	64.2	78.5	69.2	11,220	COAL	94,529	23,599,940	2,230,878.7	4,561,636	2.29	48.26
B.B.#2	416	211,189	68.2	82.8	76.0	10,895	COAL	95,766	23,584,920	2,258,633.4	4,621,330	2.19	48.26
B.B.#3	433	177,818	55.2	66.4	74.5	10,352	COAL	78,239	23,526,640	1,840,700.8	3,775,536	2.12	48.26
B.B. 1 - 3	**1,265**	**587,834**	**62.5**	**76.5**	**73.3**	**10,769**	**COAL**	**268,534**	**23,573,227**	**6,330,212.9**	**12,958,504**	**2.20**	**48.26**
B.B.#4	442	274,132	83.4	98.3	83.4	10,414	COAL	126,600	22,549,298	2,854,752.9	5,999,832	2.19	47.39
B.B. STATION	**1,707**	**861,966**	**67.9**	**82.1**	**75.9**	**10,656**	**COAL**	**395,134**	**23,245,162**	**9,184,965.8**	**18,958,336**	**2.20**	**47.98**
SEB-PHIL. #1(HVY OIL)	17	3,820	30.2	98.5	69.2	11,071	HVY.OIL	6,741	6,273,540	42,290.8	196,805	5.15	29.20
SEB-PHIL. #2(HVY OIL)	17	5,007	39.6	99.1	95.6	8,446	HVY.OIL	6,741	6,273,540	42,290.8	196,804	3.93	29.20
SEB-PHILLIPS TOTAL	**34**	**8,827**	**34.9**	**98.8**	**82.4**	**9,582**	**HVY.OIL**	**13,482**	**6,273,540**	**84,581.6**	**393,609**	**4.46**	**29.20**
POLK #1 GASIFIER	250	148,315	79.7	85.2	89.3	10,775	COAL	68,604	23,295,040	1,598,132.0	3,101,381	2.09	45.21
POLK #1 CT (OIL)	225	10,372	6.2	99.2	65.8	8,350	LGT.OIL	15,061	5,810,731	86,606.8	541,483	5.22	35.95
POLK #1 TOTAL	**250**	**158,687**	**85.3**	**94.1**	**87.3**	**10,617**	**-**	**-**	**-**	**1,684,738.8**	**3,642,864**	**2.30**	**-**
POLK #2 CT (GAS)	150	26,237	23.5	82.6	79.1	11,750	GAS	327,711	972,290	308,289.0	183,494	0.70	0.56
POLK #2 CT (OIL)	150	11	0.0	77.2	22.0	15,092	LGT.OIL	29	5,810,641	166.0	1,027	9.34	35.41
POLK #2 TOTAL	**150**	**26,248**	**23.5**	**87.8**	**79.1**	**11,752**	**-**	**-**	**-**	**308,455.0**	**184,521**	**0.70**	**-**
POLK STATION TOTAL	**400**	**184,935**	**62.1**	**91.7**	**84.2**	**10,778**	**-**	**-**	**-**	**1,993,193.8**	**3,827,385**	**2.07**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	0	0.0	99.1	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	66	1,848	3.8	100.0	66.7	16,483	LGT.OIL	5,220	5,834,944	30,460.1	175,301	9.49	33.58
B.B.C.T.#3	66	1,690	3.4	100.0	65.7	15,973	LGT.OIL	4,626	5,834,949	26,993.7	155,353	9.19	33.58
C.T. TOTAL	**144**	**3,538**	**3.3**	**99.9**	**60.7**	**16,239**	**LGT.OIL**	**9,846**	**5,834,946**	**57,453.8**	**330,654**	**9.35**	**33.58**
CITY OF TAMPA	**6**	**1,086**	**0.0**	**0.0**	**0.0**	**9,329**	**GAS**	**10,770**	**940,734**	**10,131.7**	**107,325**	**9.88**	**9.97**
TOT. COAL (GN,BB,POLK)	**3,077**	**1,452,631**	**63.5**	**77.7**	**72.9**	**10,934**	**COAL**	**692,337**	**22,940,669**	**15,882,685.0**	**31,425,599**	**2.16**	**45.39**
SYSTEM	**3,501**	**1,502,442**	**57.7**	**79.6**	**70.7**	**10,935**	**-**	**-**	**-**	**16,429,913.9**	**32,983,191**	**2.20**	**-**

* Hookers Point boiler limited to 90 MW

LEGEND:
H.P. = HOOKERS POINT
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: AUGUST 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	30	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	39	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-268	0.0	0.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION	**90**	**-268**	**0.0**	**71.3**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	46,986	55.4	79.4	80.3	12,809	COAL	25,689	23,428,000	601,841.9	1,136,197	2.42	44.23
GAN.#2	98	47,007	64.5	82.4	74.2	12,762	COAL	31,674	18,940,000	599,905.6	1,400,907	2.98	44.23
GAN.#3	145	64,050	59.4	81.3	89.5	12,182	COAL	42,008	18,574,000	780,256.6	1,857,968	2.90	44.23
GAN.#4	159	64,501	54.5	64.9	68.5	13,121	COAL	45,578	18,568,000	846,292.3	2,015,866	3.13	44.23
GAN.#5	232	116,138	67.3	85.6	75.5	10,531	COAL	52,790	23,168,000	1,223,038.7	2,334,845	2.01	44.23
GAN.#6	372	189,873	68.6	81.4	76.9	10,524	COAL	83,487	23,934,000	1,998,177.9	3,692,540	1.94	44.23
GANNON STATION	**1,120**	**528,555**	**63.4**	**79.8**	**73.2**	**11,445**	**COAL**	**281,226**	**21,511,215**	**6,049,513.0**	**12,438,323**	**2.35**	**44.23**
B.B.#1	416	219,246	70.8	82.0	76.2	11,215	COAL	103,506	23,755,520	2,458,838.9	4,691,040	2.14	45.32
B.B.#2	416	229,872	74.3	87.7	77.6	10,622	COAL	102,932	23,720,720	2,441,621.2	4,665,025	2.03	45.32
B.B.#3	433	219,766	68.2	79.4	75.7	10,669	COAL	98,602	23,779,240	2,344,691.6	4,468,783	2.03	45.32
B.B. 1 - 3	1,265	668,884	71.1	83.0	76.5	10,832	COAL	305,040	23,751,445	7,245,151.7	13,824,848	2.07	45.32
B.B.#4	442	239,172	72.7	82.1	86.8	10,488	COAL	112,805	22,237,150	2,508,456.4	5,760,557	2.41	51.07
B.B. STATION	**1,707**	**908,056**	**71.5**	**82.8**	**79.2**	**10,741**	**COAL**	**417,845**	**23,342,634**	**9,753,608.1**	**19,585,405**	**2.16**	**46.87**
SEB-PHIL. #1(HVY OIL)	17	5,083	40.2	97.9	88.2	10,118	HVY.OIL	8,197	6,273,540	51,428.7	228,815	4.50	27.89
SEB-PHIL. #2(HVY OIL)	17	5,593	44.2	92.1	98.0	9,195	HVY.OIL	8,198	6,273,540	51,428.8	228,643	4.09	27.89
SEB-PHILLIPS TOTAL	**34**	**10,676**	**42.2**	**95.0**	**92.1**	**9,634**	**HVY.OIL**	**16,395**	**0**	**102,857.5**	**457,258**	**4.28**	**27.89**
POLK #1 GASIFIER	250	102,681	55.2	59.9	77.9	11,409	COAL	52,990	22,104,000	1,171,294.1	2,382,338	2.30	44.58
POLK #1 CT (OIL)	225	16,947	10.1	94.0	68.2	8,703	LGT.OIL	26,578	5,812,666	147,483.3	916,906	5.41	34.50
POLK #1 TOTAL	**250**	**119,608**	**64.3**	**80.7**	**76.3**	**11,026**	**-**	**-**	**-**	**1,318,777.4**	**3,279,244**	**2.74**	**-**
POLK #2 CT (GAS)	150	38,630	32.8	89.4	77.7	11,013	GAS	380,928	972,290	403,402.9	1,701,503	4.65	4.47
POLK #2 CT (OIL)	150	1,800	1.6	97.3	68.6	14,220	LGT.OIL	4,403	5,812,665	25,595.2	151,909	8.44	34.50
POLK #2 TOTAL	**150**	**38,430**	**34.4**	**97.3**	**77.2**	**11,163**	**-**	**-**	**-**	**428,998.1**	**1,853,412**	**4.82**	**-**
POLK STATION TOTAL	**400**	**158,038**	**53.1**	**86.9**	**76.6**	**11,059**	**-**	**-**	**-**	**1,747,775.5**	**5,132,656**	**3.25**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	244	2.7	84.3	101.7	17,616	LGT.OIL	737	5,830,993	4,298.2	24,322	9.97	33.00
B.B.C.T.#2	66	4,802	9.8	100.0	68.6	15,969	LGT.OIL	13,180	5,818,330	76,684.6	434,955	9.06	33.00
B.B.C.T.#3	66	420	0.9	24.2	63.6	15,797	LGT.OIL	1,140	5,818,316	6,634.8	37,621	8.96	33.00
C.T. TOTAL	**144**	**5,466**	**5.1**	**64.0**	**69.1**	**16,030**	**LGT.OIL**	**15,057**	**5,818,949**	**87,617.6**	**496,898**	**9.09**	**33.00**
CITY OF TAMPA	**6**	**1,417**	**0.0**	**0.0**	**0.0**	**10,564**	**GAS**	**14,135**	**972,290**	**14,969.0**	**56,909**	**4.02**	**4.03**
TOT. COAL (GN,BB,POLK)	**3,077**	**1,539,272**	**67.2**	**79.8**	**76.9**	**11,028**	**COAL**	**752,061**	**22,570,519**	**16,974,416.2**	**34,386,066**	**2.23**	**45.72**
SYSTEM	**3,501**	**1,611,940**	**61.9**	**81.2**	**74.5**	**11,016**	**-**	**-**	**-**	**17,756,340.7**	**38,167,449**	**2.37**	**-**

* Hookers Point limited to 90 MW

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: SEPTEMBER 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0 0	100.0	0 0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	30	0	0.0	100.0	0 0	0	HVY.OIL	-	0	0.0	0	0 00	0.00
H.P.#3	30	0	0 0	100.0	0.0	0	HVY.OIL	-	0	0 0	0	0.00	0.00
H.P.#4	39	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-240	0.0	0.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	90	-240	0.0	71.3	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	50,370	61.4	87.2	62.7	11,566	COAL	25,387	22,948,000	582,580.9	1,181,653	2.35	46 55
GAN.#2	98	42,859	60.7	77.1	66.1	14,332	COAL	33,114	18,550,000	614,264.7	1,541,311	3.60	46.55
GAN.#3	145	56,930	54 5	70.6	60.2	12,597	COAL	39,557	18,130,000	717,168.4	1,841,204	3.23	46.55
GAN.#4	159	58,265	50.9	62 3	65.7	13,243	COAL	42,022	18,362,000	771,608 0	1,955,939	3.36	46.55
GAN.#5	232	46,405	27.8	35.5	59.0	11,766	COAL	23,899	22,886,000	546,952.5	1,112,393	2.40	46.55
GAN #6	372	120,661	45.0	55.1	58.1	12,450	COAL	55,282	27,174,000	1,502,233.1	2,573,133	2.13	46 55
GANNON STATION	1,120	375,490	46.6	59.3	60.8	12,610	COAL	219,261	21,594,390	4,734,807.6	10,205,633	2.72	46.55
B.B.#1	416	173,580	58.0	68.1	64.3	11,291	COAL	82,519	23,749,820	1,959,811.4	3,740,551	2.15	45.33
B.B.#2	416	195,788	65.4	74.9	70.6	10,532	COAL	87,299	23,620,400	2,062,037.3	3,957,227	2.02	45.33
B.B.#3	433	152,682	49.0	56.8	76.7	10,493	COAL	68,806	23,283,940	1,602,073 8	3,118,947	2.04	45.33
B.B. 1 - 3	1,265	522,050	57.3	66.5	70.6	10,773	COAL	238,624	23,568,138	5,623,922.3	10,816,725	2.07	45.33
B.B.#4	442	196,803	61.8	72.7	79.9	10,558	COAL	95,593	21,735,450	2,077,749.3	5,098,932	2.59	53.34
B.B. STATION	1,707	718,853	58.5	68.1	73.0	10,714	COAL	334,217	23,043,953	7,701,671.6	15,915,657	2.21	47.62
SEB-PHIL. #1(HVY OIL)	17	4,110	33 6	91.0	84.5	9,475	HVY.OIL	6,207	6,273,540	38,941.2	171,394	4.17	27.61
SEB-PHIL. #2(HVY OIL)	17	4,964	40.6	99.0	97.4	9,475	HVY.OIL	7,497	6,273,540	47,032.6	207,015	4.17	27.61
SEB-PHILLIPS TOTAL	34	9,074	37.1	95.0	91.0	9,475	HVY.OIL	13,704	6,273,540	85,973.8	378,409	4.17	27.61
POLK #1 GASIFIER	250	85,045	47.2	49.4	80.8	11,497	COAL	44,841	21,805,340	977,781.5	1,989,507	2.34	44.37
POLK #1 CT (OIL)	225	16,340	10.1	91 0	67.1	8,874	LGT.OIL	25,570	5,770,348	145,002.3	895,458	5.48	35.02
POLK #1 TOTAL	250	101,385	56.3	78.6	78.2	11,074	-	-	-	1,122,783.8	2,884,965	2.85	-
POLK #2 CT (GAS)	150	44,460	41.2	98.0	81.1	11,368	GAS	478,602	972,290	505,404.0	1,451,345	3.26	3.03
POLK #2 CT (OIL)	150	1,725	1.6	62.6	102.7	11,974	LGT.OIL	3,580	5,770,348	20,656.0	125,362	7.27	35.02
POLK #2 TOTAL	150	46,185	42.8	98.0	81.7	11,390	-	-	-	526,060.0	1,576,707	3.41	-
POLK STATION TOTAL	400	147,570	51.2	85.9	79.5	11,173	-	-	-	1,648,843.8	4,461,672	3.02	-
GAN.C.T.#1	0	0	0.0	0 0	0.0	0	LGT.OIL	0	0	0.0	0	0 00	0 00
B.B.C.T.#1	12	102	1 2	100.0	111.1	17,062	LGT.OIL	299	5,819,623	1,740.3	9,942	9.75	33.25
B.B C.T.#2	66	2,212	4.7	100 0	64 5	16,413	LGT.OIL	6,255	5,804,098	36,306.2	207,977	9 40	33 25
B.B.C.T.#3	66	0	0 0	0 0	0 0	0	LGT.OIL	0	0	0.0	0	0 00	0.00
C.T. TOTAL	144	2,314	2.2	54.2	38.8	16,442	LGT.OIL	6,554	5,804,806	38,046.5	217,919	9.42	33.25
CITY OF TAMPA	6	1,463	0.0	0.0	0.0	10,426	GAS	14,444	972,290	15,252.9	107,301	7.33	7.43
TOT. COAL (GN,BB,POLK)	3,077	1,179,388	53.2	63.4	69.2	11,374	COAL	598,319	22,419,915	13,414,260.7	28,110,797	2.38	46.98
SYSTEM	3,501	1,264,524	49.8	67.0	66.6	11,339	-	-	-	14,224,596.2	31,286,591	2.49	-

* Hookers Point limited to 90 MW

LEGEND:
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: OCTOBER 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0.0	100 0	0.0	0	HVY OIL	-	0	0 0	0	0.00	0.00
H.P.#2	30	0	0.0	100 0	0 0	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P.#3	30	0	0 0	100.0	0 0	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P.#4	39	0	0 0	100 0	0.0	0	HVY OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-228	0 0	0 0	0.0	0	HVY OIL	-	0	0 0	0	0.00	0.00
H.P. STATION	**90**	**-228**	**0.0**	**71.3**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN #1	114	43,500	51.2	78.6	59.4	11,609	COAL	21,998	22,956,000	504,986.1	967,748	2.22	43 99
GAN.#2	98	42,707	58.5	85.3	67.7	13,303	COAL	30,233	18,792,000	568,138.5	1,330,027	3.11	43 99
GAN #3	145	39,813	36 9	48.8	62 9	12,172	COAL	25,961	18,666,000	484,588.0	1,142,090	2 87	43.99
GAN.#4	159	48,594	41.0	56.8	58.4	11,554	COAL	33,682	16,670,000	561,478 9	1,481,757	3 05	43.99
GAN.#5	232	109,312	63.2	82 3	68.7	10,711	COAL	49,406	23,698,000	1,170,823 4	2,173,496	1 99	43 99
GAN.#6	372	181,504	65.5	82.1	74.8	10,488	COAL	77,887	24,440,000	1,903,558 3	3,426,446	1 89	43 99
GANNON STATION	**1,120**	**465,430**	**55.8**	**74.2**	**67.5**	**11,159**	**COAL**	**239,167**	**21,715,258**	**5,193,573.2**	**10,521,566**	**2.26**	**43.99**
B.B.#1	416	152,535	49.2	58 0	51.9	11,286	COAL	71,177	24,185,840	1,721,475.5	3,305,444	2.17	46 44
B.B.#2	416	202,532	65.3	79.0	68.7	10,536	COAL	88,393	24,141,480	2,133,937.8	4,104,952	2.03	46 44
B.B #3	433	183,123	56 8	72 3	73.3	10,609	COAL	79,302	24,332,860	1,942,808 5	3,682,767	2 01	46.44
B.B. 1 - 3	1,265	538,190	57.1	69.8	64.7	10,774	COAL	238,872	24,218,492	5,798,221 8	11,093,163	2 06	46 44
B.B.#4	442	254,699	77.3	93 6	81.4	10,390	COAL	119,345	22,173,452	2,646,283.7	6,399,751	2 51	53.62
B.B. STATION	**1,707**	**792,889**	**62.3**	**76.0**	**69.1**	**10,650**	**COAL**	**358,217**	**23,536,187**	**8,444,505.5**	**17,492,914**	**2.21**	**48.83**
SEB-PHIL. #1(HVY OIL)	17	2,845	22.5	99.9	80.2	9,632	HVY.OIL	4,368	6,273,540	27,403.7	127,055	4.47	29 09
SEB-PHIL. #2(HVY OIL)	17	3,361	26.5	95.8	95.2	9,632	HVY.OIL	5,161	6,273,540	32,374 0	150,121	4.47	29 09
SEB-PHILLIPS TOTAL	**34**	**6,206**	**24.5**	**97.9**	**87.7**	**9,632**	**HVY.OIL**	**9,529**	**6,273,540**	**59,777.7**	**277,176**	**4.47**	**29.09**
POLK #1 GASIFIER	250	107,520	57.7	61 3	86.7	10,578	COAL	51,795	21,958,000	1,137,320.8	2,378,947	2 21	45 89
POLK #1 CT (OIL)	225	15,256	9 1	99.8	62.3	9,267	LGT OIL	25,123	5,794,430	141,381.4	834,627	5 47	33 22
POLK #1 TOTAL	**250**	**122,776**	**65.9**	**91.2**	**82.7**	**10,415**	**-**	**-**	**-**	**1,278,702.2**	**3,211,574**	**2.62**	**-**
POLK #2 CT (GAS)	150	5,083	4 5	81 6	78.7	11,814	GAS	57,030	972,290	60,053 0	221,594	4 36	3 89
POLK #2 CT (OIL)	150	68	0 1	81.0	31.6	12,219	LGT.OIL	143	5,794,407	830.9	4,764	7.01	33.31
POLK #2 TOTAL	**150**	**5,151**	**4.6**	**81.6**	**77.2**	**11,820**	**-**	**-**	**-**	**60,883.9**	**226,358**	**4.39**	**-**
POLK STATION TOTAL	**400**	**127,927**	**42.9**	**87.6**	**80.6**	**10,471**	**-**	**-**	**-**	**1,339,586.0**	**3,437,932**	**2.69**	**-**
GAN C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	21	0.2	100.0	87 5	20,629	LGT.OIL	74	5,831,987	433 2	2,442	11 63	33 00
B.B.C.T #2	66	1,969	4 0	99.1	65.1	16,206	LGT OIL	5,487	5,815,417	31,910.3	181,087	9 20	33 00
B.B.C.T.#3	66	0	0.0	0 0	0 0	0	LGT.OIL	0	0	0.0	0	0 00	0.00
C.T. TOTAL	**144**	**1,990**	**1.9**	**53.8**	**37.1**	**16,253**	**LGT.OIL**	**5,561**	**5,815,639**	**32,343.5**	**183,529**	**9.22**	**33.00**
CITY OF TAMPA	**6**	**1,167**	**0.0**	**0.0**	**0.0**	**10,240**	**GAS**	**11,349**	**972,290**	**11,950.5**	**53,586**	**4.59**	**4.72**
TOT. COAL (GN,BB,POLK)	**3,077**	**1,365,839**	**59.6**	**74.1**	**69.9**	**10,818**	**COAL**	**649,179**	**22,741,181**	**14,775,399.5**	**30,391,427**	**2.23**	**46.82**
SYSTEM	**3,501**	**1,395,381**	**53.5**	**75.8**	**66.9**	**10,807**	**-**	**-**	**-**	**15,081,736.5**	**31,966,703**	**2.29**	**-**

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
B.B. = BIG BEND
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: NOVEMBER 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	30	0	0.0	100 0	0 0	0	HVY.OIL	0	0	0 0	0	0 00	0 00
H.P #2	30	0	0.0	100 0	0 0	0	HVY OIL	0	0	0 0	0	0.00	0 00
H.P #3	30	0	0.0	100 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H.P.#4	39	0	0.0	100 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H.P #5	52	-201	0.0	0 0	0 0	0	HVY.OIL	0	0	0 0	0	0.00	0 00
H.P. STATION *	**90**	**-201**	**0.0**	**71.3**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN #1	114	38,995	47 5	91.5	56.0	11,362	COAL	19,301	22,956,000	443,073 8	841,535	2 16	43 60
GAN.#2	98	26,223	37.2	85 2	62.4	11,047	COAL	15,416	18,792,000	289,697.5	672,147	2 56	43.60
GAN #3	145	16,049	15 4	22.7	65.8	12,102	COAL	10,406	18,666,000	194,238.4	453,708	2.83	43 60
GAN.#4	159	24,549	21.4	29 5	59 3	11,269	COAL	16,596	16,670,000	276,655.3	723,596	2.95	43 60
GAN.#5	232	73,513	44.0	67 4	58 6	10,576	COAL	32,807	23,698,000	777,460.3	1,430,405	1.95	43.60
GAN.#6	372	185,616	69.3	93.8	69.5	10,926	COAL	82,978	24,440,000	2,027,982 3	3,817,892	1.95	43 60
GANNON STATION	**1,120**	**364,945**	**45.3**	**69.0**	**63.3**	**10,985**	**COAL**	**177,504**	**22,586,013**	**4,009,107.6**	**7,739,283**	**2.12**	**43.60**
B.B.#1	416	179,187	59 8	77 5	69.4	10,986	COAL	79,842	24,656,320	1,968,609 9	3,692,418	2.06	46 25
B.B.#2	416	191,839	64.0	77 5	76 4	10,333	COAL	81,472	24,329,940	1,982,208 9	3,767,800	1.96	46 25
B.B #3	433	218,888	70 2	90 4	73.0	10,280	COAL	91,433	24,610,600	2,250,240 8	4,228,462	1.93	46 25
B.B. 1 - 3	1,265	589,914	64.8	81 9	72 9	10,512	COAL	252,747	24,534,646	6,201,059.6	11,688,680	1.98	46 25
B.B.#4	442	198,563	62.4	77 4	77 1	10,602	COAL	93,516	22,511,984	2,105,217.0	4,896,232	2 47	52.36
B.B. STATION	**1,707**	**788,477**	**64.2**	**80.7**	**74.0**	**10,535**	**COAL**	**346,263**	**23,988,384**	**8,306,276.6**	**16,584,912**	**2.10**	**47.90**
SEB-PHIL. #1(HVY OIL)	17	1,286	10 5	100.0	75 8	9,998	HVY OIL	2,049	6,273,540	12,853 7	60,074	4 67	29.32
SEB-PHIL. #2(HVY OIL)	17	1,572	12.8	99.7	95 1	9,998	HVY.OIL	2,505	6,273,540	15,718 7	73,442	4 67	29 32
SEB-PHILLIPS TOTAL	**34**	**2,858**	**11.7**	**99.8**	**85.4**	**9,998**	**HVY.OIL**	**4,554**	**6,273,540**	**28,572.4**	**133,516**	**4.67**	**29.32**
POLK #1 GASIFIER	250	84,310	46 8	50 3	88.0	10,929	COAL	39,886	23,100,780	921,406 3	1,773,915	2 10	44 47
POLK #1 CT (OIL)	225	5,859	3 6	98 8	46 6	11,207	LGT.OIL	12,320	5,796,360	65,664 0	393,425	6 71	31 93
POLK #1 TOTAL	**250**	**90,169**	**50.1**	**91.4**	**83.2**	**10,947**	**-**	**-**	**-**	**987,070.3**	**2,167,340**	**2.40**	**-**
POLK #2 CT (GAS)	150	9,425	8.7	46.1	86 6	9,317	GAS	84,031	972,290	87,812.0	198,146	2 10	2 36
POLK #2 CT (OIL)	150	722	0.7	52.4	63.5	12,680	LGT OIL	1,580	5,796,358	9,160.4	50,469	6.99	31 94
POLK #2 TOTAL	**150**	**10,147**	**9.4**	**52.4**	**84.4**	**9,557**	**-**	**-**	**-**	**96,972.4**	**248,615**	**2.45**	**-**
POLK STATION TOTAL	**400**	**100,316**	**34.8**	**76.7**	**83.7**	**10,806**	**-**	**-**	**-**	**1,084,042.7**	**2,415,955**	**2.41**	**-**
GAN.C.T.#1	0	0	0.0	0 0	0.0	0	LGT OIL	0	0	0 0	0	0 00	0.00
B.B.C.T.#1	12	0	0.0	99.9	0.0	0	LGT OIL	0	0	0.0	0	0 00	0 00
B.B C.T.#2	66	0	0 0	100.0	0.0	0	LGT.OIL	0	0	0 0	0	0 00	0.00
B.B.C.T.#3	66	0	0 0	0.0	0.0	0	LGT.OIL	0	0	0 0	0	0.00	0.00
C.T. TOTAL	**144**	**-**	**0.0**	**54.2**	**0.0**	**0**	**LGT.OIL**	**0**	**0**	**-**	**-**	**0.00**	**0.00**
CITY OF TAMPA	**6**	**602**	**0.0**	**0.0**	**0.0**	**10,745**	**GAS**	**6,190**	**0**	**6,468.8**	**43,905**	**7.29**	**7.09**
TOT. COAL (GN,BB,POLK)	**3,077**	**1,237,732**	**55.9**	**74.0**	**71.3**	**10,694**	**COAL**	**563,653**	**23,483,942**	**13,236,790.5**	**26,098,110**	**2.11**	**46.30**
SYSTEM	**3,501**	**1,256,997**	**49.9**	**75.2**	**68.7**	**10,688**	**-**	**-**	**-**	**13,434,468.1**	**25,917,571**	**2.14**	**-**

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: DECEMBER 2001

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	0	0 0	100.0	0.0	0	HVY.OIL	-	0	0 0	0	0.00	0 00
H.P.#2	32	0	0.0	100 0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	32	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	41	0	0.0	100.0	0.0	0	HVY.OIL	-	0	0 0	0	0.00	0.00
H.P.#5	52	-204	0.0	0.0	0.0	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	90	-204	0.0	71.3	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	28,050	33.1	67.4	54.3	12,648	COAL	15,100	23,496,000	354,769.6	661,464	2.36	43.81
GAN.#2	98	25,113	34.4	68.2	57.1	10,705	COAL	14,434	18,625,000	268,833 3	632,289	2 52	43.81
GAN.#3	145	55,867	51.8	87.0	60.9	12,290	COAL	37,236	18,440,000	686,631.8	1,631,144	2.92	43 81
GAN.#4	169	33,809	26.9	46.8	52.2	13,181	COAL	24,448	18,228,000	445,638.1	1,070,958	3 17	43.81
GAN.#5	207	86,136	55.9	73.0	61.4	11,481	COAL	42,709	23,156,000	988,969.6	1,870,892	2.17	43.81
GAN.#6	392	164,830	56.5	76.8	65.9	11,082	COAL	76,459	23,890,000	1,826,605.5	3,349,329	2.03	43.81
GANNON STATION	1,125	393,805	47.0	71.2	60.4	11,608	COAL	210,386	21,728,955	4,571,467.9	9,216,076	2.34	43.81
B.B.#1	426	176,729	55.8	71.9	65.9	10,968	COAL	79,135	24,493,280	1,938,275.7	3,677,327	2.08	46.47
B.B.#2	426	194,572	61.4	78 6	72.1	10,529	COAL	83,331	24,585,580	2,048,741.0	3,872,311	1.99	46.47
B.B.#3	443	173,938	52.8	73.6	62.5	10,646	COAL	75,070	24,666,840	1,851,743 6	3,488,431	2 01	46 47
B.B. 1 - 3	1,295	545,239	56.6	74.7	66.7	10,709	COAL	237,536	24,580,511	5,838,760.3	11,038,069	2.02	46.47
B.B.#4	447	163,541	49.2	63.2	73 1	10,760	COAL	78,090	22,534,886	1,759,753.7	4,134,719	2 53	52.95
B.B. STATION	1,742	708,780	54.7	71.8	68.4	10,721	COAL	315,626	24,074,396	7,598,514.0	15,172,788	2.14	48.07
SEB-PHIL. #1(HVY OIL)	17	696	5.5	99.8	62.9	10,213	HVY.OIL	1,133	6,273,540	7,106.5	32,717	4.70	28.88
SEB-PHIL. #2(HVY OIL)	17	1,024	8.1	100.0	91.2	0	HVY.OIL	1,667	0	0.0	48,138	4.70	28.86
SEB-PHILLIPS TOTAL	34	1,720	6.8	99.9	77.0	4,132	HVY.OIL	2,800	6,273,540	7,106.5	80,855	4.70	28.88
POLK #1 GASIFIER	250	144,853	77.9	83 8	90.0	10,945	COAL	59,801	26,512,000	1,585,439.1	2,497,786	1.72	41.77
POLK #1 CT (OIL)	245	5,939	3.3	98.5	34.0	9,746	LGT.OIL	10,688	5,783,675	57,877.6	321,012	5.41	30.03
POLK #1 TOTAL	250	150,792	81.1	95.3	84.5	10,898	-	-	-	1,643,316.7	2,818,798	1.87	-
POLK #2 CT (GAS)	160	5,796	4.9	99.5	51.5	11,062	GAS	64,113	972,290	64,113.0	168,749	2.91	2 63
POLK #2 CT (OIL)	170	0	0.0	99.5	0.0	0	LGT OIL	0	0	0.0	0	0 00	0 00
POLK #2 TOTAL	165	5,796	4.9	99.5	51.5	11,062	-	-	-	64,113.0	168,749	2.91	-
POLK STATION TOTAL	415	156,588	50.7	97.0	70.8	10,904	-	-	-	1,707,429.7	2,987,547	1.91	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0 00	0 00
B.B.C.T.#1	17	0	0.0	100.0	0.0	0	LGT.OIL	9	0	0.0	274	0 00	30.44
B B.C.T.#2	80	137	0.2	100.0	24.1	219,754	LGT.OIL	710	42,365,732	30,106.4	21,598	15.78	30.42
B.B.C.T.#3	80	13	0.0	59.9	19 1	0	LGT.OIL	1	0	0.0	30	0 23	30.00
C.T. TOTAL	177	150	0.1	81.9	19.5	200,709	LGT.OIL	720	41,816,712	30,106.4	21,902	14.60	30.42
CITY OF TAMPA	6	491	0.0	0.0	0.0	11,385	GAS	5,329	0	5,590.1	27,282	5.56	5.12
TOT. COAL (GN,BB,POLK)	3,117	1,247,438	53.8	72.5	67.2	11,027	COAL	585,813	23,480,901	13,755,421.0	26,886,650	2.16	45.90
SYSTEM	3,589	1,261,330	47.2	75.1	62.0	11,036	-	-	-	13,920,214.6	27,506,450	2.18	-

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
GAN. = GANNON
B B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: JANUARY 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P #1	32	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H P #2	32	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P #3	32	0	—	—	—	0	HVY OIL	-	0	0 0	0	0.00	0.00
H.P.#4	41	0	—	—	—	0	HVY OIL	-	0	0.0	0	0 00	0 00
H.P #5	52	-188	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P. STATION *	**90**	**-188**	**—**	**—**	**—**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	35,443	41.8	83.6	63 8	12,428	COAL	18,799	23,432,000	440,498 2	921,938	2 60	49 04
GAN #2	98	23,260	31 9	52 3	67.2	12,658	COAL	12,816	22,974,000	294,434 8	628,521	2.70	49 04
GAN.#3	155	58,009	50.3	91.5	62.6	12,346	COAL	39,008	18,360,000	716,186 9	1,913,026	3.30	49 04
GAN #4	159	40,730	34.4	64 0	85.7	13,537	COAL	28,783	19,156,000	551,367 1	1,411,573	3 47	49 04
GAN.#5	217	72,050	44 6	57.0	69 6	11,519	COAL	35,228	23,560,000	829,971.7	1,727,648	2.40	49 04
GAN.#6	392	153,653	52.7	70.8	69 0	10,831	COAL	70,890	23,476,000	1,664,213 6	3,476,579	2 26	49 04
GANNON STATION	**1,135**	**383,145**	**45.4**	**69.7**	**67.1**	**11,736**	**COAL**	**205,524**	**21,879,062**	**4,496,672.3**	**10,079,285**	**2.63**	**49.04**
B B.#1	426	179,770	56.7	71.8	73 1	10,722	COAL	78,744	24,478,940	1,927,569.7	3,592,548	2 00	45.62
B.B #2	426	227,352	71 7	84 4	79.0	10,480	COAL	96,725	24,633,840	2,382,708 2	4,412,894	1 94	45 62
B B.#3	433	160,327	49.8	59.6	63 9	10,764	COAL	70,360	24,526,740	1,725,711 5	3,210,041	2 00	45 62
B B. 1 - 3	1,285	567,449	59 4	71.9	72 0	10,637	COAL	245,829	24,553,569	6,035,989 4	11,215,481	1 98	45.62
B B.#4	447	246,026	74 0	90 1	80.7	10,296	COAL	116,973	21,655,523	2,533,105 7	6,208,516	2 52	53 08
B.B. STATION	**1,732**	**813,475**	**63.1**	**76.6**	**74.2**	**10,534**	**COAL**	**362,802**	**23,619,197**	**8,569,095.1**	**17,423,997**	**2.14**	**48.03**
SEB-PHIL. #1(HVY OIL)	17	1,703	13.5	100 0	74.1	9,618	HVY.OIL	2,611	6,273,540	16,379.9	69,689	4.09	26 69
SEB-PHIL. #2(HVY OIL)	17	2,094	16.6	100.0	92.9	9,618	HVY.OIL	3,210	6,273,540	20,140 6	85,677	4 09	26 69
SEB-PHILLIPS TOTAL	**34**	**3,797**	**15.0**	**100.0**	**83.5**	**9,618**	**HVY.OIL**	**5,821**	**6,273,540**	**36,520.5**	**155,366**	**4.09**	**26.69**
POLK #1 GASIFIER	250	156,607	84.2	87.4	90 6	10,601	COAL	62,631	26,508,000	1,660,219 9	2,565,935	1 64	40 97
POLK #1 CT (OIL)	245	5,466	3 0	89 8	74 2	7,917	LGT OIL	7,876	5,789,821	43,277 0	208,770	3.82	26 51
POLK #1 TOTAL	**250**	**162,073**	**87.1**	**84.3**	**89.9**	**10,511**	**-**	**-**	**-**	**1,703,496.9**	**2,774,705**	**1.71**	**-**
POLK #2 CT (GAS)	160	2,696	2 3	98.8	82 4	11,617	GAS	29,630	972,290	31,319 0	111,941	4.15	3 78
POLK #2 CT (OIL)	180	3,305	2.5	91 9	63.8	12,657	LGT.OIL	7,225	5,789,827	41,832.6	191,514	5 79	26 51
POLK #2 TOTAL	**170**	**6,001**	**5.0**	**100.0**	**71.0**	**12,190**	**-**	**-**	**-**	**73,151.6**	**303,455**	**5.06**	**-**
POLK STATION TOTA	**420**	**168,074**	**53.8**	**90.6**	**80.6**	**10,571**	**-**	**-**	**-**	**1,776,648.5**	**3,078,160**	**1.83**	**-**
B.B C T.#1	17	47	0.4	100 0	55 3	19,962	LGT.OIL	161	5,829,139	938 2	4,704	10 01	29 22
B.B.C T.#2	80	1,320	2 2	100 0	50 0	16,559	LGT OIL	3,748	5,831,172	21,857 8	109,520	8 30	29 22
B.B.C T.#3	80	176	0 3	100.0	73.3	587	LGT OIL	18	5,832,863	103 3	526	0 30	29.22
C.T. TOTAL	**177**	**1,543**	**1.2**	**100.0**	**61.1**	**14,841**	**LGT.OIL**	**3,927**	**5,831,097**	**22,899.3**	**114,750**	**7.44**	**29.22**
CITY OF TAMPA	**6**	**621**	**0.0**	**0.0**	**0.0**	**10,422**	**GAS**	**6,123**	**972,290**	**6,472.0**	**34,818**	**5.57**	**5.65**
TOT. COAL (GN,BB,POLK)	**3,117**	**1,353,227**	**58.4**	**74.9**	**72.9**	**10,882**	**COAL**	**630,957**	**23,339,128**	**14,725,987.3**	**30,069,217**	**2.22**	**47.66**
SYSTEM	**3,504**	**1,370,467**	**52.7**	**77.5**	**72.1**	**10,877**	**-**	**-**	**-**	**14,908,307.7**	**30,886,176**	**2.25**	**-**

* Hookers Point limited to 90 MW

LEGEND:

H.P = HOOKERS POINT
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: FEBRUARY 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	41	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-163	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-163**	—	—	—	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	32,948	43.0	94.9	57.3	11,955	COAL	16,768	23,490,200	393,883.7	584,856	1.78	34.88
GAN.#2	98	18,304	27.8	44.3	78.7	12,935	COAL	10,057	23,542,000	236,761.9	350,781	1.92	34.88
GAN.#3	155	47,969	46.1	98.5	52.2	14,050	COAL	31,844	21,174,000	674,264.9	1,110,696	2.31	34.88
GAN.#4	159	41,861	39.2	72.7	64.7	12,267	COAL	26,747	19,198,000	513,488.9	932,916	2.23	34.88
GAN.#5	217	34,488	23.7	31.1	64.8	9,606	COAL	15,952	20,768,000	331,291.1	556,394	1.61	34.88
GAN.#6	392	169,401	64.3	86.7	69.3	10,830	COAL	78,708	23,310,000	1,834,683.5	2,745,279	1.62	34.88
GANNON STATION	**1,135**	**344,991**	**45.2**	**72.9**	**65.1**	**11,549**	**COAL**	**180,076**	**22,126,069**	**3,984,374.0**	**6,280,922**	**1.82**	**34.88**
B.B.#1	426	105,397	36.8	46.7	68.8	10,750	COAL	47,043	24,084,300	1,132,997.7	1,936,838	1.84	41.17
B.B.#2	426	89,239	31.2	39.0	75.8	10,402	COAL	39,069	23,759,720	928,268.5	1,608,536	1.80	41.17
B.B.#3	433	189,583	65.2	81.3	72.2	10,520	COAL	81,526	24,464,140	1,994,452.2	3,356,561	1.77	41.17
B.B. 1 - 3	1,285	384,219	44.5	55.8	72.3	10,556	COAL	167,638	24,193,378	4,055,718.4	6,901,935	1.80	41.17
B.B.#4	447	253,321	84.3	95.3	86.8	10,324	COAL	117,504	22,257,112	2,615,294.1	6,161,847	2.43	52.44
B.B. STATION	**1,732**	**637,540**	**54.8**	**66.0**	**76.0**	**10,464**	**COAL**	**285,142**	**23,395,463**	**6,671,012.5**	**13,063,782**	**2.05**	**45.82**
SEB-PHIL. #1(HVY OIL)	17	163	1.4	100.0	35.3	12,399	HVY.OIL	322	6,273,540	2,021.0	9,000	5.52	27.95
SEB-PHIL. #2(HVY OIL)	17	400	3.5	100.0	86.6	12,399	HVY.OIL	791	6,273,540	4,959.5	22,108	5.53	27.95
SEB-PHILLIPS TOTAL	**34**	**563**	**2.5**	**100.0**	**60.9**	**12,399**	**HVY.OIL**	**1,113**	**6,273,540**	**6,980.5**	**31,108**	**5.53**	**27.95**
POLK #1 GASIFIER	250	124,293	74.0	78.9	93.8	10,423	COAL	48,381	26,778,000	1,295,547.5	1,555,803	1.25	32.16
POLK #1 CT (OIL)	245	6,359	3.9	80.6	70.5	8,539	LGT.OIL	10,112	5,749,366	54,301.5	268,366	4.22	26.54
POLK #1 TOTAL	**250**	**130,652**	**77.5**	**80.6**	**92.3**	**10,332**	**-**	**-**	**-**	**1,349,849.0**	**1,824,169**	**1.40**	**-**
POLK #2 CT (GAS)	160	683	0.6	96.6	52.4	15,735	GAS	10,148	972,290	10,747.0	57,433	8.41	5.66
POLK #2 CT (OIL)	180	0	0.0	96.2	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**170**	**683**	**0.6**	**97.7**	**52.4**	**15,735**	**-**	**-**	**-**	**10,747.0**	**57,433**	**8.41**	**-**
POLK STATION TOTAL	**420**	**131,335**	**46.5**	**87.5**	**74.9**	**10,360**	**-**	**-**	**-**	**1,360,596.0**	**1,881,602**	**1.43**	**-**
B.B.C.T.#1	17	51	0.4	100.0	75.0	17,761	LGT.OIL	156	5,799,347	905.8	4,500	8.82	28.85
B.B.C.T.#2	80	204	0.4	100.0	51.0	17,936	LGT.OIL	629	5,814,859	3,659.0	18,144	8.89	28.85
B.B.C.T.#3	80	7	0.0	100.0	8.8	62,300	LGT.OIL	75	5,814,667	436.1	2,163	30.90	28.84
C.T. TOTAL	**177**	**262**	**0.2**	**100.0**	**34.2**	**19,087**	**LGT.OIL**	**860**	**5,812,026**	**5,000.9**	**24,807**	**9.47**	**28.85**
CITY OF TAMPA	**6**	**206**	**0.0**	**0.0**	**0.0**	**12,112**	**GAS**	**2,356**	**972,290**	**2,495.0**	**12,146**	**5.90**	**5.16**
TOT. COAL (GN,BB,POLK)	**3,117**	**1,106,824**	**52.8**	**69.5**	**73.5**	**10,798**	**COAL**	**513,599**	**23,269,028**	**11,950,934.0**	**20,900,507**	**1.89**	**40.69**
SYSTEM	**3,504**	**1,114,734**	**47.4**	**72.9**	**70.1**	**10,791**	**-**	**-**	**-**	**12,030,458.9**	**21,294,367**	**1.91**	**-**

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: MARCH 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	41	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-173	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-173**	**—**	**—**	**—**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	53,089	62.6	90.0	67.5	12,276	COAL	27,679	23,546,000	651,729.7	1,058,450	1.99	38.24
GAN.#2	98	49,384	67.7	88.4	75.9	12,640	COAL	26,475	23,578,000	624,227.6	1,012,409	2.05	38.24
GAN.#3	155	71,380	61.9	83.9	71.2	12,745	COAL	44,769	20,320,000	909,706.1	1,711,974	2.40	38.24
GAN.#4	159	1,726	1.5	2.5	58.0	14,810	COAL	1,335	19,148,000	25,562.6	51,051	2.96	38.24
GAN.#5	217	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	392	153,458	52.6	62.6	70.4	11,224	COAL	73,058	23,576,460	1,722,449.0	2,793,750	1.82	38.24
GANNON STATION	**1,135**	**329,837**	**39.9**	**50.1**	**55.5**	**11,955**	**COAL**	**173,316**	**22,696,549**	**3,933,675.0**	**6,627,634**	**2.01**	**38.24**
B.B.#1	428	210,314	66.4	78.0	77.8	10,714	COAL	93,895	23,998,400	2,253,329.6	3,918,157	1.86	41.73
B.B.#2	428	172,920	54.6	60.3	72.7	10,544	COAL	76,491	23,837,240	1,823,334.3	3,191,903	1.85	41.73
B.B.#3	433	7,905	2.5	3.2	76.0	9,008	COAL	2,951	24,128,000	71,208.2	123,142	1.56	41.73
B.B. 1 - 3	1,285	391,139	40.9	46.9	75.5	10,605	COAL	173,337	23,929,489	4,147,872.3	7,233,202	1.85	41.73
B.B.#4	447	292,678	88.0	97.8	88.0	10,288	COAL	135,503	22,222,263	3,011,178.7	7,217,512	2.47	53.26
B.B. STATION	**1,732**	**683,817**	**53.1**	**60.1**	**78.7**	**10,469**	**COAL**	**308,840**	**23,180,448**	**7,159,851.0**	**14,450,714**	**2.11**	**46.79**
SEB-PHIL. #1(HVY OIL)	17	4,398	34.8	100.0	85.8	9,670	HVY.OIL	6,779	6,273,540	42,527.1	169,429	3.85	24.99
SEB-PHIL. #2(HVY OIL)	17	4,785	37.8	96.3	94.9	9,670	HVY.OIL	7,375	6,273,540	46,269.3	184,325	3.85	24.99
SEB-PHILLIPS TOTAL	**34**	**9,183**	**36.3**	**98.2**	**90.4**	**9,670**	**HVY.OIL**	**14,154**	**6,273,540**	**88,796.4**	**353,754**	**3.85**	**24.99**
POLK #1 GASIFIER	250	102,307	55.0	62.8	87.4	10,983	COAL	42,171	26,646,000	1,123,683.7	1,591,601	1.56	37.74
POLK #1 CT (OIL)	245	35,398	19.4	99.2	73.0	8,190	LGT.OIL	50,469	5,749,370	289,911.6	1,414,396	4.00	28.03
POLK #1 TOTAL	**250**	**137,705**	**74.9**	**96.4**	**83.2**	**10,265**	**-**	**-**	**-**	**1,413,595.3**	**3,005,997**	**2.18**	**-**
POLK #2 CT (GAS)	160	17,276	14.5	96.5	78.7	11,401	GAS	187,408	972,290	196,966.0	737,351	4.27	3.93
POLK #2 CT (OIL)	180	1,335	1.0	94.6	84.6	11,201	LGT.OIL	2,601	5,749,379	14,953.1	72,889	5.46	28.02
POLK #2 TOTAL	**170**	**18,611**	**15.6**	**96.5**	**79.1**	**11,387**	**-**	**-**	**-**	**211,919.1**	**810,240**	**4.35**	**-**
POLK STATION TOTAL	**420**	**156,316**	**50.0**	**97.6**	**79.6**	**10,399**	**-**	**-**	**-**	**1,625,514.4**	**3,816,237**	**2.44**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	17	229	1.8	100.0	80.2	17,032	LGT.OIL	670	5,817,498	3,900.4	18,747	8.19	27.98
B.B.C.T.#2	80	3,248	5.5	100.0	54.3	16,483	LGT.OIL	9,202	5,817,807	53,537.9	257,481	7.93	27.98
B.B.C.T.#3	80	83	0.1	100.0	64.0	8,242	LGT.OIL	118	5,817,672	684.1	3,302	3.98	27.98
C.T. TOTAL	**177**	**3,560**	**2.7**	**100.0**	**61.2**	**16,327**	**LGT.OIL**	**9,990**	**5,817,784**	**58,122.4**	**279,530**	**7.85**	**27.98**
CITY OF TAMPA	**6**	**1,324**	**0.0**	**0.0**	**0.0**	**9,927**	**GAS**	**12,505**	**972,290**	**13,142.8**	**78,690**	**5.94**	**6.29**
TOT. COAL (GN,BB,POLK)	**3,117**	**1,115,161**	**48.1**	**56.7**	**71.0**	**10,955**	**COAL**	**524,327**	**23,299,225**	**12,216,409.7**	**22,669,949**	**2.03**	**43.24**
SYSTEM	**3,504**	**1,183,064**	**45.5**	**63.7**	**70.5**	**10,884**	**-**	**-**	**-**	**12,878,302.0**	**25,606,559**	**2.16**	**-**

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: APRIL 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0.00	0 00
H.P.#3	0	0	—	—	—	0	HVY OIL	-	0	0 0	0	0.00	0 00
H.P.#4	0	0	—	—	—	0	HVY OIL	-	0	0 0	0	0 00	0 00
H.P.#5	0	-167	—	—	—	0	HVY OIL	-	0	0 0	0	0.00	0 00
H.P. STATION *	90	-167	—	—	—	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN #1	114	48,902	59.7	79.5	71.8	13,734	COAL	25,049	26,812,000	671,613.8	995,904	2 04	39 76
GAN.#2	98	43,565	61.8	75 2	80.0	12,845	COAL	23,724	23,588,000	559,601.7	943,225	2.17	39.76
GAN.#3	145	75,890	72.8	90.6	78.4	12,746	COAL	48,833	19,808,000	967,284.1	1,941,514	2 56	39 76
GAN.#4	159	32,648	28.6	36.9	77.1	13,216	COAL	20,714	20,830,000	431,472.8	823,552	2 52	39.76
GAN.#5	217	573	0.4	1.7	21.4	20,261	COAL	559	20,768,000	11,609 3	22,225	3 88	39.76
GAN.#6	372	165,068	61.7	69.2	66.2	11,256	COAL	78,759	23,590,000	1,857,924 8	3,131,319	1.90	39.76
GANNON STATION	1,105	366,646	46.1	55.7	62.4	12,272	COAL	197,638	22,766,403	4,499,508.3	7,857,739	2.14	39.76
B.B.#1	416	195,388	65.3	76.7	72.5	11,337	COAL	90,717	24,417,980	2,215,125 9	3,943,046	2.02	43.47
B.B.#2	416	101,042	33.8	37.9	79.6	10,821	COAL	45,359	24,104,240	1,093,344 2	1,971,545	1.95	43 47
B.B.#3	433	2,533	0.8	1.6	34.9	11,373	COAL	1,194	24,128,000	28,808 8	51,898	2.05	43 47
B.B. 1 - 3	1,265	298,963	32.9	38.2	62.0	11,163	COAL	137,270	24,311,786	3,337,278 9	5,966,489	2 00	43 47
B.B.#4	442	275,996	86 8	96.5	86.8	10,552	COAL	131,149	22,206,376	2,912,337 4	6,932,278	2.51	52.86
B.B. STATION	1,707	574,959	46.8	53.3	68.4	10,870	COAL	268,419	23,283,088	6,249,616.3	12,898,767	2.24	48.05
SEB-PHIL. #1(HVY OIL)	17	5,019	41.1	82 9	93 0	9,366	HVY.OIL	7,493	6,273,540	47,009.3	193,457	3 85	25.82
SEB-PHIL. #2(HVY OIL)	17	-277	0.0	0.0	0.0	0	HVY.OIL	0	6,273,540	0.0	0	0 00	0 00
SEB-PHILLIPS TOTAL	34	4,742	19.4	41.5	46.5	9,913	HVY.OIL	7,493	6,273,540	47,009.3	193,457	4.08	25.82
POLK #1 GASIFIER	250	109,735	61 0	66.4	91.1	10,746	COAL	44,334	26,598,000	1,179,206 4	1,674,085	1 53	37.76
POLK #1 CT (OIL)	225	33,950	21.0	100.0	76.4	8,413	LGT.OIL	49,327	5,821,236	285,816.1	1,567,351	4.62	31.77
POLK #1 TOTAL	250	143,685	79.9	98.1	87.2	10,195	-	-	-	1,464,822.5	3,241,436	2.26	-
POLK #2 CT (GAS)	150	46,522	43.1	100.0	81.5	11,320	GAS	500,142	972,290	526,649 0	1,722,667	3.70	3 44
POLK #2 CT (OIL)	160	0	0.0	98.8	0.0	0	LGT.OIL	0	0	0.0	0	0 00	0 00
POLK #2 TOTAL	155	46,522	43.1	100.0	81.5	11,320	-	-	-	526,649.0	1,722,667	3.70	-
POLK #3 CT (GAS)	150	14,195	36.2	99.3	59 7	11,352	GAS	153,037	972,290	161,148.0	568,047	4 00	3.71
POLK #3 CT (OIL)	160	2,132	2.9	100.0	33.8	13,119	LGT.OIL	4,493	6,225,381	27,970 2	142,762	6 70	31 77
POLK #3 TOTAL	155	16,327	15.1	100.0	92.8	11,583	-	-	-	189,118.2	710,809	4.35	-
POLK STATION TOTAL	405	206,534	70.9	97.6	84.0	10,558	-	-	-	2,180,589.7	5,674,912	2.75	-
GAN.C.T.#1	0	0	0.0	0 0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0 00
B B.C.T.#1	12	681	7.9	89.8	113.5	16,825	LGT.OIL	1,975	5,800,860	11,457 8	58,001	8 52	29 37
B.B.C.T.#2	66	4,286	9.0	65.8	61.3	16,775	LGT OIL	12,365	5,814,523	71,895 7	363,131	8.47	29 37
B.B.C.T.#3	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	144	4,967	4.8	83.5	37.5	16,781	LGT.OIL	14,340	5,812,600	83,353.5	421,132	8.48	29.37
CITY OF TAMPA	6	1,890	0.0	0.0	0.0	10,221	GAS	18,348	972,290	19,318.3	110,189	5.83	6.01
TOT. COAL (GN,BB,POLK)	3,062	1,051,340	47.8	55.2	68.1	11,346	COAL	510,391	23,370,958	11,928,329.0	22,430,591	2.13	43.95
SYSTEM	3,401	1,159,571	47.5	60.5	66.8	11,278	-	-	-	13,079,393.4	27,156,196	2.34	-

* Hookers Point boiler limited to 90MW

LEGEND:

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: MAY 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H P #1	0	0	—	—	—	0	HVY OIL	-	0	0.0	0	0.00	0 00
H P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0 00	0 00
H.P.#3	0	0	—	—	—	0	HVY OIL	-	0	0 0	0	0 00	0 00
H.P.#4	0	0	—	—	—	0	HVY OIL	-	0	0.0	0	0 00	0.00
H.P.#5	0	-177	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P. STATION *	**90**	**-177**	—	—	—	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**209,599** **	**-118.42**	**0.00**
GAN.#1	114	45,994	54.2	76 5	67 2	12,216	COAL	23,440	23,970,000	561,856 8	936,829	2 04	39 97
GAN.#2	98	45,722	62 7	80 9	76 7	12,189	COAL	23,386	23,830,000	557,288 4	934,671	2 04	39.97
GAN.#3	145	71,839	66 6	87 5	74 0	12,196	COAL	46,645	18,784,000	876,179.7	1,864,265	2.60	39.97
GAN.#4	159	79,840	67.5	90 0	72 5	12,682	COAL	53,175	19,042,000	1,012,558.4	2,125,251	2 66	39 97
GAN.#5	217	99,739	61.8	77.1	78 7	10,656	COAL	44,909	23,666,000	1,062,816.4	1,794,882	1 80	39.97
GAN.#6	372	189,537	68.5	78 9	77.7	10,878	COAL	86,699	23,782,000	2,061,875.6	3,465,108	1.83	39.97
GANNON STATION	**1,105**	**532,671**	**64.8**	**81.2**	**75.5**	**11,513**	**COAL**	**278,254**	**22,039,487**	**6,132,575.3**	**11,121,006**	**2.09**	**39.97**
B.B.#1	416	185,181	59.8	69.1	73.8	10,760	COAL	81,260	24,521,100	1,992,584 6	3,540,725	1 91	43.57
B.B.#2	416	251,345	81.2	86.0	81 2	10,863	COAL	109,912	24,842,120	2,730,447 1	4,789,172	1.91	43 57
B.B.#3	433	164,896	51.2	32.5	73 5	10,560	COAL	71,298	24,422,900	1,741,292 0	3,108,652	1.88	43.57
B.B. 1 - 3	1,265	601,422	63 9	62.1	76 1	10,748	COAL	262,470	24,628,856	6,464,323.7	11,436,549	1 90	43 57
B.B.#4	442	258,891	78.7	90.8	78 7	10,662	COAL	121,741	22,674,033	2,760,358.6	6,531,712	2.52	53 65
B.B. STATION	**1,707**	**860,313**	**67.7**	**69.6**	**76.8**	**10,722**	**COAL**	**384,211**	**24,009,451**	**9,224,682.3**	**17,968,261**	**2.09**	**46.77**
SEB-PHIL #1(HVY OIL)	17	4,579	36.2	100 0	79.3	9,806	HVY OIL	7,157	6,273,540	44,901 4	213,140	4 65	29 78
SEB-PHIL. #2(HVY OIL)	17	3,040	24 0	88.6	82 0	9,806	HVY OIL	4,752	6,273,540	29,810 1	141,517	4 66	29 78
SEB-PHILLIPS TOTAL	**34**	**7,619**	**30.1**	**84.3**	**80.7**	**9,806**	**HVY.OIL**	**11,909**	**6,273,540**	**74,711.5**	**354,657**	**4.65**	**29.78**
POLK #1 GASIFIER	250	87,867	47.2	50 5	84.8	11,068	COAL	35,958	27,046,000	972,510.9	1,368,182	1 56	38 05
POLK #1 CT (OIL)	225	7,452	4.5	73 7	60.7	9,739	LGT.OIL	12,602	5,758,744	72,574.4	413,531	5 55	32 81
POLK #1 TOTAL	**250**	**95,319**	**51.2**	**66.6**	**82.2**	**10,964**	**-**	**-**	**-**	**1,045,085.3**	**1,781,713**	**1.87**	**-**
POLK #2 CT (GAS)	150	25,128	22.5	99.4	78 4	11,581	GAS	277,425	972,290	291,019.0	1,978,753	7 87	7 13
POLK #2 CT (OIL)	160	4,538	3.8	99.9	77 0	11,721	LGT.OIL	9,125	5,828,982	53,191.5	299,434	6 60	32.81
POLK #2 TOTAL	**155**	**29,666**	**25.7**	**100.0**	**78.2**	**11,603**	**-**	**-**	**-**	**344,210.5**	**2,278,187**	**7.68**	**-**
POLK #3 CT (GAS)	150	28,436	25.5	94 9	78 2	11,268	GAS	305,461	972,290	320,429 0	2,472,946	8 70	8 10
POLK #3 CT (OIL)	160	2,274	1 9	95 4	96 3	9,494	LGT OIL	3,704	5,828,991	21,588 6	121,530	5 34	32 81
POLK #3 TOTAL	**155**	**30,710**	**26.6**	**95.4**	**79.3**	**11,137**	**-**	**-**	**-**	**342,017.6**	**2,594,476**	**8.45**	**-**
POLK STATION TOTAL	**560**	**155,695**	**37.4**	**83.8**	**57.6**	**11,120**	**-**	**-**	**-**	**1,731,313.4**	**6,654,376**	**4.27**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0 0	0	0 00	0 00
B.B.C.T.#1	12	344	3 9	98 7	104.8	17,360	LGT OIL	1,030	5,800,874	5,972.0	30,657	8 91	29 76
B.B.C.T.#2	66	4,459	9 1	100 0	65.6	16,303	LGT OIL	12,502	5,814,522	72,695.6	372,117	8 35	29 76
B.B C.T #3	66	0	0.0	100 0	0 0	0	LGT.OIL	0	0	0 0	0	0 00	0 00
C.T. TOTAL	**144**	**4,803**	**4.5**	**99.9**	**38.8**	**16,379**	**LGT.OIL**	**13,532**	**5,813,484**	**78,667.6**	**402,774**	**8.39**	**29.76**
CITY OF TAMPA	**6**	**1,680**	**0.0**	**0.0**	**0.0**	**9,716**	**GAS**	**15,560**	**972,290**	**16,322.4**	**106,202**	**6.32**	**6.83**
TOT. COAL (GN,BB,POLK)	**3,062**	**1,480,851**	**65.0**	**72.2**	**77.0**	**11,027**	**COAL**	**698,423**	**23,380,944**	**16,329,768.5**	**30,457,449**	**2.06**	**43.61**
SYSTEM	**3,556**	**1,562,604**	**59.2**	**76.8**	**71.9**	**11,043**	**-**	**-**	**-**	**17,258,272.5**	**36,816,875**	**2.36**	**-**

* Hookers Point boiler limited to 90 MW
** Sale of Hookers Point #6 Oil inventory

LEGEND:
H.P. = HOOKERS POINT
GAN = GANNON
B.B = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

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ACTUAL FOR MONTH OF: JUNE 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	—	—	—	0	HVY OIL	-	0	0 0	0	0 00	0 00
H P.#2	0	0	—	—	—	0	HVY OIL	-	0	0.0	0	0 00	0 00
H P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0 00	0 00
H.P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0.00	0.00
H.P.#5	0	(175)	—	—	—	0	HVY OIL	-	0	0.0	0	0 00	0 00
H.P. STATION *	90	(175)	—	—	—	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	42,306	51.5	70.8	69 0	11,437	COAL	20,366	23,758,000	483,855.4	854,508	2 02	41 96
GAN.#2	98	41,350	58 6	68.5	93.1	11,661	COAL	20,059	24,038,000	482,178 2	841,627	2.04	41 96
GAN.#3	145	17,829	17.1	21.6	76 8	12,697	COAL	12,372	18,298,000	226,382 9	519,099	2 91	41 96
GAN.#4	159	67,869	59.3	73.3	75.6	12,907	COAL	43,919	19,946,000	876,008 4	1,842,736	2 72	41 96
GAN.#5	217	110,417	70.7	81 5	85.6	10,272	COAL	47,836	23,710,000	1,134,191.6	2,007,084	1 82	41 96
GAN.#6	372	171,501	64.0	75 6	81.5	10,342	COAL	74,445	23,824,000	1,773,577.7	3,123,533	1.82	41 96
GANNON STATION	1,105	451,272	56.7	68.2	79.7	11,027	COAL	218,997	22,722,659	4,976,194.2	9,188,587	2.04	41.96
B.B.#1	416	164,010	54.8	63.8	70.2	10,936	COAL	75,140	23,870,040	1,793,594.8	3,356,650	2.05	44 67
B.B.#2	416	188,592	63.0	69 2	66.4	11,157	COAL	88,412	23,799,940	2,104,202.9	3,949,537	2 09	44.67
B B.#3	433	137,274	44.0	51.1	75.3	10,487	COAL	59,195	24,272,520	1,436,807 7	2,644,356	1 93	44 67
B.B. 1 - 3	1,265	489,876	53.8	61.2	70.7	10,890	COAL	222,747	23,949,175	5,334,605.4	9,950,543	2.03	44 67
B.B.#4	442	254,361	79.9	90.8	79.9	10,466	COAL	123,663	21,527,900	2,662,206 2	6,875,514	2 70	55 60
B.B. STATION	1,707	744,237	60.6	68.9	73.1	10,745	COAL	346,410	23,084,817	7,996,811.6	16,826,057	2.26	48.57
SEB-PHIL. #1(HVY OIL)	17	1,785	14.6	53.1	71.1	9,860	HVY.OIL	2,805	6,273,540	17,599 3	86,291	4 83	30.76
SEB-PHIL. #2(HVY OIL)	17	4,600	37.6	96.5	82 9	9,860	HVY OIL	7,229	6,273,540	45,353.9	222,388	4.83	30.76
SEB-PHILLIPS TOTAL	34	6,385	26.1	74.8	77.0	9,860	HVY.OIL	10,034	6,273,540	62,953.2	308,679	4.83	30.76
POLK #1 GASIFIER	250	133,659	74.3	84.2	81.2	11,957	COAL	59,233	26,980,000	1,598,113.4	2,184,329	1 63	36.88
POLK #1 CT (OIL)	225	17,456	10.8	99.3	120.2	7,654	LGT.OIL	22,928	5,827,634	133,612.3	722,948	4.14	31 53
POLK #1 TOTAL	250	151,115	84.0	91.2	84.4	11,460	-	-	-	1,731,725.7	2,907,277	1.92	-
POLK #2 CT (GAS)	150	21,565	20.0	98.8	77.6	11,425	GAS	234,876	972,290	246,385 0	1,257,177	5.83	5 35
POLK #2 CT (OIL)	160	2,787	2 4	98 8	79 2	11,700	LGT OIL	5,595	5,827,528	32,607 0	176,430	6.33	31 53
POLK #2 TOTAL	155	24,352	21.8	98.8	77.7	11,457	-	-	-	278,992.0	1,433,607	5.89	-
POLK #3 CT (GAS)	150	36,541	33.8	98.7	77.6	11,070	GAS	385,597	972,290	404,491.0	2,142,690	5 86	5 56
POLK #3 CT (OIL)	160	1	0.0	98.7	1 2	399,600	LGT OIL	69	5,827,621	399.6	2,182	216.20	31 33
POLK #3 TOTAL	155	36,542	32.7	98.8	77.4	11,080	-	-	-	404,890.6	2,144,852	5.87	-
POLK STATION TOTAL	560	212,009	52.6	95.4	58.5	11,394	-	-	-	2,415,608.3	6,485,736	3.06	-
GAN C T #1	0	0	0 0	0.0	0 0	0	LGT.OIL	0	0	0.0	0	0 00	0 00
B.B.C.T.#1	12	21	0 2	100.0	87.5	18,238	LGT.OIL	66	5,828,641	383.0	1,955	9 31	29 62
B.B.C.T.#2	66	1,681	3.5	97.9	65 3	17,000	LGT.OIL	4,879	5,856,684	28,576 4	144,490	8.60	29.61
B.B.C.T.#3	66	0	0 0	7.6	0.0	0	LGT OIL	75	0	0 0	2,221	0 00	29 61
C.T. TOTAL	144	1,702	1.6	56.7	37.2	17,015	LGT.OIL	5,020	5,768,816	28,959.4	148,666	8.73	29.61
CITY OF TAMPA	6	2,028	0.0	0.0	0.0	10,254	GAS	19,823	972,290	20,794.3	127,437	6.28	6.43
TOT. COAL (GN,BB,POLK)	3,062	1,329,168	60.3	69.9	76.1	10,963	COAL	624,640	23,327,217	14,571,119.2	28,198,973	2.12	45.14
SYSTEM	3,556	1,417,458	55.5	72.4	71.4	10,935	-	-	-	15,501,321.0	33,085,162	2.33	-

* Hookers Point boiler limited to 90 MW

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JULY 2002

SCHEDULE A4
PAGE 1 OF 1

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H P.#1	0	0	—	—	—	0	HVY OIL	-	0	0.0	0	0 00	0.00
H.P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0 00	0.00
H.P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0.00	0.00
H.P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	-178	—	—	—	0	HVY.OIL	-	0	0 0	0	0.00	0 00
H.P. STATION *	90	-178	—	—	—	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	53,279	62.8	88 0	88.5	12,972	COAL	28,926	23,894,000	691,157 8	1,214,260	2.28	41.98
GAN.#2	98	48,092	66.0	78.3	81.6	13,675	COAL	28,006	23,482,000	657,636 9	1,175,641	2 44	41.98
GAN.#3	145	83,695	77.6	73.2	77.6	12,842	COAL	56,320	19,084,000	1,074,810.9	2,364,210	2.82	41.98
GAN.#4	159	75,796	64.1	82.3	70.0	13,625	COAL	55,026	18,768,000	1,032,728.0	2,309,891	3.05	41.98
GAN.#5	217	94,666	58.6	74.1	78.5	11,648	COAL	46,481	23,728,000	1,102,901.2	1,951,187	2.06	41.98
GAN.#6	372	154,914	56.0	65.0	81.6	11,343	COAL	73,356	23,954,000	1,757,169 6	3,079,350	1 99	41.98
GANNON STATION	1,105	510,464	62.1	76.5	77.4	12,374	COAL	288,115	21,923,206	6,316,404.4	12,094,539	2.37	41.98
B.B.#1	416	218,014	70.4	80.9	77.7	10,850	COAL	96,666	24,469,160	2,365,349.0	4,215,299	1.93	43.61
B.B.#2	416	190,833	61.7	67.1	78.0	10,612	COAL	82,611	24,515,080	2,025,209 6	3,600,362	1.89	43 56
B.B.#3	433	112,095	34.8	40.0	72.6	10,606	COAL	48,211	24,660,020	1,188,876.1	2,102,691	1.88	43.61
B.B. 1 - 3	1,265	520,942	55.4	62.4	76.0	10,710	COAL	227,487	24,526,284	5,579,434.7	9,918,352	1.90	43.60
B.B.#4	442	258,189	78.5	89.3	78.7	10,602	COAL	125,167	21,868,830	2,737,261.5	6,534,767	2.53	52.21
B.B. STATION	1,707	779,131	61.3	69.4	76.7	10,674	COAL	352,654	23,583,078	8,316,696.2	16,453,119	2.11	46.66
SEB-PHIL. #1(HVY OIL)	17	5,068	40.1	99.6	90.9	9,665	HVY.OIL	7,808	6,273,540	48,961.6	241,517	4.77	30 93
SEB-PHIL. #2(HVY OIL)	17	5,074	40.1	99.6	91.1	9,665	HVY.OIL	7,817	6,273,540	49,039.6	241,795	4.77	30.93
SEB-PHILLIPS TOTAL	34	10,142	40.1	99.6	91.0	9,665	HVY.OIL	15,625	6,273,540	98,021.2	483,312	4.77	30.93
POLK #1 GASIFIER	250	130,133	70.0	74.1	83.4	11,695	COAL	56,782	26,802,000	1,521,854 8	2,171,885	1.67	38.25
POLK #1 CT (OIL)	225	10,534	6.3	99.1	70.1	8,089	LGT.OIL	14,640	5,835,965	85,205.9	461,880	4 38	31.55
POLK #1 TOTAL	250	140,667	75.6	87.7	82.2	11,425	-	-	-	1,607,060.7	2,633,765	1.87	-
POLK #2 CT (GAS)	150	20,535	18.4	99.7	78.8	12,223	GAS	237,468	972,290	251,004.0	1,945,831	9 48	6 19
POLK #2 CT (OIL)	160	1,883	1.6	99.7	70.5	13,290	LGT.OIL	4,288	5,835,974	25,026.0	135,285	7.18	31.55
POLK #2 TOTAL	155	22,418	19.4	99.7	78.0	12,313	-	-	-	276,030.0	2,081,116	9.28	-
POLK #3 CT (GAS)	150	27,467	24.6	99.8	76.5	11,131	GAS	289,256	972,290	305,743 0	1,705,983	6.21	5.90
POLK #3 CT (OIL)	160	0	0.0	99.8	0.0	0	LGT.OIL	0	0	0.0	0	0 00	0.00
POLK #3 TOTAL	155	27,467	23.8	99.8	76.5	11,131	-	-	-	305,743.0	1,705,983	6.21	-
POLK STATION TOTAL	560	190,552	45.7	94.4	57.6	11,487	-	-	-	2,188,833.7	6,420,864	3.37	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0 00	0.00
B.B.C.T.#1	12	48	0.5	100.0	100.0	18,038	LGT.OIL	149	5,827,556	865.8	4,421	9.21	29 67
B.B.C.T.#2	66	2,318	4.7	100.0	65.0	16,456	LGT.OIL	6,588	5,807,716	38,145.6	194,874	8 41	29.57
B.B.C.T.#3	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	144	2,366	2.2	54.2	38.1	16,488	LGT.OIL	6,717	5,808,155	39,011.4	199,295	8.42	29.67
CITY OF TAMPA	6	3,086	0.0	0.0	0.0	6,663	GAS	19,452	972,290	20,560.8	145,524	4.72	7.48
TOT. COAL (GN,BB,POLK)	3,062	1,419,728	62.3	72.3	77.5	11,379	COAL	697,552	23,159,512	16,154,955.4	30,719,543	2.16	44.04
SYSTEM	3,556	1,496,563	56.6	75.2	72.5	11,352	-	-	-	16,979,527.7	35,796,653	2.39	-

* Hookers Point boiler limited to 90 MW

LEGEND.
H.P. = HOOKERS POINT
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
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ACTUAL FOR MONTH OF: AUGUST 2002

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP-ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
H.P.#1	0	0	—	—	—	0	HVY OIL	-	0	0 0	0	0 00	0 00
H.P.#2	0	0	—	—	—	0	HVY OIL	-	0	0 0	0	0 00	0 00
H.P #3	0	0	—	—	—	0	HVY OIL	-	0	0 0	0	0 00	0 00
H.P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P #5	0	-171	—	—	—	0	HVY OIL	-	0	0 0	0	0 00	0 00
H.P. STATION	* 90	-171	—	—	—	0	HVY OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	44,015	51.9	79 2	61 1	12,810	COAL	24,297	23,206,320	563,844 0	935,610	2 13	38 51
GAN #2	98	44,741	61.4	75 3	78 4	13,021	COAL	25,372	22,960,360	582,550 3	977,005	2 18	38 51
GAN.#3	145	64,750	60 0	78 0	69 2	12,728	COAL	45,797	17,995,780	824,152 7	1,763,515	2 72	38 51
GAN #4	159	67,872	57 4	71.6	71 8	12,893	COAL	47,448	18,443,360	875,100 5	1,827,091	2 69	38 51
GAN.#5	217	122,031	75.6	95 4	75 6	11,312	COAL	59,355	23,256,380	1,380,382 4	2,285,596	1 87	38 51
GAN.#6	372	179,658	64 9	79 0	77.1	10,994	COAL	84,060	23,497,260	1,975,179 7	3,236,917	1 80	38 51
GANNON STATION	1,105	523,067	63.6	80.7	73.5	11,855	COAL	286,329	21,657,637	6,201,209 6	11,025,734	2.11	38 51
B.B.#1	416	156,729	50.6	58 4	73 5	11,291	COAL	72,873	24,282,820	1,769,552 0	3,413,102	2 18	46 84
B.B #2	416	210,930	68 2	73 2	75 6	11,201	COAL	97,276	24,286,880	2,362,532 0	4,556,049	2 16	46 84
B.B.#3	433	147,523	45.6	55.5	74 8	10,841	COAL	65,412	24,449,000	1,599,266 5	3,063,657	2 08	46 84
B.B 1 - 3	1,265	515,182	54.7	62 3	74 6	11,125	COAL	235,561	24,330,643	5,731,350 5	11,032,808	2 14	46 84
B B.#4	442	248,022	75.4	87.2	75 4	10,948	COAL	125,413	21,651,984	2,715,442 7	6,265,540	2 53	49 96
B.B. STATION	1,707	763,204	60.1	68.7	74.8	11,068	COAL	360,974	23,399,997	8,446,793.2	17,298,348	2.27	47.92
SEB-PHIL. #1(HVY OIL)	17	5,647	44.6	100 0	91 2	9,615	HVY OIL	8,654	6,273,540	54,293 6	264,651	4 69	30 58
SEB-PHIL. #2(HVY OIL)	17	5,681	44.9	99 9	91 2	9,615	HVY OIL	8,706	6,273,540	54,620 5	266,241	4 69	30.58
SEB-PHILLIPS TOTAL	34	11,328	44.8	100.0	91.2	9,615	HVY.OIL	17,360	6,273,540	108,914.1	530,892	4.69	30.58
POLK #1 GASIFIER	250	149,858	80 6	85 6	90.8	10,815	COAL	62,074	26,110,000	1,620,757 4	2,394,851	1 60	38 58
POLK #1 CT (OIL)	225	4,726	2 8	98 5	58 0	9,185	LGT OIL	8,107	5,823,622	43,409 8	252,886	5 35	31 19
POLK #1 TOTAL	250	154,584	83.1	94.4	89.2	10,765	-	-	-	1,664,167.2	2,647,737	1.71	-
POLK #2 CT (GAS)	150	14,533	13 0	100 0	77 0	11,118	GAS	152,717	972,290	161,574 0	683,602	4 70	4 48
POLK #2 CT (OIL)	160	-5	0 0	100 0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
POLK #2 TOTAL	155	14,528	12.6	100.0	76.6	11,122	-	-	-	161,574.0	683,602	4.71	-
POLK #3 CT (GAS)	150	37,062	33.2	99 7	76.6	11,914	GAS	417,341	972,290	441,547 0	2,540,661	6 86	6 09
POLK #3 CT (OIL)	160	28	0 0	99.7	22.8	51,557	LGT OIL	248	5,823,786	1,443 6	7,733	27 62	31 18
POLK #3 TOTAL	155	37,090	32.2	99.7	76.4	11,944	-	-	-	442,990.6	2,548,394	6 87	-
POLK STATION TOTAL	560	206,202	49.5	97.4	80.3	11,002	-	-	-	2,268,731.8	5,879,733	2.85	-
GAN.C.T.#1	0	0	0 0	0.0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
B B.C.T.#1	12	0	0.0	100 0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
B.B.C.T #2	66	1,697	3 5	100.0	71.4	16,038	LGT.OIL	4,649	5,853,890	27,216 9	138,518	8 16	29 80
B.B C.T.#3	66	0	0.0	0.0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
C.T. TOTAL	144	1,697	1.6	54.2	32.7	16,038	LGT.OIL	4,649	5,853,890	27,216.9	138,518	8.16	29 80
CITY OF TAMPA	6	2,077	0.0	0.0	0.0	10,368	GAS	20,353	972,290	21,533.5	29,071	1.40	1.43
TOT. COAL (GN,BB,POLK)	3,062	1,436,129	63.0	74.4	75.6	11,328	COAL	709,377	22,933,860	16,268,760.2	30,718,933	2.14	43.30
SYSTEM	3,556	1,507,404	57.1	76.7	70.6	11,326	-	-	-	17,074,399.1	34,902,296	2.32	-

* Hookers Point limited to 90 MW

LEGEND

H P = HOOKERS POINT
GAN = GANNON
B B = BIG BEND
C T = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: SEPTEMBER 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H P.#1	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0 00	0 00
H P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0.00	0 00
H P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H P #5	0	-165	—	—	—	0	HVY OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	90	-165	—	—	—	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	40,940	49.9	64 3	74 2	12,129	COAL	22,289	22,278,000	496,554.3	873,246	2 13	39 18
GAN #2	98	39,108	55 4	62.5	79 4	12,402	COAL	21,371	22,696,000	485,036 2	837,280	2 14	39.18
GAN #3	145	65,992	63 2	72.2	78.7	12,417	COAL	41,483	19,754,000	819,455 2	1,625,235	2.46	39 18
GAN #4	159	61,896	54.1	65 7	75.6	13,660	COAL	41,400	20,422,000	845,470 8	1,621,983	2 62	39 18
GAN #5	217	89,300	57.2	71 6	74 1	11,961	COAL	45,420	23,516,000	1,068,096 7	1,779,480	1 99	39 18
GAN.#6	372	176,356	66 6	79 5	75 3	10,910	COAL	82,742	23,518,000	1,945,926.4	3,241,695	1 82	39 18
GANNON STATION	1,105	475,592	59.8	71.9	75.8	11,902	COAL	254,705	22,223,905	5,660,539.6	9,978,919	2.10	39.18
B B.#1	416	225,793	75 4	84 3	75.4	11,295	COAL	103,307	24,687,000	2,550,346 8	4,722,152	2 09	45 71
B B #2	416	166,375	55 5	59.9	67.9	11,278	COAL	76,415	24,555,720	1,876,416 5	3,492,922	2 10	45 71
B B.#3	433	194,783	62 5	71.4	71.9	10,722	COAL	86,478	24,150,420	2,088,489.9	3,952,900	2.03	45 71
B.B. 1 - 3	1,265	586,951	64.4	71.8	71 7	11,100	COAL	266,200	24,475,001	6,515,255 2	12,167,974	2 07	45 71
B.B.#4	442	55,348	17 4	22 6	68 7	12,043	COAL	29,315	22,737,953	666,552.4	1,594,959	2 88	54.41
B.B. STATION	1,707	642,299	52.3	59.1	70.9	11,181	COAL	295,515	24,302,689	7,181,807.6	13,762,933	2.14	46.57
SEB-PHIL. #1(HVY OIL)	17	5,581	45 6	94.6	91.3	9,662	HVY.OIL	8,595	6,273,540	53,922 1	265,345	4 75	30 87
SEB-PHIL #2(HVY OIL)	17	5,729	46.8	100 0	90 0	9,662	HVY.OIL	8,823	6,273,540	55,352 0	272,383	4.75	30 87
SEB-PHILLIPS TOTAL	34	11,310	46.2	97.3	90.6	9,662	HVY.OIL	17,418	6,273,540	109,274.1	537,728	4.75	30.87
POLK #1 GASIFIER	250	120,941	67 2	73 3	84 8	11,150	COAL	51,757	26,054,000	1,348,488 3	2,140,978	1 77	41 37
POLK #1 CT (OIL)	225	11,202	6.9	97.5	74.7	8,312	LGT.OIL	16,562	5,810,967	93,107.9	536,443	4 79	32 39
POLK #1 TOTAL	250	132,143	73.4	89.7	83.8	10,909	-	-	-	1,441,576.2	2,677,421	2.03	-
POLK #2 CT (GAS)	150	23,776	22 0	99 7	98.3	11,164	GAS	252,314	972,290	265,434 0	1,865,614	7 85	7 39
POLK #2 CT (OIL)	160	617	0 5	98 9	48 2	15,412	LGT OIL	1,636	5,810,942	9,509 2	53,009	8 59	32 40
POLK #2 TOTAL	155	24,393	21.9	100.0	95.8	11,271	-	-	-	274,943.2	1,918,623	7.87	-
POLK #3 CT (GAS)	150	49,434	45 8	100 0	78 4	11,726	GAS	551,107	972,290	579,765 0	2,867,793	5 80	5 20
POLK #3 CT (OIL)	160	0	0.0	100 0	0 0	0	LGT OIL	0	0	0.0	0	0 00	0 00
POLK #3 TOTAL	155	49,434	44.3	100.0	78.4	11,726	-	-	-	579,765.0	2,867,793	5.80	-
POLK STATION TOTAL	560	205,970	51.1	95.4	63.1	11,149	-	-	-	2,296,284.4	7,463,837	3.62	-
GAN C T.#1	0	0	0 0	0 0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
B B C.T.#1	12	48	0 6	100.0	100 0	18,704	LGT OIL	153	5,855,345	897 8	4,610	9 60	30 13
B B C.T.#2	66	1,121	2 4	32 9	70 8	15,047	LGT OIL	2,881	5,853,913	16,867 7	86,807	7 74	30 13
B B.C.T.#3	66	0	0 0	0 0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
C.T. TOTAL	144	1,169	1.1	23.4	40.8	15,197	LGT.OIL	3,034	5,853,986	17,765.5	91,417	7.82	30.13
CITY OF TAMPA	6	1,875	0.0	0.0	0.0	10,386	GAS	18,511	972,290	19,473.6	115,203	6.14	6.22
TOT. COAL (GN,BB,POLK)	3,062	1,238,832	56.2	64.9	73.8	11,455	COAL	601,977	23,573,699	14,190,815.5	25,882,830	2.09	43.00
SYSTEM	3,556	1,338,050	52.4	67.7	70.2	11,422	-	-	-	15,285,144.8	31,950,037	2.39	-

* Hookers Point limited to 90 MW

LEGEND

H P. = HOOKERS POINT
GAN = GANNON
B B = BIG BEND
C T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: OCTOBER 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	—	—	—	0	HVY OIL	-	0	0 0	0	0 00	0 00
H.P.#2	0	0	—	—	—	0	HVY OIL	-	0	0 0	0	0 00	0 00
H.P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0.00	0.00
H.P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P.#5	0	-158	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0.00
H.P. STATION *	90	-158	—	—	—	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	51,079	60.1	76.9	73.6	11,437	COAL	26,562	21,994,000	584,204 6	1,029,632	2.02	38.76
GAN.#2	98	52,415	71.8	83.7	80.2	12,566	COAL	29,231	22,532,000	658,632 9	1,133,092	2 16	38.76
GAN.#3	145	57,911	53.6	74.5	64.0	13,308	COAL	39,499	19,512,000	770,704.5	1,531,114	2 64	38 76
GAN.#4	159	60,861	51.4	69.1	66.1	14,136	COAL	42,460	20,262,000	860,324.5	1,645,892	2 70	38.76
GAN.#5	217	83,099	51.4	67.0	73.8	11,430	COAL	40,900	23,224,000	949,861.6	1,585,422	1.91	38.76
GAN.#6	372	39,227	14.2	17 8	73.6	10,861	COAL	18,115	23,518,000	426,028 6	702,198	1 79	38.76
GANNON STATION	1,105	344,592	41.9	54.2	71.9	12,333	COAL	196,767	21,597,914	4,249,756.7	7,627,350	2.21	38.76
B.B.#1	416	189,295	61.1	69.2	72.4	11,445	COAL	87,465	24,769,480	2,166,458 9	3,855,150	2.04	44.08
B.B.#2	416	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
B.B.#3	433	251,706	78.0	89.8	76.4	10,877	COAL	111,012	24,661,860	2,737,765 6	4,893,020	1 94	44.08
B.B. 1 - 3	1,265	441,003	46.8	53.5	50.7	11,121	COAL	198,477	24,709,286	4,904,224 5	8,748,170	1.98	44.08
B.B.#4	442	227,995	69.2	77.3	73.0	11,088	COAL	111,893	22,593,607	2,528,077.3	5,658,353	2 48	50.57
B.B. STATION	1,707	668,998	52.6	59.6	56.4	11,110	COAL	310,370	23,946,550	7,432,301.8	14,406,523	2.15	46.42
SEB-PHIL. #1(HVY OIL)	17	6,020	47.5	99.9	92.7	9,575	HVY.OIL	9,188	6,273,540	57,642.3	300,633	4.99	32 72
SEB-PHIL. #2(HVY OIL)	17	6,041	47.7	100.0	93.4	9,575	HVY.OIL	9,220	6,273,540	57,843.4	301,681	4 99	32 72
SEB-PHILLIPS TOTAL	34	12,061	47.6	99.9	93.0	9,575	HVY.OIL	18,408	6,273,540	115,485.7	602,314	4.99	32.72
POLK #1 GASIFIER	250	172,687	92.7	95.7	93.4	10,490	COAL	68,834	26,316,000	1,811,427.6	2,707,430	1.57	39.33
POLK #1 CT (OIL)	225	1,355	0.8	100.0	86.9	7,459	LGT.OIL	1,738	5,818,715	10,106.6	59,746	4.41	34.39
POLK #1 TOTAL	250	174,042	93.4	96.4	93.4	10,486	-	-	-	1,821,534.2	2,767,176	1.59	-
POLK #2 CT (GAS)	150	32,915	29.5	91.6	79.6	10,136	GAS	317,741	972,290	333,628.0	1,540,681	4.68	4.85
POLK #2 CT (OIL)	160	1,214	1.0	92.7	65.4	12,552	LGT.OIL	2,620	5,818,710	15,238.5	90,085	7.42	34.38
POLK #2 TOTAL	155	34,129	29.6	93.1	79.0	10,222	-	-	-	348,866.5	1,630,766	4.78	-
POLK #3 CT (GAS)	150	42,567	38.1	95.0	82.1	12,847	GAS	520,809	972,290	546,849 0	3,222,625	7 57	6.19
POLK #3 CT (OIL)	160	0	0.0	94.7	0.0	0	LGT.OIL	0	0	0 0	0	0.00	0 00
POLK #3 TOTAL	155	42,567	36.9	95.0	82.1	12,847	-	-	-	546,849.0	3,222,625	7.57	-
POLK STATION TOTAL	560	250,738	60.1	95.1	82.9	10,837	-	-	-	2,717,249.7	7,620,567	3.04	-
GAN.C.T.#1	0	0	0.0	0 0	0.0	0	LGT OIL	0	0	0 0	0	0.00	0.00
B.B.C.T.#1	12	345	3.9	100.0	102.7	18,201	LGT OIL	1,072	5,855,496	6,279 2	32,959	9 55	30.75
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0 00	0 00
B.B.C.T.#3	66	0	0 0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0 00	0.00
C.T. TOTAL	144	345	0.3	8.3	8.6	18,201	LGT.OIL	1,072	5,855,496	6,279.2	32,959	9.55	30.75
CITY OF TAMPA	6	196	0.0	0.0	0.0	10,077	GAS	1,881	972,290	1,975.1	12,875	6.57	6.84
TOT. COAL (GN,BB,POLK)	3,062	1,186,277	52.0	60.6	65.0	11,375	COAL	575,971	23,427,364	13,493,486.1	24,741,303	2.09	42.96
SYSTEM	3,556	1,276,772	48.3	61.9	60.7	11,373	-	-	-	14,523,048.2	30,302,588	2.37	-

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
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ACTUAL FOR MONTH OF: NOVEMBER 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P #1	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H P.#4	0	0	—	—	—	0	HVY OIL	-	0	0 0	0	0 00	0 00
H.P.#5	0	-138	—	—	—	0	HVY.OIL	-	0	0 0	0	0 00	0 00
H.P. STATION *	90	-138	—	—	—	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	36,494	44 5	40 7	62 6	12,471	COAL	19,033	23,912,000	455,117 1	677,183	1 86	35 58
GAN.#2	98	37,407	53 0	65 6	73.8	12,261	COAL	19,226	23,856,000	458,655 5	684,050	1 83	35 58
GAN.#3	145	23,448	22.5	30 0	67.6	11,619	COAL	11,655	23,376,000	272,447.3	414,678	1 77	35 58
GAN.#4	159	55,035	48 1	64 8	69 5	12,743	COAL	33,224	21,108,000	701,292 2	1,182,090	2 15	35 58
GAN #5	217	102,738	65 8	85 7	68 5	11,248	COAL	48,751	23,704,000	1,155,593 7	1,734,532	1 69	35 58
GAN #6	372	0	0.0	0 0	0 0	0	COAL	0	0	0 0	0	0 00	0 00
GANNON STATION	1,105	255,122	32.1	40,1	45.3	11,926	COAL	131,889	23,073,234	3,043,105.8	4,692,533	1.84	35.58
B.B #1	416	172,711	57.7	64 7	75.1	10,717	COAL	77,521	23,876,360	1,850,923 8	3,447,151	2 00	44 47
B.B #2	416	0	0 0	0 0	0 0	0	COAL	0	0	0 0	0	0 00	0 00
B B.#3	433	190,457	61.1	71 5	75 1	10,860	COAL	85,201	24,276,760	2,068,395 5	3,788,661	1 99	44 47
B.B. 1 - 3	1,265	363,168	39.9	45.7	50 4	10,792	COAL	162,722	24,066,008	3,919,319 3	7,235,812	1 99	44 47
B.B.#4	442	226,376	71.1	82 1	61.6	10,499	COAL	104,984	22,638,310	2,376,664 6	5,174,965	2.29	49 29
B.B. STATION	1,707	589,544	48.0	55.1	58.5	10,679	COAL	267,706	23,518,275	6,295,983.9	12,410,777	2.11	46.36
SEB-PHIL. #1(HVY OIL)	17	3,466	28 3	100 0	90 1	9,786	HVY OIL	5,407	6,273,540	33,918 9	188,946	5 45	34 94
SEB-PHIL. #2(HVY OIL)	17	3,432	28 0	100 0	89 8	9,786	HVY OIL	5,354	6,273,540	33,586 2	187,093	5 45	34 94
SEB-PHILLIPS TOTAL	34	6,898	28.2	100.0	90.0	9,786	HVY.OIL	10,761	6,273,540	67,505.1	376,039	5.45	34.94
POLK #1 GASIFIER	250	155,707	86.5	92 5	92 0	10,713	COAL	62,836	26,546,000	1,668,049 0	2,532,618	1 63	40 31
POLK #1 CT (OIL)	225	5,285	3.3	99 8	77.8	8,892	LGT.OIL	8,061	5,815,034	46,992 8	276,821	5 24	34 25
POLK #1 TOTAL	250	160,992	89.4	97.5	91.4	10,653	-	-	-	1,715,041.8	2,809,439	1.75	-
POLK #2 CT (GAS)	150	5,566	5 2	100 0	77.2	9,685	GAS	51,342	972,290	53,909 0	1,153,438	20 72	22 47
POLK #2 CT (OIL)	160	0	0 0	100 0	0 0	0	LGT.OIL	0	0	0 0	0	0 00	0 00
POLK #2 TOTAL	155	5,566	5.0	100.0	77.2	9,685	-	-	-	53,909.0	1,153,438	20.72	-
POLK #3 CT (GAS)	150	5,498	5.1	100.0	75 0	14,072	GAS	73,685	972,290	77,369 0	913,775	16 62	12 40
POLK #3 CT (OIL)	160	0	0 0	100 0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
POLK #3 TOTAL	155	5,498	4.9	100.0	75.0	14,072	-	-	-	77,369.0	913,775	16.62	-
POLK STATION TOTAL	560	172,056	42.7	98.9	61.5	10,731	-	-	-	1,846,319.8	4,876,652	2.83	-
GAN.C.T.#1	0	0	0 0	0 0	0 0	0	LGT.OIL	0	0	0 0	0	0 00	0 00
B.B C.T #1	12	14	0.2	100 0	116 7	18,721	LGT.OIL	45	5,855,675	262 1	1,376	9 83	30 58
B.B.C.T.#2	66	0	0 0	0 0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
B.B.C.T #3	66	0	0 0	0.0	0 0	0	LGT.OIL	0	0	0 0	0	0 00	0 00
C.T. TOTAL	144	14	0.0	8.3	9.7	18,721	LGT.OIL	45	5,855,675	262.1	1,376	9.83	30.58
CITY OF TAMPA	8	0	0.0	0.0	0.0	0	GAS	0	0	0.0	-1,720	0.00	0.00
TOT. COAL (GN,BB,POLK)	3,062	1,000,373	45.4	52.8	56.5	11,003	COAL	462,431	23,802,760	11,007,138.7	19,635,928	1.96	42.46
SYSTEM	3,556	1,023,496	40.0	55.9	53.2	10,993	-	-	-	11,253,176.7	22,355,657	2.18	-

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
GAN. = GANNON
B.B = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: DECEMBER 2002

(A) PLANT/UNIT	(B) NET CAP- ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	41	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-135	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	90	-135	—	—	—	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	27,043	31.9	43.1	50.2	12,302	COAL	14,180	23,462,000	332,691.2	564,926	2.09	39.84
GAN.#2	98	24,878	33.8	37.4	63.8	12,641	COAL	13,237	23,566,000	311,943.1	527,357	2.14	39.84
GAN.#3	155	39,051	33.8	51.9	62.1	13,446	COAL	22,956	22,874,000	525,095.5	914,559	2.34	39.84
GAN.#4	159	51,249	43.3	61.9	65.6	11,880	COAL	26,766	22,746,000	606,819.4	1,066,347	2.08	39.84
GAN.#5	217	99,138	61.4	86.2	65.0	11,484	COAL	46,136	23,652,000	1,138,512.7	1,917,720	1.93	39.84
GAN.#6	392	57,508	19.7	33.1	48.2	13,567	COAL	33,130	23,550,000	780,211.5	1,319,887	2.30	39.84
GANNON STATION	1,135	298,867	35.4	51.2	56.8	12,379	COAL	158,405	23,340,636	3,697,273.4	6,310,796	2.11	39.84
B.B.#1	426	223,156	70.4	82.1	70.4	10,369	COAL	102,004	22,685,220	2,313,981.6	4,409,582	1.98	43.23
B.B.#2	426	48,051	15.2	16.4	58.3	10,765	COAL	21,657	23,886,000	517,292.7	936,221	1.95	43.23
B.B.#3	433	217,841	67.6	82.9	67.6	10,042	COAL	97,929	22,338,660	2,187,612.2	4,233,421	1.94	43.23
B.B. 1 - 3	1,285	489,048	51.2	60.6	65.4	10,263	COAL	221,590	22,649,418	5,018,886.5	9,579,224	1.96	43.23
B.B.#4	447	249,537	75.0	87.4	79.2	10,213	COAL	120,473	21,154,775	2,548,587.9	6,319,493	2.53	52.46
B.B. STATION	1,732	738,585	57.3	67.5	69.0	10,246	COAL	342,063	22,123,010	7,567,474.4	15,898,717	2.15	46.48
SEB-PHIL. #1(HVY OIL)	17	2,302	18.2	100.0	89.2	9,649	HVY.OIL	3,540	6,273,540	22,211.9	117,535	5.11	33.20
SEB-PHIL. #2(HVY OIL)	17	2,306	18.2	98.9	88.6	9,649	HVY.OIL	3,547	6,273,540	22,250.5	117,767	5.11	33.20
SEB-PHILLIPS TOTAL	34	4,608	18.2	99.5	88.9	9,649	HVY.OIL	7,087	6,273,540	44,462.4	235,302	5.11	33.20
POLK #1 GASIFIER	250	120,118	64.6	72.1	88.3	11,018	COAL	50,026	26,456,000	1,323,496.1	2,057,525	1.71	41.13
POLK #1 CT (OIL)	245	9,331	5.1	92.6	65.0	9,079	LGT.OIL	14,898	5,813,937	84,712.2	512,763	5.50	34.42
POLK #1 TOTAL	250	129,449	69.6	91.1	88.0	10,878	-	-	-	1,408,208.3	2,570,288	1.98	-
POLK #2 CT (GAS)	160	2,265	1.9	100.0	75.9	11,876	GAS	25,546	972,290	26,900.0	510,385	22.53	19.98
POLK #2 CT (OIL)	180	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	170	2,265	1.8	100.0	75.9	11,876	-	-	-	26,900.0	510,385	22.53	-
POLK #3 CT (GAS)	160	3,807	3.2	99.1	72.8	12,022	GAS	43,463	972,290	45,766.0	906,879	23.82	20.87
POLK #3 CT (OIL)	180	0	0.0	99.1	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	170	3,807	3.0	99.1	72.8	12,022	-	-	-	45,766.0	906,879	23.82	-
POLK STATION TOTAL	590	135,521	30.9	96.0	57.0	10,927	-	-	-	1,480,874.3	3,987,552	2.94	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	17	29	0.2	100.0	85.3	11,707	LGT.OIL	58	5,844,379	339.5	1,809	6.24	31.19
B.B.C.T.#2	80	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	80	116	0.2	0.0	29.0	9,212	LGT.OIL	183	5,854,701	1,068.6	5,707	4.92	31.19
C.T. TOTAL	177	145	0.1	9.6	21.3	9,711	LGT.OIL	241	5,852,209	1,408.1	7,516	5.18	31.19
CITY OF TAMPA	6	0	0.0	0.0	0.0	0	GAS	0	972,290	0.0	-123	0.00	0.00
TOT. COAL (GN,BB,POLK)	3,117	1,157,370	49.9	61.9	66.0	10,877	COAL	550,494	22,867,144	12,588,243.9	24,267,038	2.10	44.08
SYSTEM	3,674	1,177,391	43.1	64.8	61.1	10,863	-	-	-	12,791,492.6	26,439,760	2.25	-

* Hookers Point limited to 90 MW

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JANUARY 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	2,747	0.00	0.00
GAN.#1	114	41,855	49.3	72.0	54.8	11,939	COAL	21,187	23,586,000	499,716.6	969,287	2.32	45.75
GAN.#2	98	41,051	56.3	75.4	73.6	12,189	COAL	21,052	23,768,000	500,363.9	963,110	2.35	45.75
GAN.#3	155	55,931	48.5	70.5	61.8	12,123	COAL	28,827	23,522,000	678,068.7	1,318,810	2.36	45.75
GAN.#4	159	55,826	47.2	72.0	59.5	13,780	COAL	36,444	21,108,000	769,260.0	1,867,281	2.99	45.75
GAN.#5	217	73,740	45.7	78.4	51.6	11,425	COAL	35,990	23,408,000	842,453.9	1,646,511	2.23	45.75
GAN.#6	372	152,841	55.2	74.2	62.0	11,438	COAL	73,691	23,692,000	1,745,887.2	3,371,298	2.21	45.75
GANNON STATION	1,115	421,044	50.8	74.1	59.9	11,960	COAL	217,191	23,185,815	5,035,750.3	9,836,297	2.36	45.75
B.B.#1	426	194,245	61.3	71.4	69.1	10,994	COAL	89,811	23,778,960	2,135,613.6	4,174,814	2.15	46.48
B.B.#2	426	123,813	39.1	43.3	77.0	10,567	COAL	54,770	23,887,900	1,308,334.3	2,545,953	2.06	46.48
B.B.#3	433	214,627	66.6	78.6	74.8	10,735	COAL	96,662	23,835,560	2,303,996.0	4,493,279	2.09	46.48
B.B.#4	447	221,664	66.7	77.9	77.4	10,373	COAL	106,491	21,590,760	2,299,230.5	4,950,175	2.23	46.48
B.B. STATION	1,732	754,349	58.5	68.0	74.6	10,668	COAL	347,734	23,141,730	8,047,174.4	16,164,221	2.14	46.48
SEB-PHIL. #1(HVY OIL)	17	4,437	35.1	100.0	90.3	9,537	HVY.OIL	6,745	6,273,540	42,316.4	238,644	5.38	35.38
SEB-PHIL. #2(HVY OIL)	17	4,280	33.8	98.1	90.7	9,537	HVY.OIL	6,507	6,273,540	40,819.0	230,223	5.38	35.38
SEB-PHILLIPS TOTAL	34	8,717	34.5	99.0	90.5	9,537	HVY.OIL	13,252	6,273,541	83,135.4	468,867	5.38	35.38
POLK #1 GASIFIER	250	119,476	64.2	70.6	87.5	11,572	COAL	50,701	27,268,000	1,382,517.0	2,184,614	1.83	43.09
POLK #1 CT (OIL)	245	27,801	15.3	98.9	59.3	8,441	LGT.OIL	40,372	5,812,417	234,662.4	1,488,323	5.35	36.87
POLK #1 TOTAL	250	147,277	79.2	95.6	80.3	10,981	-	-	-	1,617,179.4	3,672,937	2.49	-
POLK #2 CT (GAS)	165	8,066	6.6	100.0	64.8	11,676	GAS	88,516	972,290	94,181.0	1,181,522	14.65	13.35
POLK #2 CT (OIL)	175	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	170	8,066	6.4	100.0	64.8	11,676	-	-	-	94,181.0	1,181,522	14.65	-
POLK #3 CT (GAS)	165	1,794	1.5	100.0	59.1	15,357	GAS	25,893	972,290	27,550.0	185,273	10.33	7.16
POLK #3 CT (OIL)	175	2,732	2.1	100.0	59.7	15,346	LGT.OIL	7,213	5,812,415	41,924.6	265,903	9.73	36.86
POLK #3 TOTAL	170	4,526	3.6	100.0	59.5	15,350	-	-	-	69,474.6	451,176	9.97	-
POLK STATION TOTAL	590	159,869	36.4	98.1	52.2	11,139	-	-	-	1,780,835.0	5,305,635	3.32	-
B.B.C.T.#1	17	19	0.2	100.0	59.1	5,358	LGT.OIL	18	5,777,526	101.8	0	0.00	0.00
B.B.C.T.#2	80	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	39	0.1	100.0	31.7	6,710	LGT.OIL	45	5,769,400	261.7	0	0.00	0.00
C.T. TOTAL	157	58	0.0	49.0	18.5	6,267	LGT.OIL	63	5,771,674	363.5	-	0.00	0.00
CITY OF TAMPA	6	356	0.0	0.0	0.0	10,024	GAS	3,354	972,290	3,568.7	148	0.04	0.04
TOT. COAL (GN,BB,POLK)	3,097	1,294,869	56.2	70.4	70.3	11,171	COAL	615,626	23,497,110	14,465,441.7	28,285,132	2.18	45.95
SYSTEM	3,634	1,344,393	49.7	74.2	64.1	11,121	-	-	-	14,950,827.3	31,877,915	2.37	-

LEGEND:
H.P. = HOOKERS POINT
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SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: FEBRUARY 2003

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP-ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	HVY.OIL	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	94	37,272	59.0	78.8	72.6	11,666	COAL	18,256	23,818,000	434,821.4	771,907	2.07	42.28
GAN.#2	100	39,294	58.5	82.7	69.3	12,750	COAL	20,839	24,042,000	501,011.2	881,122	2.24	42.28
GAN.#3	155	44,832	43.0	62.6	65.5	11,709	COAL	21,843	24,032,000	524,931.0	923,574	2.06	42.28
GAN.#4	164	10,685	9.7	14.8	58.5	12,430	COAL	5,710	23,260,000	132,814.6	241,432	2.26	42.28
GAN.#5	0	-226	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	372	128,435	51.4	68.6	69.0	11,195	COAL	60,140	23,908,000	1,437,827.1	2,542,861	1.98	42.28
GANNON STATION	**685**	**260,292**	**43.8**	**60.2**	**66.9**	**11,646**	COAL	**126,788**	**23,909,245**	**3,031,405.3**	**5,360,896**	**2.06**	**42.28**
B.B.#1	428	178,959	62.2	73.9	66.4	10,744	COAL	81,064	23,717,880	1,922,671.2	3,875,139	2.17	47.80
B.B.#2	433	73,719	25.3	30.6	74.0	10,133	COAL	31,100	24,018,560	746,969.8	1,486,688	2.02	47.80
B.B.#3	438	223,190	75.8	92.6	75.8	10,670	COAL	98,908	24,077,580	2,381,481.9	4,728,144	2.12	47.80
B.B.#4	460	197,136	63.8	74.1	75.4	10,593	COAL	93,138	22,421,140	2,088,252.7	4,452,318	2.26	47.80
B.B. STATION	**1,759**	**673,004**	**56.9**	**68.0**	**73.0**	**10,608**	COAL	**304,210**	**23,468,555**	**7,139,355.6**	**14,542,289**	**2.16**	**47.80**
SEB-PHIL. #1(HVY OIL)	17	3,214	28.1	100.0	79.4	9,552	HVY.OIL	4,894	6,273,540	30,698.8	190,856	5.94	39.00
SEB-PHIL. #2(HVY OIL)	17	3,271	28.6	100.0	90.0	9,552	HVY.OIL	4,980	6,273,540	31,243.2	194,210	5.94	39.00
SEB-PHILLIPS TOTAL	**34**	**6,485**	**28.4**	**100.0**	**84.7**	**9,552**	HVY.OIL	**9,874**	**6,273,535**	**61,942.0**	**385,066**	**5.94**	**39.00**
POLK #1 GASIFIER	260	123,062	70.4	77.8	84.4	10,511	COAL	47,412	27,282,000	1,293,503.5	2,107,293	1.71	44.45
POLK #1 CT (OIL)	245	18,357	11.1	98.9	68.4	8,498	LGT.OIL	26,866	5,806,527	155,996.0	1,080,766	5.89	40.23
POLK #1 TOTAL	**260**	**141,419**	**80.9**	**92.4**	**81.9**	**10,250**	-	-	-	**1,449,499.5**	**3,188,059**	**2.25**	-
POLK #2 CT (GAS)	175	1,933	1.6	72.5	72.4	12,198	GAS	22,265	972,290	23,579.0	1,158,954	59.96	52.05
POLK #2 CT (OIL)	180	0	0.0	72.5	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**178**	**1,933**	**1.6**	**72.5**	**72.4**	**12,198**	-	-	-	**23,579.0**	**1,158,954**	**59.96**	-
POLK #3 CT (GAS)	175	0	0.0	98.7	0.0	0	GAS	0	972,290	0.0	-3,890	0.00	0.00
POLK #3 CT (OIL)	180	1,499	1.2	98.7	65.7	15,289	LGT.OIL	3,947	5,806,520	22,918.8	158,786	10.59	40.23
POLK #3 TOTAL	**178**	**1,499**	**1.3**	**98.7**	**65.7**	**15,289**	-	-	-	**22,918.8**	**154,896**	**10.33**	-
POLK STATION TOTAL	**615**	**144,851**	**35.0**	**88.6**	**55.2**	**10,328**	-	-	-	**1,495,997.3**	**4,501,909**	**3.11**	-
B.B.C.T.#1	15	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	583	0.00	0.00
B.B.C.T.#2	80	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	70	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	1,456	0.00	0.00
C.T. TOTAL	**165**	**0**	**0.0**	**51.5**	**0.0**	**0**	LGT.OIL	**0**	**0**	**0.0**	**2,039**	**0.00**	**0.00**
CITY OF TAMPA	**6**	**278**	**0.0**	**0.0**	**0.0**	**11,801**	GAS	**3,098**	**0**	**3,280.8**	**58,501**	**21.04**	**18.88**
TOT. COAL (GN,BB,POLK)	**2,904**	**1,056,358**	**54.1**	**66.5**	**72.1**	**10,853**	COAL	**478,410**	**23,963,274**	**11,464,264.4**	**22,010,478**	**2.08**	**46.01**
SYSTEM	**3,464**	**1,084,910**	**46.6**	**69.2**	**64.9**	**10,814**	-	-	-	**11,731,981.0**	**24,850,700**	**2.29**	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: MARCH 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0 0	0	HVY.OIL	0	0	0.0	0	0 00	0 00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0 00	0 00
H.P.#4	0	0	0 0	0 0	0.0	0	HVY.OIL	0	0	0 0	0	0 00	0 00
H.P.#5	0	0	0 0	0 0	0 0	0	HVY.OIL	0	0	0 0	0	0 00	0.00
H.P. STATION	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	94	32,677	46.7	62.8	71.9	11,862	COAL	16,426	23,598,000	387,620.7	721,433	2 21	43.92
GAN.#2	100	39,755	53 4	73.5	66.3	12,341	COAL	20,647	23,762,000	490,614.0	906,820	2.28	43.92
GAN.#3	155	64,446	55.9	80.3	67.9	11,839	COAL	31,645	24,110,000	762,961.0	1,389,854	2 16	43 92
GAN.#4	164	60,159	49.3	66.1	73 5	11,387	COAL	28,771	23,810,000	685,037.5	1,263,627	2.10	43.92
GAN.#5	0	-229	0.0	0.0	0 0	0	COAL	0	0	0 0	0	0.00	0.00
GAN.#6	372	116,781	42.2	57.5	66.5	11,323	COAL	54,838	24,114,000	1,322,363.5	2,408,494	2.06	43.92
GANNON STATION	885	313,589	47.6	65.5	68.6	11,635	COAL	152,327	23,952,396	3,648,596.7	6,690,228	2.13	43.92
B.B.#1	428	190,435	59.8	67.1	72.6	10,970	COAL	85,820	24,342,140	2,089,047.8	4,121,708	2.16	48.03
B.B #2	433	206,163	64.0	72.7	74.4	10,756	COAL	91,862	24,139,580	2,217,504.5	4,411,889	2.14	48.03
B.B.#3	438	186,320	57 2	66.4	72.7	10,737	COAL	82,662	24,201,740	2,000,556.7	3,970,038	2.13	48.03
B.B.#4	460	245,982	71.9	82.5	74.0	10,740	COAL	119,863	22,041,060	2,641,914 4	5,756,704	2.34	48.03
B.B. STATION	1,759	828,900	63.3	72.3	73.4	10,796	COAL	380,207	23,537,241	8,949,023.4	18,260,339	2.20	48.03
SEB-PHIL. #1(HVY OIL)	17	4,969	39 3	95 1	92.1	9,592	HVY.OIL	7,598	6,273,540	47,663.8	300,526	6.05	39 55
SEB-PHIL. #2(HVY OIL)	17	5,415	42 8	99.8	89.8	9,592	HVY.OIL	8,279	6,273,540	51,941.9	327,461	6 05	39 55
SEB-PHILLIPS TOTAL	34	10,384	41.0	97.4	91.0	9,592	HVY.OIL	15,877	6,273,541	99,605.7	627,987	6.05	39.55
POLK #1 GASIFIER	260	33,739	17.4	21.8	80.0	12,777	COAL	15,801	27,282,000	431,072.5	667,813	1.98	42.26
POLK #1 CT (OIL)	245	131	0.1	22.0	17.3	25,469	LGT.OIL	602	5,794,574	3,336 4	25,324	19.33	42.09
POLK #1 TOTAL	260	33,870	17.5	21.9	78.9	12,826	-	-	-	434,408.9	693,137	2.05	-
POLK #2 CT (GAS)	175	16,635	12.8	64.0	67.0	10,978	GAS	172,441	972,290	182,615.0	1,501,565	9.03	8 71
POLK #2 CT (OIL)	180	31	0 0	65.4	15 2	35,223	LGT.OIL	188	5,794,725	1,091.9	7,932	25 59	42.19
POLK #2 TOTAL	178	16,666	12.6	65.4	66.5	11,023	-	-	-	183,706.9	1,509,597	9.06	-
POLK #3 CT (GAS)	175	26,208	20.1	98.3	67.5	11,757	GAS	290,956	972,290	308,122.0	2,620,291	10.00	9 01
POLK #3 CT (OIL)	180	1,798	1.3	96.6	62.2	14,261	LGT.OIL	4,425	5,794,567	25,640.9	186,267	10.36	42.09
POLK #3 TOTAL	178	28,006	21.1	98.6	67.1	11,916	-	-	-	333,762.9	2,806,558	10.02	-
POLK STATION TOTAL	615	78,542	17.2	58.8	52.3	12,119	-	-	-	951,878.7	5,009,292	6.38	-
B.B.C.T.#1	15	120	1.1	100.0	80.0	17,748	LGT.OIL	367	5,808,378	2,129.7	0	0 00	0.00
B.B.C.T.#2	80	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0 00
B.B.C.T.#3	70	530	1.0	100.0	68 8	14,570	LGT.OIL	1,322	5,838,998	7,721 9	0	0.00	0 00
C.T. TOTAL	165	650	0.5	100.0	36.5	15,156	LGT.OIL	1,689	5,832,352	9,851.6	-	0.00	0.00
CITY OF TAMPA	5	305	0.0	0.0	0.0	11,500	GAS	3,312	972,290	3,507.4	39,989	13.11	12.07
BAYSIDE UNIT 1	779	14,274	-	-	-	14,776	GAS	199,165	1,059,001	210,916.0	1,906,143	13.35	9.57
BAYSIDE UNIT 2	0	0	-	-	-	0	GAS	0	0	0 0	0	0.00	0.00
BAYSIDE STATION	779	14,274	-	-	-	14,776	GAS	199,165	1,059,001	210,916.0	1,906,143	13.35	9.57
TOT. COAL (GN,BB,POLK)	2,904	1,176,228	54.4	65.7	72.5	11,077	COAL	548,335	23,760,478	13,028,692.6	25,618,380	2.18	46.72
SYSTEM	4,243	1,246,644	48.4	69.4	66.8	11,129	-	-	-	13,873,379.5	32,533,978	2.61	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: APRIL 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0.00
H.P.#2	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H.P.#3	0	0	0 0	0.0	0 0	0	HVY.OIL	0	0	0 0	0	0 00	0 00
H.P.#4	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0.0	0	0 00	0.00
H P.#5	0	0	0.0	0 0	0 0	0	HVY.OIL	0	0	0 0	0	0.00	0 00
H.P. STATION	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN #1	75	7,560	14.1	98.2	87.3	11,248	COAL	3,613	23,598,000	85,259.6	154,597	2 04	42.79
GAN.#2	96	7,082	10 1	95 6	60.1	11,811	COAL	3,520	23,762,000	83,642.2	150,617	2.13	42 79
GAN #3	150	24,103	22.3	34.1	63.7	12,383	COAL	12,478	23,920,000	298,473 8	533,921	2.22	42.79
GAN.#4	164	53,574	45 4	65 0	69.1	12,496	COAL	27,837	24,050,000	669,479 9	1,191,117	2.22	42 79
GAN.#5	0	0	0 0	0 0	0 0	0	COAL	0	0	0 0	0	0.00	0 00
GAN.#6	353	98,704	38 9	51.6	69.3	11,713	COAL	47,942	24,116,000	1,156,169 3	2,051,389	2 08	42 79
GANNON STATION	840	191,043	31.6	60.4	68.8	12,003	COAL	95,390	24,038,419	2,293,024.8	4,081,641	2.14	42.79
B.B #1	421	211,988	70 0	82 5	70 0	11,232	COAL	97,069	24,525,000	2,381,099 1	4,730,045	2.23	48 72
B B.#2	411	227,232	76 9	88 9	80 1	10,673	COAL	99,085	24,477,320	2,425,331 6	4,827,288	2.12	48.72
B.B #3	428	208,037	67.6	79 5	78.7	10,626	COAL	91,020	24,287,180	2,210,617 2	4,434,372	2 13	48 72
B.B.#4	452	212,390	65 4	76 7	81 3	10,634	COAL	99,782	22,634,780	2,258,550.0	4,861,245	2.29	48 72
B.B. STATION	1,712	859,647	69.8	81.7	77.6	10,790	COAL	386,976	23,969,458	9,275,597.9	18,852,950	2.19	48.72
SEB-PHIL. #1(HVY OIL)	17	676	5.5	44 2	58.4	14,916	HVY.OIL	1,607	6,273,540	10,083 0	64,237	9 50	39 97
SEB-PHIL. #2(HVY OIL)	17	5	0 0	1 0	33 3	14,920	HVY.OIL	12	6,273,540	74 5	480	9.60	40 00
SEB-PHILLIPS TOTAL	34	681	2.8	22.6	45.9	14,916	HVY.OIL	1,619	6,273,540	10,157.6	64,717	9.50	39.97
POLK #1 GASIFIER	255	9,135	5 0	13.5	35.7	26,599	COAL	9,003	26,990,000	242,982.1	434,670	4.76	48 28
POLK #1 CT (OIL)	225	6,378	3 9	37.5	28 9	13,281	LGT OIL	18,307	5,781,809	84,703 1	743,433	11 66	40 61
POLK #1 TOTAL	255	15,513	8.5	34.4	32.6	21,123	-	-	-	327,685.2	1,178,103	7.59	-
POLK #2 CT (GAS)	150	11,467	10.6	98.7	78 4	10,928	GAS	118,444	972,290	125,314 0	696,751	6 08	5.88
POLK #2 CT (OIL)	160	32	0.0	86.0	0 9	66,331	LGT.OIL	367	5,781,761	2,122 5	14,908	46.59	40.62
POLK #2 TOTAL	155	11,499	10.3	99.1	63.9	11,082	-	-	-	127,436.6	711,659	6.19	-
POLK #3 CT (GAS)	150	18,227	16.9	99 0	78.7	11,874	GAS	204,566	972,290	216,431.0	1,201,751	6 59	5 87
POLK #3 CT (OIL)	165	53	0.0	89 4	20 9	26,389	LGT OIL	242	5,781,728	1,398.6	9,823	18.53	40 59
POLK #3 TOTAL	158	18,280	16.1	99.0	78.1	11,916	-	-	-	217,829.6	1,211,574	6.63	-
POLK STATION TOTAL	568	45,292	11.1	70.0	53.8	14,858	-	-	-	672,951.4	3,101,336	6.85	-
B.B.C.T.#1	14	3	0 0	100.0	100.0	31,633	LGT.OIL	16	5,861,643	94 9	60,493	2016.43	3780 81
B.B.C T.#2	66	0	0.0	100 0	0.0	0	LGT OIL	0	0	0 0	0	0 00	0 00
B.B.C.T.#3	60	0	0 0	100.0	0.0	0	LGT.OIL	0	0	0 0	0	0.00	0.00
C.T. TOTAL	140	3	0.0	100.0	10.0	31,633	LGT.OIL	16	5,861,643	94.9	60,493	2016.43	3780.81
CITY OF TAMPA	6	502	0.0	0.0	0.0	10,481	GAS	4,973	972,290	5,261.4	39,864	7.94	8.02
BAYSIDE ST 1	246	63,660	63 9	78 1	81 8	0		0	0	0 0	0	0 00	0 00
BAYSIDE CT1A	148	30,006	48.9	52 7	92 5	10,555	GAS	299,357	972,290	316,720 2	2,260,484	7 53	7.55
BAYSIDE CT1B	148	50,582	84 8	99.1	85 6	10,556	GAS	504,583	972,290	533,954 1	3,810,928	7.53	7 55
BAYSIDE CT1C	148	61,360	80.9	61 2	132.2	10,548	GAS	611,727	972,290	647,206.7	4,619,231	7 53	7 55
BAYSIDE UNIT 1 TOTAL	690	205,608	68.8	73.5	95.7	7,285	GAS	1,415,767	972,290	1,497,881.0	10,690,644	5.20	7.55
BAYSIDE UNIT 2 TOTAL	0	-5	-	-	-	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE STATION TOTAL	690	205,603	41.4	93.8	95.7	7,285	GAS	1,415,767	972,290	1,497,881.0	10,690,644	5.20	7.55
TOT. COAL (GN,BB,POLK)	2,807	1,059,825	52.5	69.1	71.1	11,145	COAL	491,369	24,038,187	11,811,604 8	23,369,261	2.21	47.56
SYSTEM	3,990	1,302,771	45.4	74 3	56 3	10,558	-	-	-	13,754,969.0	36,891,645	2.83	-

LEGEND:
H P = HOOKERS POINT
GAN = GANNON
B B = BIG BEND
C T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: MAY 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	75	2,742	4.9	90.9	60.3	14,536	COAL	1,689	23,598,000	39,857.0	82,208	3.00	48.67
GAN.#2	98	4,946	6.8	99.7	9.8	13,399	COAL	2,789	23,762,000	66,272.2	135,748	2.74	48.67
GAN.#3	150	51,015	45.7	66.4	65.5	12,213	COAL	26,299	23,690,000	623,023.3	1,280,045	2.51	48.67
GAN.#4	164	52,778	43.3	63.3	64.6	12,330	COAL	26,945	24,152,000	650,775.6	1,311,487	2.48	48.67
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	353	162,321	61.8	78.9	66.9	11,843	COAL	81,168	23,684,000	1,922,382.9	3,950,670	2.43	48.67
GANNON STATION	**840**	**273,802**	**43.8**	**77.1**	**59.0**	**12,061**	**COAL**	**138,890**	**23,776,449**	**3,302,311.0**	**6,760,158**	**2.47**	**48.67**
B.B.#1	421	145,612	46.5	54.9	67.7	11,272	COAL	68,372	24,006,940	1,641,408.5	3,341,670	2.29	48.87
B.B.#2	411	220,950	72.3	84.6	72.6	10,930	COAL	99,708	24,221,460	2,415,076.5	4,873,211	2.21	48.87
B.B.#3	428	159,606	50.1	58.1	62.0	11,171	COAL	72,715	24,520,400	1,782,983.0	3,553,933	2.23	48.87
B.B.#4	452	258,678	76.9	88.1	78.5	10,536	COAL	120,634	22,592,260	2,725,399.2	5,895,966	2.28	48.87
B.B. STATION	**1,712**	**784,846**	**61.6**	**71.6**	**70.3**	**10,913**	**COAL**	**361,429**	**23,697,243**	**8,564,867.2**	**17,664,780**	**2.25**	**48.87**
SEB-PHIL. #1(HVY OIL)	17	3,578	28.3	71.3	87.1	9,731	HVY.OIL	5,550	6,273,540	34,818.3	225,068	6.29	40.55
SEB-PHIL. #2(HVY OIL)	17	4,706	37.2	94.0	89.5	9,731	HVY.OIL	7,300	6,273,540	45,795.1	296,036	6.29	40.55
SEB-PHILLIPS TOTAL	**34**	**8,284**	**32.7**	**82.7**	**88.3**	**9,731**	**HVY.OIL**	**12,850**	**6,273,543**	**80,613.4**	**521,104**	**6.29**	**40.55**
POLK #1 GASIFIER	255	161,373	85.1	90.0	89.3	10,191	COAL	61,677	26,664,000	1,644,559.5	2,641,064	1.64	42.82
POLK #1 CT (OIL)	225	4,697	2.8	98.6	65.2	7,599	LGT.OIL	6,157	5,796,705	35,691.3	239,823	5.11	38.95
POLK #1 TOTAL	**255**	**166,070**	**87.5**	**92.9**	**88.4**	**10,118**	**-**	**-**	**-**	**1,680,250.8**	**2,880,887**	**1.73**	**-**
POLK #2 CT (GAS)	150	22,161	19.9	99.6	79.4	10,844	GAS	227,345	972,290	240,304.0	1,548,774	6.99	6.81
POLK #2 CT (OIL)	160	1,513	1.3	97.1	73.4	13,029	LGT.OIL	3,401	5,796,721	19,713.2	132,460	8.75	38.95
POLK #2 TOTAL	**155**	**23,674**	**20.5**	**99.6**	**79.0**	**10,983**	**-**	**-**	**-**	**260,017.2**	**1,681,234**	**7.10**	**-**
POLK #3 CT (GAS)	150	26,788	24.0	99.9	78.4	11,733	GAS	297,348	972,290	314,296.0	1,969,569	7.35	6.62
POLK #3 CT (OIL)	165	1,257	1.0	99.9	74.4	13,821	LGT.OIL	2,997	5,796,700	17,373.0	116,736	9.29	38.95
POLK #3 TOTAL	**158**	**28,045**	**23.9**	**99.9**	**78.2**	**11,826**	**-**	**-**	**-**	**331,669.0**	**2,086,305**	**7.44**	**-**
POLK STATION TOTAL	**568**	**217,789**	**51.5**	**96.7**	**83.0**	**10,432**	**-**	**-**	**-**	**2,271,937.0**	**6,648,426**	**3.05**	**-**
B.B.C.T.#1	14	412	4.0	100.0	86.6	18,152	LGT.OIL	1,274	5,868,975	7,478.6	42,954	10.43	33.72
B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	754	1.7	100.0	71.4	13,222	LGT.OIL	1,718	5,804,053	9,969.1	57,923	7.68	33.72
C.T. TOTAL	**140**	**1,166**	**1.1**	**100.0**	**39.3**	**14,964**	**LGT.OIL**	**2,992**	**5,831,704**	**17,447.7**	**100,877**	**8.65**	**33.72**
CITY OF TAMPA	**6**	**968**	**0.0**	**0.0**	**0.0**	**10,367**	**GAS**	**9,494**	**972,290**	**10,035.2**	**80,277**	**8.29**	**8.46**
BAYSIDE ST 1	246	116,706	63.8	100.0	63.8	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	88,462	80.3	94.1	92.2	11,084	GAS	927,650	972,290	980,526.4	5,896,535	6.67	6.36
BAYSIDE CT1B	148	61,665	56.0	72.1	88.1	11,084	GAS	646,641	972,290	683,499.3	4,110,323	6.67	6.36
BAYSIDE CT1C	148	80,956	73.5	90.5	93.2	11,084	GAS	848,938	972,290	897,327.3	5,396,208	6.67	6.36
BAYSIDE UNIT 1 TOTAL	**690**	**347,789**	**67.7**	**90.7**	**81.4**	**7,365**	**GAS**	**2,423,229**	**972,290**	**2,561,353.0**	**15,403,068**	**4.43**	**6.36**
BAYSIDE UNIT 2 TOTAL	**0**	**0**	**-**	**-**	**-**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**347,789**	**67.7**	**90.7**	**81.4**	**7,365**	**GAS**	**2,423,229**	**972,290**	**2,561,353.0**	**15,403,068**	**4.43**	**6.36**
TOT. COAL (GN,BB,POLK)	**2,807**	**1,220,021**	**58.4**	**74.9**	**68.7**	**11,075**	**COAL**	**561,996**	**24,042,409**	**13,511,737.7**	**27,066,002**	**2.22**	**48.16**
SYSTEM	**3,990**	**1,634,644**	**55.1**	**80.7**	**56.6**	**10,283**	**-**	**-**	**-**	**16,808,564.5**	**47,178,688**	**2.89**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JUNE 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H P #1	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H P #2	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H P #3	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H P.#4	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H P.#5	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H.P. STATION	0	0	0.0	0 0	0 0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN #1	75	0	0 0	100 0	0 0	0	COAL	0	0	0 0	0	0 00	0 00
GAN #2	98	0	0 0	100 0	0 0	0	COAL	0	0	0 0	0	0 00	0 00
GAN #3	150	70,309	65 1	86 9	69 4	12,100	COAL	36,249	23,470,000	850,764 0	1,764,312	2 51	48 67
GAN #4	164	53,909	45 7	15 4	67 8	12,481	COAL	28,715	23,432,000	672,849 9	1,397,617	2 59	48 67
GAN #5	0	0	0 0	0 0	0 0	0	COAL	0	0	0 0	0	0 00	0 00
GAN #6	353	70,031	27.6	34 7	57 6	11,738	COAL	34,665	23,714,000	822,045 8	1,687,216	2 41	48 67
GANNON STATION	840	194,249	32.1	53.7	49.8	12,076	COAL	99,629	23,543,945	2,345,659.7	4,849,145	2.50	48.67
B B #1	421	157,833	52 1	59 1	62 6	11,324	COAL	74,759	23,907,000	1,787,263 4	3,753,959	2 38	50 21
B B #2	411	193,416	65 4	75 9	68 0	10,994	COAL	87,730	24,238,380	2,126,433 1	4,405,286	2 28	50 21
B B.#3	428	189,726	61 6	71 1	67 4	11,023	COAL	85,348	24,502,840	2,091,273 8	4,285,676	2 26	50 21
B.B #4	452	232,398	71 4	79 6	72 4	10,641	COAL	109,842	22,513,740	2,472,946 3	5,515,622	2 37	50 21
B.B. STATION	1,712	773,375	62.7	71.5	67 7	10,962	COAL	357,679	23,702,593	8,477,916.6	17,960,543	2.32	50.21
SEB-PHIL. #1(HVY OIL)	17	4,934	40.3	100.0	90 0	9,743	HVY.OIL	7,662	6,273,540	48,070 4	270,392	5 48	35 29
SEB-PHIL. #2(HVY OIL)	17	4,704	38 4	92 7	90 7	9,743	HVY OIL	7,305	6,273,540	45,829 6	257,794	5 48	35 29
SEB-PHILLIPS TOTAL	34	9,638	39.4	96.4	90.3	9,743	HVY.OIL	14,967	6,273,538	93,900.0	528,186	5.48	35.29
POLK #1 GASIFIER	255	121,785	66 3	70 6	88 4	10,497	COAL	47,899	26,668,000	1,278,318 6	1,986,768	1 63	41 48
POLK #1 CT (OIL)	225	8,909	5 5	90 8	50 6	9,399	LGT OIL	14,927	5,796,496	83,734 9	570,579	6 40	38 22
POLK #1 TOTAL	255	130,694	71.2	84.5	84.1	10,422	-	-	-	1,362,053.5	2,557,367	1.96	-
POLK #2 CT (GAS)	150	17,686	16 4	96 1	79 0	10,597	GAS	176,148	972,290	187,421 0	1,696,302	9 59	9 63
POLK #2 CT (OIL)	160	1,756	1 5	96 5	75 0	13,126	LGT OIL	3,976	5,796,502	23,049 5	151,999	8 66	38 23
POLK #2 TOTAL	155	19,442	17.4	96.5	78.6	10,826	-	-	-	210,470.5	1,848,301	9.51	-
POLK #3 CT (GAS)	150	20,462	18 9	96 5	81 2	11,885	GAS	228,557	972,290	243,185 0	2,202,877	10 77	9 64
POLK #3 CT (OIL)	165	744	0 6	98 3	94 9	11,519	LGT OIL	1,479	5,796,522	8,570 1	56,515	7 60	38 21
POLK #3 TOTAL	158	21,206	18.6	98.5	81.7	11,872	-	-	-	251,755.1	2,259,392	10.65	-
POLK STATION TOTAL	568	171,342	41.9	91.7	81.9	10,647	-	-	-	1,824,279.1	6,665,060	3.89	-
B B,C T.#1	14	14	0 1	100 0	100 0	19,507	LGT OIL	48	5,734,985	273.1	1,617	11 55	33 69
B B C T #2	66	0	0 0	100 0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
B.B.C T.#3	60	21	0 0	100 0	35 0	15,667	LGT OIL	56	5,828,167	329 0	1,887	8 99	33 70
C.T. TOTAL	140	35	0.0	100.0	25.0	17,203	LGT.OIL	104	5,785,529	602.1	3,504	10.01	33.69
CITY OF TAMPA	6	821	0.0	0.0	0.0	10,426	GAS	8,045	972,290	8,559.9	95,891	11.68	11.92
BAYSIDE ST 1	246	130,606	73 7	96 4	76 5	0		0	0	0 0	0	0 00	0 00
BAYSIDE CT1A	148	87,098	81 7	95 7	85 4	11,161	GAS	913,602	972,290	972,072 6	7,711,016	8 85	8 44
BAYSIDE CT1B	148	85,140	79 9	97 2	86 2	11,161	GAS	893,065	972,290	950,220 7	7,537,679	8 85	8 44
BAYSIDE CT1C	148	76,221	71 5	93 3	85 1	11,161	GAS	799,512	972,290	850,680 6	6,748,069	8 85	8 44
BAYSIDE UNIT 1 TOTAL	690	379,065	76 3	95.8	82 3	7,315	GAS	2,606,179	972,290	2,772,973.9	21,996,764	5.80	8.44
BAYSIDE UNIT 2 TOTAL	0	(299)	-	-	-	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE STATION TOTAL	690	378,766	76.2	95.8	82.3	7,321	GAS	2,606,179	972,290	2,772,973.9	21,996,764	5.81	8.44
TOT. COAL (GN,BB,POLK)	2,807	1,089,409	53.9	66.1	64.2	11,109	COAL	505,207	23,954,353	12,101,894.9	24,796,476	2 28	49.08
SYSTEM	3,990	1,528,226	53.2	76.1	52.9	10,158	-	-	-	15,523,891.3	52,099,093	3.41	-

LEGEND
H P = HOOKERS POINT
GAN = GANNON
B B = BIG BEND
C T = COMBUSTION TURBINE

SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JULY 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H P #1	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H P.#2	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H.P.#3	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H.P.#4	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0.00
H.P.#5	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0.00
H.P. STATION	0	0	0 0	0.0	0.0	0	HVY.OIL	0	0	0 0	0	0.00	0.00
GAN #1	75	0	0 0	100 0	0 0	0	COAL	0	0	0 0	0	0 00	0 00
GAN.#2	98	0	0 0	100 0	0 0	0	COAL	0	0	0 0	0	0 00	0 00
GAN #3	150	72,440	64 9	85 5	73 3	12,308	COAL	38,444	23,192,000	891,593.2	1,834,213	2 53	47.71
GAN #4	164	42,359	34 7	51 7	62 0	13,230	COAL	24,292	23,070,000	560,416 4	1,159,003	2 74	47 71
GAN.#5	0	0	0 0	0.0	0 0	0	COAL	0	0	0 0	0	0 00	0 00
GAN #6	353	133,883	51 0	63 7	64 3	11,995	COAL	67,663	23,714,000	1,604,560 4	3,228,290	2 41	47 71
GANNON STATION	840	248,682	39 8	72.7	52.2	12,291	COAL	130,399	23,440,134	3,056,570.0	6,221,506	2.50	47.71
B B #1	421	169,176	54 0	58 9	68 4	11,198	COAL	77,772	24,358,120	1,894,379.7	3,818,851	2 26	49 10
B B.#2	411	213,042	69 7	78 0	69 7	10 873	COAL	94,584	24,489,580	2,316,336 9	4,644,373	2 18	49 10
B B #3	428	178,586	56 1	68.5	56 2	11,665	COAL	84,993	24,511,300	2,083,280 8	4,173,425	2 34	49 10
B B #4	452	191 005	56 8	66.9	75 7	11 074	COAL	89,739	23 571 140	2,115,252 9	4,406,469	2 31	49 10
B.B. STATION	1,712	751,809	59.0	68.0	67.6	11,185	COAL	347,088	24,227,981	8,409,250.3	17,043,118	2.27	49.10
SEB-PHIL. #1(HVY OIL)	17	5 691	46 6	100 0	98 5	9,789	HVY.OIL	9,192	6,273,540	57,668 5	302,584	5 14	32 92
SEB-PHIL #2(HVY OIL)	17	5,956	47 1	100 0	99 3	9,789	HVY OIL	9,294	6,273,540	58 304 8	305,941	5 14	32 92
SEB-PHILLIPS TOTAL	34	11,847	46.8	100.0	98.9	9,789	HVY.OIL	18,486	6,273,540	115,973.3	608,525	5.14	32.92
POLK #1 GASIFIER	255	155,723	82 1	87 4	83 7	10,845	COAL	66,338	25,458,000	1,688,821.6	2,730,630	1 75	41 18
POLK #1 CT (OIL)	225	2,564	1 5	99.5	77 3	7,341	LGT OIL	3,283	5,801,362	18,823.1	124,871	4 87	38 03
POLK #1 TOTAL	255	158,287	83.4	88.7	83.6	10,788	-	-	-	1,707,644.7	2,855,501	1.80	-
POLK #2 CT (GAS)	150	22,359	20 0	99.2	78 5	10,810	GAS	226,730	972,290	241,694.0	1,764,561	7 89	7 78
POLK #2 CT (OIL)	160	79	0 1	96.9	23 7	64,754	LGT OIL	882	5,801,381	5,115.6	33,547	42 46	38.04
POLK #2 TOTAL	155	22,438	19.5	99.4	77.8	11,000	-	-	-	246,809.6	1,798,108	8.01	-
POLK #3 CT (GAS)	150	31,352	28 1	98.7	79 8	11,900	GAS	349,990	972,290	373,089 0	2,723,674	8 69	7,78
POLK #3 CT (OIL)	165	38	0 0	96 6	13 8	20,155	LGT.OIL	132	5,801,394	765 9	5,023	13 22	38 05
POLK #3 TOTAL	158	31,390	26 7	99.4	79.3	11,910	-	-	-	373,854.9	2,728,697	8 69	-
POLK STATION TOTAL	568	212,115	50.2	94.6	80.8	10,977	-	-	-	2,328,309 2	7,382,306	3 48	-
B.B C.T #1	14	357	3 4	100 0	79 7	18,739	LGT OIL	1,167	5,734,417	6,690 0	39,341	11 02	33 71
B.B.C.T.#2	66	0	0 0	100.0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
B.B C.T.#3	60	1,499	3 4	100.0	75 7	15,089	LGT OIL	3,880	5,828,517	22,618.2	130,800	8 73	33 71
C.T. TOTAL	140	1,856	1.8	100.0	40.4	15,791	LGT.OIL	5,047	5,806,766	29,308.2	170,141	9.17	33.71
CITY OF TAMPA	6	1,432	0.0	0.0	0.0	10,134	GAS	13,613	972,290	14,511.5	128,884	9 00	9.47
BAYSIDE ST 1	246	110,399	60 3	89 2	67 6	0		0	0	0 0	0	0 00	0.00
BAYSIDE CT1A	148	72,180	65 6	95 5	80.0	11,447	GAS	775,094	972,290	826,249.9	5,595,761	7 75	7 22
BAYSIDE CT1B	148	72,497	65 8	95 3	77.9	11,447	GAS	778,497	972,290	829,878 7	5,620,329	7 75	7.22
BAYSIDE CT1C	148	67,427	61 2	94 9	79 7	11,447	GAS	724,053	972,290	771,840.5	5,227,273	7 75	7 22
BAYSIDE UNIT 1 TOTAL	690	322,503	62.8	93.1	75.1	7,529	GAS	2,277,644	972,290	2,427,969.1	16,443,363	5 10	7,22
BAYSIDE UNIT 2 TOTAL	0	(144)	-	-	-	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE STATION TOTAL	690	322,359	62.8	93.1	75.1	7,532	GAS	2,277,644	972,290	2,427,969.1	16,443,363	5 10	7.22
TOT. COAL (GN,BB,POLK)	2,807	1,156,214	55.4	71.2	64.5	11,377	COAL	543,825	24,189,112	13,154,641.9	25,995,254	2.25	47.80
SYSTEM	3,990	1,550,100	52.2	78.5	53.8	10,568	-	-	-	16,381,891.6	47,997,843	3.10	-

LEGEND
H P = HOOKERS POINT
GAN = GANNON
B B = BIG BEND
C T = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: AUGUST 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H P.#1	0	0	0 0	0.0	0 0	0	HVY OIL	0	0	0.0	0	0 00	0 00
H.P.#2	0	0	0 0	0.0	0 0	0	HVY.OIL	0	0	0 0	0	0 00	0 00
H.P.#3	0	0	0.0	0 0	0.0	0	HVY OIL	0	0	0.0	0	0 00	0 00
H.P #4	0	0	0.0	0.0	0 0	0	HVY OIL	0	0	0 0	0	0.00	0 00
H P.#5	0	0	0.0	0 0	0 0	0	HVY.OIL	0	0	0.0	0	0 00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	HVY.OIL	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	75	0	0.0	100 0	0.0	0	COAL	0	0	0 0	0	0 00	0 00
GAN.#2	98	0	0.0	100 0	0 0	0	COAL	0	0	0.0	0	0 00	0 00
GAN #3	150	73,428	65 6	87.8	72 3	12,728	COAL	39,690	23,548,000	934,620.1	1,713,520	2.33	43 17
GAN.#4	164	52,344	42.9	85 0	47.2	14,247	COAL	33,023	22,582,000	745,725 4	1,425,689	2 72	43 17
GAN.#5	0	0	0 0	0 0	0 0	0	COAL	0	0	0	0	0 00	0 00
GAN #6	353	139,688	53 2	61.1	67 0	11,916	COAL	70,043	23,764,000	1,664,501.9	3,023,938	2 16	43.17
GANNON STATION	**840**	**265,460**	**42.5**	**76.5**	**50.3**	**12,600**	COAL	**142,756**	**23,430,521**	**3,344,847.4**	**6,163,147**	**2.32**	**43.17**
B.B #1	421	162,277	51 8	60.0	52 3	11,436	COAL	76,741	24,183,560	1,855,874.9	3,695,776	2.28	48 16
B.B.#2	411	139,794	45.7	50.6	72.4	11,095	COAL	64,637	23,995,940	1,551,026.3	3,112,859	2.23	48.16
B.B.#3	428	188,794	59 3	68 5	62 9	11,566	COAL	89,154	24,493,260	2,183,670 4	4,293,575	2 27	48 16
B.B #4	452	275,957	82.1	92 1	82.1	10,872	COAL	133,240	22,517,140	3,000,180.6	6,418,717	2 33	48.16
B.B. STATION	**1,712**	**766,822**	**60.2**	**68.4**	**70.1**	**11,203**	COAL	**363,772**	**23,615,760**	**8,590,752.2**	**17,518,927**	**2.28**	**48.16**
SEB-PHIL. #1(HVY OIL)	17	5,705	45 1	100 0	92 2	9,675	HVY OIL	8,798	6,273,540	55,193.1	302,989	5 31	34 44
SEB-PHIL #2(HVY OIL)	17	4,935	39 0	87 5	90 4	9,675	HVY OIL	7,610	6,273,540	47,744 9	262,077	5 31	34 44
SEB-PHILLIPS TOTAL	**34**	**10,640**	**42.1**	**93.8**	**91.3**	**9,675**	HVY.OIL	**16,408**	**6,273,540**	**102,938.0**	**565,066**	**5.31**	**34.44**
POLK #1 GASIFIER	255	140,164	73 9	82 7	83 4	11,163	COAL	60,922	25,682,000	1,564,595 7	2,053,853	1 47	33 71
POLK #1 CT (OIL)	225	6,096	3.6	100.0	68 6	8,756	LGT OIL	9,585	5,795,766	53,377 7	366,389	6 01	38 23
POLK #1 TOTAL	**255**	**146,260**	**77.1**	**92.8**	**82.6**	**11,062**	-	-	-	**1,617,973.4**	**2,420,242**	**1.65**	-
POLK #2 CT (GAS)	150	22,175	19.9	97 9	83 2	10,995	GAS	228,505	1,067,000	243,815 0	1,614,089	7.28	7.06
POLK #2 CT (OIL)	160	342	0 3	98.7	47 3	20,535	LGT.OIL	1,211	5,795,768	7,017.7	46,285	13 53	38.22
POLK #2 TOTAL	**155**	**22,517**	**19.5**	**98.7**	**82.3**	**11,140**	-	-	-	**250,832.7**	**1,660,374**	**7.37**	-
POLK #3 CT (GAS)	150	24,348	21.8	97.9	79.8	12,619	GAS	287,926	1,067,000	307,217 0	2,037,727	8 37	7 08
POLK #3 CT (OIL)	165	469	0.4	77.8	69.8	11,704	LGT OIL	946	5,795,767	5,485.5	36,180	7 71	38.25
POLK #3 TOTAL	**158**	**24,815**	**21.1**	**97.9**	**79.5**	**12,601**	-	-	-	**312,702.5**	**2,073,907**	**8.36**	-
POLK STATION TOTAL	**568**	**193,592**	**45.8**	**95.8**	**81.7**	**11,269**	-	-	-	**2,181,508.6**	**6,154,523**	**3.18**	-
B B.C T #1	14	42	0 4	100.0	75 0	20,062	LGT OIL	145	5,820,669	842.6	5,151	12 26	35 52
B.B C T.#2	66	0	0 0	100 0	0 0	0	LGT OIL	0	0	0 0	0	0 00	0 00
B B.C.T.#3	60	0	0 0	100 0	0.0	0	LGT OIL	0	0	0 0	0	0 00	0 00
C.T. TOTAL	**140**	**42**	**0.0**	**100.0**	**7.5**	**20,062**	LGT.OIL	**145**	**5,820,669**	**842.6**	**5,151**	**12.26**	**35.52**
CITY OF TAMPA	**6**	**1,199**	**26.9**	**0.0**	**0.0**	**10,236**	GAS	**11,502**	**1,067,000**	**12,272.6**	**103,761**	**8.65**	**9.02**
BAYSIDE ST 1	248	116,265	53 5	99 1	64.1	0		0	0	0 0	0	0.00	0.00
BAYSIDE CT1A	148	73,034	66 3	99 0	82 8	11,368	GAS	778,083	1,067,000	830,215 0	5,296,721	7 25	6 81
BAYSIDE CT1B	148	72,700	66 0	91.3	82 7	11,368	GAS	774,526	1,067,000	826,418 9	5,272,502	7 25	6 81
BAYSIDE CT1C	148	71,004	64 5	95 6	82.3	11,368	GAS	756,455	1,067,000	807,137.1	5,149,485	7 25	6 81
BAYSIDE UNIT 1 TOTAL	**690**	**333,003**	**64.9**	**96.7**	**76.0**	**7,399**	GAS	**2,309,064**	**1,067,000**	**2,463,771.0**	**15,718,708**	**4.72**	**6.81**
BAYSIDE UNIT 2 TOTAL	**0**	**(206)**	**-**	**-**	**-**	**0**	GAS	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**332,797**	**64.8**	**96.7**	**76.0**	**7,403**	GAS	**2,309,064**	**1,067,000**	**2,463,771.0**	**15,718,708**	**4.72**	**6.81**
TOT. COAL (GN,BB,POLK)	**2,807**	**1,172,446**	**56.1**	**72.7**	**65.4**	**11,515**	COAL	**567,450**	**23,790,992**	**13,500,195.3**	**25,735,927**	**2.20**	**45.35**
SYSTEM	**3,990**	**1,570,852**	**52.9**	**80.7**	**66.8**	**10,631**	-	-	-	**16,696,932.4**	**46,229,283**	**2.94**	-

LEGEND
H P = HOOKERS POINT
GAN = GANNON
B B = BIG BEND
C T = COMBUSTION TURBINE

SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: SEPTEMBER 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H P.#1	0	0	0 0	0 0	0.0	0	HVY.OIL	0	0	0 0	0	0 00	0 00
H.P #2	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H P #3	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H P.#4	0	0	0 0	0 0	0 0	0	HVY.OIL	0	0	0.0	0	0 00	0.00
H P #5	0	0	0 0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H.P. STATION	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN #1	94	0	0 0	100 0	0 0	0	COAL	0	0	0 0	0	0 00	0 00
GAN #2	100	0	0.0	100 0	0.0	0	COAL	0	0	0 0	0	0 00	0 00
GAN.#3	150	69,015	63 9	78.0	76 2	11,655	COAL	33,101	24,300,000	804,354 3	1,421,797	2 06	42 95
GAN #4	164	47,735	40 4	80 5	47 7	13,432	COAL	26,524	24,174,000	641,191 2	1,139,294	2.39	42 95
GAN.#5	0	0	0 0	0 0	0 0	0	COAL	0	0	0 0	0	0.00	0.00
GAN #6	353	163,359	64 3	77 8	65 3	11,523	COAL	78,116	24,096,000	1,882,439 4	3,355,340	2.05	42 95
GANNON STATION	861	280,109	45.2	83.4	49.1	11,881	COAL	137,741	24,161,179	3,327,984.9	5,916,431	2.11	42.95
B B #1	421	183,306	60 5	66 5	62.6	11,478	COAL	89,245	23,574,920	2,103,949.6	4,457,852	2.43	49.95
B.B #2	411	138,368	46 6	51 4	65 4	10,960	COAL	63,202	23,995,140	1,516,540 8	3,156,986	2.28	49.95
B B #3	428	115,134	37.4	41 6	48 9	11,574	COAL	55,445	24,033,960	1,332,559 5	2,769,518	2 41	49 95
B B #4	452	262,409	80 6	86 9	81 1	10,842	COAL	126,870	22,425,800	2,845,164.2	6,337,249	2 42	49 95
B.B. STATION	1,712	699,217	56.7	62.0	64.7	11,153	COAL	334,762	23,294,784	7,798,214.1	16,721,605	2.39	49.95
SEB-PHIL #1(HVY OIL)	17	5,922	48.4	100 0	92 8	9,696	HVY OIL	9,152	6,273,540	57,417 7	306,240	5 17	33 46
SEB-PHIL. #2(HVY OIL)	17	5,775	47 2	98 5	92 8	9,696	HVY OIL	8,927	6,273,540	56,000.7	298,711	5 17	33.46
SEB-PHILLIPS TOTAL	34	11,697	47.8	99.3	92.8	9,696	HVY.OIL	18,079	6,273,541	113,41814	604,951	5.17	33.46
POLK #1 GASIFIER	255	30,083	16 4	19 7	78 1	12,011	COAL	13,738	26,300,000	361,317 6	567,996	1.89	41.34
POLK #1 CT (OIL)	225	3,612	2 2	23 2	82 8	8,117	LGT OIL	5,050	5,805,737	29,317.3	190,691	5 28	37 76
POLK #1 TOTAL	255	33,695	18.4	21.7	78.6	11,593	-	-	-	390,634.9	758,687	2.25	-
POLK #2 CT (GAS)	150	30,180	27.9	91 6	82 6	11,006	GAS	319,391	1,040,000	332,166 6	2,120,540	7 03	6 64
POLK #2 CT (OIL)	160	78	0.1	82 9	28 9	36,218	LGT OIL	486	5,805,741	2,819 5	18,339	23 51	37 73
POLK #2 TOTAL	155	30,258	27.1	91.6	82.2	11,071	-	-	-	334,986.1	2,138,879	7.07	-
POLK #3 CT (GAS)	150	29,231	27 1	94 5	79 4	12,466	GAS	350,396	1,040,000	364,411 4	2,327,003	7 96	6 64
POLK #3 CT (OIL)	165	32	0.0	94 5	14 7	16,944	LGT.OIL	92	5,805,746	535 3	3,482	10 88	37 85
POLK #3 TOTAL	158	29,263	25.7	94.5	79 0	12,471	-	-	-	364,946.7	2,330,485	7.96	-
POLK STATION TOTAL	568	93,216	22.8	61.0	79.7	11,699	-	-	-	1,090,567.7	5,228,051	5.61	-
B.B.C.T.#1	14	136	1 3	100 0	61 0	18,913	LGT.OIL	442	5,820,706	2,572.2	15,746	11.58	35.62
B B.C.T.#2	66	0	0.0	0 0	0 0	0	LGT OIL	0	0	0 0	0	0.00	0.00
B B.C T.#3	60	254	0 6	100 0	60 5	15,806	LGT.OIL	693	5,793,985	4,014 7	24,688	9 72	35 62
C.T. TOTAL	140	390	0.4	52.9	34.0	16,889	LGT.OIL	1,135	5,804,408	6,586.9	40,434	10.37	35.62
CITY OF TAMPA	6	1,543	35.7	0.0	0.0	10,203	GAS	15,138	1,040,000	15,743.5	120,597	7.82	7.97
BAYSIDE ST 1	246	115,771	65 4	100.0	65 4	0		0	0	0 0	0	0.00	0 00
BAYSIDE CT1A	148	74,864	70 3	97 4	86 0	11,348	GAS	816,897	1,040,000	849,572 7	5,457,522	7 29	6 68
BAYSIDE CT1B	148	69,237	65 0	96.0	85 7	11,348	GAS	755,496	1,040,000	785,715.9	5,047,317	7 29	6 68
BAYSIDE CT1C	148	75,293	70.7	98 3	85 4	11,348	GAS	821,582	1,040,000	854,445 3	5,488,823	7 29	6.68
BAYSIDE UNIT 1 TOTAL	690	335,165	67.5	98.2	78.4	7,428	GAS	2,393,975	1,040,000	2,489,733.9	15,993,662	4.77	6.68
BAYSIDE UNIT 2 TOTAL	0	(589)	-	-	-	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE STATION TOTAL	690	334,576	67.3	98.2	78.4	7,441	GAS	2,393,975	1,040,000	2,489,733.9	15,993,662	4.78	6.68
TOT. COAL (GN,BB,POLK)	2,828	1,009,409	49.6	64.7	61.2	11,380	COAL	486,241	23,625,123	11,487,516.6	23,206,032	2.30	47.73
SYSTEM	4,011	1,420,748	49.2	72.7	65.0	10,447	-	-	-	14,842,249.4	44,625,731	3.14	-

LEGEND
H P. = HOOKERS POINT
GAN. = GANNON
B B = BIG BEND
C T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: OCTOBER 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H P.#1	0	0	0.0	0 0	0.0	0	HVY.OIL	0	0	0.0	0	0 00	0.00
H.P.#2	0	0	0.0	0 0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0 0	0 0	0	HVY.OIL	0	0	0.0	0	0.00	0 00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0 0	0	0.00	0.00
H.P.#5	0	0	0.0	0 0	0 0	0	HVY.OIL	0	0	0.0	0	0.00	0 00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	94	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0 00
GAN.#2	100	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	29,484	26.4	34 3	64.7	14,079	COAL	17,082	24,300,000	415,092.6	(59,746)	(0.20)	(3.50)
GAN.#4	164	16,525	13.5	51.3	14.7	12,279	COAL	6,394	24,174,000	202,916.6	(29,359)	(0.18)	(3.50)
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0 0	0	0.00	0.00
GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0 00	0 00
GANNON STATION	**508**	**46,009**	**12.2**	**54.9**	**23.9**	**13,432**	**COAL**	**25,476**	**24,258,486**	**618,009.2**	**(89,105)**	**(0.19)**	**(3.50)**
B.B.#1	421	141,655	45.2	49.3	89.1	11,154	COAL	65,391	24,161,900	1,579,970.8	3,195,962	2.26	48 87
B.B.#2	411	224,289	73.3	80.1	75.9	10,771	COAL	99,910	24,180,900	2,413,328.2 *	4,883,066	2.18	48 87
B.B.#3	428	154,880	48.6	58 3	69.8	11,260	COAL	71,713	24,287,140	1,741,715.6	3,504,947	2.27	48 87
B.B.#4	452	237,353	70.5	74.7	74.7	10,501	COAL	115,022	21,669,200	2,492,430.2	5,621,659	2.37	48.87
B.B. STATION	**1,712**	**757,977**	**59.4**	**60.8**	**72.4**	**10,858**	**COAL**	**352,036**	**23,378,358**	**8,227,444.8**	**17,205,634**	**2.27**	**48.87**
SEB-PHIL. #1(HVY OIL)	17	5,577	44.0	100.0	94.3	9,816	HVY.OIL	8,726	6,273,540	54,745.8	287,843	5.16	32.99
SEB-PHIL. #2(HVY OIL)	17	5,570	44.0	100.0	94.4	9,816	HVY.OIL	8,715	6,273,540	54,672 0	287,480	5.16	32.99
SEB-PHILLIPS TOTAL	**34**	**11,147**	**44.0**	**100.0**	**94.4**	**9,816**	**HVY.OIL**	**17,441**	**6,273,539**	**109,417.8**	**575,323**	**5.16**	**32.99**
POLK #1 GASIFIER	255	(5,257)	0.0	3.0	0 0	17,316	COAL	1,165	26,300,000	30,639.5	64,408	(1.23)	55.29
POLK #1 CT (OIL)	225	1,125	0.7	2 8	95.0	12,536	LGT.OIL	3,729	5,830,484	14,107.0	140,601	12.50	37.70
POLK #1 TOTAL	**255**	**(4,132)**	**0.9**	**2.8**	**0.0**	**15,460**	**-**	**-**	**-**	**44,746.5**	**205,009**	**(4.96)**	**-**
POLK #2 CT (GAS)	150	24,684	22.1	99 9	78.9	11,589	GAS	275,317	1,039,000	286,054.0	1,660,579	6 73	6.03
POLK #2 CT (OIL)	160	31	0.0	100.0	13.0	15,526	LGT.OIL	84	5,830,527	488.2	3,157	10.18	37.58
POLK #2 TOTAL	**155**	**24,715**	**21.4**	**99.9**	**78.4**	**11,594**	**-**	**-**	**-**	**286,542.2**	**1,663,736**	**6.73**	**-**
POLK #3 CT (GAS)	150	17,241	15.4	100.0	79.9	13,076	GAS	216,964	1,039,000	225,446 4	1,316,202	7.63	6.07
POLK #3 CT (OIL)	165	24	0.0	97.0	22.7	21,217	LGT.OIL	86	5,830,518	504.0	3,259	13.58	37.90
POLK #3 TOTAL	**158**	**17,265**	**14.7**	**97.0**	**79.7**	**13,087**	**-**	**-**	**-**	**225,950.4**	**1,319,461**	**7.64**	**-**
POLK STATION TOTAL	**568**	**37,848**	**8.9**	**55.5**	**43.6**	**14,723**	**-**	**-**	**-**	**557,239.1**	**3,188,206**	**8.42**	**-**
B.B.C.T.#1	14	30	0.3	100 0	71.4	18,553	LGT.OIL	96	5,786,880	556.6	3,404	11.35	35.46
B B.C.T.#2	66	0	0 0	100.0	0.0	0	LGT.OIL	0	0	0 0	0	0 00	0 00
B.B.C.T.#3	60	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0 00
C.T. TOTAL	**140**	**30**	**0.0**	**100.0**	**7.1**	**18,553**	**LGT.OIL**	**96**	**5,786,464**	**556.6**	**3,404**	**11.35**	**35.46**
CITY OF TAMPA	**6**	**902**	**20.2**	**0.0**	**0.0**	**10,317**	**GAS**	**8,957**	**1,039,000**	**9,306.3**	**73,644**	**8.16**	**8.22**
BAYSIDE ST 1	246	111,440	60 8	99.6	61.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	65,769	59.6	84.7	79 1	11,764	GAS	744,687	1,039,000	773,730 0	4,427,516	6.73	5.95
BAYSIDE CT1B	148	67,010	60.8	97.5	81.9	11,764	GAS	758,731	1,039,000	788,321.4	4,511,013	6.73	5 95
BAYSIDE CT1C	148	75,589	68 6	97 9	83 5	11,764	GAS	855,872	1,039,000	889,250.6	5,088,560	6.73	5.95
BAYSIDE UNIT 1 TOTAL	**690**	**319,808**	**62.2**	**95.6**	**74.2**	**7,665**	**GAS**	**2,359,290**	**1,039,000**	**2,451,302.0**	**14,027,089**	**4.39**	**5.95**
BAYSIDE ST 2	0	0	0.0	0.0	0.0	0		0	0	0 0	0	0.00	0 00
BAYSIDE CT2A	148	9,748	8.8	0.0	0.0	10,980	GAS	103,014	1,039,000	107,031 8	573,656	5.89	5 57
BAYSIDE CT2B	148	5,054	4.6	0.0	0.0	10,980	GAS	53,414	1,039,000	55,497.2	297,447	5.89	5.57
BAYSIDE CT2C	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0 00	0.00
BAYSIDE CT2D	0	0	0.0	0.0	0.0	0	GAS	0	0	0 0	0	0 00	0.00
BAYSIDE UNIT 2 TOTAL	**296**	**14,802**	**6.7**	**0.0**	**0.0**	**10,980**	**GAS**	**156,428**	**1,039,000**	**162,529.0**	**871,103**	**5.89**	**5.57**
BAYSIDE STATION TOTAL	**986**	**334,610**	**45.6**	**95.8**	**74.2**	**7,812**	**GAS**	**2,515,718**	**1,039,000**	**2,613,831.0**	**14,898,192**	**4.45**	**5.92**
TOT. COAL (GN,BB,POLK)	**2,475**	**798,729**	**43.3**	**55.7**	**55.0**	**11,116**	**COAL**	**378,677**	**23,446,559**	**8,876,093.5**	**17,180,937**	**2.15**	**45.37**
SYSTEM	**3,954**	**1,188,523**	**40.3**	**69.8**	**59.2**	**10,213**	**-**	**-**	**-**	**12,135,804.8**	**35,855,298**	**3.02**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN = GANNON
B B = BIG BEND
C T. = COMBUSTION TURBINE

* Includes adjustment of (2,585 5) MMBTU for August 2003

SCHEDULE A4
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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: NOVEMBER 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0 0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0 0	0 0	0	HVY OIL	0	0	0 0	0	0 00	0 00
H.P.#3	0	0	0 0	0.0	0 0	0	HVY.OIL	0	0	0.0	0	0 00	0 00
H.P.#4	0	0	0.0	0 0	0 0	0	HVY.OIL	0	0	0.0	0	0 00	0 00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0 00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	0.00
GAN.#1	94	0	0.0	100.0	0.0	0	COAL	0	0	0 0	0	0 00	0.00
GAN.#2	100	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	0	0.0	100.0	0.0	0	COAL	0	0	0.0	8,404	0.00	0.00
GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	4,130	0 00	0 00
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0 00
GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0 0	0	0.00	0.00
GANNON STATION	**344**	**0**	**0.0**	**100.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**12,534**	**0.00**	0.00
B.B.#1	421	200,071	66.0	72.7	66.0	11,128	COAL	91,962	24,210,040	2,226,403 7	4,414,373	2.21	48 00
B.B #2	411	136,885	46.3	39.0	75.0	10,725	COAL	60,829	24,135,380	1,468,131.0	2,919,922	2.13	48 00
B.B.#3	428	111,433	36.2	41.6	74.2	10,779	COAL	48,924	24,550,720	1,201,131.2	2,348,457	2.11	48.00
B.B.#4 (1)	452	191	0.1	0 3	15.3	0	COAL	0	0	0.0	0	0.00	0 00
B.B. STATION	**1,712**	**448,580**	**36.4**	**37.7**	**56.8**	**10,914**	**COAL**	**201,715**	**24,270,155**	**4,895,665.9**	**9,682,752**	**2.16**	48.00
SEB-PHIL. #1(HVY OIL)	17	4,005	32.7	99.9	94.1	9,574	HVY.OIL	6,111	6,273,540	38,338.7	210,067	5.25	34.38
SEB-PHIL. #2(HVY OIL)	17	4,005	32.7	100.0	91.7	9,574	HVY.OIL	6,113	6,273,540	38,347.7	210,136	5.25	34.38
SEB-PHILLIPS TOTAL	**34**	**8,010**	**32.7**	**99.9**	**92.9**	**9,574**	**HVY.OIL**	**12,224**	**6,273,542**	**76,686.4**	**420,203**	**5.25**	34.38
POLK #1 GASIFIER	255	170,153	92.7	95.8	93.7	9,661	COAL	61,311	26,812,000	1,643,859.0	2,408,481	1.42	39 28
POLK #1 CT (OIL)	225	1,969	1.2	100.0	102.3	8,025	LGT.OIL	2,728	5,792,870	15,801.6	102,565	5.21	37 60
POLK #1 TOTAL	**255**	**172,122**	**93.7**	**96.7**	**93.8**	**9,642**	-	-	-	**1,659,660.6**	**2,511,046**	**1.46**	-
POLK #2 CT (GAS)	150	21,393	19.8	100.0	80.6	10,786	GAS	223,372	1,033,000	230,743.0	1,378,248	6.44	6 17
POLK #2 CT (OIL)	160	28	0.0	99.4	41.7	12,100	LGT.OIL	58	5,792,866	336 2	2,182	7.79	37.62
POLK #2 TOTAL	**155**	**21,421**	**19.2**	**100.0**	**80.5**	**10,788**	-	-	-	**231,079.2**	**1,380,430**	**6.44**	-
POLK #3 CT (GAS)	150	14,899	13.8	100.0	78.2	11,641	GAS	167,899	1,033,000	173,440.0	1,039,190	6 97	6.19
POLK #3 CT (OIL)	165	32	0.0	99.2	38.3	18,719	LGT.OIL	102	5,792,833	591.7	3,841	12.00	37.66
POLK #3 TOTAL	**158**	**14,931**	**13.1**	**100.0**	**78.0**	**11,856**	-	-	-	**174,031.7**	**1,043,031**	**6.99**	-
POLK STATION TOTAL	**568**	**208,474**	**51.0**	**98.5**	**85.8**	**9,904**	-	-	-	**2,064,771.5**	**4,934,507**	**2.37**	-
B.B C.T.#1	14	165	1.6	100.0	89.6	17,970	LGT OIL	512	5,786,834	2,965.0	17,911	10.86	34.98
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0 00	0.00
B.B.C.T.#3	60	563	1.3	100.0	87.5	14,194	LGT.OIL	1,377	5,801,716	7,991.4	49,171	8.56	34 98
C.T. TOTAL	**140**	**728**	**0.7**	**52.9**	**46.5**	**15,050**	**LGT.OIL**	**1,889**	**5,797,681**	**10,956.4**	**66,082**	**9.08**	34.98
CITY OF TAMPA	**6**	**962**	**22.3**	**0.0**	**0.0**	**10,312**	**GAS**	**9,603**	**1,033,000**	**9,919.9**	**63,899**	**6.64**	6.65
BAYSIDE ST 1	246	101,657	57.4	88.6	64.8	0		0	0	0.0	0	0.00	0 00
BAYSIDE CT1A	148	62,838	59.0	89.7	84 8	11,737	GAS	713,943	1,033,000	737,502.9	3,929,184	6 25	5.50
BAYSIDE CT1B	148	72,976	68.5	97.1	84.9	11,737	GAS	829,125	1,033,000	856,486.0	4,563,088	6.25	5.50
BAYSIDE CT1C	148	64,235	60.3	95.8	85.1	11,737	GAS	729,820	1,033,000	753,904.1	4,016,504	6 25	5 50
BAYSIDE UNIT 1 TOTAL	**690**	**301,706**	**60.7**	**92.2**	**77.7**	**7,782**	**GAS**	**2,272,888**	**1,033,000**	**2,347,893.0**	**12,508,836**	**4.15**	5.50
BAYSIDE ST 2	318	41,003	18.0	0.0	0.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	148	50,167	47.1	0 0	0.0	10,256	GAS	498,055	1,033,000	514,491.3	2,547,022	5 08	5 11
BAYSIDE CT2B	148	37,195	34.9	0.0	0 0	10,256	GAS	369,263	1,033,000	381,449 1	1,888,368	5 08	5 11
BAYSIDE CT2C	148	346	0.3	0.0	0.0	10,256	GAS	3,440	1,033,000	3,553 2	17,590	5.08	5 11
BAYSIDE CT2D	148	2,308	2.2	0.0	0.0	10,256	GAS	22,915	1,033,000	23,671.4	117,188	5 08	5 11
BAYSIDE UNIT 2 TOTAL	**908**	**131,019**	**20.0**	**0.0**	**0.0**	**7,046**	**GAS**	**893,674**	**1,033,000**	**923,165.0**	**4,570,188**	**3.49**	5.11
BAYSIDE STATION TOTAL	**1,598**	**432,725**	**37.6**	**92.2**	**77.7**	**7,559**	**GAS**	**3,166,561**	**1,033,000**	**3,271,058.0**	**17,079,024**	**3.95**	5.39
TOT. COAL (GN,BB,POLK)	**2,311**	**618,733**	**37.2**	**53.4**	**52.4**	**10,569**	**COAL**	**263,026**	**24,862,651**	**6,539,524.9**	**12,103,767**	**1.96**	46.02
SYSTEM	**4,402**	**1,099,479**	**34.7**	**65.7**	**63.7**	**9,394**	-	-	-	**10,329,058.1**	**32,259,001**	**2.93**	-

(1) Tons consumed and associated fuel expense were included in October 2003.

LEGEND:

H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: DECEMBER 2003

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	94	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	100	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	155	0	0.0	100.0	0.0	0	COAL	0	0	0.0	609	0.00	0.00
GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	299	0.00	0.00
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GANNON STATION (1)	**349**	**0**	**0.0**	**100.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**908**	**0.00**	**0.00**
B.B.#1	428	181,978	57.1	61.7	60.4	11,147	COAL	84,997	23,866,540	2,028,586.2	4,258,182	2.34	50.10
B.B.#2	433	120,784	37.5	44.6	55.3	10,772	COAL	54,663	23,802,000	1,301,094.2	2,738,509	2.27	50.10
B.B.#3	438	56,579	17.4	26.4	65.9	10,605	COAL	25,194	23,816,000	600,013.4	1,262,170	2.23	50.10
B.B.#4	460	147,521	43.1	54.4	72.9	10,386	COAL	71,623	21,421,160	1,532,095.6	3,583,161	2.43	50.10
B.B. STATION	**1,759**	**506,862**	**38.7**	**46.8**	**63.8**	**10,775**	**COAL**	**236,377**	**23,106,308**	**5,461,789.4**	**11,842,022**	**2.34**	**50.10**
SEB-PHIL. #1(HVY OIL)	17	2,676	22.7	98.5	86.6	9,747	HVY.OIL	4,468	6,273,540	28,033.4	155,206	5.40	34.74
SEB-PHIL. #2(HVY OIL)	17	2,832	22.4	100.0	82.8	9,747	HVY.OIL	4,400	6,273,540	27,601.7	152,844	5.40	34.74
SEB-PHILLIPS TOTAL	**34**	**5,708**	**22.5**	**99.3**	**84.7**	**9,747**	**HVY.OIL**	**8,868**	**6,273,529**	**55,635.1**	**308,050**	**5.40**	**34.74**
POLK#1 GASIFIER	260	162,788	84.1	90.8	92.7	8,924	COAL	80,286	26,794,160	1,816,291.4	2,409,364	1.48	39.97
POLK#1 CT (OIL)	245	3,024	1.7	97.5	48.2	10,326	LGT OIL	5,570	5,812,588	31,222.5	210,312	6.95	37.76
POLK#1 TOTAL	**260**	**165,792**	**85.7**	**97.0**	**91.2**	**9,931**	**-**	**-**	**-**	**1,846,513.9**	**2,619,676**	**1.58**	**-**
POLK#2 CT (GAS)	175	9,246	7.1	98.0	63.0	11,035	GAS	98,013	1,041,000	102,032.0	496,816	5.37	5.07
POLK#2 CT (OIL)	180	16	0.0	98.0	13.0	10,770	LGT OIL	29	5,812,457	168.0	1,091	6.82	37.62
POLK#2 TOTAL	**178**	**9,262**	**7.0**	**98.0**	**62.6**	**11,034**	**-**	**-**	**-**	**102,200.9**	**497,907**	**5.38**	**-**
POLK#3 CT (GAS)	175	5,117	3.9	100.0	63.7	11,486	GAS	56,461	1,041,000	58,775.4	286,855	5.61	5.08
POLK#3 CT (OIL)	180	582	0.4	100.0	53.0	12,509	LGT.OIL	1,252	5,812,585	7,278.8	47,287	8.12	37.77
POLK#3 TOTAL	**178**	**5,699**	**4.3**	**100.0**	**62.4**	**11,599**	**-**	**-**	**-**	**66,054.2**	**334,142**	**5.86**	**-**
POLK STATION TOTAL	**516**	**180,753**	**39.4**	**96.1**	**74.6**	**10,040**	**-**	**-**	**-**	**1,814,768.1**	**3,451,725**	**1.91**	**-**
B.B.C.T.#1	15	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	80	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	70	318	0.6	100.0	67.6	14,124	LGT OIL	771	5,788,362	4,463.3	27,675	8.76	35.89
C.T. TOTAL	**165**	**318**	**0.3**	**51.5**	**28.7**	**14,124**	**LGT.OIL**	**771**	**5,788,375**	**4,463.3**	**27,675**	**8.76**	**35.89**
CITY OF TAMPA	**6**	**245**	**5.5**	**0.0**	**0.0**	**11,132**	**GAS**	**2,620**	**1,041,000**	**2,727.4**	**26,529**	**10.83**	**10.13**
BAYSIDE ST 1	260	85,993	44.5	71.5	59.4	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	173	59,369	46.1	71.7	74.9	11,079	GAS	631,816	1,041,000	657,720.9	4,759,804	8.02	7.53
BAYSIDE CT1B	173	37,950	29.5	58.0	74.0	11,079	GAS	403,872	1,041,000	420,430.4	3,042,577	8.02	7.53
BAYSIDE CT1C	173	65,878	51.2	80.4	73.4	11,079	GAS	701,094	1,041,000	729,838.8	5,281,709	8.02	7.53
BAYSIDE UNIT 1 TOTAL	**779**	**249,190**	**43.0**	**70.5**	**69.2**	**7,255**	**GAS**	**1,736,782**	**1,041,000**	**1,807,990.1**	**13,084,090**	**5.25**	**7.53**
BAYSIDE ST 2	330	53,647	21.9	0.0	0.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	173	24,424	19.0	0.0	0.0	11,063	GAS	259,562	1,041,000	270,204.0	917,436	3.76	3.53
BAYSIDE CT2B	173	28,329	22.0	0.0	0.0	11,063	GAS	301,067	1,041,000	313,410.4	1,064,136	3.76	3.53
BAYSIDE CT2C	173	35,296	27.4	0.0	0.0	11,063	GAS	375,103	1,041,000	390,482.4	1,325,822	3.76	3.53
BAYSIDE CT2D	173	33,618	26.1	0.0	0.0	11,063	GAS	357,271	1,041,000	371,919.3	1,262,793	3.76	3.53
BAYSIDE UNIT 2 TOTAL	**1,022**	**175,315**	**23.1**	**0.0**	**0.0**	**7,678**	**GAS**	**1,293,003**	**1,041,000**	**1,346,016.1**	**4,570,187**	**2.61**	**3.53**
BAYSIDE STATION TOTAL	**1,801**	**424,505**	**31.7**	**70.5**	**69.2**	**7,430**	**GAS**	**3,029,785**	**1,041,000**	**3,154,006.2**	**17,654,277**	**4.16**	**5.83**
TOT. COAL (GN,BB,POLK	**2,368**	**669,630**	**38.0**	**59.4**	**57.5**	**10,568**	**COAL**	**296,662**	**23,855,727**	**7,077,090.8**	**14,252,294**	**2.13**	**48.04**
SYSTEM	**4,730**	**1,118,389**	**31.8**	**66.0**	**61.5**	**9,383**	**-**	**-**	**-**	**10,493,389.5**	**33,311,186**	**2.98**	**-**

(1) Dollars shown are for October 2003 fuel analysis.

LEGEND:

H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE

EXHIBIT NO. 95 Conf.

DOCKET NO: 031033-EI

WITNESS: JOANN WEHLE

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: TAMPA ELECTRIC COMPANY'S RESPONSES TO STAFF'S 5th REQUEST FOR PRODUCTION OF DOCUMENTS (NO. 38)

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 95
COMPANY/ FPSC Staff
WITNESS: TEC's Response to Staff's 5th Request (No. 38)
DATE: 05/27-28/04

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIFTH REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 38
BATES STAMPED PAGE: 5 - 22
FILED: MAY 5, 2004

38. Please provide all documents received by Tampa Electric from Drummond Company, Inc. (or any affiliate) after July 1, 2003, in which Drummond Company, Inc. (or any affiliate) proposes to provide coal commodity or any coal transportation or terminalling services for Tampa Electric.

A. The requested documents are attached.

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530 Beacon Parkway West, Suite 800
Birmingham, AL 35209
Tel: (205) 945-6400
Fax: (205) 945-6440

Drummond Coal Sales Inc.

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIFTH REQUEST FOR PODS

Fax

To: Karen Bramley	**From:** Dennis J. Steul
Fax: 813-228-1545	**Pages:** 2 inclusive
Phone:	**Date:** February
Re: FINANCIAL	**CC:**

☐ **Urgent** ☒ **For Review** ☐ **Please Comment** ☐ **Please Reply** ☐ **Please Recycle**

FitchRatings

55 East Monroe
Chicago, IL 60603

T 312 368 3100 / 800 48 FITCH
www.fitchratings.com

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIFTH REQUEST FOR PODS

July 3, 2003

Mr. John P. Stilwell
Senior Vice President,
Chief Financial Officer
Drummond Company, Inc.
P.O. Box 10246
Birmingham, AL 35202-0246

Dear Mr. Stilwell,

We hereby advise you that Fitch Ratings has affirmed the 'BBB' (Triple-B) corporate rating of Drummond Company for the following senior unsecured note issuances: Our Outlook is Stable.

Issuance	Due Date
$160 million - 9.51% Senior Notes, Series A	March 27, 2007
$30 million - 9.43% Senior Notes, Series B,	March 27, 2007
$150 million - 7.80% Senior Notes,	April 5, 2008

The rating is based on our review of a number of documents, including historical and projected financial information, industry data, discussions with senior management, and others.

In order to maintain our rating on the senior unsecured debt of Drummond Company, Inc. through the term of our rating agreement expiring December 31, 2003, we expect to receive all relevant financial information and other data deemed necessary for our ongoing monitoring, including financial statements, any amendments to the bank credit and note agreements, and covenant compliance reports. Notwithstanding the above, Fitch reserves the right to change this rating should business, financial or other conditions warrant.

Sincerely,

Randall P. Biang
Senior Director
Corporate Finance

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIFTH REQUEST FOR PODS

INTEROCEAN COAL SALES, LDC

c/o Truman Bodden & Company
P. O. Box 866
George Town, Grand Cayman
Cayman Islands, B.W.I.

January 28, 2004

Ms. Joann T. Wehle
Director – Wholesale Marketing & Fuels
Tampa Electric Company
P. O. Box 111
Tampa, FL 33601-0111

Dear Ms. Wehle:

Thank you for your recent correspondence requesting additional information relevant to our coal offers for the Big Bend Station Unit Number 4. Financial information listed below was supplied by our Senior Vice President and Chief Financial Officer.

Financial Information

Drummond Company Inc.'s revenues for the twelve months ended December 31, 2003 were approximately $1.0 billion, while the total assets at December 31, 2003 exceeded $1.2 billion.

Interocean Coal Sales

Interocean Coal Sales, LDC ("Interocean") was established in 1999 as a Cayman Islands limited duration company. Interocean purchases all of Drummond Ltd's coal production. Interocean manages the sales, marketing, credit, shipping and technical support to utility companies and product support activities related to coal sales to customers in North American, Europe and the Middle East. Drummond Coal Sales provides assistance to Interocean in carrying out these functions.

The purpose for establishing Interocean in a foreign jurisdiction was to provide an additional layer of support in maintaining the foreign source income characteristics of Colombian coal sales to U.S. customers. This is important because coal sales from Colombia to the U.S. are taxed in Colombia. To avoid double taxation (ie the U.S. and Colombia), the Company must be able to claim a foreign tax credit in the U.S. for the Colombian taxes. U.S. tax rules limit the amount of credit that can be claimed to U.S. income tax imposed on "foreign source income". By acting as an intermediary, Interocean provides the additional assurance that U.S. destined coal sales are considered foreign source income.

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIFTH REQUEST FOR PODS

Credit Rating Agency

Attached is a copy of the most current Fitch Rating letter dated July 3, 2003.

Price Reopener

Drummond accepts the price reopener after every 30 months. The parties will agree to determine a new price every 30 months, which will be applicable for the subsequent 30 months. We will also agree as to what will happen if there is no price agreement.

Big Bend Offer

In preparing our Big Bend offer we instructed our vessel agent to contact Big Bend personnel for port regulations, vessel size requirements, draft, etc. Big Bend personnel refused to answer these questions that were essential to preparing a transportation package into Big Bend. Therefore, we assumed an estimated LOA, beam, draft, daily discharge rate, structure clearances, etc. Should any of these assumptions be inaccurate, we may have to revise our delivered FOB offer to Big Bend. However, we are confident that we can bring ocean going vessels directly to the Big Bend Power Station which can be unloaded at the facility. We assumed a draft of 33.5 feet. Vessels arriving at Big Bend would clear customs at Big Bend.

Marigold Land Offer

Our coal would be transported from Colombia to the Port of Tampa where it would be unloaded directly to barge, to stockpile and then reloaded into trucks or into barges.

Any agreement between Tampa Electric and Interocean is subject to mutual agreement of all terms and conditions.

Sincerely,

George Wilbanks
Attorney in Fact

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TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIFTH REQUEST FOR PODS

FAX

Date 1/28/04

Number of pages including cover sheet 3

TO:	*Karen Bramley*
Cc:	
Phone	*813-228-1578*
Fax Phone	*813-228-1545*

FROM:	*George E. Wilbanks*
Phone	*205-945-6410*
Fax Phone	*205-945-6440*

CC:

REMARKS: ☐ *Urgent* ☐ *For your review* ☐ *Reply ASAP* ☐ *Please Comment*

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TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIFTH REQUEST FOR PODS

TECO
TAMPA ELECTRIC

FACSIMILE COVER SHEET

TO: George Wilbanks

FAX NO 205-945-6440
FROM: Karen Bramley

PHONE NO.: 813/228-1578
FAX NO.: 813/228-1545

DATE: January 19, 2004

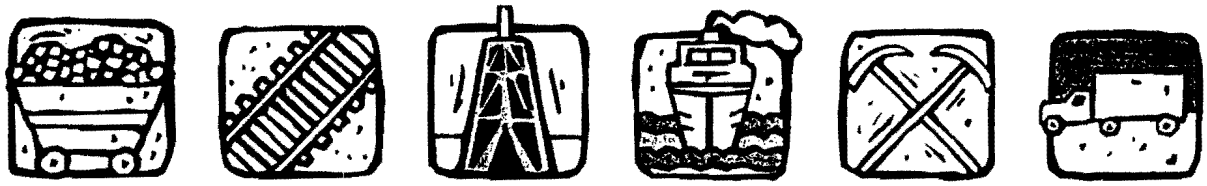
NO. OF PAGES (INCLUDING THIS COVER): 3

PLEASE DELIVER TO RECIPIENT AS SOON AS POSSIBLE

MESSAGE: PLEASE CONTACT OPERATOR IF PROBLEM WITH TRANSMISSION

Please see the attached.

TAMPA ELECTRIC COMPANY
Wholesale Marketing & Fuels Department
P.O. Box 111
Tampa, FL 33601
Switchboard: 813/228-4111



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TAMPA ELECTRIC

January 19, 2004

VIA FACSIMILE AND U.S. MAIL

Mr. George Wilbanks
Interocean Coal Sales, LDC
c/o Truman Bodden & Company
P.O. Box 866
George Town, Grand Cayman
Cayman Islands, B.W.I.

Dear Mr.Wilbanks:

Tampa Electric's Wholesale Marketing and Fuels Department would like to thank you for submitting a bid in response to our solicitation, Gen - 2005, for coal for Big Bend Station Unit Number 4.

Your bid is being evaluated to determine whether it was responsive to the terms of the solicitation and Tampa Electric's needs. In order to complete our evaluation, please provide the following information omitted from your response within 7 business days of receipt of this letter:

- Most recent Form10-K, Annual Report, or audited financial statements, including certified independent accountants report thereon for at least three full fiscal years.
- Please clarify your pricing. Do you accept Tampa Electric's reopener concept?
- For the Big Bend option, please provide more specifics about this delivery option including, the draft of the vessel? Will this be a customs cleared product?
- Please provide specific detail on the Marigold option? Specifically, how would the transportation to Big Bend be handled?

As indicated in the solicitation, Tampa Electric's final evaluation will include, but not be limited to, price, ability to supply, financial stability, credit worthiness, and other pertinent factors. After completing this evaluation, Tampa Electric will provide information on the status of your proposal.

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

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

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

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We appreciate the time and effort you expended in preparing your bid and look forward to receiving the additional information.

Sincerely,

Joann T. Wehle

Joann T. Wehle
Director – Wholesale Marketing & Fuels

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INTEROCEAN COAL SALES, LDC

c/o Truman Bodden & Company
P. O. Box 866
George Town, Grand Cayman
Cayman Islands, B.W.I.

1 0

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIFTH REQUEST FOR PODS

12/19/03.

December 18, 2003

Mr. Martin Duff
Wholesale Marketing & Fuels Department
Bid Proposal GEN-2005
Tampa Electric Company
702 North Franklin Street, P-5
Tampa, Florida 33602

Dear Mr. Duff,
Interocean Coal Sales, LDC is pleased to offer coal from Colombia, South America. Interocean Coal Sales, LDC is a subsidiary of Drummond Company, located in Birmingham, Alabama.

Drummond Company currently mines coal in Colombia at Mina Pribbenow, and next year plans to open two additional reserve tracts near Mina Pribbenow. These reserves will meet all of Tampa Electric's Big Bend No.4 quality parameters as stated in your tender dated November 21, 2003.

This coal is offered to Tampa Electric delivered to the Big Bend Dock via ocean-going vessels. As an option, we also offer this coal FOB barge at our coal transloading facility, Marigold Land Dock, located at the Port of Tampa, Tampa, Florida.

Term:	January 1, 2005 through December 31, 2014
Volume:	850,000 net tons per year
Specifications:	As per attached sheet supplied in the tender.
Weighing Method:	For vessels delivered directly to Big Bend, a vessel draft survey will be performed at Puerto Drummond by an mutually agreeable draft surveying organization. --OR-- For barges loaded at the Marigold Land Dock at the Port of Tampa, weights will be determined by a barge draft survey to be conducted by a mutually agreeable surveying organization.

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Price: As per attached sheet supplied in tender. Prices to escalate two-percent (2%) every 12 months commencing January 1, 2006.

This bid is valid for 120 days or through March 18, 2004.

All terms and conditions are subject to mutual agreement between Interocean Coal Sales, LDC, and Tampa Electric.

Sincerely,

George Wilbanks

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TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIFTH REQUEST FOR PODS

EXHIBIT 2

BIDDER'S PROPOSED PRICING AND QUALITY SPECIFICATIONS

Amount of Tons Offered	Term	Delivery Point	Pricing
850,000 NT per year	2005-2014	FOB Vessel Big Bend Dock	$41.35/NT
850,000 NT per year	2005-2014	FOB Barge Marigold Land Dock, Port of Tampa, Florida	$39.70/NT
Sales prices escalate 2% every 12 months. First escalation would be January 1, 2006			

These proposed as received **guaranteed** specifications will be used to determine delivered pricing and delivered quality. Unless otherwise stated, the guaranteed quality specifications should be a monthly average.

1. Monthly Average Specification

14.5 % Moisture. 12.0 % Ash 11,000 Btu/lb.
1.0 % Sulfur 0.10 % Chlorine

Shipment Specification

16.5 % Moisture. 13.0 % Ash 10,800 Btu/lb.
1.0 % Sulfur 0.10 % Chlorine

2. Please provide breakdown of typical Sulfur Forms (dry)
0.03 Sulfate (SO_4) 0.49 Organic 0.23 Pyritic (FeS_2)

3. Fusion Temperature of Ash F°

	(Reducing)	(Oxidizing)
Initial	2100 (Typical)	2275
Softening	2300 (Maximum)	2390
Hemispherical	2400 (Typical)	2475
Fluid	2500 (Typical)	2550

4. 47 Hardgrove Grindability Index.

5. 34-37 % Volatile Matter (Nominal Average).

6. 40-45 % Fixed Carbon (Nominal Average).

7. N/A % Sulfur in Ash.

8. 1.55 Average Fouling Index 0.28 Average Slagging Index 4.48 Average $\%SO_3$

9. Sizing
5-25% % 2" x 1 ¼"
35-80% % 1 ¼" x ¼"
10-55% % ¼" X 0"

10. Please provide the following trace minerals in coal (in ppm). (typical)
0.06 Mercury 3.89 Arsenic 4.15 Chromium
3.08 Lead N/A Vanadium

11. Indicate type of sample (core, pit, run-of-mine, run-of-prep plant, per ASTM, etc.) and conditions under which sample was taken core per ASTM. A STOPBELT, CROSS CUT, RUN-OF-PREP PLANT, OR RUN-OF-MINE SAMPLE TAKEN BY AN INDEPENDENT TESTING LAB IS PREFERRED.

As a reminder, please submit a recent (i) Proximate Analysis (as received and dry basis), (ii) Ultimate Analysis (as received and dry), (iii) Ash Mineral Analysis - ignited basis (include Silica Value, Base/Acid Ratio, and T-250 Temperature), and (iv) recent independent lab analysis report conducted using most recent ASTM standards on the proposed coal.

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EXHIBIT 3

COAL SELLER'S STATEMENT

1. The undersigned, herein referred to as Seller, is (check one):

_X_ A corporation organized under the laws of the ~~State~~ Country of British West Indies

operating as Interocean Coal Sales, LDC.
(full company name)

____ A partnership consisting of _____.
(list partner's names)
as _____.
(full company name)

____ An LLC organized under the laws of the State of _____.

____ An individual _____, of
(name)
_____, _____.
(city) (state)

2. Coal is available for sale from the mine described below and outlined on the Mine Location Map (to be attached).

Mine Name: Mina Pribbenow

State Mine Permit Number(s): N/A

Name of permittee if different than Seller. Explain any relationship, past or present, on a separate sheet: N/A

Previous mine name and producer, if any: None

Mine Location: (Nearest Town, County, State) La Loma, Cesar, Colombia

Loading Point: (Dock or Tipple Name) Puerto Drummond

River Name and Mile Point or Rail Line(s) serving loading point: Drummond Railroad, Puerto Drummond, and Marigold Land Dock - Tampa

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Acres of Property (Coal Reserves) controlled at this mine: 148,200

Proven Minable Reserves: (Tons) + One Billion Tons

Seam Name(s): Various

AverageThickness: Three meters

Days Mine Operated in last 12 months: 362

Tons Produced in last 12 months: 18 million net tons

Productivity of last 12 months: _____

Average Number of Production Employees for this mine for last 12 months: 1400

12-Month Production at Full Capacity: (Tons) 2004- 22 million net tons

Percentage of Full Capacity at Mine Available for Sale: +40 %

Will additional capacity or sections be required to satisfy this solicitation's requirements?

No. New reserves will be opened in 2004 which would satisfy TECO's requirements

Type Mine: _____ Underground or X Surface

If a subcontractor will mine, process, or transport the coal, list name(s) and contractual basis on a separate sheet.

3. Seller, if a producer has been operating coal mines for 60+ years and (check one or both):

_____ owns the described mining property and/or
X leases the described mining property from Colombian Govt, on the basis of (royalty or otherwise) royalty.

The rights to the property are recorded in the public records of N/A County, State of _____, Volume _____, Page(s) _____.

4. The Seller hereby certifies that the foregoing statements are true and correct.

Interocean Coal Sales, LDC	George E. Wilbanks
(Type or Print Producer's Full Name)	(Original Signature)
530 Beacon Parkway West, Suite 800, Birmingham AL 35209	Attorney-In-Fact
(Address)	(Title of Person Signing)

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ATTACHMENT I

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
STAFF'S FIFTH REQUEST FOR PODS

THE FOLLOWING NOTARIZATION IS REQUIRED IF THE SELLER IS THE BIDDER:

STATE OF Alabama

COUNTY OF Jefferson

On this 18th day of December, 2003,

_____, _____

(Owner) (Partner)

George E. Wilbanks to me personally known,

(Attorney-in-Fact)* appeared before me and, being by me duly sworn, did say he/she is of the firm described as Seller in the foregoing instrument, and that he/she executed the same with full authority so to do and as the free act and deed of such Seller.

WITNESS my hand and seal this 18th day of December, 2003

Notary Public

My Commission Expires:

6/22/04

* If Seller is a corporation, the person signing the instrument should insert his/her official title.

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(ED BASIS)

Undetermined	Silica Value	B/A Ratio	T250	Ash Type	Fouling Index	Slagging Index	TRACE ELEMENT ANALYSIS Antimony ug/g	Arsenic ug/g	Beryllium ug/g	Cadmium ug/g	Chromium ug/g	Cobalt ug/g	Copper ug/g	Lead ug/g	Manganese ug/g	Mercury ug/g	Nickel ug/g	Selenium ug/g	Zinc ug/g
0 00	57.05	0 61	2244	Bituminous	1 74	0 49	<1	8	<0 1	0 1	3	1	4	<1	37	0 10	3	3	6
0.00	62 64	0 47	2333	Bituminous	1.90	0 44													
0 00	79 18	0 27	2612	Bituminous	0 85	0 15	<1	1	0 2	<0 1	2	1	2	<1	15	0 10	2	2	6
0.00	62 13	0.53	2288	Bituminous	3 43	0 40	2	3	0.3	<0.1	2	2	2	1	25	0 07	4	2	5
0 00	84 25	0 23	2750	Bituminous	1 01	0 09													
0 00	81 60	0.30	2585	Bituminous	1 96	0 11	<1	<1	<0 1	<0 1	<1	<1	2	<1	5	0 03	1	4	2
0.00	87 94	0 17	2900	Bituminous	0 64	0.09	6	2	1 0	<0 2	4	6	2	<2	29	0 04	13	3	5
0 00	96 76	0 05	2900	Bituminous	0 05	0 02													
0.00	93 18	0.09	2900	Bituminous	0 14	0 06													
0.00	79.06	0 30	2562	Bituminous	1 11	0 25	2	3	0 4	<0 1	2	2	2	<1	12	0 04	6	3	7
0 00	78.23	0.30	2563	Bituminous	2 11	0 08	1	2	<0 1	<0.1	2	2	2	<1	8	0 09	4	3	9
0 00	72 60	0.33	2509	Bituminous	1 70	0 09	<1	2	<0 1	<0 1	<1	1	2	1	10	0 08	2	1	6
0 00	79 04	0 24	2868	Bituminous	0 22	0 26													
0 00	88 01	0 14	2900	Bituminous	0 21	0 09	4	3	1 2	<0 2	4	3	5	<2	7	0 06	10	<1	7
0 00	85.36	0.16	2900	Bituminous	0 13	0 11	3	3	0 5	<0 2	10	4	6	4	7	0 11	8	2	15
0 00	84 50	0 23	2752	Bituminous	1 04	0.07	<1	<1	0 1	<0 1	<1	<1	1	<1	15	0.03	2	<1	3
0 00	80 17	0 24	2681	Bituminous	0 62	0 15													
0.00	72 54	0 39	2419	Bituminous	2 02	0.14	1	<1	0 1	<0 1	3	2	3	<1	17	0 05	5	1	4
0 00	58 25	0.62	2237	Bituminous	3 77	0 28	1	1	0 3	<0 1	2	1	2	<1	29	0 04	4	1	4
0 00	59 33	0.52	2294	Bituminous	2 57	0 24													
0 00	81 20	0 22	2702	Bituminous	0 51	0 19	2	3	0 3	<0 2	8	4	6	5	75	0 06	12	2	16
0 00	87.59	0 37	2450	Bituminous	1 88	0 16	<1	<1	<0 1	<0.1	2	1	3	2	14	0 02	2	1	5
0.00	85.82	0 44	2365	Bituminous	3 15	0 15													
0 00	55 11	0 65	2225	Bituminous	4 97	0 23													
0.00	69.03	0 35	2482	Bituminous	0 61	0 81	8	11	1 1	0.8	15	10	14	8	6	0 03	34	5	37
0 00	68 39	0.39	2421	Bituminous	0 83	0 79													
0 00	65 60	0 39	2423	Bituminous	1 27	0 56	2	6	0 3	0 4	5	5	8	5	3	0 08	15	2	33
0 00	69 38	0 38	2458	Bituminous	1 40	0 26													
0 00	75 86	0 27	2596	Bituminous	1 37	0 19	3	1	0 2	<0 1	2	4	5	3	6	0 04	9	2	5
0.00	94 51	0 08	2900	Bituminous	0 16	0 04													
0 00	72 60	0 35	2481	Bituminous	1 25	0 32	2	3	0 3	<0 2	3	3	4	2	17	0 04	7	2	9
0 00	56 93	0 62	2238	Bituminous	4 85	0 47													
0 00	77 76	0 31	2545	Bituminous	1 80	0 22	2	<1	0 4	0 3	2	1	4	<1	2	0.03	3	<1	10
0 00	77 79	0 30	2557	Bituminous	1 31	0 31													
0 00	56 15	0 65	2224	Bituminous	2 51	0 84	2	12	0 3	0 2	3	2	4	2	13	0 11	6	<1	8
0 00	84 48	0 20	2742	Bituminous	1 03	0 13	<1	2	0 2	<0 1	3	2	5	2	2	0 04	3	<1	5
0.00	81 53	0 24	2664	Bituminous	1 26	0 12													
0.00	91 96	0 10	2900	Bituminous	0 24	0 07													
0 00	46 39	0 85	2170	Bituminous	2 89	1 33	2	4	0 6	<0 1	5	3	5	2	99	0 09	9	2	14
	74 36	0.34	2552		1 55	0 28	2 69	3 89	0 43	0 36	4 15	2 86	4 04	3 08	19 70	0 06	7 13	2 28	9 61

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12/17/2003

Seam Composite Description	Lab Number	Total Moisture	Dry Ash	Dry Sulfur	Dry Volatile	Dry BTU	Mef BTU	EQ MOIST	REDUCING FUSION IT	RF ST	RF HT	RF FT	OXIDIZING FUSION IT	OF ST	OF HT	OF FT	Sent for Trace	ULTIMATE ANALYSIS Dry Carbon	Dry Hydrogen	Dry Nitrogen	Dry Oxygen	CHLORINE Total Dry	Water Soluble	SULFUR FORMS Dry Pyritic	Dry Sulfate	Dry Organic	WATER SOLUBLE ALKALIS Dry Sodium Oxide	Dry Potassium Oxide	Total Phosphorus ug/g	MINERAL ANALYSIS OF ASH (IGNIT)										
258 #1	578504	18 85	3 97	0 80	41 12	13149	13674	13 8	2063	2151	2215	2325	2170	2230	2290	2360	X	74 35	5 07	1 61	14 30	0 03	0 01	0 29	0 01	0 50	0 093	0 003	20	39 71	14 98	0 62	15 89	0 60	3 85	0 89	2 85	12 01	0 09	0 10	0 57	0 08
240 #2	578507	18 58	4 75	0 94	39 80	13025	13672	13 8	2010	2100	2190	2270						74 16	4 96	1 53	13 66	0 04	0 01	0 30	0 01	0 63	0 139	0 003	20	38 88	20 28	0 62	15 46	6 26	1 85	1 01	4 05	9 76	0 10	0 10	0 65	0 04
238 #1	578509	14 82	4 44	0 5	39 72	13125	13736	12 3	2083	2260	2561	2698					X	75 06	5 01	1 50	12 85	0 04	0 01	0 18	0 01	0 35	0 066	0 002	10	58 60	12 56	0 51	8 82	4 82	1 67	0 79	3 16	8 23	0 05	0 09	0 54	0 04
238A #2	578511	16 09	4 38	0 75	41 22	13044	13643	13 2	1970	2030	2154	2415	2234	2361	2421	2450	X	74 41	5 20	1 60	13 65	0 05	0 01	0 23	0 01	0 51	0 049	0 002	20	38 17	18 97	0 68	14 40	7 05	1 82	0 94	6 48	10 34	0 08	0 13	0 98	0 05
238B #1	578512	15 52	8 54	0 41	39 50	12659	13481	12 2	1995	2253	2472	2612						72 44	4 86	1 47	14 28	0 08	0 01	0 09	0 01	0 31	0 062	0 001	20	62 48	12 50	0 48	6 94	3 48	1 26	0 98	4 37	8 73	0 05	0 10	0 58	0 05
238B #2	578513	15 81	4 13	0 37	39 80	13131	13698	13 0	1972	2251	2405	2486	2008	2256	2431	2544	X	75 48	5 08	1 52	13 42	0 04	0 01	0 04	0 01	0 32	0 053	0 001	10	58 92	7 50	0 28	7 23	4 68	1 38	0 85	6 52	12 40	0 08	0 12	0 80	0 04
238A #1	578608	17 36	7 40	0 52	38 80	12533	13529	14 0	2077	2540	2700	2700					X	71 82	4 70	1 42	14 14	0 04	0 01	0 09	0 01	0 42	0 088	0 002	20	68 35	10 21	0 40	8 30	2 18	1 02	0 68	3 78	5 43	0 05	0 08	0 46	0 05
238A #2	578609	14 08	21 71	0 34	31 86	10595	13013	12 2	2700	2700	2700	2700						60 60	3 83	1 16	12 36	0 04	0 01	0 02	0 01	0 31	0 048	0 003	30	66 39	8 09	0 29	1 50	0 98	0 41	0 52	0 94	0 59	0 03	0 05	0 19	0 03
238B #1	578610	13 28	17 05	0 86	38 23	11278	13595	11 8	2685	2700	2700	2700						64 18	4 40	1 36	12 14	0 04	0 01	0 03	0 01	0 52	0 132	0 002	20	81 58	8 77	0 25	4 37	0 90	0 70	0 63	1 54	0 91	0 03	0 00	0 21	0 04
238B #2	578611	14 68	5 02	0 82	40 28	12920	13603	12 8	1880	2333	2685	2700					X	74 03	5 12	1 56	13 45	0 05	0 01	0 23	0 01	0 58	0 096	0 002	10	82 56	6 03	0 28	11 31	4 03	1 23	0 37	3 70	9 82	0 03	0 08	0 52	0 04
218 #1	578612	15 85	4 08	0 28	41 07	13172	13728	12 8	2013	2132	2325	2677					X	75 35	5 12	1 45	13 74	0 05	0 01	0 02	0 01	0 25	0 044	0 001	20	50 24	20 25	0 89	8 14	4 08	1 76	0 35	7 03	6 05	0 13	0 12	0 82	0 04
218A #1	578613	14 81	3 27	0 28	39 78	13256	13704	12 1	2290	2395	2582	2700					X	76 52	5 11	1 40	13 42	0 08	0 01	0 02	0 01	0 25	0 039	0 001	10	47 37	21 98	0 84	9 86	5 48	2 51	0 11	5 16	5 39	0 10	0 11	0 82	0 04
218B #1	578615	14 37	13 21	1 10	38 64	11740	13286	12 2	2290	2436	2629	2700						66 58	4 54	1 37	13 10	0 04	0 01	0 33	0 01	0 78	0 145	0 007	30	61 36	18 68	0 67	13 59	1 78	0 91	1 60	0 91	7 03	0 06	0 05	0 28	0 06
208 #3	578618	13 32	8 81	0 67	40 37	12660	13420	11 2	2294	2697	2700	2700					X	72 45	4 99	1 50	13 58	0 06	0 01	0 11	0 01	0 55	0 083	0 003	10	66 36	17 73	0 50	5 02	2 70	1 23	0 91	1 53	3 35	0 05	0 07	0 42	0 04
178A #1	578736	17 35	10 49	0 68	38 64	12228	13681	12 9	2254	2428	2548	2700					X	69 71	4 74	1 37	13 00	0 01	0 02	0 25	0 01	0 43	0 070	0 003	40	59 72	21 55	1 07	5 59	3 07	1 58	2 40	0 80	1 08	0 08	0 07	0 36	0 03
178B #1	578737	14 85	3 41	0 32	40 85	13193	13643	12 5	2020	2420	2685	2700					X	76 20	5 33	1 40	13 34	0 01	0 01	0 03	0 01	0 28	0 052	0 001	30	68 02	7 85	0 26	6 78	3 99	1 71	0 14	4 53	5 76	0 23	0 06	0 80	0 05
178C #1	578739	14 52	5 28	0 81	39 97	13037	13765	11 7	2003	2294	2542	2700						73 86	5 20	1 50	13 54	0 01	0 02	0 14	0 01	0 46	0 074	0 001	30	50 62	18 27	0 96	9 28	3 55	1 92	1 91	2 57	1 14	0 14	0 08	0 52	0 04
178C #2	578740	13 58	3 37	0 37	40 60	13189	13828	11 9	1960	2094	2240	2530					X	76 56	5 17	1 54	12 99	0 01	0 01	0 04	0 01	0 32	0 051	0 001	10	52 57	13 15	0 77	11 61	5 38	2 80	1 09	5 17	9 32	0 08	0 11	0 79	0 05
178D #1	578741	13 53	3 12	0 45	41 07	13418	13848	11 2	1930	1961	2022	2085	2110	2260	2386	2447	X	76 87	5 10	1 54	12 92	0 01	0 01	0 07	0 01	0 37	0 061	0 001	30	35 05	18 57	0 73	16 70	7 52	3 05	1 03	6 08	8 86	0 22	0 12	1 90	0 07
158 #1	578742	15 45	3 33	0 46	41 08	13343	13803	12 2	1953	2045	2317	2432	2273	2356	2423	2496		76 40	5 18	1 53	13 09	0 01	0 01	0 03	0 01	0 42	0 052	0 003	170	38 91	22 02	1 12	18 20	5 94	2 53	0 78	4 95	3 33	1 15	0 14	0 85	0 07
140 #1	578745	13 58	7 37	0 88	38 56	12842	13457	10 8	2180	2445	2575	2700					X	73 44	5 00	1 44	11 87	0 01	0 01	0 32	0 01	0 55	0 128	0 004	30	56 79	23 30	1 05	10 74	1 47	0 94	2 19	2 33	0 83	0 10	0 06	0 37	0 03
140A #1	578673	15 18	2 56	0 42	40 26	13610	13867	11 7	2030	2140	2245	2380	2280	2350	2439	2475	X	77 51	5 15	1 48	12 65	0 01	0 01	0 29	0 01	0 12	0 068	0 001	90	41 61	27 50	1 05	11 65	5 86	2 44	0 94	5 04	2 24	0 78	0 10	0 15	0 04
140A #2	578674	15 33	2 29	0 35	40 60	13587	13816	12 2	1960	2080	2188	2265	2348	2475	2492	2523		78 02	5 18	1 54	11 62	0 01	0 01	0 03	0 01	0 31	0 034	0 001	80	39 11	24 13	1 09	11 25	6 46	2 60	0 90	7 15	5 37	0 78	0 14	0 97	0 05
140A #3	578675	16 24	2 25	0 35	40 83	13471	13781	12 8	2018	2055	2100	2154	2177	2280	2335	2418		78 48	5 06	1 56	12 30	0 01	0 01	0 02	0 01	0 32	0 040	0 001	150	31 80	48 98	0 67	14 17	8 45	3 28	0 60	7 65	10 20	1 57	0 18	1 19	0 06
140B #1	578676	13 37	11 15	2 30	40 59	12276	13818	10 8	2120	2250	2370	2400	2520	2570	2595	2630	X	68 14	4 78	1 51	12 11	0 01	0 01	1 09	0 25	0 96	0 170	0 008	40	48 36	24 15	0 93	10 64	1 34	0 73	2 06	1 73	0 48	0 09	0 06	0 36	0 03
140B #2	578677	14 87	8 41	2 03	41 34	12517	13672	11 7	1870	2025	2114	2250	2485	2580	2644	2688		70 17	5 02	1 53	12 84	0 01	0 01	0 96	0 17	0 88	0 164	0 005	30	53 73	16 58	0 81	22 16	1 77	0 67	0 45	2 14	1 11	0 09	0 06	0 40	0 03
130 #1	579078	14 17	5 86	1 44	40 63	13032	13808	11 4	2120	2170	2260	2380	2510	2600	2660	2675	X	74 20	4 89	1 54	13 57	0 01	0 01	0 99	0 01	0 44	0 173	0 005	50	44 06	25 87	1 01	20 47	2 01	0 62	1 33	3 26	0 57	0 29	0 07	0 49	0 03
130 #2	579079	14 75	3 12	0 73	40 27	13490	13924	12 0	2080	2170	2250	2334	2321	2376	2467	2557		77 06	5 07	1 59	12 43	0 01	0 01	0 21	0 01	0 51	0 057	0 002	30	47 43	22 08	1 07	14 52	4 90	1 51	0 66	3 89	2 75	0 23	0 09	0 61	0 04
130B #1	579080	18 29	4 27	0 69	41 30	13189	13786	12 8	2230	2320	2418	2510					X	75 07	5 15	1 60	13 22	0 01	0 02	0 15	0 01	0 53	0 092	0 001	30	47 18	28 75	1 55	9 85	3 94	1 22	0 56	5 08	0 92	0 18	0 06	0 68	0 03
128 #3	579082	14 12	7 24	0 46		12994	14009	11 4	2800	2700	2700	2700						74 09	4 79	1 58	11 86	0 01	0 01	0 02	0 01	0 43	0 052	0 001	30	78 15	13 67	0 43	2 65	1 37	0 32	0 14	2 28	0 30	0 10	0 06	0 29	0 04
128 #3	579083	16 38	4 93	0 80	41 30	13007	13687	12 6	2083	2243	2321	2486	2220	2350	2535	2620	X	74 85	5 01	1 58	12 72	0 01	0 01	0 30	0 01	0 59	0 124	0 003	80	57 05	16 10	0 54	10 85	7 98	0 61	0 78	3 56	0 44	0 37	0 09	0 47	0 04
118 #1	579084	15 89	1 56	0 75	41 08	13675	13892	12 0	1995	2033	2074	2103	2321	2443	2501	2615		78 67	5 14	1 72	12 18	0 01	0 01	0 13	0 01	0 61	0 087	0 002	40	34 80	20 65	0 93	19 58	5 13	1 67	0 70	7 82	7 15	0 54	0 12	0 92	0 04
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118 #3	579086	15 95	4 81	1 02	43 00	13209	13690	12 9	1995	2099	2220	2330	2740	2488	2559	2665		76 60	4 63	1 70	10 94	0 01	0 01	0 30	0 13	0 61	0 166	0 004	30	61 17	13 24	0 55	14 20	2 44	0 62	0 85	4 35	1 63	0 15	0 07	0 50	0 03
108 #1	579087	16 85	4 38	1 29	41 15	13202	13487	13 3	1920	1988	2075	2218	2235	2323	2375	2485	X	75 20	5 08	1 65	12 31	0 01	0 01	0 45	0 12	0 72	0 132	0 003	40	41 30	14 72	0 67	23 17	1 70	1 38	0 75	3 86	5 55	0 22	0 08	0 56	0 04
108A #1	579088	14 99	3 48	0 65	40 75	13302	13780	12 4	2220	2350	2480	2530					X	76 38	5 09	1 71	12 37	0 01	0 01	0 07	0 01	0 57	0 054	0 001	130	55 47	24 13	0 97	5 94	3 42	0 82	0 78	5 17	1 52	0 87	0 14	0 78	0 03
108A #2	579089	13 57	2 42	0 51	40 68	13503	13837	11 3	2128	2250	2413	2695						77 73	5 10	1 63	12 61	0 01	0 01	0 01	0 01	0 48	0 044	0 001	60	56 58	20 46	0 88	7 82	3 97	1 23	0 44	5 26	2 16	0 57	0 11	0 67	0 05
108A #3	579090	13 56	5 04	0 50	39 78	13157	13652	11 0	2290	2685	2700	2700						76 28	4 86	1 65	11 52	0 01	0 01	0 01	0 01	0 63	0 045	0 001	40	73 21	15 39	0 67	3 25	2 68	0 47	0 35	2 38	0 93	0 18	0 07	0 37	0 04
108B #1	579091	13 47	4 51	1 57	38 32	13324	13954	11 7	1921	2140	2298	2645					X	75 60	4 91	1 69	11 72	0 01	0 01	0 68	0 08	0 83	0 129	0 003	20	35 19	17 21	0 66	35 98	3 45	1 22	0 91	3 40	1 24	0 12	0 05	0 44	0 09
		15 03	5 75	0 75	40 12	12971	13736	12 21	2104	2267	2396	2502	2274	2390	2475	2547		74 20	4 87	1 53	12 76	0 02	0 01	0 23	0 03	0 49	0 09	0		54 10	17 55	0 74	11 93	4 75	1 52	0 88	4 86	4 48	0 26	0 09	0 68	0 04

EXHIBIT NO. 96

DOCKET NO: 031033-EI

WITNESS: JOANN WEHLE

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: TAMPA ELECTRIC COMPANY'S RESPONSE TO STAFF'S 3RD SET OF INTERROGATORIES IN DOCKET NO. 020001-EI (NO. 58)

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 96
COMPANY/ FPSC Staff
WITNESS: IECD Transp. Market Price Application 1992-2004
DATE 05/27-28/04

Please identify the amount of the difference between the Municipal Utility Railroad Benchmark for Coal Transportation and the Tampa Electric Weighted Average per ton Water Transportation Price for each of the years 1992 to 2001?

See the attached sheets that show the difference between the Municipal Utility Railroad Benchmark for Coal Transportation and the Tampa Electric Weighted Average per ton Water Transportation Price for each of the years 1992 to 2001.

EXHIBIT NO. ___
TAMPA ELECTRIC COMPANY
DOCKET NO. 930001-EI
(WNC-1)
DOCUMENT NO. 1
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1992 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources ($108,967,616 divided by 5,528,669)	$ 19.71
Transportation Benchmark	24.86
Over/(Under) Benchmark	$ (5.15)
Total Tons Transported in 1992	5,528,669
Total Transportation Cost in 1992	$ 108,967,616
Total Amount Allowable for Recovery Using Benchmark ($24.86 x 5,528,669)	$ 137,442,711
Total Cost Over/(Under) Benchmark - 1992	$ (28,475,095)
Prior Years' Cumulative Benefit (1988-1991)	$ (99,930,239)
Net Benefit for 1988-1992	$(128,405,334)

EXHIBIT NO. _____
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TAMPA ELECTRIC COMPANY
(WNC-1)
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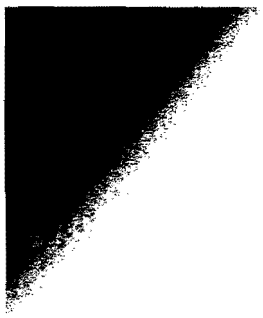
1993 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources ($110,153,430.70 divided by 5,598,533.05)	$19.68
Transportation Benchmark	$24.59
Over/(Under) Benchmark	(4.91)
Total Tons Transported in 1993	5,598,533
Total Transportation Cost in 1993	$ 110,153,430
Total Amount Allowable for Recovery Using Benchmark ($24.59 x 5,598,533)	$ 137,667,926
Total Cost Over/(Under) Benchmark - 1993	$ (27,514,496)
Prior Year's Cumulative Benefit (1988-1992)	$(128,405,334)
Net Benefit for 1988-1993	$(155,919,830)



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1994 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources ($118,100,936.70 divided by 5,911,253.65)	$19.98
Transportation Benchmark	$25.70
Over/(Under) Benchmark	(5.72)
Total Tons Transported in 1994	5,911,254
Total Transportation Cost in 1994	$ 118,100,937
Total Amount Allowable for Recovery Using Benchmark ($25.70 x 5,911,254)	$ 151,919,219
Total Cost Over/(Under) Benchmark - 1994	$ 33,818,282
Prior Year's Cumulative Benefit (1988-1993)	$(155,919,830)
Net Benefit for 1988-1994	$ 189,738,112

TAMPA ELECTRIC COMPANY
DOCKET NO. 020001-EI
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INTERROGATORY NO. 58
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FILED: OCTOBER 21, 2002

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TAMPA ELECTRIC COMPANY
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1995 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources ($112,667,576.96 divided by 5,358,447.19)	$21.03
Transportation Benchmark	$27.08
Over/(Under) Benchmark	(6.05)
Total Tons Transported in 1995	5,358,447.19
Total Transportation Cost in 1995	$ 112,667,576.96
Total Amount Allowable for Recovery Using Benchmark ($ 27.08 x 5,358,447.19)	$ 145,106,749.90
Total Cost Over/(Under) Benchmark - 1995	$(32,439,172.94)
Prior Year's Cumulative Benefit (1988-1994)	$(189,738,112.00)
Net Benefit for 1988-1995	$(222,177,284.94)

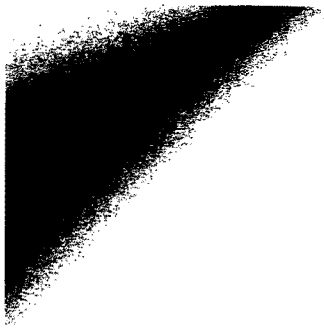

EXHIBIT NO. _____
DOCKET NO. 970001-EI
TAMPA ELECTRIC COMPANY
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Revised: 07/03/97

1996 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources ($123,459,906.58 divided by 6,391,305.11)	$19.32
Transportation Benchmark	$27.46
Over/(Under) Benchmark	(8.14)
Total Tons Transported in 1996	6,391,305.11
Total Transportation Cost in 1996	$ 123,459,906.58
Total Amount Allowable for Recovery Using Benchmark ($ 27.46 x 6,391,305.11)	$ 175,518,537.95
Total Cost Over/(Under) Benchmark - 1996	$(52,058,631.37)
Prior Year's Cumulative Benefit (1988-1995)	$(222,177,284.94)
Net Benefit for 1988-1996	$(274,235,916.31)

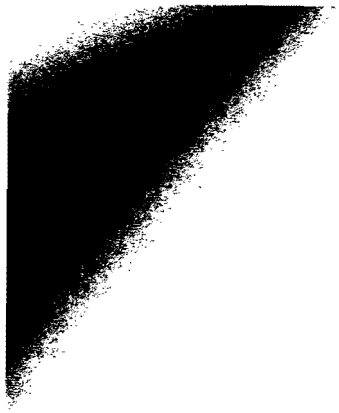

EXHIBIT NO. RB-1
DOCKET NO. 980001-EI
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(RB-1)
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1997 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources ($134,037,857.58 divided by 7,184,320.18)	$18.66
Transportation Benchmark	$28.10
Over/(Under) Benchmark	(9.44)
Total Tons Transported in 1997	7,184,320.18
Total Transportation Cost in 1997	$ 134,037,857.58
Total Amount Allowable for Recovery Using Benchmark ($ 28.10 x 7,184,320.18)	$ 201,895,989.25
Total Cost Over/(Under) Benchmark - 1997	$(67,858,131.67)
Prior Year's Cumulative Benefit (1988-1996)	$(260,742,395.51)
Net Benefit for 1988-1997	$(328,600,527.18)

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1998 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources (135,530,607.65 divided by 7,315,351.25)	$	18.53
Transportation Benchmark	$	28.14
Over/(Under) Benchmark		(9.61)
Total Tons Transported in 1998		7,315,351.25
Total Transportation Cost in 1998		$135,530,607.65
Total Amount Allowable for Recovery Using Benchmark ($28.14 x 7,315,351.25)		$ 205,872,272.55
Total Cost Over/(Under) Benchmark – 1998		$ (70,341,664.90)
Prior Years' Cumulative Benefit (1988-1997)		$(328,600,527.18)
Net Benefit for 1988 – 1998		$(398,942,192.08)

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1999 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources ($111,954,908.42 divided by 6,257,382.58)	$17.89
Transportation Benchmark	$25.85
Over/(Under) Benchmark	$(7.96)
Total Tons Transported in 1999	6,257,382.58
Total Transportation Cost in 1999	$111,954,908.42
Total Amount Allowable for Recovery Using Benchmark ($25.85 x 6,257,382.58)	$161,769,608.89
Total Cost Over/(Under) Benchmark – 1999	$(49,814,700.47)
Prior Year's Cumulative Benefit (1988-1998)	$(398,942,192.08)
Net Benefit for 1988 – 1999	$(448,756,892.55)

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DOCUMENT NUMBER-DATE
11890 SEP 21 8

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EXHIBIT NO. ___
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TAMPA ELECTRIC COMPANY
(JTW-1)
PAGE 2 OF 2

2000 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources ($129,165,507.33 divided by 6,187,276.74	$20.88
Transportation Benchmark	$26.23
Over/(Under) Benchmark	$(5.35)
Total Tons Transported in 2000	6,187,276.74
Total Transportation Cost in 2000	$129,165,507.33
Total Amount Allowable for Recovery Using Benchmark ($26.23 x 6,187,276.74)	$162,292,268.80
Total Cost Over/(Under) Benchmark – 2000	$ (33,126,761.50)
Prior Year's Cumulative Benefit (1988-1999)	$(448,756,892.55)
Net Benefit for 1988 – 2000	$(481,883,654.05)

CTR

MICHAEL B. TWOMEY
ATTORNEY AT LAW
POST OFFICE BOX 5256
TALLAHASSEE, FLORIDA 32314-5256
Tel. (850) 421-9530 Fax. (850) 421-8543
e-mail: miketwomey@talstar.com

July 9, 2004

Blanca Bayo
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 031033-EI - Review of Tampa Electric Company's waterborne transportation contract with TECO Transport and associated benchmark

Dear Ms. Bayo:

Enclosed are the Residential Customers submissions to Hearing Exhibit No. 97 to which TECO has already supplied the transcript of the deposition of Dr. Anatoly Hochstein.

Sincerely,

Michael B. Twomey
Attorney for the
Residential Electric Customers

cc: Parties

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 97
COMPANY/ Mike Twomey, Esq. for Res. Customers
WITNESS: Dr. A. Hochstein, late Filed exhibit
DATE 07/22-28/04

Teco letter to Blaca Bayo with late exhibit July 9, 2004.wpd

DOCUMENT NUMBER-DATE
07498 JUL-9 04
FPSC-COMMISSION CLERK

Dr. Anatoly Hochstein – Brief Bio

I received Masters Degree with honors in hydraulic engineering in 1955 from St. Petersburg University and PhD in economics in 1963, from Moscow University, both in Russia. Since my graduation I have devoted my professional life to water transportation industry and has participated in development of practically all major waterway and port systems around the world.

Since coming to the U.S. in 1973 I joined consulting company CACI, which at that time was engaged by the U.S. Army Corps of Engineers to develop Inland Navigation System Analysis (INSA) program. For this program I designed so called Flotilla model to calculate costs of barge operations. This model, although significantly modified by now, still is being utilized by USCOE as a principle analytical tool for inland waterway planning. In 1977 I joined Louis Berger Group, one of the largest international consulting companies with headquarter in East Orange, N.J. and three years later became Vice President in charge of water transportation programs. Among many projects I directed in that period can be mentioned a large-scale program "U.S. National Waterway Study", prepared for the U.S. Congress, participation as expert witness in litigation regarding construction of the Tennessee-Tombigbee Waterway, Structural and Non-Structural methods to increase navigation capacity and a long list of ports and waterways projects in South America and Asia.

In 1982 I was recruited to become Director and Distinguished Chair Professor of the newly established Ports and Waterways Institute at Louisiana State University. Concurrently I retain my position as a Vice President with Louis Berger Group. During my tenure as a first and current director of the Institute it has developed in the largest University based research center of maritime and intermodal research. In recognition of the Institute role it was designated by the Federal Maritime Administration as the National Institute. Among the programs completed under my direction just within last year are: - Market assessment for expansion of the Panama Canal; - Master Plan for Yangshan (Shanghai) port, the World's largest port construction project ($15 billion); - Louisiana Statewide Intermodal Plan and; - Evaluation of Shipping costs and Pricing in the Gulf of Mexico. The latter two research programs specifically included assessment of markets for coal and other bulk commodities, existing terminal capacities and detailed information on shipping costs in the Gulf of Mexico. Shipping costs were analyzed based on actual records for a variety of origin/destinations and vessel types in the Gulf and to/from the Lower Mississippi and ports of Houston and Tampa.

I authored or contributed to 5 books and published more than 60 articles in professional and scientific journals dealing with a broad range of water transportation issues. My latest book titled "Domestic Water Transportation-Comparative Review" is currently in print.

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Louisiana Statewide Intermodal Transportation Plan

THE MARITIME SECTOR

Submitted by:

National Ports and Waterways Institute
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LOUISIANA STATEWIDE INTERMODAL TRANSPORTATION PLAN

THE MARITIME SECTOR

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I. INTRODUCTION

The network of ports and navigable waterways in Louisiana is an important component of the intermodal freight transportation infrastructure. In terms of physical infrastructure it includes the navigable waterways-shallow and deep-draft, ports and intermodal connections serving waterfront activities, and the vessel fleet operating on the network. On a functional basis, it can essentially be defined as two subsystems: an inland barge transportation system engaged primarily in domestic commerce; and a deep-draft ports system providing access to international markets through the Gulf of Mexico.

The combination of inland barge transportation with ocean shipping has a pervasive effect on the system with regard to the type of cargos handled, terminal configurations, and the market structure of the maritime industry. The inland waterways system enabling efficient movement of low-value cargos for long distances through the interior has favored bulk material handling. Responding to scale economies typical to all phases of bulk cargo handling, namely, barge transportation, materials transfer at terminals and bulk ocean carriers, the maritime industry has developed as vertically integrated mega-terminals operated by large multi-national firms. The terminals handling grain and coal for export, cement, steel and crude petroleum imports, chemicals, etc. fall into this category and are responsible for a greater part of the tonnage handled.

However, the industry consists of other stakeholders at the waterfront, such as shallow and deep-draft public ports, small-scale service industries, shipbuilding and barge repair, offshore oil and gas supply services, etc. Therefore, the public policy framework for the state's maritime sector must recognize the physical and institutional characteristics of each subsystem within the industry.

1996 Statewide Intermodal Plan

The purpose of this section is to make an assessment of the current situation in the maritime industry as an update to the Louisiana Statewide Intermodal Transportation Plan (SITP) completed in 1996. As a complete assessment of physical capacities was undertaken and the results are included in that report, only important changes since then are discussed in this report[1]. The emphasis in this review will be more on institutional aspects of the industry that will help in public policy formulation. As the construction and maintenance of navigable waterways is a federal responsibility, the role of the state is mainly in facilitating federal agencies in their efforts. The ownership and operation of private terminals, barge transportation, and ocean shipping, etc., are largely by the private sector where infrastructure investment decisions are made under open market conditions. Therefore, the public sector role is mainly to create a favorable environment to attract private capital to the industry, and make selective public sector investments.

[1] For a detailed analysis in this area see The Working Paper on Water, Rail, and Intermodal Freight Transportation, Louisiana Statewide Intermodal Plan, LSU National Ports and Waterways Institute, July 1995.

For analytical convenience the discussion will concentrate on structural components of the industry in terms of the navigable waterway network, the port system and intermodal connections, the vessel fleet, etc. However, as economic development and industry productivity are inextricably linked with the institutional framework as well, the review will focus on several aspects such as industry structure and management, barriers to entry, throughput capacities and the market environment and emerging policy issues, etc.

II. THE NAVIGABLE WATERWAYS NETWORK

The physical infrastructure of the water transportation subsystem could be defined in terms of three main components, each component having a distinct set of issues relating to infrastructure planning.

- **The network of navigable waterways.** Federal funding for construction and maintenance of navigable waterways; the State share of such fundings, multi-dimensional uses of waterways for transport, flood control, water supply and water-based recreational activities

- **Ports and intermodal land connections**. Competing and complementary interests of public ports and private terminals, issues related to inland ports and ports handling foreign commerce, market competition from out-of-state ports, and strategic planning issues to meet the market competition.

- **The vessels fleet.** Completely operated by the private sector, incentives to the barge and ship building industry, capacity issues to meet seasonal demand, safety regulations for safety of humans and the environment, etc.

II.1 Navigable Waterways

Louisiana is located at the intersection of the two largest waterway networks, the Mississippi River System and the Gulf Intra-coastal Waterway, comprising 86 percent of the national network in terms of length and 97 percent of the system's overall tonnage. Therefore, the water transportation system provides accessibility to a large hinterland including states in the Mid-West and the Gulf Coast. These highly developed transportation systems with heavy traffic are efficient modes of transportation with increasing economies of scale, especially for low-value high volume bulk cargoes. As a result, a large number of multinational businesses engaged in foreign commerce, petrochemical industries, shipbuilding and many other value-added industrial activities are located at the waterfront.

The basic physical features and the traffic densities of the navigable waterway segments are shown in Table 1. As the data is reported from the U.S. Army Corps of Engineers database, the information on some segments extends beyond state boundaries. The major economic activities in foreign commerce are concentrated on the 236 river-mile long section on the Lower Mississippi below Baton Rouge. The ship cannel in this section is maintained at 45 feet. In addition, the Calcasieu Ship Channel (40 feet deep) serves as the access channel to the Port of Lake Charles and several other private terminals.

The data provided in Table 2 offers more information on the type of vessels and the type of major activities. Although the number of trips without vessel characteristics yields very limited information, it can be used to compare traffic densities on similar waterway segments. However, due to the principle difference between deep draft and shallow draft segments they should be viewed separately.

As the Lower Mississippi dredging up to Baton Rouge was completed in 1995 from 40 feet to 45 feet, we analyzed the vessel trips data for 1999 to make an assessment of the effect of this improvement. The data indicate that vessels with more than 40 ft draft used the river for 833 trips (Table 3). The major beneficiaries are the dry cargo terminals at the Port of South Louisiana accounting for more than 52 percent of the vessel trips. A similar analysis for trips made by vessels with more than 35ft. draft is also included for the Calcasieu Ship Channel and the Mississippi River Gulf Outlet (MRGO). The results indicate that in 1999 the Calcasieu Ship Channel had 434 such trips and 79 percent of these vessel trips were by tankers supplying crude petroleum to the refineries in the area.

Table 1
The Navigable Waterways Network in Louisiana by Major Segments

Waterway Segment	Length-miles	Depth-feet	Vessel trips in 1999
Atchafalaya River	121	14	15,442
Calcasieu River and Pass	110	12-40	50,640
GIWW- Mobile Bay, AL to New Orleans	134	12	48,655
GIWW- Mississippi R. to Sabine River	266	10-12	126,038
GIWW- Morgan City Port Allen Route	64	10	29,811
Baton Rouge to state border*	271	9	232,466
Miss. R. New Orleans to Mouth of Passes	106	45	209,254
Mississippi R. Baton Rouge to New Orleans	130	40-45	273,313
Mississippi R. Gulf Outlet	75	35	2,368
Red River Shreveport to Mississippi R**	236	9	5,787

Note:
* Trips shown for this waterway segment are from the Mouth of Ohio River to Baton Rouge.
**Trips shown for the Red River segment are traffic below Fulton, AR.
Source: Waterborne Commerce of the United States, U.S Army Corps of Engineers, 1999.

As no major capacity expansion projects are planned by the U.S. Army Corps of Engineers the waterway network and capacities are expected to remain at the present levels for the foreseeable future. The replacement of the Inner Harbor Navigation Canal (IHNC) lock with a larger (1200 feet by 110 feet) one is expected to improve operational efficiency of the system, eliminating congestion at the lock which averages delays of 11.5 hours per tow. IHNC which links barge traffic between the Mississippi River and the Gulf Intracoastal Waterway is also serving as a passage for deep-draft vessels between the Mississippi River and the Mississippi River Gulf Outlet (MRGO). The total cost of

the project is estimated to be $531 million and the construction period is expected to be about 14 years. The funding for the shallow-draft component of the project ($463 million) is from federal funds and the deep-draft component ($68 million) is to be funded by the Port of New Orleans.

Table 2
Travel Densities by Trips on Deep-Draft Navigable Channels in Louisiana-1999

Port Area*	Self-propelled vessels			Non self-propelled		Total
	Passenger /dry cargo	Tanker	Tow/tug	Dry cargo	Tanker	
Domestic:						
Baton Rouge	1,258	239	24,660	23,366	19,991	69,514
S. Louisiana	4,266	400	25,732	86,673	24,844	141,915
New Orleans	31,995	236	24,804	30,262	12,826	100,123
Plaquemine	24,032	726	4,864	22,528	3,539	55,689
MRGO	300	1	282	521	117	1,221
Lake Charles	28,697	313	5,797	3,782	10,102	48,691
Total	90,548	1,915	86,139	167,132	71,419	417,153
Foreign:						
Baton Rouge	564	597	1	0	1	1,163
S. Louisiana	2,462	1,110	23	19	4	3,618
New Orleans	5,260	766	76	68	8	6,178
Plaquemine	833	219	19	18	0	1,089
MRGO	1,093	26	14	12	2	1,147
Lake Charles	894	895	93	67	0	1,949
Total	11,106	3,613	226	184	15	15,144
Grand Total	101,654	5,528	86,365	167,316	71,434	432,297

Note:
The Mississippi River segments for port areas are measured by river miles beginning AtHead of Passes (AHP): Baton Rouge 253-168.5 AHP; South Louisiana 168.5-114.9 AHP; New Orleans 114.9-81.2 AHP; and Plaquemine 81.2-0 AHP.
Source: Waterborne Commerce of the United States, U.S Army Corps of Engineers, 1999.

II.2 Mississippi River Gulf Outlet

The Mississippi River Gulf Outlet (MRGO) provides a 36 ft. deep access channel to ocean liners from the Gulf of Mexico to the Port of New Orleans Inner Harbor Facilities. The outlet is about 37 miles and about 4 hours in travel time shorter than the traditional Mississippi River route. With that channel in place, the Port of New Orleans built the France Road and Jourdan Road Terminals. They have come to be known as the Tidewater Terminals and are the primary location of container activities at the Port of New Orleans.

In recent years, the MRGO has experienced grave problems related to coastal erosion and siltation raising environmental concerns. These problems have led to excessive

maintenance costs for the Army Corps of Engineers. Due to the excessive cost and environmental pressures, it is anticipated that the dredging funded by the Federal Government will cease in five to ten years. Due to these circumstances, the Port of New Orleans has undertaken a major rehabilitation program of the Mississippi River terminals. This includes major renovations at the Nashville Avenue Terminal. Once complete, the port container capacity will be doubled. Container vessels will continue to call at the Tidewater Terminals (as long as adequate draft is available) but the ports entire container operation will not be dependant on that single location.

Table 3
Vessel Trips Made in Deep-Draft Waterway Segments in 1999

Port	Passenger/dry cargo	Tankers	Total
Vessel Trips >40 ft draft:			
Baton Rouge	60	6	66
South Louisiana	431	13	444
New Orleans	86	58	144
Plaquemine	141	38	179
Vessel Trips >35 ft draft:			
Lake Charles	92	342	434
MRGO	86	5	91
Total	896	462	1,820

Source: Waterborne Commerce of the United States, U.S Army Corps of Engineers, 1999

II.3 The Red River Waterway

The major addition to the waterway network since 1990 was the opening of the J. Bennett Johnston Waterway (Red River) in 1994. It extends north to Shreveport adding another 236 miles of navigable waterways to the state's network. The total cost of the project is estimated to have been $1.989 billion, with a federal funding share of $1.889 billion. The Red River Waterway infrastructure includes five locks and dams, with a total lift of 141 feet. With its 200-foot wide channel and the depth of 9 feet, the waterway is designed to carry a six-barge-tow (Table 4).

Table 4
The Red River Waterway – Lock and Dam Characteristics

Lock and Dam	Location - River mile	Year of completion	Chamber width- feet	Chamber length-feet	Lift-feet
Lindy C. Boggs	28.7	1984	84	685	36
John H. Overton	88.0	1987	84	685	36
L&D 3	140.0	1991	84	685	36
Russell B. Long	208.0	1994	84	685	25
Joe E. Waggonner, Jr.	250.0	1994	84	685	25

Source: The 1997 Inland Waterway Review, U.S. Army Corps of Engineers, September 1997, Revised August 1999.

In addition, the U.S. Army Corps of Engineers is conducting a systems analysis on the seven locks on GIWW between the Mississippi and Sabine Rivers. The results of the reconnaissance phase of the systems analysis have indicated that all locks are structurally sound and the delays currently experienced are due to restrictive lock dimensions. Two of the locks, Bayou Sorrel and Calcasieu locks have been identified as priority projects for capacity expansion. However, the projects are in feasibility study stages and so far no investment decisions have been made.

Emerging Issues. The emerging issues on inland waterways are mainly national in scope, because the capacity of the network depends on the weakest link. Some of the issues that are of particular relevance to Louisiana are briefly discussed below.

- *Congestion* - Traffic congestion on the Upper Mississippi River and the consequent cost increases are of direct relevance to the Louisiana maritime sector. Low capacity for navigation in the Upper Mississippi may result in stagnation or even reduction of the element for Louisiana Maritime related infrastructure, first of all in grain export. Therefore, the proposed replacement of 600-foot long locks with longer (1,200-foot) is of direct relevance to Louisiana.

- *Funding*- The current fuel taxed system is limited to a fixed 20 cents per gallon levy, which becomes progressively smaller with inflation. With an aging infrastructure and escalating costs, the operation and maintenance budgets will be under constant pressure to cut down services. As a result a series of changes are likely to emerge.

- *Local Participation*- Higher amounts of cost sharing by local and state agencies

- *Abandon low-volume waterways*- This policy, which is referred to as "Navigation mission policy changes" by the Corp, is to adjust service levels at lower used segments of the network.

- *Revenue generating measures* – This suggests increased fuel taxes and user fees.

III. THE DEEP-DRAFT PORTS

The port system in Louisiana consisting of a large number of private terminals and twenty-six public ports can be classified in several ways. For the purposes of our analysis, the port sector will be discussed under three main categories: (1) Deep-draft ports, both public and private, engaged in foreign commerce; (2) Shallow-draft public and private ports mainly engaged in industrial processing activities and, (3) Coastal ports functioning as supply bases to the offshore oil and gas industry in the Gulf of Mexico.

The major differences can be discussed in terms of ownership as public and private ports, or in terms of shallow-draft and deep-draft ports, or as cargo-handling ports in contrast to ports functioning as industrial parks. In a typical port facility these differences are not very clear, for example, the private sector operating public facilities, dual operations of

industrial processing and cargo handling, etc. A detailed analysis of these characteristics is beyond this study. However, for statewide infrastructure planning and in public policy formulation, it is vitally important to recognize these divergent (and complementary) economic, regional and political interests.

All maritime terminals on the Lower Mississippi River segment (including MRGO) and the Calcasieu Ship Channel fall into this category. In general, the navigable waterway segments with more than 25 feet in depth are regarded as deep-draft port terminals. The six deep draft public ports located on the waterway segment from Baton Rouge to Mouth of Passes are among the largest in the nation in terms of tonnage handled (Table 5). A large number of private terminals operating in each public port area are primarily responsible for this performance.

The tonnage shown in Table 5 includes cargo handled at public as well as private terminals. The private sector contribution to the total tonnage comes from (1) the privately owned and operated port terminals typically dedicated to handle one type of cargo such as grains and coal export terminals and crude petroleum import terminals. These terminals are mostly under the management of multi-national firms with vertically integrated operations (e. g., grain buying at farm level, cleaning, blending for export and loading for shipping). The cargo handling activities are highly automated using state of the art equipment, with scale economies. Consequent to the recent increases in steel imports, several mid-stream terminals exhibiting similar characteristics have developed, transferring cargo direct from ship to barges in large volumes. (2) The private sector operators also lease public port facilities, and manage bulk cargo terminals, general cargo and container berths at public ports. The role of public ports is mainly to function as 'landlord' ports supplying port facilities to the private sector and engaging in port marketing and promotion activities.

Table 5
Deep-Draft Ports in Louisiana, Tonnages Handled, and National Rankings in 1999 (in 1000 tons)

Port	Total	Imports	Exports	Rank
South Louisiana	214,197	29,407	65,336	1
New Orleans	87,511	29,187	19,722	4
Baton Rouge	63,729	13,331	7,074	7
Plaquemines	62,461	12,839	9,011	8
Lake Charles	50,742	27,001	3,751	13

Note: Port of St. Bernard data is included with New Orleans *Source:* Waterborne Commerce of the United States, Part 5-National Summaries, U.S. Army Corps of Engineers, 1999

The private sector plays a significant role in operating public port facilities as well as supporting a large number of dedicated private terminals. In terms of waterfront infrastructure investments, the private sector is the largest, second only to the federal government outlays. One cornerstone of public policy must be to maintain favorable conditions for the private sector participation and encourage larger capital inflows to the industry from the private sector.

IV. CARGO FLOW ANALYSIS

An analysis of freight handled by the ports and waterways system is important for infrastructure planning studies to determine existing capacity utilization levels and constraints as well as future infrastructure needs based upon changing market conditions. An overview of the cargo volumes handled by the Lower Mississippi ports network in the 1990's indicates several important characteristics and trends (Tables 6 and 7).

- *Dependence on foreign trade* - The foreign trade share in total cargo handled remained steady at about 80 percent of the total traffic during the periods 1992-94 and 1997-99. Therefore, the variations in tonnage handled are closely related to international trade conditions. For example, the total traffic increased by 2.6 percent or by 6 million tons (214 to 220 million tons) during the period and the corresponding increase in foreign trade was 2.0 percent or by 4 million tons (181-185 million tons) (Tables6-7).

- *Few Major Commodities* - Six major commodity groups account for more than 90 percent of the cargo handled, and farm products remain at the top accounting for more than 30 percent of the total (Table 8). The petrochemical industry with links to commodity groups of crude petroleum, petroleum products, industrial and agricultural chemicals constituted 37 percent of all traffic handled during the 1997-99 period.

- *Cargo Trends* - Based upon the changes between 1992/94 and 1997/99 periods, all traffic grew by 2.6 percent and foreign trade by 2.0 percent, which is less than one percent annual growth in total tonnage for the Lower Mississippi segment. On the Calcasieu segment all traffic grew by 11. 4 percent and foreign trade by 15.1 percent, registering an annual growth of 2 percent and 3 percent for foreign trade respectively (Table 9). The trends for major commodity groups will be examined further under the cargo terminal analysis.

- *Structural Trends* - The variations in trends among individual commodity groups have resulted in significant structural changes in the total traffic and the total volumes of foreign trade (Table 8). For example, coal exports that contributed 6.5 percent to total foreign trade in 1992/94 decreased to 3.8 percent in 1997-98. A significant change from an economic viewpoint is the emergence of metals and primary manufactures as the third largest category, indicating an increase in container cargo. general cargo and neo-bulk cargo, mainly steel.

Table 6
Freight Traffic on the Lower Mississippi River – Baton Rouge to Mouth of Passes, Including MRGO (in tons 1000)

Commodity	1992-94 3-year average	1997-1999 3-year average	Change in tons	Change (%)
Coal	26,368	18,673	-7,695	-29.2
Crude petroleum	9,964	9,565	-399	-4.0
Petroleum products	42,018	40,562	-1,456	-3.5
Agricultural Chemicals	8,342	7,525	-817	-9.8
Industrial chemicals	21,987	24,028	2,041	9.3
Forest Products	246	857	611	248.4
Non metallic minerals	20,706	25,923	5,217	25.2
Metals and manufactures	9,571	17,602	8,031	83.9
Farm products	74,526	73,446	-1,080	-1.4
Other	541	1,703	1,162	214.7
Total	214,416	220,000	5,584	2.6

Source: Waterborne Commerce of the United States, Various issues, U.S. Army Corps of Engineers.

Table 7
Foreign Commerce Traffic on the Lower Mississippi River – Baton Rouge to Mouth of Passes, Including MRGO (in tons 1000)*

Commodity	1992-94 3-year average	1997-1999 3-year average	Change in tons	Change (%)
Coal	11,838	7,019	-4,819	-40.7
Crude petroleum	44,422	40,155	-4266	-9.6
Petroleum products	16,862	14,576	-2285	-13.6
Agricultural Chemicals	3,689	3,767	78	2.1
Industrial chemicals	3,261	4,088	827	25.4
Forest Products	652	1,160	508	78.0
Non metallic minerals	12,056	13,933	1877	15.6
Metals and manufactures	8,938	18,048	9110	101.9
Farm products	79,544	82,070	2526	3.2
Other	354	385	8	2.1
Total	181,667	185,240	3574	2.0

Source: Waterborne Commerce of the United States, Various issues, U.S. Army Corps of Engineers.

Table 8
Structural Changes in Waterborne Commodity Tonnage – 1992/94 and 1997/98 periods, Lower Mississippi including MRGO

Major Commodity Group	1992-94 average		1997-99 average		Trend
	Rank	Share of Total	Rank	Share of Total	1992/94 to 1997-99
All Traffic					
Farm products	1	34.7	1	33.4	(-)
Petroleum products	2	19.6	2	18.4	(-)
Coal	3	12.3	5	8.5	(-)
Industrial chemicals	4	10.3	4	10.9	(+)
Non metallic minerals	5	9.7	3	11.7	(+)
Manufactures and metals	6	4.5	6	8.0	(+)
Total	N.A.	91.1	N.A.	90.9	N.A.
Foreign Commerce					
Farm products	1	43.8	1	46.7	(+)
Crude petroleum	2	24.5	2	21.7	(-)
Petroleum products	3	9.3	4	7.9	(-)
Non metallic minerals	4	6.6	5	7.5	(+)
Coal	5	6.5	6	3.8	(-)
Manufactures and metals	6	4.9	3	9.7	(+)
Total	N.A	95.6	N.A	97.3	N.A.

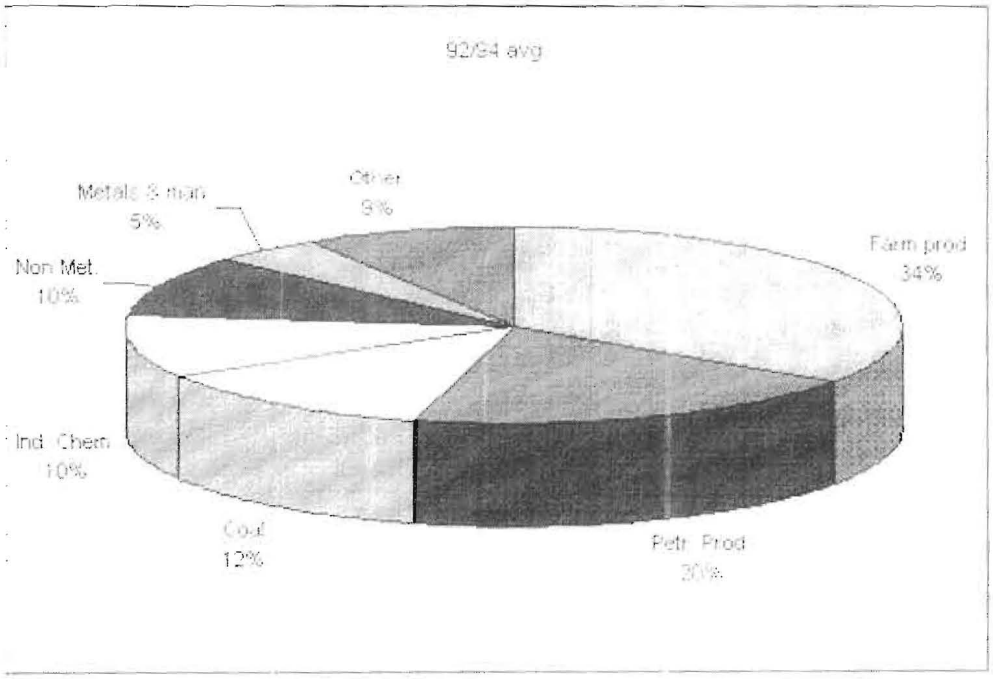
Source: Tables 6 and 7.

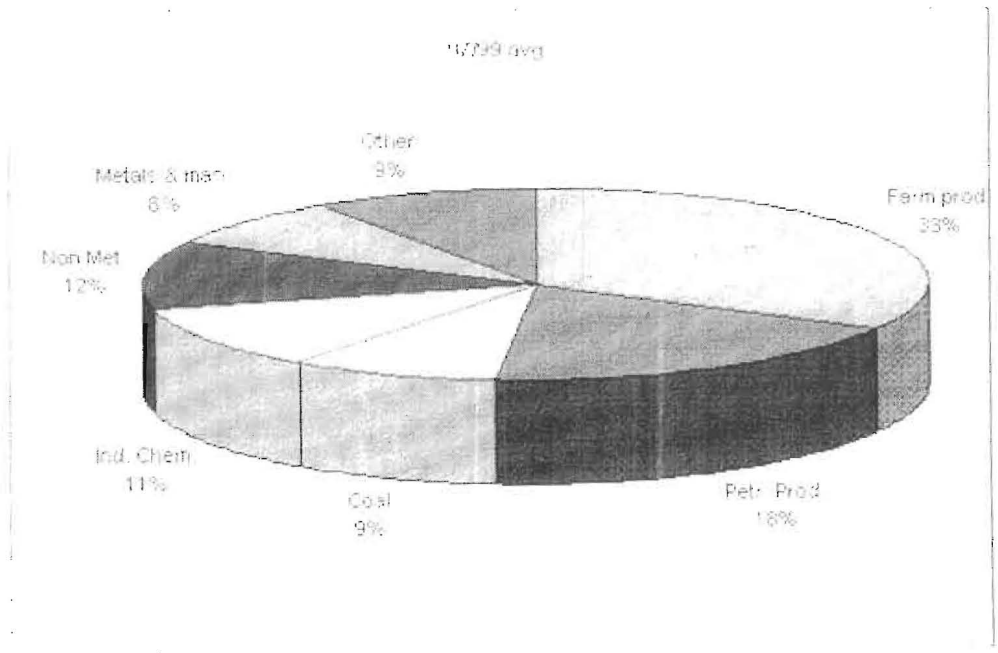
Table 9
Foreign Commerce and All-Traffic on the Calcasieu Ship Channel (in thousand tons)

	All Traffic			Foreign Commerce		
Commodity	92/94	97/99	Change%	92/94	97/99	Change%
Coal	119	119	-0.07	1.7	6.5	290.00
Crude petroleum	22,404	26,596	18.71	18,265	23,367	27.93
Petroleum products	15,664	15,365	-1.91	5,000	4,485	-10.30
Agricultural Chemicals	3,097	3,351	8.20	599	544	-9.09
Industrial chemicals	1,543	2,013	30.45	598	866	44.78
Forest Products	597	130	-78.17	487	119	-75.51
Non metallic minerals	1,854	3,008	62.25	1,018	1,872	83.78
Metals & manufactures	397	544	37.08	161	263	62.71
Farm products	1,410	1,223	-13.28	916	747	-18.50
Other	392	1,852	372.32	73	205	181.42
Total	45,935	51,172	11.40	26,520	30,358	15.15

Source: Waterborne Commerce of the United States, Various issues, U.S. Army Corps of Engineers.

Figure 1
Waterborne traffic on the Lower Mississippi- commodity shares 92/94 and 97/99 periods





IV.1 Grain Export Elevators

During the 1990's farm products were responsible for more than one-third of the tonnage handled. Grains and grain products constituted more than 70 percent of this tonnage. For example, out of the 79 million tons handled in 1999, 77 million tons consisted of corn, wheat, soybeans, and processed grains for animal feed. The mutual interdependence of agriculture and inland waterways in the U.S. is due to several interesting factors. The interior location of farms far away from domestic markets and deep-draft ports for exports and the bulky nature of inputs and outputs fits in very well with what inland waterways can offer- economical long distance transportation for low-value bulky cargoes. On the other hand, as farm products provide the vitally important cargo base for inland waterways, the interdependence is mutual.

The grain exports from Louisiana are handled by land-based export elevators (Table 10), by floating rigs located mid-river (Table 11) and by direct transfer from barges to ocean vessels. The essential difference is that the land-based elevators have the added capability of performing two important value-added activities: grain blending and grain storage.

Table 10
Grain Export Elevators in Louisiana – Shipping Capacities

Name of Elevator	River mile	Storage Capacity (bushels)	Load Cap./hr (bushels0	Number Shipping bins	Capacity in each bin	Number Shipping Spouts	Number Shipping Belts
Myrtle Grove	61.0	6.5 m.	90,000	6	30,000	4	1
Cargill-Westwego	102.8	4.3m	100,000	12	30,000	6	4
ADM-Growmark-Ama	117.5	5.0m	80,000	8 8	20,000 40,000	4	2
Bunge Grain	120.1	6.2m	80,000	7	20,000	8	2
ADM-Growmark-Destrehan	121.0	6.27m	80,000	9	25,000	7	2
ADM-Growmark-Reserve	139.0	3.6m	80,000	4	5,000	3	2
Zen-Noh Grain	164.5	4.0m	120,000	12	30,000	4	2
Port of Baton Rouge	228.0	7.0m	60,000	none	n.a.	4	1
Lake Charles Public Elevator	N.A.	0.75m	25,000	3	12,000	2	2
Total	---	43.62m	715,000	68	1.72m*	42	18

*Total bin capacity
Source: Directory of Export Elevators, Foreign Grain Inspection Service, U.S. Department of Agriculture, August, 2000.

Table 11
Mid-River Direct Loading Facilities for Grain Exports in Louisiana–Shipping Capacities

Name of Facility	River mile	Storage Capacity (bushels)	Load Cap./hr (bushels)	Number Shipping Spouts	Number Shipping Belts
Gemini Floating Rig	121.1	None	27,500	1	none
Cargill-Terre Haute	140.0	7.743m	100,000	4	2
Peavey Elevator	150.0	2.0m	60,000	1	1
Delta Floating Rig	157.0	None	50,000	1	1
K-2 Barge Floating Rig	158.0	None	60,000	1	none
RG-1 Floating Rig	175.0	None	30,000	1	none
Rig-America	175.0	None	47,000	1	none
Total	---	9.743m	374,500	10	4

Source: Directory of Export Elevators, Foreign Grain Inspection Service. U.S. Department of Agriculture, August 2000.

Except for the public grain elevator at the Port of Lake Charles, all other grain export elevators are located on the Lower Mississippi River (Table 12). The concentration of thirteen of them on a 75-mile stretch of the River is partly related to the fleeting operations of barges. The land-based grain elevators are complete facilities with long-term storage and highly automated grain-conveying systems. They are typically owned and operated by large multinational corporations with vertically integrated marketing functions controlling activities from the farm level all the way to international transactions. In order to exploit progressively increasing scale economies the land-based export elevators are designed to handle large volumes. The floating rigs, where grain is loaded directly using floating cranes are more modest investments compared to land-based elevators. The flexible aspects of this operation are the ability to use the mooring and cranes to handle variety of cargo at low costs. However, the uninterrupted supply of barges for loading and minimizing barge demurrage are two major challenges.

Table 12
Summary of Export Grain Elevator Characteristics on the Lower Mississippi

Characteristics	Description
Number and type	Land-based 8 and floating rigs 7. Total 15
Location	Thirteen out of the fifteen are located between River miles 100-175.
Average storage capacity	5.36 million bushels for land-based elevators.
Average loading capacity per hour	Land–based elevators 86,000 bushels/hour; floating rigs 53,500 bushels/hour.
Avg. # of shipping bins and capacity	7.2 shipping bins with 191,000 bushels capacity (land-based elevators only).
Avg. # of shipping spouts	Land-based elevators 4.4; floating rigs 1.4
Avg. # of shipping belts	Land-based elevators 1.7; floating rigs 0.6

Sources: Tables 10 and 11

Emerging Trends. The U.S. role as an exporter of food is projected to continue into the foreseeable future. However, the long-term growth rates of grain exports are tied up with a combination of economic factors and government policy in the U.S. as well as in importing countries. In general, the major determinants are:

- *Economic* - As grains and oilseeds are food or feed products the demand will depend on population growth, income and consumer preferences.

- *Trade*- Volumes of foreign trade will be determined by domestic production and use patterns, trends in global trade and regional specialization.

- *Technology*- Even though agricultural biotechnology is in its infancy, separate handling systems for bio-engineered products and non-bio-engineered products may be necessary to maintain grain quality. Further, as genetically modified crops are not accepted in certain markets additional storage systems may be necessary.

The export projections made by the USDA for major export crops are shown in Table 13. A key assumption in deriving these estimates is that U.S. government agricultural policies will continue without substantial change during the period. According to the estimates export volumes are projected to grow in the next 20 years by 42 percent, mostly corn and soybean shipments.

As export volume is the excess production left over after domestic use, grain and oilseeds utilization patterns in the domestic markets are an important determinant. Because of the fast growing livestock industries (poultry, beef, pork, and dairy), increasing quantities of corn and soybean will be diverted to the domestic market. Therefore, the demand for grains as feed is projected to increase in the next 20 years by an average of 28 percent.

Table 13
U.S. Grains and Oilseeds Exports - 1999 (actual) and 2020 (projected)

Commodity	1999	2020	Change in Volume	Change in (%)
	Million	bushels		
Corn	1875	2810	935	49.9
Soybeans	965	1488	523	54.2
Wheat	1090	1293	203	18.6
Total	3930	5591	1661	42.3

Source: U.S. Department of Agriculture, *Agricultural Transportation Challenges of the 21st Century, Agricultural Marketing Service, November 2000.*

IV.2 Coal Terminals

Coal is a major commodity transported on the Lower Mississippi contributing on the average 10 to 12 percent of the total waterborne tonnage. The transportation of coal in Louisiana is primarily for three purposes: for local use at electric utilities and industrial plants; through traffic in transit from producing states to consumption states and coal shipments for export.

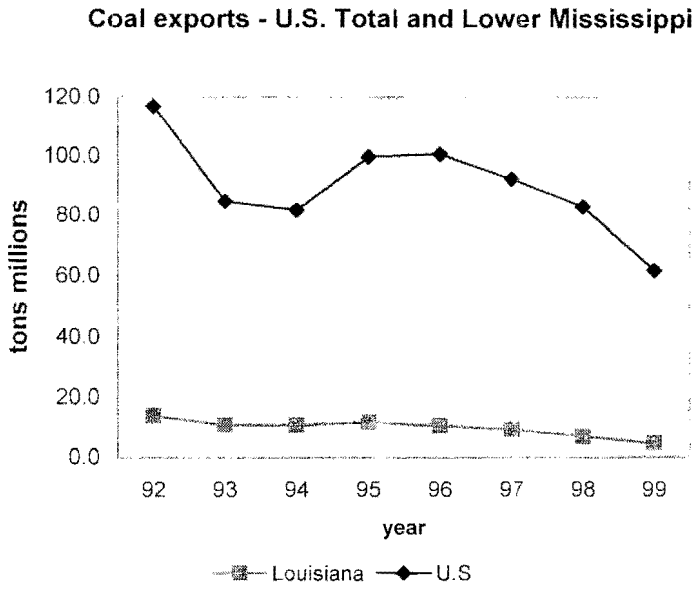
Coal for local use – Electric utilities and other industrial plants used 15.8 million tons of coal in 1998. Out of this tonnage 10.3 million tons were transported by rail from Wyoming to the Big Cajun Electric Utility and another 3.5 million tons were locally produced and consumed in the same area. Thus, only about 2 million tons were transported by water for local use in the state.

Coal in transit – The major movements under this category are the coal movements moving down the Mississippi and then to destination points in Florida using the Gulf Intra-coastal Waterway. In 1998, 5.2 million tons of coal moved through the Louisiana waterway system as domestic transshipments.

Coal for export – Coal exports from the lower Mississippi steadily declined from 13.9 to 4.7million tons during 1992-99 period, a decrease of 76 percent. In comparison, for the same period, the decline in total coal exports from the U.S. was more modest- from 102.5 to 58.5 million tons (43 percent decrease). As a result, export market share handled by Louisiana ports declined during the period (Figure 2).

Terminal capacities – Major coal export terminals on the Lower Mississippi along with the specifications of major components are shown in Table 14. Three of the facilities are land-based terminals with capabilities for storage, blending, and a variety of cargo transfer options such as from the yard to ship, direct transfer from barge to ship etc. The Cooper/T. Smith facility is a direct-load facility operated with floating cranes. The combined annual tonnage that can be handled by the four facilities is estimated to be 56 million tons. Obviously, the export volumes of coal in the 1990's were too low to utilize the full capacity of the terminals. Fortunately, as the designs of these terminals are suitable for handling other dry-bulk cargos, a gradual diversification of the cargo base ensued from coal to pig iron, barite, cement, steel billets, etc. For example, IMT terminal where coal to other cargo ratio was 70:30 percent 1980's diversified its cargo base to a ratio of 45:55 in 1999, making the coal tonnage less than the other cargo.

Figure 2
Coal Export Trends: U.S. Total and the Lower Mississippi 1992-1999



Emerging Trends - World coal markets were imbalanced for the greater part of the 1990's with supply exceeding demand. As this over supply will continue, U.S. coal exports are projected only to moderately exceed present levels during the next decade[2]. While U.S. coal exporters are efficient producers and supply15 percent of world demand,

Venezuela has negatively impacted U.S. steam coal exports. Export markets for metallurgical coal have been declining because of the expansion of new steel making technologies requiring less high-grade coal.

Overall, Louisiana terminals experienced modest losses in market shares during the period. For example, coal exports from Mobile declined only by an average annual rate of 2.4 percent during the period 1994 to 1998, compared to a decline of 15.4 percent for the local terminals. However, as the coal varieties handled and the time periods involved are short, this cannot be considered as a long-term trend. Further, it is possible that Louisiana coal terminals were able to substitute coal handling with other activities.

[2] U.S. Department of Commerce, International Trade Administration. http://www.ita.doc.gov/td/energy/coalexpt.html

Table 14
Louisiana Coal Terminals

Burnside Bulk Terminal	Cooper/T. Smith	Electro-Coal Transfer		International Marine Terminals
Operating Company: Burnside Bulk Marine Terminal (a division of Ormet) ***Berth Dimensions and Constraints:*** 267.3m length, 14.6m draught. Minimum of two berths available for serving panamax or larger vessels: one shipdock. One midstream buoy system. Barges discharged at landside face of ship wharf or at midstream buoys. ***Dockside Equipment:*** Two 1,000tph grab gantries for vessel loading and discharge, floating crane, conveyors, mobile plant. Annual handling capacity: Total operating capacity in all mineral bulks exceeds 5mta, 42-yard bucket. ***Coal Intake Facilities:*** Direct from ship or barge ***Reloading Facilities:*** Direct from ship to barge, or from storage to ship/barge or rail load station ***Stockyard Capacity:*** 450,000 tonnes ***Stockyard Equipment:*** Stacker, loading shovels ***Largest Vessel to Date:*** *Small Cap*	***Operating Company:*** Cooper/T. Smith ***Berth Dimensions and Constraints:*** 45 ft. draught ***Annual Throughput Capacity:*** 15mta ***Handling Equipment:*** 10 floating clamshell derricks up to 50yd capacity. ***Daily Loading Rate:*** 30,000tpd ***Daily Discharge Rate:*** 30,000tpd ***Discharge Equipment:*** Floating Cranes *Largest Vessel to Date:* 135,000dwt *Other Services:* Barge fleeting, cover handling	***Operating Company:*** Electro-Coal Transfer ***Berth Dimensions and Constraints:*** Dock 1 - 1,880 ft. length; Dock 2 – 1,164 ft. length, draught 55-85 ft. ***Max. Vessel Size/weight/capacity:*** Dock 1 – 950ft, 140ft beam, air draught 55ft. Dock 2 – 750ft, 105ft beam, air draught 75ft. ***Loading Equipment:*** Traveling shiploader, stationary shiploader, two traveling clamshell gantry cranes, two Manitowoc and three midstream cranes. ***Annual Loading Capacity:*** 25mta ***Annual Throughput Rated Capacity:*** 25mta ***Coal Intake Facilities:*** Two clam shell cranes rated at 1,500tph each ***Discharge Equipment:*** Two continuous barge unloaders and two grab bucket unloaders.	***Annual Discharge Capacity:*** 25mta -- Maximum discharge capacity 25mta ***Largest Vessel to Date:*** *Jean LD*, length 925m, width 165m, 133,000dwt ***Largest Cargo:*** 120,102 tonnes. ***Stockyard Capacity:*** ***5mt.*** ***Stockyard Equipment:*** Two stacker/reclaimers (bucket wheel) 6,000tph and 4,200tph ***Coal Processing Facilities:*** Three sizes portable screening system, cargo blending with above listed stockyard equipment and river barge unloaders. ***Other Services/Development Plans:*** Blending screening and soft loading services. Barge and tug fleeting service.	***Operating Company:*** International Marine Terminals ***Berth Dimensions and Constraints:*** Two coal loading berths (one traveling and one stationary) Traveling: length of dock 318.9m, 50 ft. draught. ***Loading Equipment:*** One traveling shiploader, one stationary loader, one level luffing crane, ISO 4 floating cranes ***Daily Loading Rate:*** Traveling: 50,000tph, Stationary: 35,000tph ***Annual Loading Capacity:*** 18mta (ground terminal and midstream) ***Coal Intake Facilities:*** Barge/coaster: Barge or vessel uploading available.

Source: *International Bulk Journal, August 1999*

Coal imports to the U.S. increased at an average annual rate of 13.2 percent during the period from 1989-1998, providing a logistical advantage to coastal states with the import terminals. The largest importing states in the Gulf Region are Florida, Louisiana, and Alabama in that order. If imports continue to increase, the current coal movements from Louisiana to utilities in Florida (about 5 million tons) may face market challenges. However, the speed of market adjustments are conditioned by long-term supply contracts in force between suppliers and users.

The substitution of imported coal in domestic markets will result in shrinking demand for transportation and tighter competition between rail and barge operators. Again, these are potential developments and the current market share of imports is very small.

IV.3 Break-bulk and Neo-bulk Terminals

The container, break-bulk and neo-bulk cargos are broadly identified as general cargo. The difference among three categories is: container cargo is in standardized steel containers and measured in twenty equivalent units (TEU); break-bulk cargo can be described as conventional packaged goods, and neo-bulk cargos are large consignments of loose cargo such as steel billets, steel wire coils, sawn timber etc. The classification is important from a cargo handling perspective as port infrastructure requirements and operations will be very different to the requirements for handling bulk cargo.

A functional classification of cargo handled by Louisiana ports in 1999 indicates that 4.3 percent of the tonnage handled falls into this category, with break-bulk and neo-bulk comprising 9.4 million tons (Figures 3 and 4). The typical terminal design for handling general cargo consists of alongside a ship-berth, transit sheds and yard space for storage, and cranes and other cargo handling equipment. Five deep-draft ports in Louisiana (except Port of Plaquemine) have facilities to handle break-bulk and neo-bulk cargo. The Ports of New Orleans and Lake Charles handle more than 98 percent of the cargo (Table 15). A substantial part of this cargo consists of steel billets and coils wire directly transferred from ship to barges.

Large shipments of steel imports made in the latter part of 1990's contributed to rapid growth of neo-bulk cargo. Between 1992/94 and 1997/1999 the tonnage handled doubled (see Table 7). In addition to the cargo that is handled at public terminals, several mid-river rigs also handle steel products. As most steel products need covered storage, bulk of the shipments are directly transferred from ship to barge or rail wherever possible. The break-bulk and neo-bulk terminals are multipurpose terminals that can adapt to variety of operations.

Emerging Trends - The construction and commissioning of the Globalplex terminal in May 2001 resulted in increasing the general cargo handling capacities. The facilities at this terminal consists of 204ft. wide and 690 ft long cargo dock, two new M-2250 Manitowac Electrical Gantry Cranes rated at 150 tons each, and 177,000 square feet of yard space. The construction of a warehouse is in planning stages. The total cost of the project is estimated at $30 million.

However, except for steel products, the markets remained tight for break-bulk and neo-bulk cargos throughout the 1990's. The remarkable growth in steel tonnage favored direct transfers from mid-river rigs using floating cranes on both sides of the vessel. The growth in mid-river rig capacities responding to increases in steel shipments is a classic example of industry adjustment to market needs. As alongside berths did not offer any additional operational advantages in direct cargo transfer their utilization was limited. For example, the general cargo docks at the Port of Greater Baton Rouge handled 222,000 tons in 1999 compared to its typical annual volumes of 600,000 to 700,000 tons. The downward pressure on rates due to fierce competition, and stagnant overseas markets for paper and forest products are among the major factors, affecting break bulk and neo-bulk market.

Table 15
Container, Break-bulk and Neo-bulk cargo Handled by Louisiana Ports in 1999

Port	Container	Neo-bulk/ break-bulk	Total	Share (%)
		(tons)		
New Orleans	3,263,475	7,948,646	11,212,121	87.0
Baton Rouge	---	222,308	222,308	1.7
Lake Charles	288,121	1,083,884	1,372,005	10.7
South Louisiana	----	75,000*	75,000	----
St. Bernard	------	----	----	----
Total	3,551,596	9,329,838	12,881,434	100.0

Notes: (---) no significant amounts, (*) Estimated

Figure 3
Classification of Louisiana Foreign Trade by Cargo Type, 1999

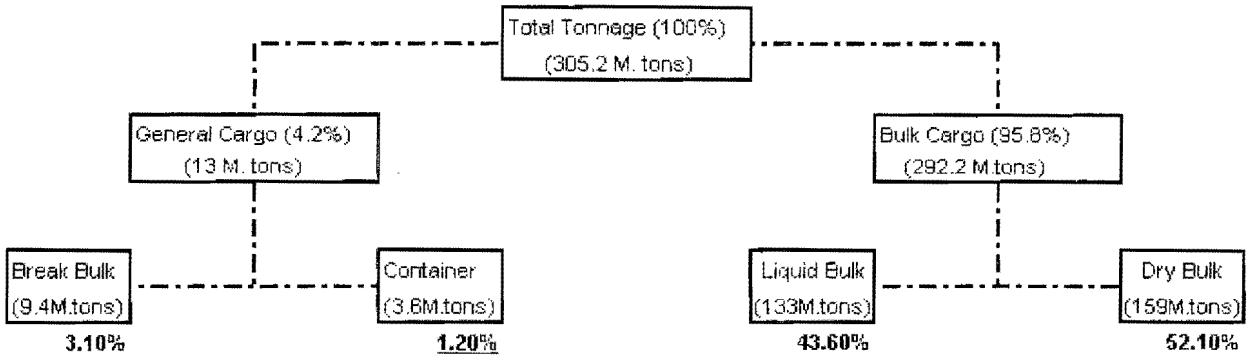
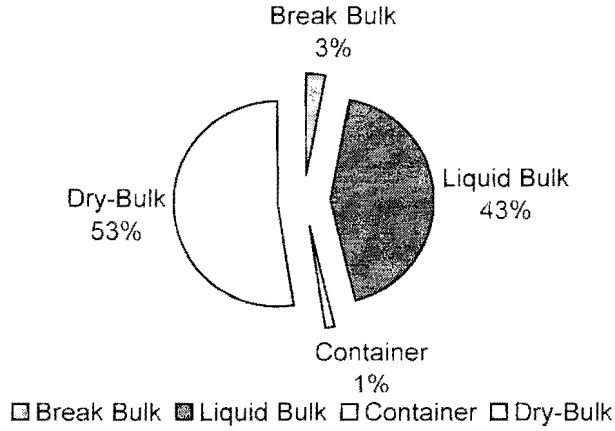


Figure 4
Classification of Cargo by Type 1999



IV.4 Container Cargo

The container volumes handled by the Gulf ports for the period 1993 to 1999 are shown in Table 16. While the total containers handled ranged from 1 to 1.5 million TEU, the largest three ports, namely, Houston, New Orleans and Gulfport, controlled more than 88 percent of the market share throughout the period. During the period the total containers handled by all ports increased by 33 percent, which is an annual growth rate of about 5 percent for the Gulf as a whole. However, the individual performances of ports varied widely as shown in Table 17. The growth rate shown in the first column of Table 15 is computed taking 1993 as the base year and 1999 as the target year. The second column is

the weighted average change for two periods, 1993-1995 base period and 1997-1999 the target period. The weighted average measure is likely to provide more robust trends by avoiding random variations that can occur in one single year. Out of the five largest ports, Freeport, Houston and Gulfport increased their market shares and the market shares of New Orleans and Galveston declined during the period. The annual volumes handled by the three largest container ports in the Gulf and trends are shown in Figure 5.

For handling containers specialized terminals equipped with gantry cranes and yard space is available at the Port of New Orleans at France Road and the new Napoleon Avenue terminals. Consequent to the navigation problems on the MRGO, which were noted earlier in this report, the Port of New Orleans has shifted the emphasis to the Mississippi River terminals. The container terminal capacities currently available at the Port are shown in Table 18. With the addition of new gantry cranes since 1996 at the Napoleon Avenue and Nashville terminals the container handling capacity at the Port has improved substantially. The addition of new cranes, coupled with the conclusion of terminal leasing agreements with P & O Ports and Ceres, the port officials expect container volumes to double within a few years.

Table 16
Container Traffic Handled by Gulf Ports- 1993-1999 (in TEU's)

Port	1999	1998	1997	1996	1995	1994	1993
Beaumont	1,387	1,038	806	971	N/A	N/A	593
Corpus Christy	-	--	--	--	--	921	5,124
Freeport	63,396	54,694	45,135	48,158	30,516	34,062	30,525
Galveston	68,874	13,391	14,376	9,609	40,423	82,212	97,818
Gulfport	125,874	144,961	154,694	153,470	108,096	93,255	89,862
Houston	1,001,170	968,169	935,600	794,481	705,367	579,868	541,497
Lake Charles	19,120	622	34,583	33,549	48,293	9,668	31,627
Manatee	13,368	16,257	16,532	16,088	16,730	13,780	10,722
Mobile	11,184	10,946	11,555	14,360	13,642	11,038	11,653
New Orleans	268,630	244,624	263,851	261,007	198,424	378,334	366,518
St. Bernard	2,976	3,177	N/A	4,341	3,800	N/A	N/A
Tampa	6,905	8,013	2,673	4,616	6,020	6,844	8,000
Gulf total	1,582,884	1,465,892	1,479,805	1,340,650	1,171,311	1,210,982	1,193,939

Source: American Association of Port Authorities

Figure 5
Volumes of Containers Handled by Houston, New Orleans and Gulfport, 1993-1999 (in T.E.U's)

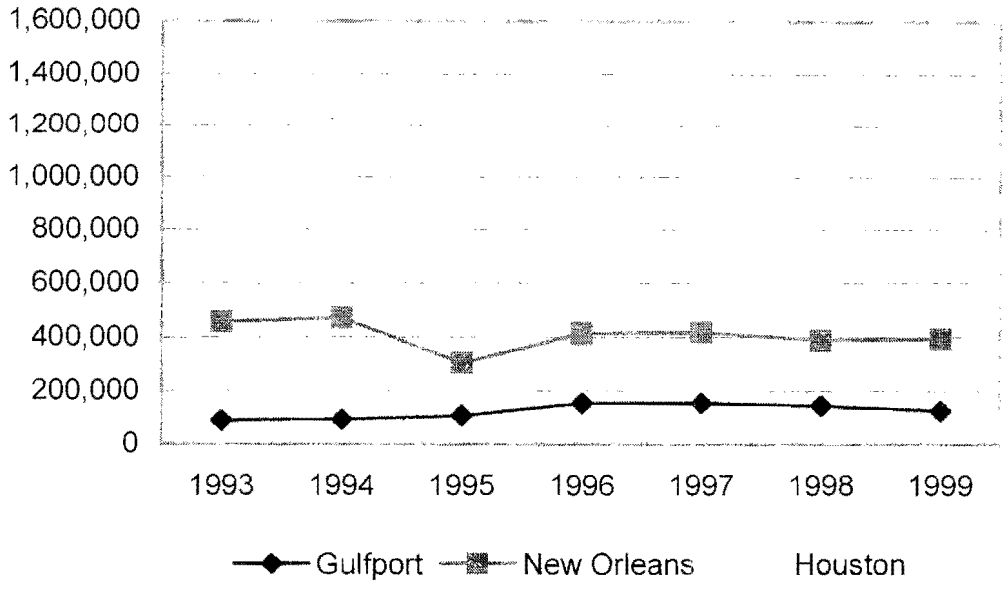
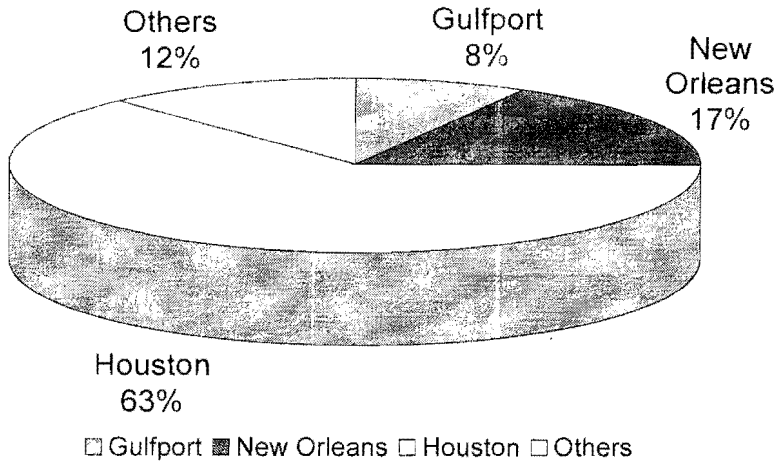


Table 17
Container Growth Rates on the Gulf, 1993 to 1999 (in TEU's)

Port	Change 1993-99 (%)	Change – weighted Average for periods 1993-95 and 1997-99 (%)
Beaumont	133.9	N/A
Corpus Christy	N/A	N/A
Freeport	107.7	71.6
Galveston	-29.6	-56.2
Gulfport	40.1	46.1
Houston	84.9	59.0
Lake Charles	-39.5	-39.4
Manatee	24.7	11.9
Mobile	-4.0	-7.3
New Orleans	-26.7	-17.6
St. Bernard	N/A	N/A
Tampa	-13.7	-15.7
Gulf total	32.6	26.6

Source: Table 14

Figure 6
Container Market Shares of Major Ports in the Gulf of Mexico



In addition, a modest amount of containers was handled at the Port of Lake Charles at a RO/RO terminal without cranes. The Port of South Louisiana has developed the Globalplex Terminal on the Mississippi River equipped with two gantry cranes capable of handling containers.

Additional deep-draft port facilities for handling break-bulk and neo-bulk cargo are available at the six public ports in the state and mid-river terminals operated by the private sector. As the handling of containers, break-bulk (packaged goods not containerized) and neo-bulk (large consignments of loose cargo, e.g., steel billets, coils steel wire, sawn timber, etc.) could be done at terminals with the basic configuration consisting of a ship berth, crane and yard they are also called as multi-use terminals. However, in competitive industries the capacity to handle alone is not sufficient, handling has to be efficient enough to meet and survive market competition.

In 1999 the Louisiana State Legislature took measures to insure Louisiana's competitive position with regard to containerized cargo by creating the Millennium Port Authority. This entity is a political subdivision of the State of Louisiana and is charged with the responsibility to promote the industrial, agricultural and petrochemical base of the Mississippi Valley region of the United States by providing a port with terminal and intermodal facilities for the handling of containerized cargoes of deep draft container vessels. The eleven-member Authority appointed by the Governor is currently examining the concept and approaches to meet the long-term needs of the industry.

The concept of building new port facilities to meet the emerging market needs of the 21st Century embodied in the millennium port concept is based on several market scenarios and the potential future challenges to the industry. The major issues are the following:

Table 18
Capacity of Container Terminals at the Port of New Orleans

Name Location Operator Name	Unit	France Road			New Napoleon (3/02)	
		Berth 1 Sea-Land	Berth 4 Ceres	Berth 5 P&O Ports	Ceres	P&O Ports
Ship's Berthage:						
Effective Transfer Rate	Moves/Hour	35	35	35	40	40
Cranes per Berth		2	3	3	2	2
Effective Transfer Rate per Berth	Moves/Hour	70	105	105	160	160
Working Hours (for vessels)	Hours/Day	24	24	24	24	24
Effective Daily Transfer per Berth	Moves/Day	1,680	2,520	2,520	1,920	1,920
Vessel Load	Moves	900	900	900	900	900
Vessel Stay	Hours	13	9	9	11	11
Preparations	Hours	2	2	2	2	2
Inter-Vessel Time	Hours	12	12	12	6	6
Vessel Cycle Time	Hours	27	23	23	19	19
Berth Utilization		.48	.38	.38	.58	.58
Number of Berths		1	1	1	3	3
Effective Time	Days	158	125	125	193	193
% of 20-foot TEUs/Move		.20	.30	.30	.30	.30
Multiplier		1.80	1.70	1.70	1.70	1.70
Berthage Capacity	TEUS/Year	478,000	537,000	537,000	1,888,000	1,888,000
Storage: Container Yard	Acres	60	37	48	27	27
Weighted Density	Teus/Acre	90	110	85	220	220
Nominal Static Capacity	TEUs	5400	4040	4098	5940	5940
Fraction Required for Empty Boxes		.15	.20	.20	.10	.10
Empty Boxes	TEUs	810	808	820	594	594
Loaded Boxes	TEUs	4590	3232	3278	5346	5346
Modifier for Operating Margins		.8	.8	.8	.8	.8
Effective Static Capacity	TEUs	3672	2586	2623	4277	4277
Avg. Dwell Time	Days	4	4	4	2	2
Peak Factor		1.5	1.5	1.5	1.9	1.9
Turnovers	1/Year	61	61	61	96	96
Yard Capacity	TEUs/Year	223,380	157,306	159,541	410,798	410,798

Vessel Technology – The next generation of container ships with carrying capacities of 4,500-8,500 TEU's will require more efficient and sophisticated terminals with 40ft to 46 ft. depth.

The Hub and Spoke System – The larger new vessels will call at major load-center ports (hub) and smaller feeder vessels will service smaller ports from the hub as in the airline industry.

Port Access – The location of ports closer to the coast and major trade routes minimizing travel time is critical to compete with other ports. Louisiana's competitive position will be adversely affected with the closure of MRGO.

North-South Trade- Gulf Ports are strategically located to benefit from the expanded trade between the U.S. and Latin American countries and a North-South trade corridor will develop across the U.S. linking Canadian markets with Gulf ports.

Several studies completed on this subject support the concept based on projected growth in international trade. However, more empirical studies are necessary to determine the competitive positions of ports, which depends on a complex combination of factors within the country. The time-tested strategy for public planning in such cases is to be guided by the private sector initiatives.

As a part of the Millennium port concept, a private sector proposal to build a container transshipment facility (called 'Sea Point') to be located on the Mississippi River about 95 miles below New Orleans near Head of Passes is under consideration. According to the proposal, the Sea Point will annually handle one million containers aiming to become the predominant Gulf Coast container hub. The facility is estimated to cost $75 million and is expected to be operational by the third quarter of 2002.

V. SHALLOW-DRAFT PORTS

The ports discussed so far are deep-draft ports with access to international trade and are among the largest in the nation in terms of tonnage handled. In addition, there are twenty shallow-draft ports either located on inland waterways or on the coast serving mainly as industrial sites for water-related industries, and servicing the offshore oil and gas industry in the Gulf of Mexico. These ports vary in size, with Port Fourchon and the Port of Iberia generating large economic impacts as bases for the offshore oil and gas industry.

As public ports are statutory authorities created by the Louisiana Legislature for the specific purpose of local economic development, they do not exercise any regulatory control over the private sector. The principal role of public ports is to function as "landlord ports' providing port facilities to the private sector as an incentive to generate economic activity. Port funding for this purpose is derived either from local property taxes, state grants or from self-generated funds. Thus, most shallow-draft ports function

as industrial parks for water related industries and facilitate diversification of the local economy and the creation of jobs in rural communities with limited opportunities. The performance evaluation of these ports cannot be gauged by a single index such as the volume of cargo tonnage handled or the amount of revenue generated. It requires a complex process of evaluation involving economic, social and regional growth factors.

Emerging Issues. As mentioned earlier, the primary mission and the driving force behind shallow-draft port activities is local economic development and they are similar to industrial parks. The main strategy followed to achieve this mission is to attract industries to locate at the port by providing incentives. The procedure of leasing cargo terminals by deep-draft ports to private operators as concession has the same effect. This policy has its positive and negative points.

The positives are:

Mobility of industries – With the development of information technology (IT) industries enjoy wider location choices and incentives will attract these "foot loose" industries.
Trigger-off economic development – For stagnant rural economies with limited opportunities, the jobs created by the new industry may be a catalyst to trigger off economic growth.
Diversification of local economy- New industries diversifying the economy will make economic cycles less painful.

Among the negatives are:

No competitive advantage - Under competitive conditions as all ports provide incentives, the ports with larger resources are at an advantage.
Local infrastructure – Some tax concessions affect local infrastructure – road maintenance and public education
Private capital inflows to the industry will be adversely affected as they have to compete with subsidized industries

VI. COASTAL PORTS

Louisiana is the nation's second largest producer of natural gas and third producer of crude oil among the 50 states. In terms of offshore oil and gas production, the Gulf of Mexico accounts for more than 90 percent of the U.S. production. Three ports, mainly, Port Fourchon, Iberia and Morgan City function as supply bases to this fast growing offshore oil and gas industry in the State. It is easy to emphasize the importance of a logistical support system for an industry with more than 7,000 offshore leases covering more than 30 million offshore acres one hundred miles away from shore, in water more than thirteen-hundred feet deep. The offshore oil and gas platforms service more than 1,750 actively producing oil and gas sites. Further, there are more than 18,000

production wells connected to one another and shore by a web of more than 19,000 miles of undersea pipelines.

The ports remain as the focal points in the logistical support system connecting the land based services with offshore deliveries. Port Fourchon with an access channel to the Gulf 300 ft. wide and 24ft. in depth is the largest supply base acting as the center for variety of services. The port infrastructure includes docks, channels and berths for the vessel interface; cargo handling equipment for cargo transfer; and open and covered space for storage. Similar facilities are available at the Port of Iberia and Morgan City, however, they specialize in fabrication of equipment and supply industries. Port Fourchon functions are more oriented toward that of a cargo and passenger transportation hub.

The operational activities at the above public ports are managed by the private sector, and they have made large investments in the industry. For example, C-port owned and operated by Edison Chouest Offshore constructed in 1996 is a multi-services terminal providing state of the art technical services under one roof. The facility provides vessel services in loading and off-loading, supplies of fuel, water, cements, barites, liquid mud, and completion fuels simultaneously in one stop shopping facility.

The investments made under the Louisiana Ports Construction and Development Priority Program to improve the capacity of offshore oil and gas industries indicate the nature of public/private partnership in the industry (Table 19). While the Program has allocated $30 million in state funds, the sponsoring ports and the private sector also have contributed another $30 million. Louisiana shipbuilding industry and metal fabrication industries are also heavily dependent on offshore oil and gas industry.

Emerging Trends - The rapid expansion of activities has imposed substantial strains on existing transportation systems, water supplies, housing, as well as on law enforcement agencies. The large migrant labor force employed by the offshore oil and gas industry has created pressures on community infrastructures, particularly on local public education systems.

The rapid expansion of the industry has created employment opportunities for the coastal parishes as evidenced by the low rates of unemployment of four to six percent. In addition, metal fabricating industries moved to other inland ports such as Caddo-Bossier and Madison Parish because of the shortage of welders in the area. For orderly development of the region, improved transportation connections remains high priority. This will facilitate not only the movement of freight and passengers, but will also improve mobility in the labor markets.

Table 19
Projects Funded Under Ports Priority Program- Coastal Ports

Port	Type of Projects	# of Projects	Investment Source ($1000)		
			Public	Port/Private	Total
Fourchon	Multi-use docks, slips, and warehouses, etc.	7	16,834	49,977	66,811
Iberia	Tenant facilities, water and sewage, bulkheads, etc.	8	5,319	8,703	14,022
Morgan City	Docks, warehouses, rail and road access, etc.	7	8,338	5,190	13,528

Source: Louisiana Department of Transportation and Development, *Status Report on the Port Construction and Development Priority Program*, March, 2001.

VII. LOUISIANA PORTS CONSTRUCTION AND DEVELOPMENT PROGRAM

The major sources of state funding to the maritime sector are channeled through either the State Capital Outlay Program or through the Louisiana Ports Construction and Development Priority Program (PCDPP) funded under the Transportation Trust Fund. The total funding allocated to shallow and deep-draft ports under the PCDPP, and funding participation by the state and other sources are shown in Table 20. It can be observed that state funds were almost equally allocated to the two categories of ports. Further, it is observed that the Program was able to leverage state funds dollar for dollar by attracting funds from the sponsoring ports and the private sector. Because of the comprehensive project evaluation procedures followed by the PCDPP for funding port projects and its successful functioning for more than ten years, the Program is reckoned as a best practice model in the area of public infrastructure investment for economic development. Several noteworthy features of the Program are as follows[3].

- *Public Participation* – Setting up of Program rules and regulations are done in consultation with the Ports Association of Louisiana (PAL).
- *Leveraging Public Investment* – The port sponsoring the project is required to pay engineering fees and 10 percent of the project cost. A higher weight is given for projects with the private sector participation.
- *Immediate Need for the Project* – All projects must establish the need for the project by under taking an economic evaluation.

[3] For details see, Jay Jayawardana and D. J. Webre "Louisiana Port Priority Program: An application of Benefit-Cost Analysis to Project Appraisal" *Transportation Research Record*, No.1511, Transportation Research Board, National Research Council, National Academy Press, Washington, D.C. 1995, pp. 26-34.

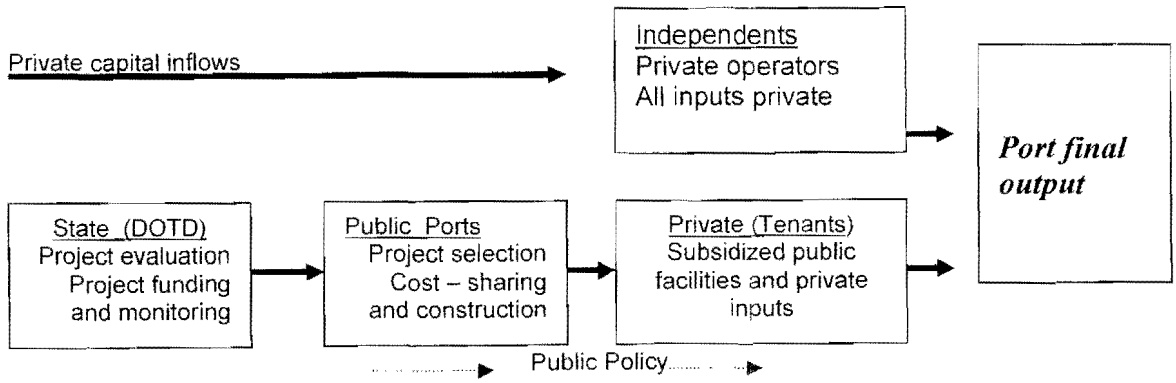
- *The Rate of Return-* all projects must generate a 3.7 percent rate of return on the state investment. This requirement is included to prevent leasing public facilities at rock bottom prices, to the detriment of private sector terminal operations and to provide funds for the maintenance of public facilities.
- *Project Monitoring-* Ports are required to submit reports comparing the project benefits claimed in the application with the actual benefits achieved during the first three years after completion of a project

The functioning of the Program and the roles played by the DOTD, public ports, public port tenants and independent operators are illustrated in a schematic diagram (Figure 7). As the private sector contribution the final output is high, public investment must not discourage private capital inflows to the industry.

Table 20
Port Investments Made Under the Ports Priority Program, 1990-2001, by Shallow and Deep-Draft Ports and by Source of Funds

Port Classification	State Funds	Other Funds	Total
	In 1,000 dollars		
Deep Draft	146,564	154,957	301,521
Shallow-Draft	103,258	151,282	254,540
Total	250,822	307,239	558,061
Funding Shares	Percent		
Deep Draft	58.4	50.0	54.0
Shallow-Draft	41.6	50.0	46.0
Total	100.0	100.0	100.0

Figure 7
Schematic Presentation of Public and Private Sector Contribution to Port Final Output



Emerging trends – The project evaluation methodology followed under the Program has received much recognition at the federal level and in other states. While the program is described and included as a model intermodal program in FHWA website, Arkansas Legislature has approved a similar Program to Arkansas Ports. More importantly, all participating ports in the state approve and direct the Program on sound economic principles. Efforts are underway to expand the same evaluation principle on intermodal projects, which may combine benefits for ports, but also other modes of transportation inclusive of improvements to roads, rail and waterways.

VIII. VALUE TO LOUISIANA

The public port system and waterfront activities along its extensive network of waterways are of great economic significance to Louisiana. Several ports on the Lower Mississippi River are among the largest in the nation, providing access to world markets for agricultural exports and coal from the Mid-Western states and handling the bulk of the nation's iron, steel and crude petroleum imports. The intermodal transportation system comprising the port system along with inland barge operations, and freight rail may be, the world's most efficient bulk cargo handling system. In addition to international trade, the waterfront has developed as a large industrial belt by attracting large oil and gas production and refining plants, petroleum-based chemical industries and service industries supporting oil and gas exploration in the Gulf. Therefore, high levels of productivity in the maritime sector are vital to Louisiana's growth and economic development.

According to estimates made by the School of Business at the University of New Orleans, the port industry continues to contribute significantly to Louisiana's economic growth and development. A study completed for the industry in 2001 assessed the impacts by evaluating: 1) the port industry (firms located in Louisiana because of the existence of ports) and 2) port users (importers and exporters who use the port industry). For each segment direct and secondary spending can be assessed and culminated to reflect the total impact.

According to this study, the port industry contributed over $4.06 billion in direct spending to the economy. When secondary spending created by the direct spending is added, the total economic impact of the port industry (direct spending plus indirect spending) is over $10.65 billion annually. The largest economic impact is derived from port users. Many of these have located their firms in Louisiana because of access to the Mississippi River and the Gulf of Mexico. This group contributes $19.11 billion to the economy and supports 151,055 jobs.

All together, the total economic impact of Louisiana's ports is $29.75 billion. This is 22.5 percent of the state's gross product. The ports generate $5.12 billion in income for Louisiana residents and support 243,621 jobs. The ports also provide income to state and local government through the taxes they generate. In 1999 ports and related activities generated $285.06 million for state government and $137.92 for local government for a total of $422.97 in state and local tax revenue.

Table 21
Summary of Port Economic Impacts 1999

Benefit	Total economic impact	Jobs supported	Taxes generated
Value	$29.5 billion	243,621	$422.97 million

IX. FACILITY REQUIREMENTS

As Louisiana maritime industry is market driven, the facility capacities and requirements will adjust responding to market prices. This is the most robust and enduring system simply because there are innumerable ways to adjust industry capacities: by controlling working hours, handling substitute commodities (e.g., barite for coal), or switching terminal operations (steel imports handling in mid-river rigs), or in the extreme, temporarily closing down facilities during an economic downturn. Under this scenario, infrastructure supply is guided by the market needs as perceived by the investors in the industry.

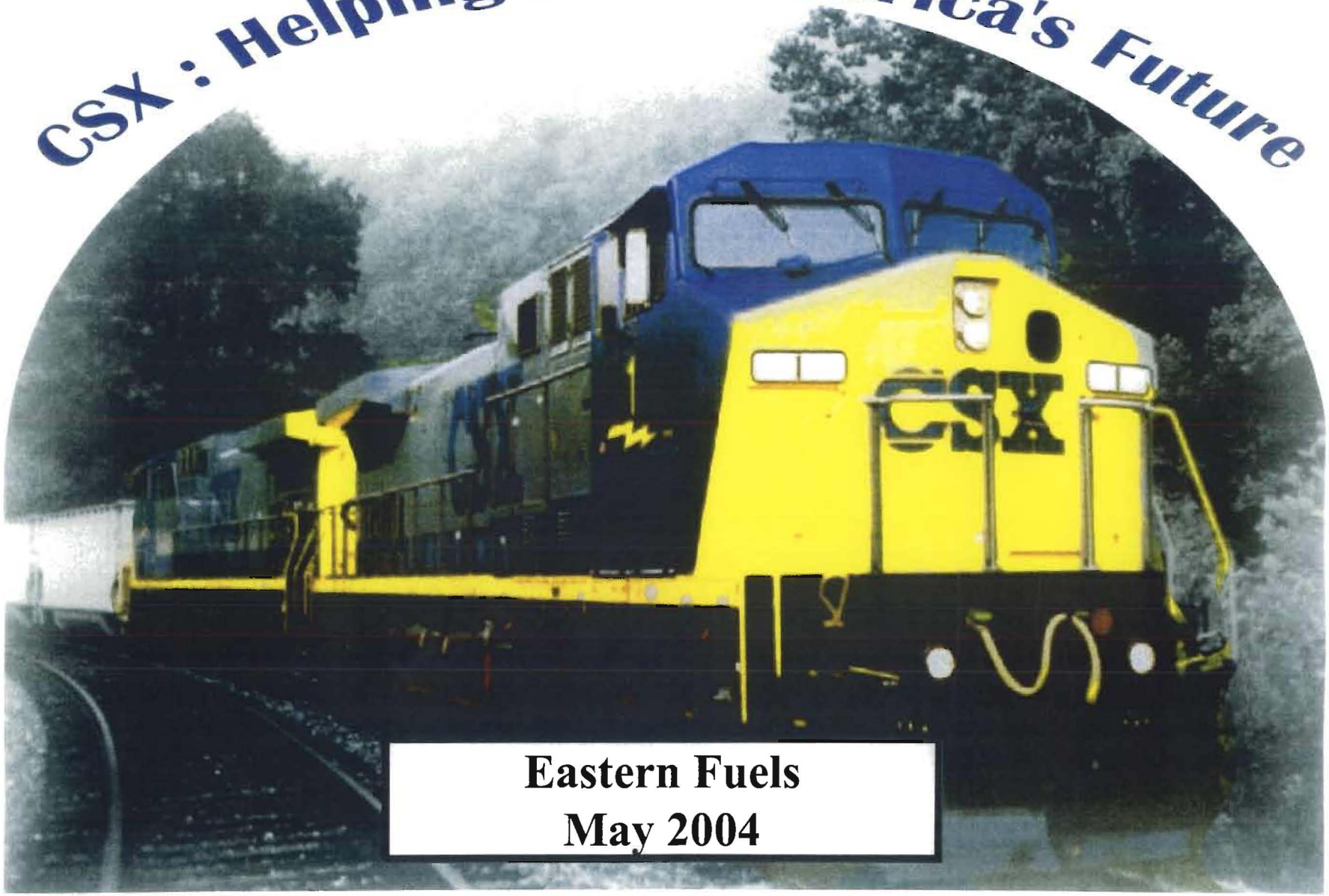
Further, the industry is based on serving large multinational firms, using state of the art equipment and management systems. In addition there are other smaller private investors who have developed their own niche operations. Therefore, the private sector under competitive conditions and motivated by profit will maintain a high productivity level for the industry.

X. PUBLIC POLICY OPTIONS

In this business environment, the role of the public sector is to play a supporting role to increase productivity and focus on other multiple public objectives such as stimulating the economy, maintain 'business-friendly' public regulation, regional growth, and income redistribution, etc. The design for long-term public policy should be guided by Louisiana's strengths and weaknesses, industry needs, and other development objectives. The policy formulation stages are: to correctly identify the industry problems; determine the desired outcomes; and select appropriate economic tools to achieve the policy objectives. Accordingly, main areas of public policy concerns for the maritime sector are: the development of public transportation infrastructure enhancing industry productivity, joint public/private investment projects, maintaining 'business-friendly' public policies.

Because of the traditional role of the State as a transportation hub of national significance and the large investments made in the industry, the maritime sector will remain an important part of the Louisiana economy. However, a significant part of the future development depends on strategic directions provided by public policies and the current planning efforts.

CSX : Helping Fuel America's Future



Eastern Fuels
May 2004

CSX TRANSPORTATION

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 98
COMPANY/ CSX
WITNESS. CSXT Presentation (Sullivan)
DATE: 05/27-28/04

We Move Coal

CSX will focus on the issues within the CSX Utility South Sector

Presentation Objectives:

1.) Overview of CSX Coal & the CSX Southern Utility Market.

- Market Size
- Sourcing Patterns
- Q1 2004

2.) Review of CSX Routes and Capacity

- 3 CAPP Routes
- Overall CSX Demand
- Actions and Steps to Improving Service/Capacity
- Erwin Gateway Jamboree

3.) Short Term and Long Term Outlook

CSX TRANSPORTATION

A review of our core ideology...

- **Vision:**
  - **To be the safest, most progressive North American railroad, relentless in the pursuit of customer and employee excellence**
- **Purpose:**
  - **To capitalize on the efficiency of rail transportation to serve America**
- **Core Values:**
  - **It starts with the customer**
  - **People make the difference**
  - **Safety is a way of life**
  - **Fact - based**
  - **Right results; right way**

CSX TRANSPORTATION

CSX Transportation

The Largest Railroad in Eastern North America

Serves all major markets in the eastern United States, and more ports than any other railroad

Operates 144 terminals

Covers 23,400 route miles in 23 states, the District of Columbia, and two Canadian Provinces

Operates a fleet of over 3,500 locomotives and 100,000 freight cars

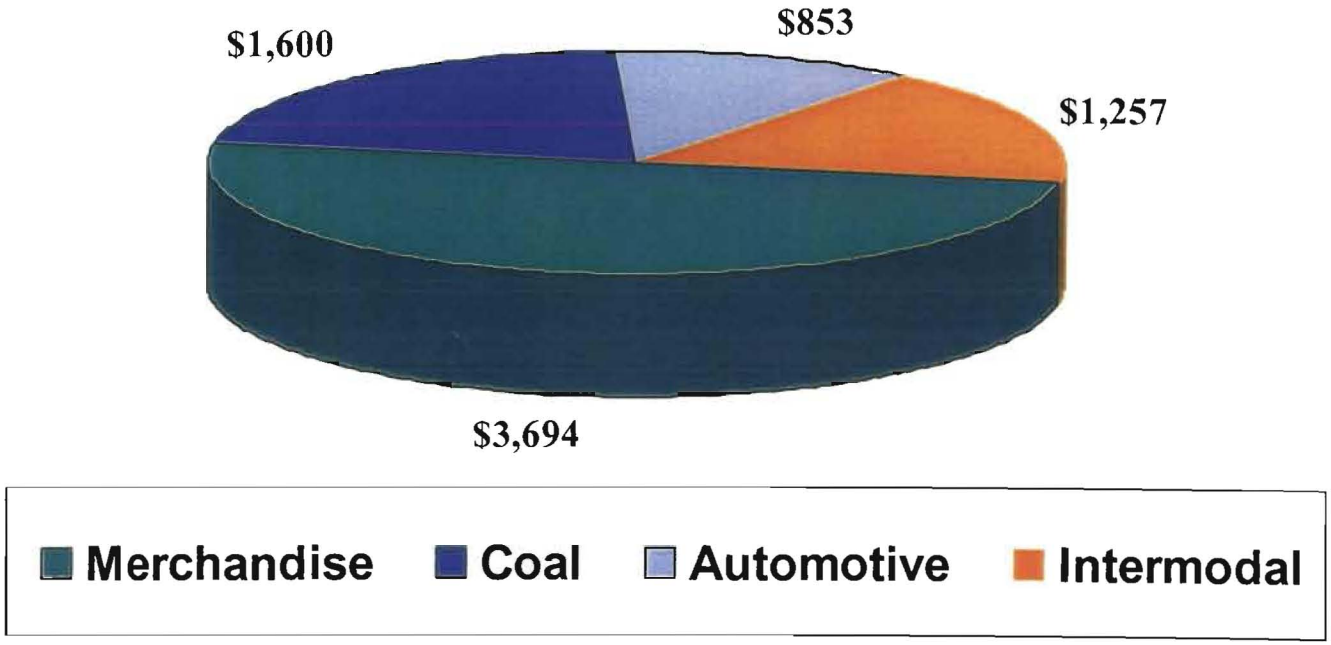
Employs 34,000 dedicated individuals

CSX TRANSPORTATION

We Move Coal

Coal represents just over one-fifth of CSX revenues.

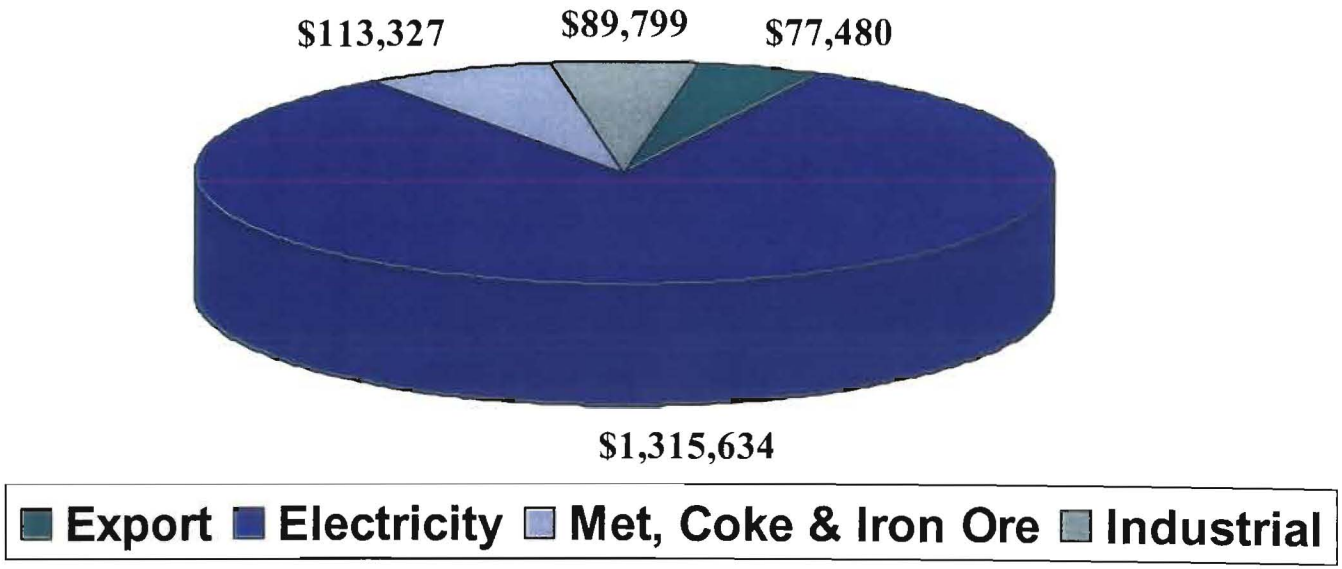
2003 CSX Revenue $7.4 Billion



CSX TRANSPORTATION

Demand for coal on CSX is driven by domestic Utility demand.

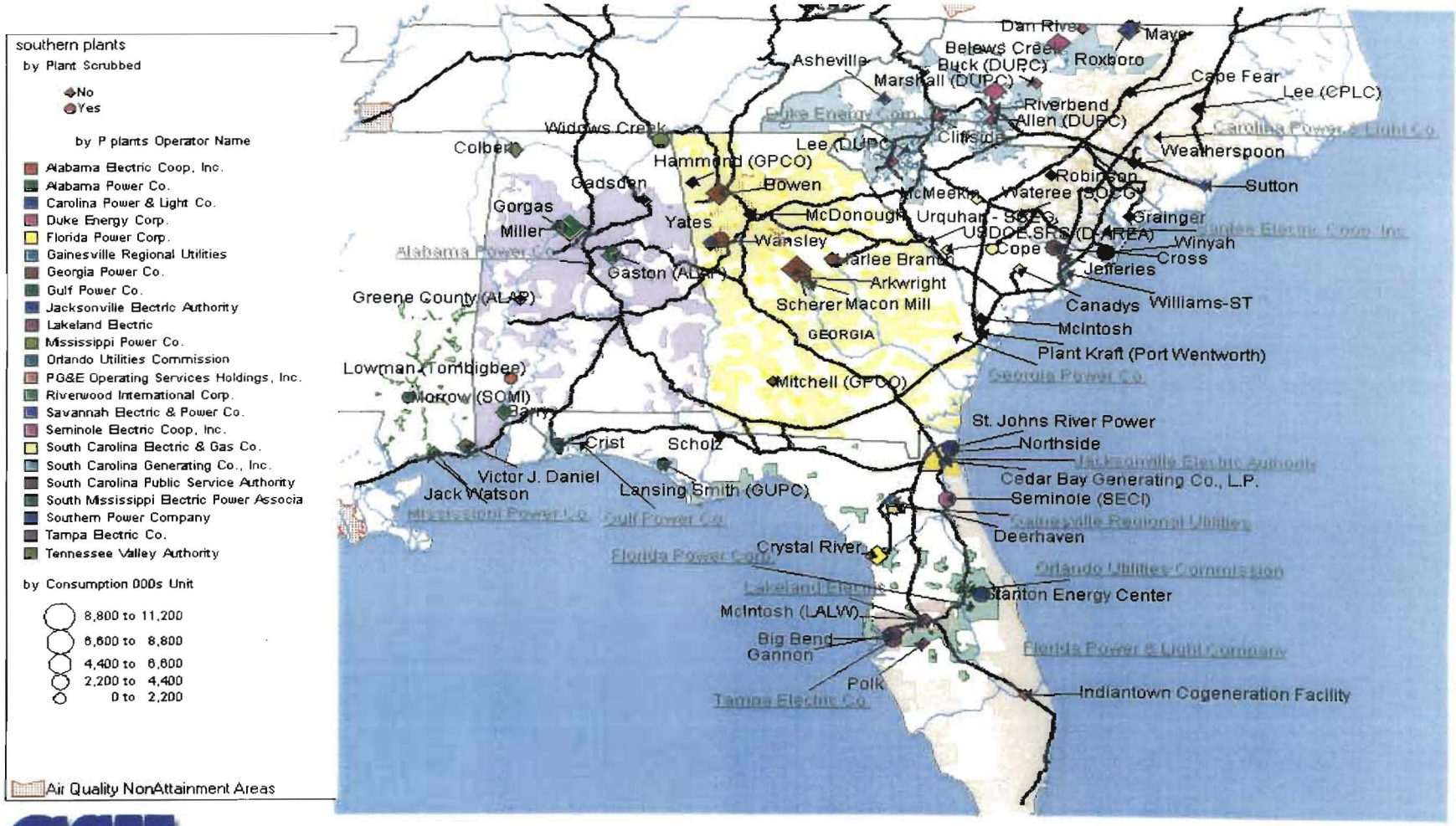
2003 CSX Coal Revenue $1.6 Billion



- Dominated by electricity generation
- Secondary markets in export, steel and industrial

CSX TRANSPORTATION

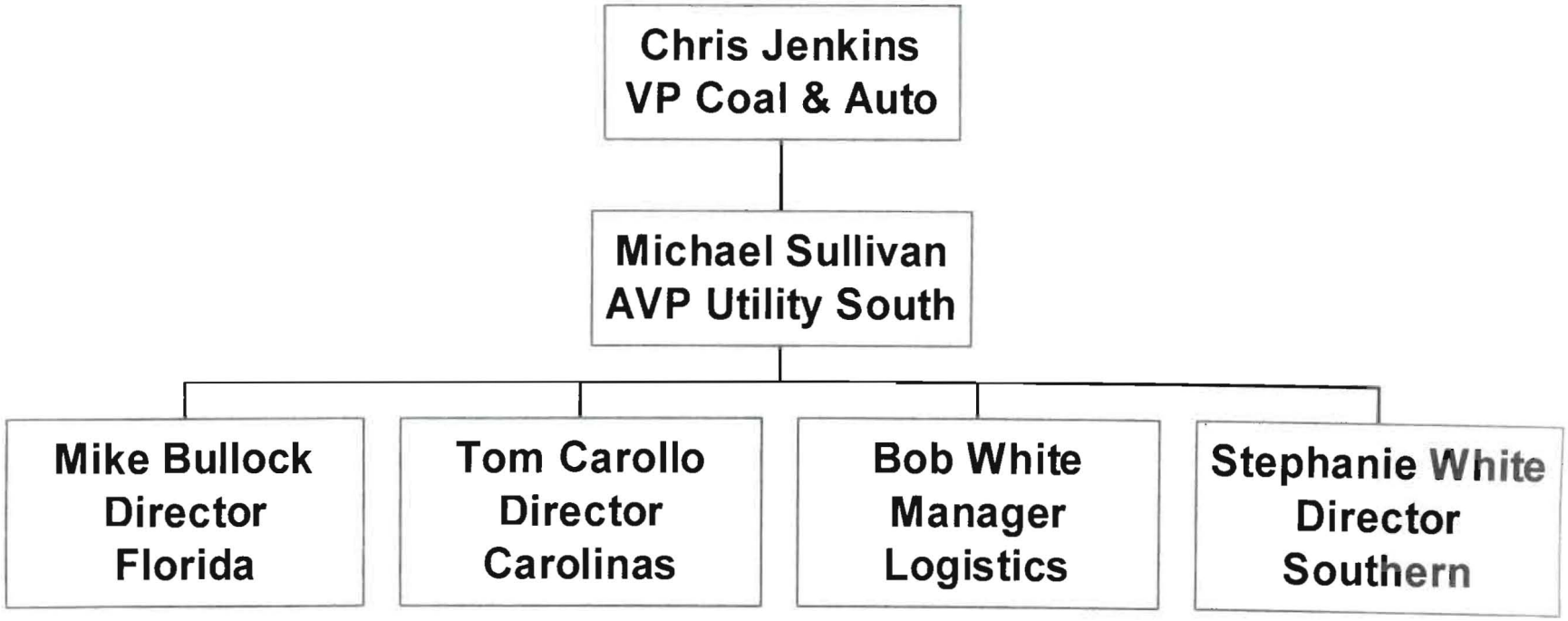
CSX defines the Utility South sector as GA, NC, SC, Fl, Al and MS. (Excluding TVA)



Source : Platts PowerMap

We Move Coal

CSX Utility South - Sales and Marketing Coverage



CSX TRANSPORTATION

The CSX Utility South rail market is heavily oriented to CAPP coals

Source	2004 P	% of Total
CAAP	50,750	90%
MGA	1,000	2%
AL	2,000	4%
Midwest / IL Basin	2,000	4%
Western	20	0%
Foreign/Pet Coke	900	2%
Total	**56,670**	

CSX TRANSPORTATION

CSXT Coal Reserves (as of 1/1/2004)

Coalfield	District	*Reserves(MM)	*Compliance (MM)
Central Appalachian	EK	451	178
Central Appalachian	CV	568	116
Central Appalachian	C&O-BS	954	333
Central Appalachian	CRR	182	79
Central Appalachian	C&O-WV	654	281
Northern Appalachian	B&O	1,779	180
Northern Appalachian	MGA	351	0
Illinois Basin	IL/IN/WKY	504	0
Alabama	AL	165	165
Total		**5,628**	**1,332**

***Reserves are determined in company portfolios as resources that can be economically mined and do not include total coal resources**

CSX TRANSPORTATION

Overall CAPP Demand is high.

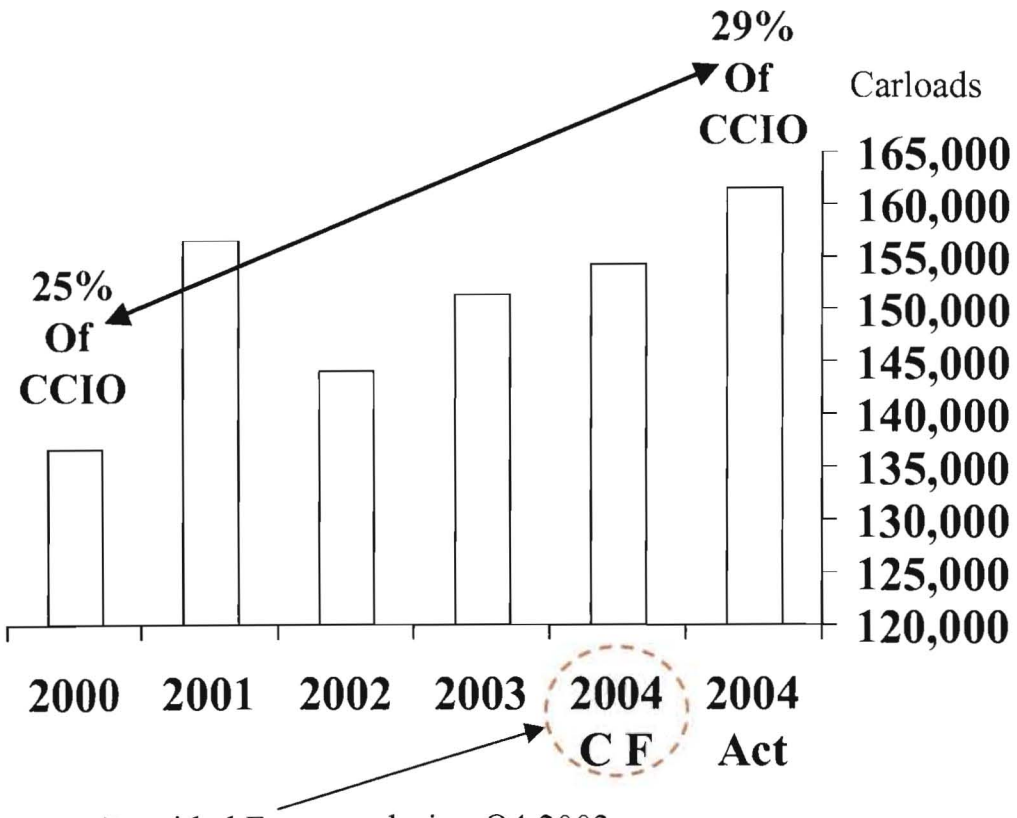
2004 vs 2003	MM Tons
Burn Growth	3
Stockpile Change	4
Reduced Imports	5
Increased Met Exports	5
Reduced Canada Exports	(3)
Displacement of Other Coal	(6)
Increase	8

Large Impact on Southern Utility Demand

Source : EVA

Deliveries into the Southern Utility Market Q1

Utility South Carloads – First 4 Months



Year over Year Growth of 7% 2004 vs. 2003

Customer Provided Forecast during Q4 2003

CSX TRANSPORTATION

Demand is strong and CSXT deliveries fell short of Customer expectations

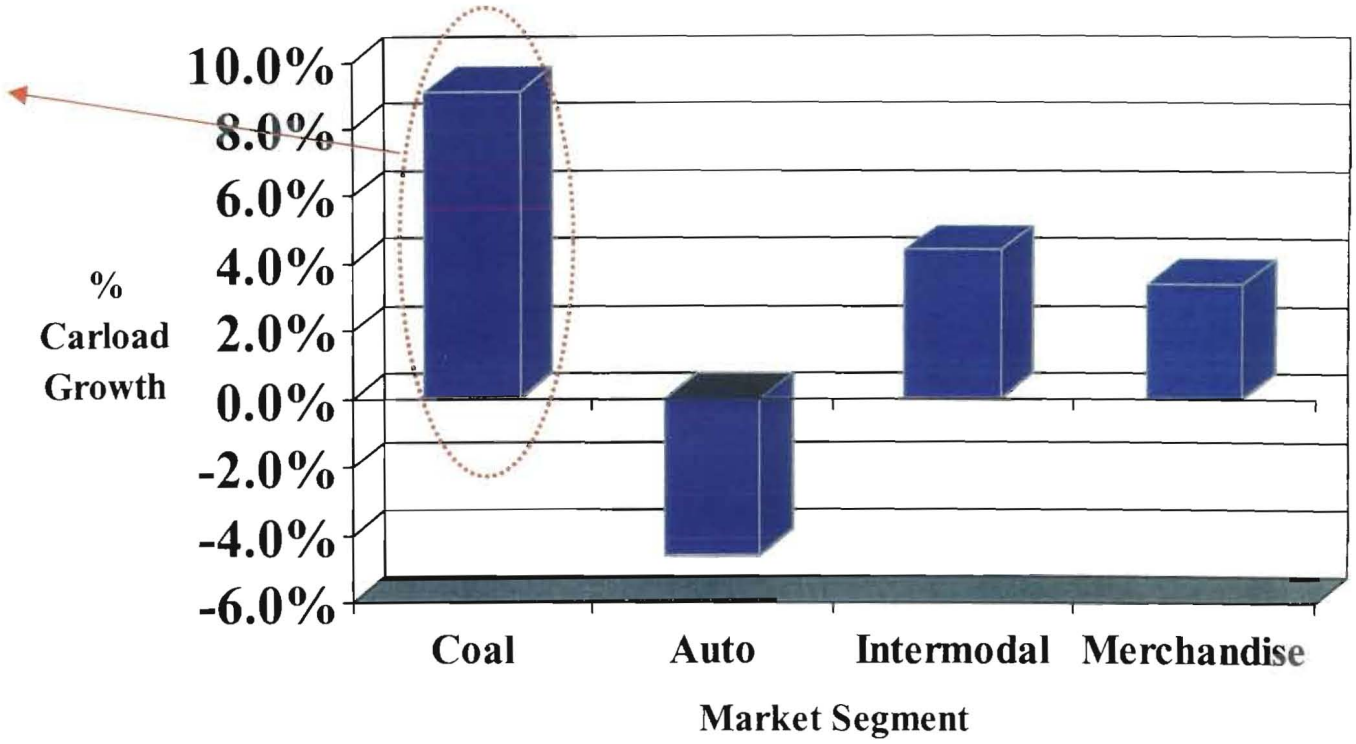
- Order fulfillment ratios dropped
- Customer complaints increased
- Transit times increased - Performance fell to 2000 levels
- Inventories are lower than summer target levels

CSX TRANSPORTATION

Overall demand for CSX services are strong.

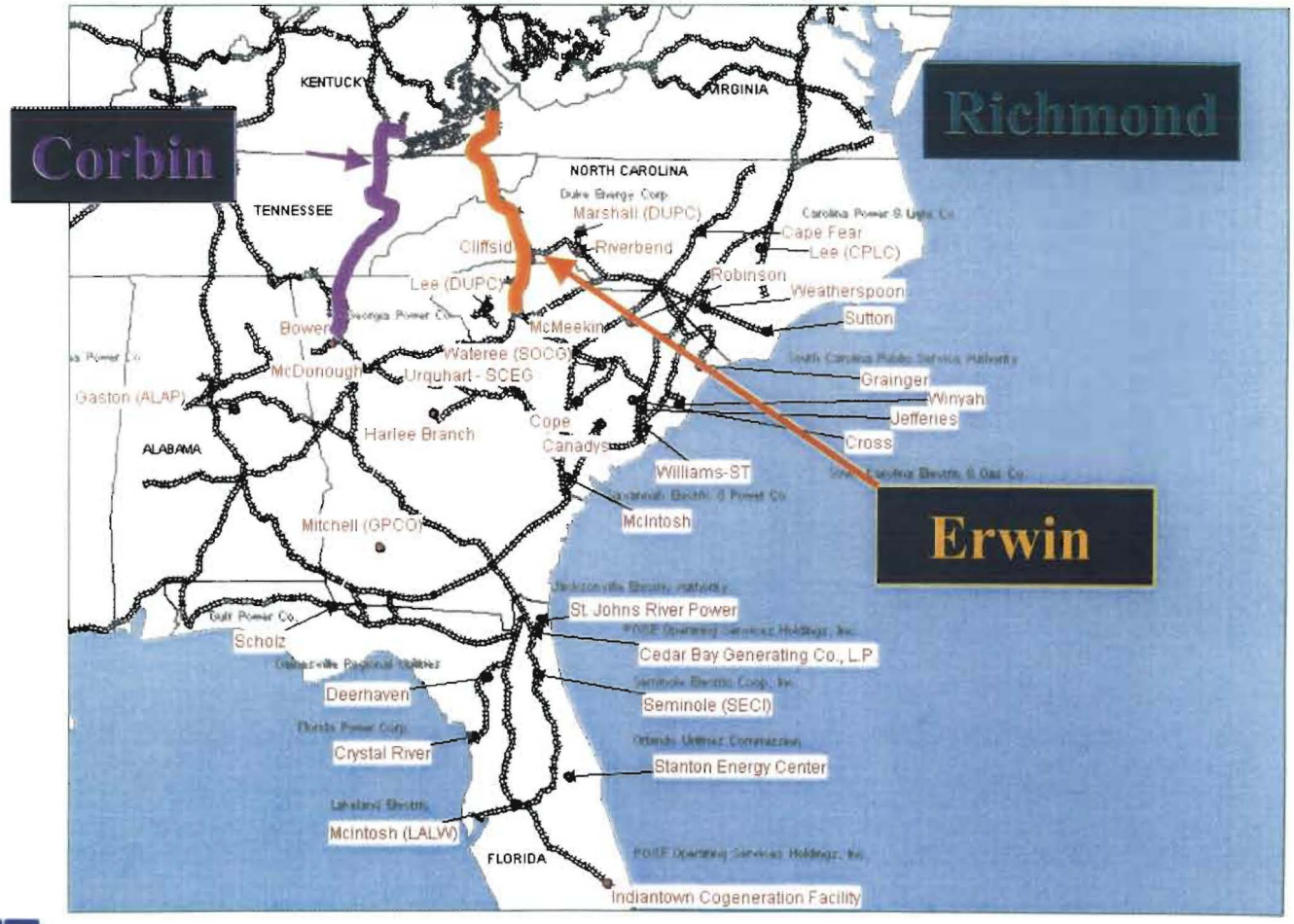
CSX Q1 Volume Growth - 2004 vs 2003

Coal demand far exceeds any other segment growth



CSX TRANSPORTATION

CSX serves the Southern Utility market via three gateways from CAPP

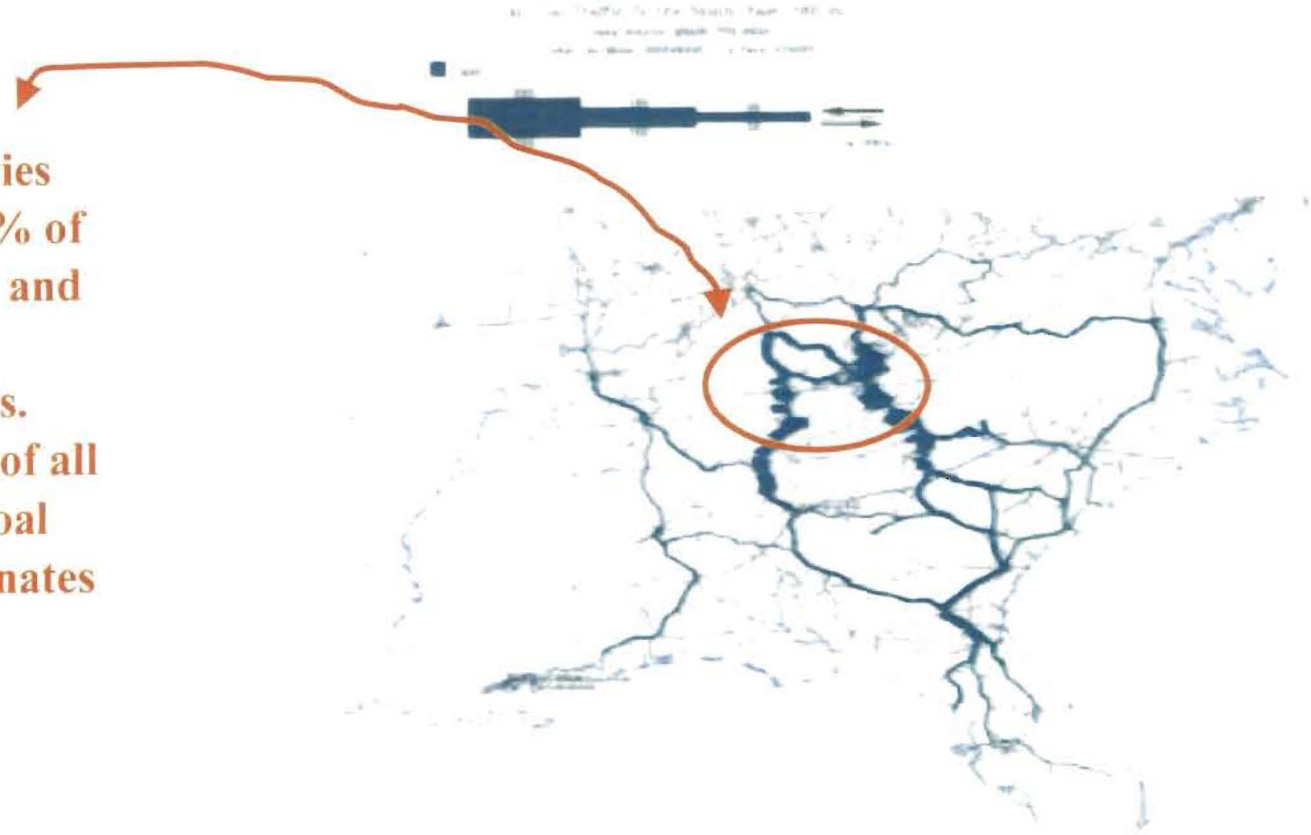


CSX TRANSPORTATION

We Move Coal

The Corbin and Erwin gateways are the dominate routes to the Southeast

Southern Utilities account for 30% of CSXT tonnage and 40% of CAPP originated coals. Roughly, 90% of all Utility South coal on CSXT originates in CAPP.



CSX TRANSPORTATION

CSX is moving ahead with several initiatives to improve capacity via Erwin

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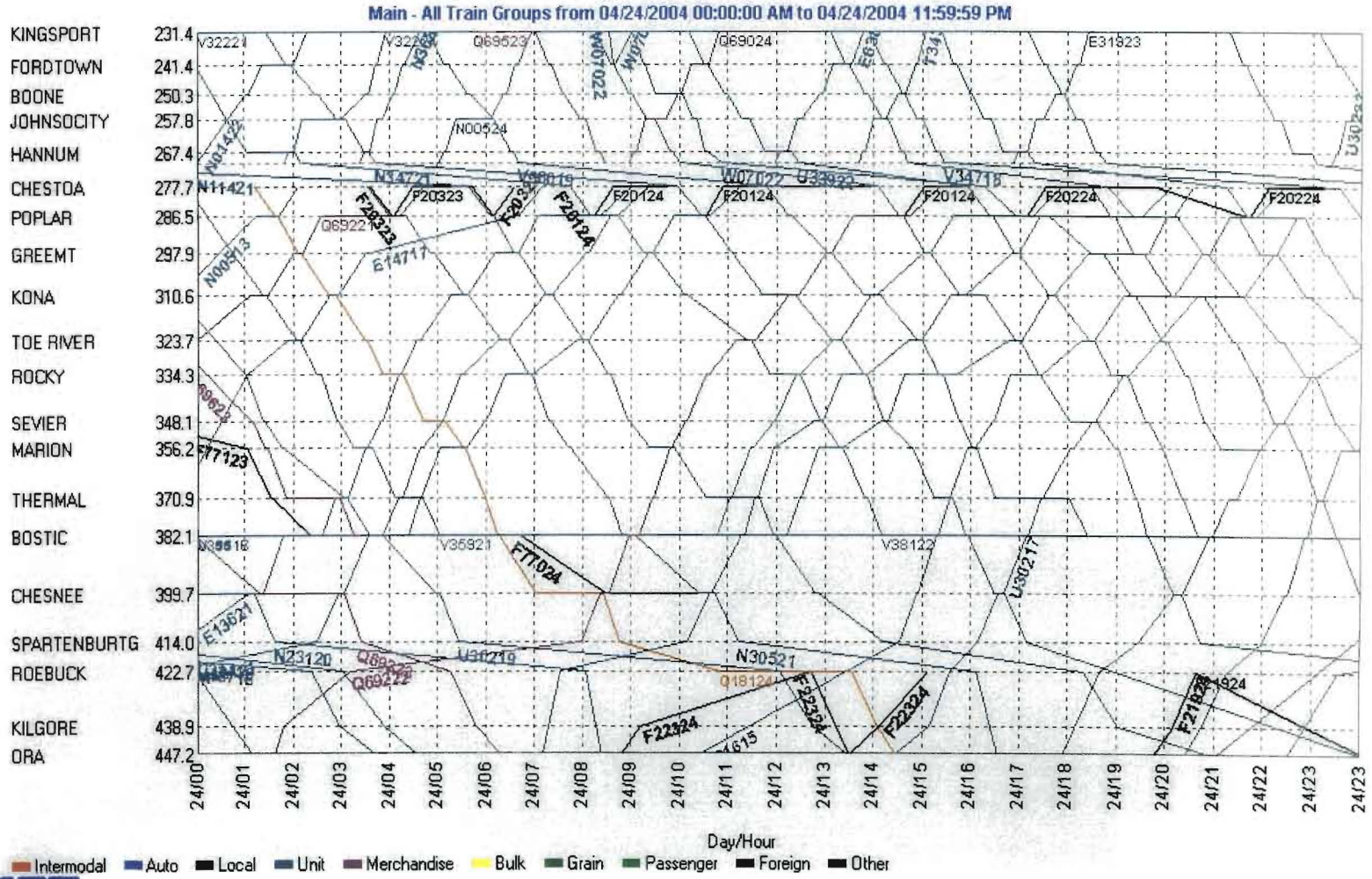
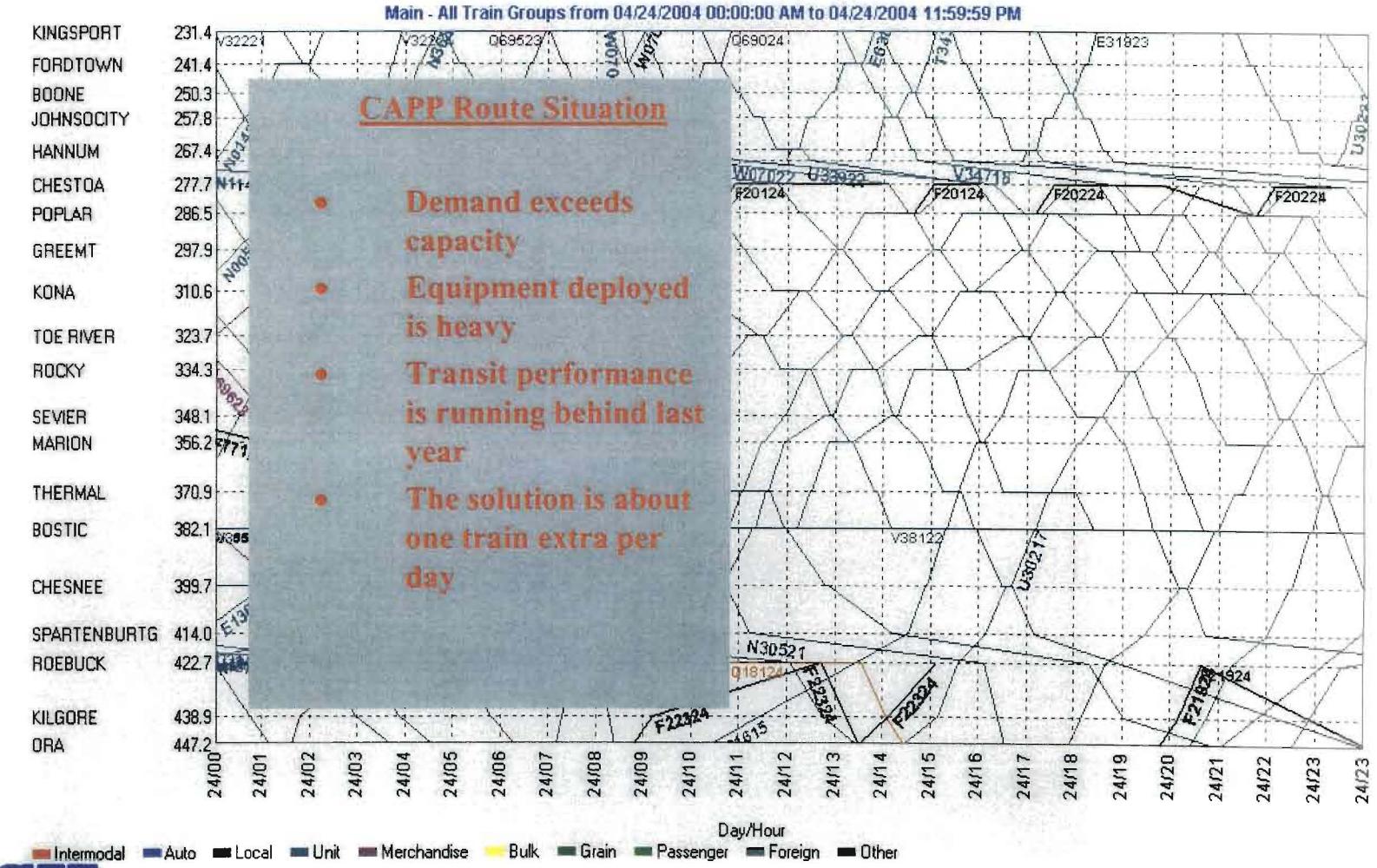


We Move Coal

CSX is moving ahead with several initiatives to improve capacity via Erwin



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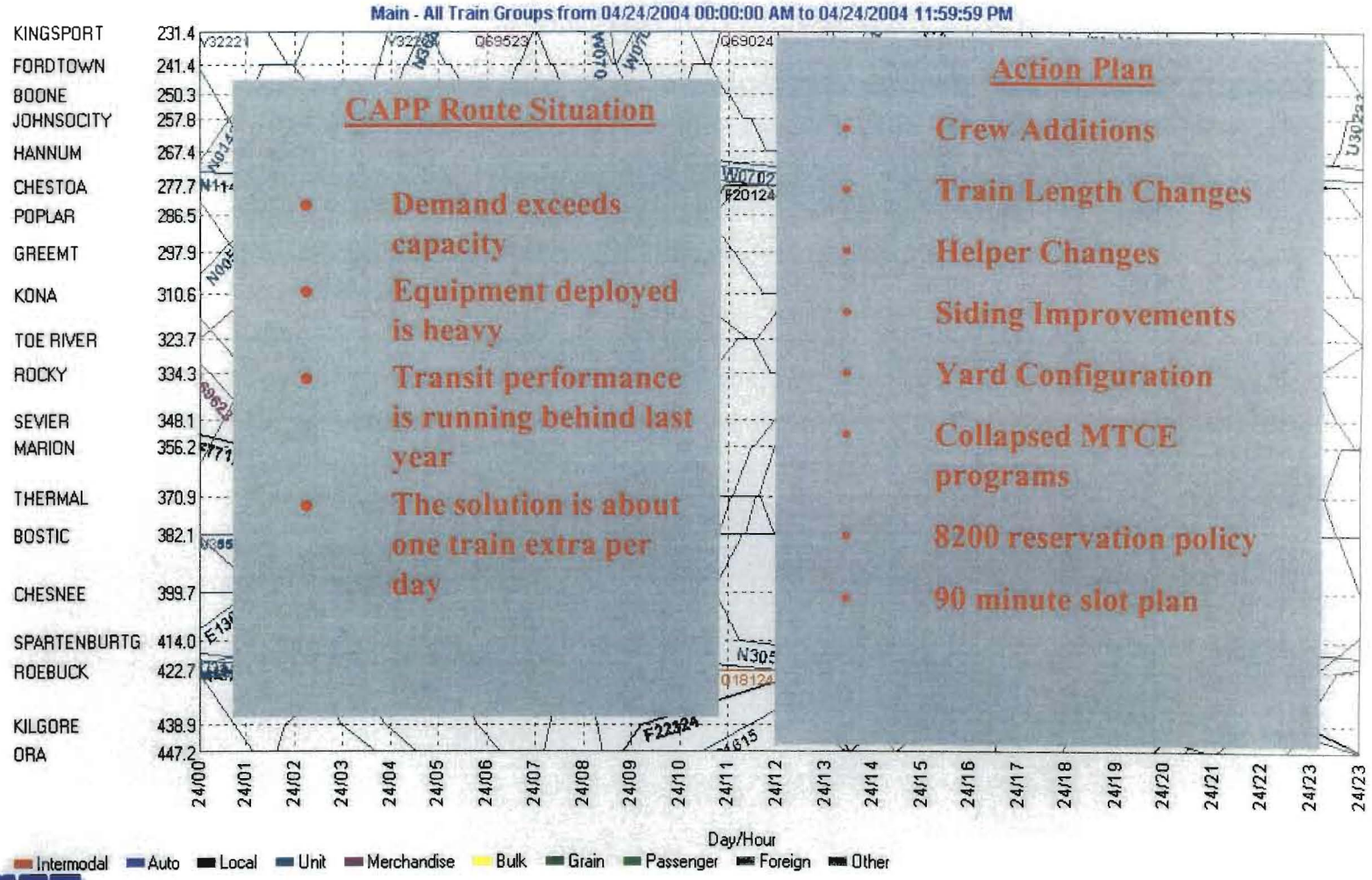


We Move Coal

CSX is making efforts to address the overall demand situation

- $200MM locomotive investment 2004-2005
  - 100 new locomotives in 2004
  - Acceleration of the 2005 purchase plan
- Delay turn-back of leased locomotives
- Accelerate crew hiring
- Keep power on trains at 24-hour receivers
- Bypass more terminals
- Lease more bottom-drop cars
- Rebuilds by CSXT
- Additional internal focus by various departments / locations on increased coal loadings

CSX TRANSPORTATION

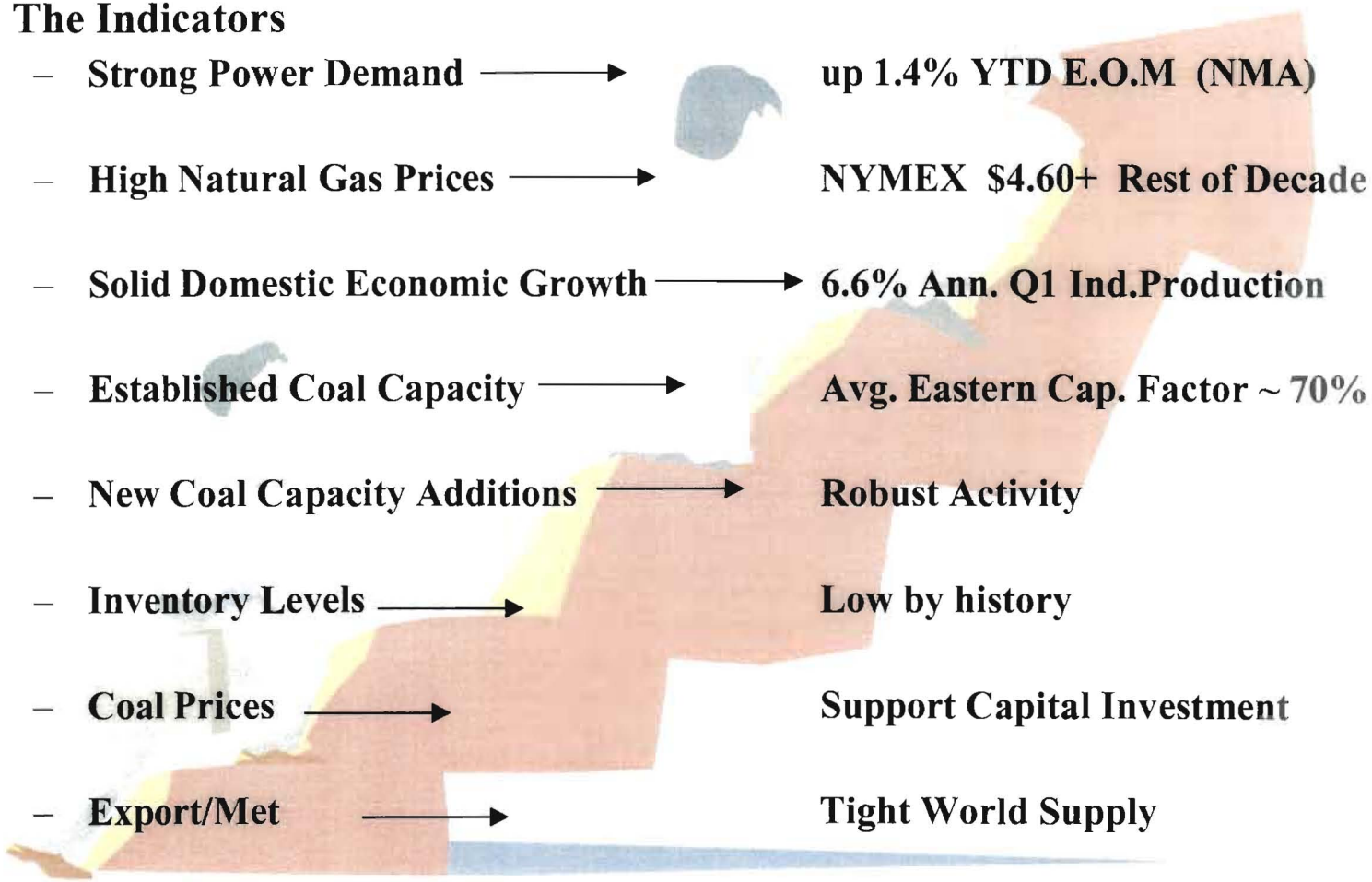
This year's Jamboree will start on June 21

- CSX has collected reservation requests from all Erwin gateway customers
  - CSX notified all receivers prior to January of this year on the Jamboree timing
- During the Jamboree Erwin gateway customers will receive roughly 60 % of the normal capacity – equivalent to a ten hour per day curfew
- The traffic normally routed via Erwin will run via Richmond and Corbin
- CSX will restrict crew vacations and issue temporary transfer notices to handle the additional volumes
- CSX has developed reservation capacity for the Corbin and I64 routes during the Jamboree

CSX TRANSPORTATION

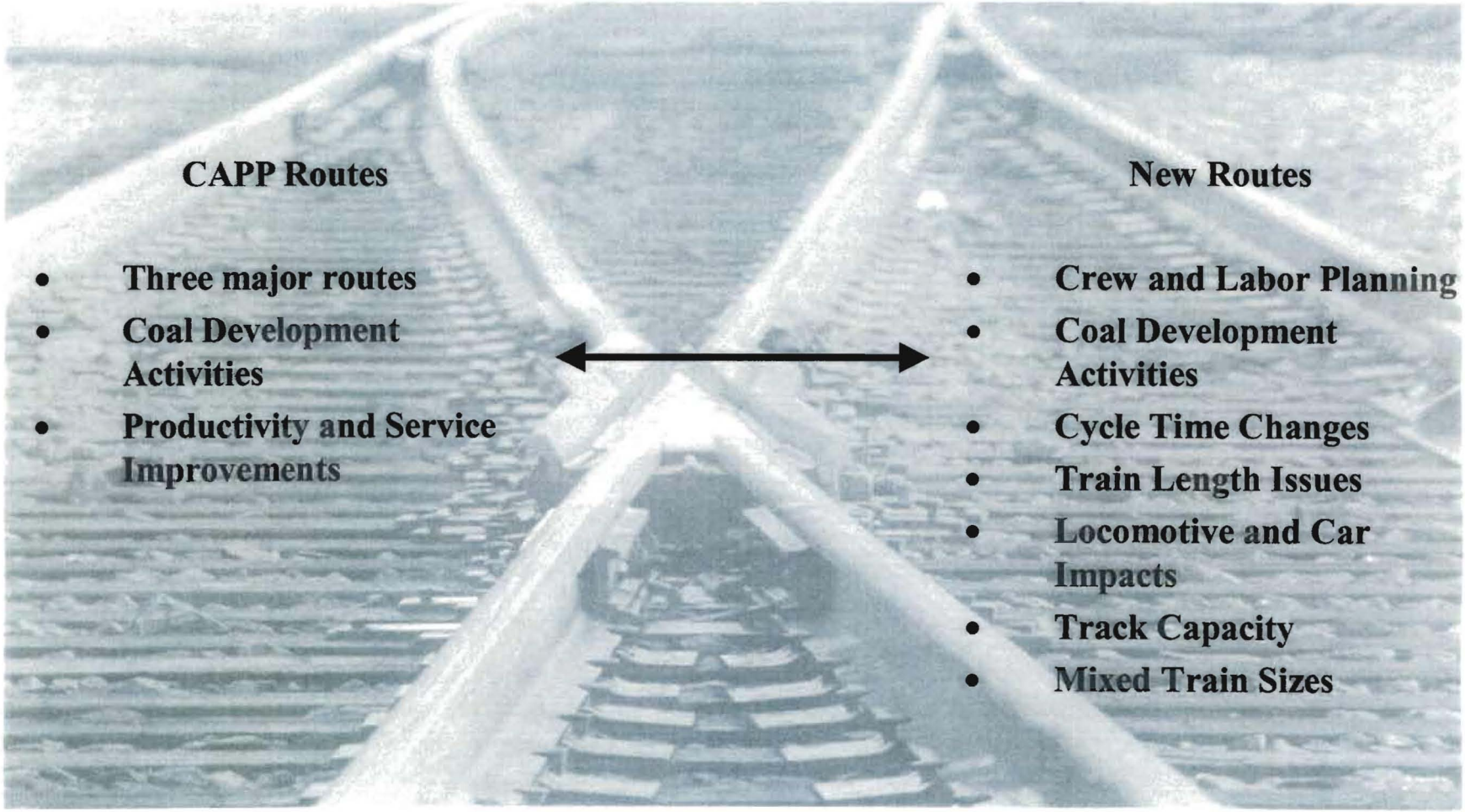
Where is demand headed?

- **The Indicators**
  - **Strong Power Demand** → **up 1.4% YTD E.O.M (NMA)**
  - **High Natural Gas Prices** → **NYMEX $4.60+ Rest of Decade**
  - **Solid Domestic Economic Growth** → **6.6% Ann. Q1 Ind.Production**
  - **Established Coal Capacity** → **Avg. Eastern Cap. Factor ~ 70%**
  - **New Coal Capacity Additions** → **Robust Activity**
  - **Inventory Levels** → **Low by history**
  - **Coal Prices** → **Support Capital Investment**
  - **Export/Met** → **Tight World Supply**



CSX TRANSPORTATION

Demand will be strong. What sourcing changes will occur over the next several years?



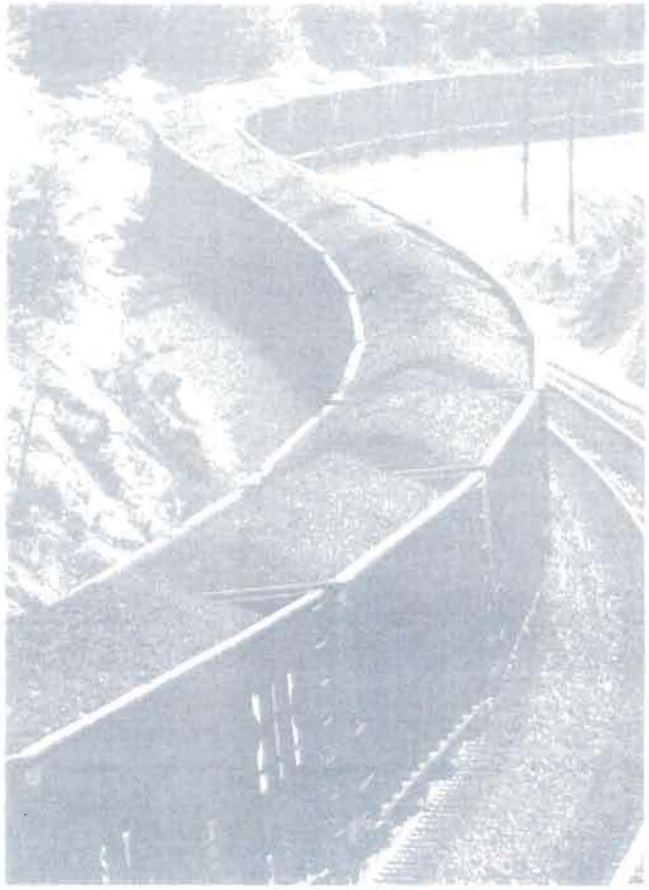
CSX TRANSPORTATION

Vision:

To be the safest, most progressive North American railroad, relentless in the pursuit of customer and employee excellence

First Quarter Earnings Release

Looking forward, Ward said, "Combined with our own growth strategies, I see the strengthening economy and improved industrial production levels as terrific opportunities to continue our record of revenue increases. At the same time, we'll be working to overcome continued service challenges and deliver consistent, continuous improvement in our operating and financial measures.

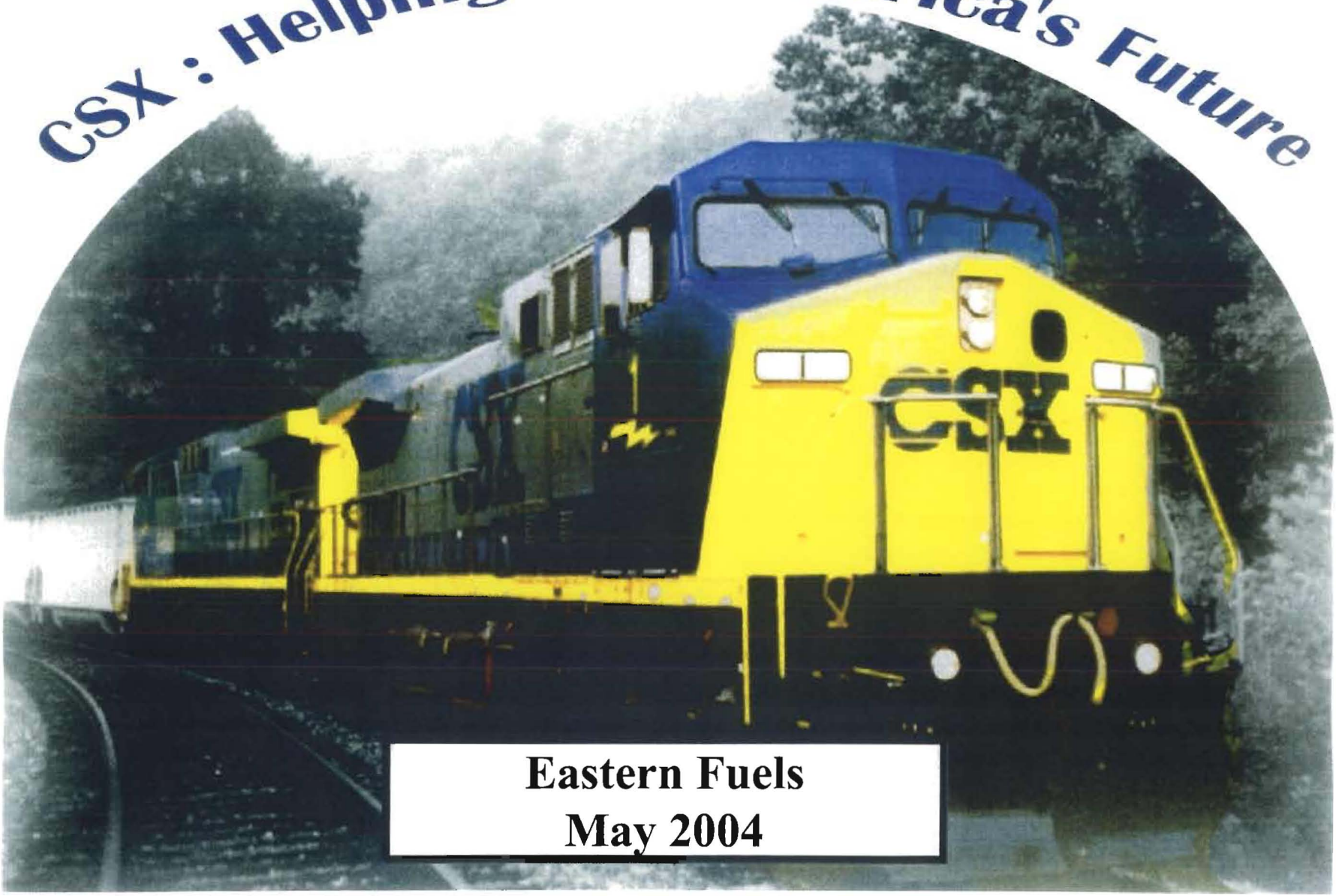


Initiatives

- **Commitment to Revenue Growth**
- **Commitment to Service**
- **Commitment to Improvement in operating and financial measures**
- **Commitment to Capital Spending**

CSX TRANSPORTATION

CSX : Helping Fuel America's Future



Eastern Fuels
May 2004

CSX TRANSPORTATION

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Tampa Electric Company

Quantification of Impact of Adjustments

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Comparison of Rates

1.	Dibner Proposed Rate	$ 17.90
2.	Snavely King Recommended Rate	12.86
3.	Difference	$ 5.04

Impact of Adjustments

4.	River Backhaul	$ 2.59
5.	Ocean Preference Trade Premium	1.69
6.	Ocean Backhaul	0.53
7.	Terminal Rate	0.23
8.	Total	$ 5.04

Source by Row

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2. Snavely King Recommendation, see Exhibit___(MJM-5).
3. Line 1 - Line 2
4. $7.47 (Dibner rate) less $4.88 (Snavely King rate).
5. $7.98 (Dibner rate) less $6.29 (Dibner model adjusted for backhaul only).
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6. $6.29 (Dibner Model adjusted for backhaul only) less $5.76 (Snavely King rate).
   See Late Filed Deposition Exhibit___(MJM-1), pages 3 and 5.
7. $2.45 (Dibner rate) less $2.22 (Snavely King rate)
8. Line 4 + Line 5 + Line 6 + Line 7

MJL 3-20-06

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DOCUMENT NUMBER-DATE
06655 JUN 16 04

dlclas 3-20-06
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 99
COMPANY/ WITNESS: Twomey
DATE: 5/27-28/04 + 6/10/04

ALL

Tampa Electric Company Waterborne Coal Transportation

Calculation of Ocean Rate by Vessel
Dibner Model with Backhaul Removed

		Vessel						
		Peggy Palmer	Gayle Eustace	Doris Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught
User Input Section								
Use Dibner Time Charter Rate? (default is no)		Yes	Yes	Yes	Yes	Yes	Yes	Yes
Adjust for Back Haul?		Yes	Yes	Yes	Yes	Yes	Yes	Yes
Backhaul Ratio Based on Days (Trips)	1/	51.16%	88.24%	38.46%	92.42%	26.47%	96.83%	38.89%
Tons to Big Bend @ 33 feet ST - Actual Delivery		33,700	32,000	21,500	28,000	22,000	16,000	16,500
Calculation of Time Charter								
TC Cost Base		15,846	32,694	14,819	18,733	10,603	13,133	13,797
Preference TC		25,000	25,000	21,000	22,000	22,000	12,000	20,000
Average TC (Dibner)		20,423	28,847	17,910	20,367	16,302	12,567	16,899
TC Used		20,423	28,847	17,910	20,367	16,302	12,567	16,898
Big Bend Delivery Analysis								
Time								
Voyage Time at Sea	2/	4.32	1.96	3.39	2.74	4.86	2.79	5.07
Big Bend Unload in Free Days		2.00	2.00	2.00	2.00	2.00	2.00	2.00
Load Rate as Above		1.12	1.07	1.00	1.00	1.00	1.00	1.00
Shifting Time at Big Bend		-	-	-	-	-	-	-
Channel Maneuvering/Docking/Undocking		0.50	0.50	0.50	0.50	0.50	0.50	0.50
Delay @ 15% of Voyage Time at Sea	2/	0.65	0.29	0.51	0.41	0.73	0.42	0.76
Total Time		8.58	5.82	7.40	6.65	9.09	6.70	9.34
Voyage Rate Assessment								
Total Time Charter Expense		175,307	167,866	132,552	135,535	148,143	84,239	157,768
Fuel at Sea	2/	23,572	10,757	13,752	15,188	20,266	12,463	16,585
Tug Generating Fuel	2/	894	978	862	388	1,100	389	840
Barge Fuel	2/	435	238	381	283	487	284	491
Lube Oil	2/	1,179	538	687	760	1,013	623	829
Tug Assist at Davant		500	500	500	500	500	500	500
Tug Assist at Big Bend		1,000	1,000	1,000	1,000	1,000	1,000	1,000
Misc. Port Expenses		3,770	3,669	2,545	4,280	2,300	2,750	1,920
Total Cost Per Voyage		206,657	185,547	152,279	157,934	174,809	102,248	179,933
Per Short Ton (Big Bend)		$ 6.13	$ 5.80	$ 7.08	$ 5.64	$ 7.95	$ 6.39	$ 9.73

1/ Percentage of round trips between LA and TPA that carried backhaul. Based on Port of Tampa data.
2/ Adjusted for backhaul. Dibner amount less 1/2 backhaul percentage.

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Tampa Electric Company Waterborne Coal Transportation

Calculation of Average Ocean Rate
Dibner Model with Backhaul Removed
Includes Preference Trade Premium

Barge	Est Rate	Capacity (000 Tons)	Tons/Yr (000)	Cum Tons (000)	Cum. Cost ($000)	Avg. Rate
Mary Turner	$ 5.64	1,024	1,024	1,024	$ 5,776	$ 5.64
Gayle Eustace	$ 5.80	1,447	1,447	2,471	$ 14,166	$ 5.73
Peggy Palmer	$ 6.13	1,111	1,111	3,582	$ 20,979	$ 5.86
Diana T	$ 6.39	560	560	4,142	$ 24,558	$ 5.93
Doris Guenther	$ 7.08	877	877	5,019	$ 30,769	$ 6.13
Diane Ludwig	$ 7.95	756	481	**5,500**	$ 34,591	**$ 6.29**
Barbara Vaught	$ 9.73	585	0	5,500	$ 34,591	$ 6.29

Average Rate with Preference Trade Premium and Backhaul Based on Days **$ 6.29**

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Tampa Electric Company Waterborne Coal Transportation

Calculation of Ocean Rate by Vessel
Dibner Model with Backhaul and Preference Trade Premium Removed

	Vessel						
	Peggy Palmer	Gayle Eustace	Doris Guenther	Mary Turner	Diane Ludwig	Diana T	Barbara Vaught
User Input Section							
Use Dibner Time Charter Rate? (default is no)	No	No	No	No	No	No	No
Adjust for Back Haul?	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Backhaul Ratio Based on Days (Trips) 1/	51.16%	88.24%	38.46%	92.42%	26.47%	96.83%	38.89%
Tons to Big Bend @ 33 feet ST - Actual Delivery	33,700	32,000	21,500	28,000	22,000	16,000	18,500
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TC Cost Base	15,846	32,694	14,819	18,733	10,603	13,133	13,797
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TC Used	15,846	32,694	14,819	18,733	10,603	13,133	13,797
Big Bend Delivery Analysis							
Time							
Voyage Time at Sea	4.32	1.86	3.39	2.74	4.86	2.79	5.07
Big Bend Unload in Free Days	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Load Rate as Above	1.12	1.07	1.00	1.00	1.00	1.00	1.00
Shifting Time at Big Bend	-	-	-	-	-	-	-
Channel Maneuvering/Docking/Undocking	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Delay @ 15% of Voyage Time at Sea	0.65	0.29	0.51	0.41	0.73	0.42	0.76
Total Time	8.58	5.82	7.40	6.65	9.09	6.70	9.34
Voyage Rate Assessment							
Total Time Charter Expense 2/	136,019	190,252	109,678	124,664	96,357	88,036	128,812
Fuel at Sea	23,572	10,757	13,752	15,188	20,266	12,463	16,585
Tug Generating Fuel	894	978	862	388	1,100	389	840
Barge Fuel	435	238	381	283	487	284	491
Lube Oil	1,179	538	687	760	1,013	623	829
Tug Assist at Davant	500	500	500	500	500	500	500
Tug Assist at Big Bend	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Misc. Port Expenses	3,770	3,669	2,545	4,280	2,300	2,750	1,920
Total Cost Per Voyage	167,369	207,933	129,406	147,064	123,023	106,045	150,977
Per Short Ton (Big Bend)	$ 4.97	$ 6.50	$ 6.02	$ 5.25	$ 5.59	$ 6.63	$ 8.16

1/ Percentage of round trips between LA and TPA that carried backhaul.
Based on Port of Tampa data.
2/ Reflects Dibner calculated Time Charter rate without Preference Trade premium.

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Tampa Electric Company Waterborne Coal Transportation

Calculation of Average Ocean Rate
Dibner Model with Backhaul and Preference Trade Premium Removed

Barge	Est Rate	Capacity (000 Tons)	Tons/Yr (000)	Cum Tons (000)	Cum. Cost ($000)	Avg. Rate
Peggy Palmer	$ 4.97	1,111	1,111	1,111	$ 5,518	$ 4.97
Mary Turner	$ 5.25	1,024	1,024	2,135	$ 10,896	$ 5.10
Diane Ludwig	$ 5.59	756	756	2,891	$ 15,124	$ 5.23
Doris Guenther	$ 6.02	877	877	3,768	$ 20,402	$ 5.41
Gayle Eustace	$ 6.50	1,447	1,447	5,215	$ 29,805	$ 5.72
Diana T	$ 6.63	560	285	5,500	$ 31,693	$ 5.76
Barbara Vaught	$ 8.16	585	0	5,500	$ 31,693	$ 5.76

Average Rate with Preference Trade Premium and Backhaul Based on Days **$ 5.76**

ALL

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Tampa Electric Company

Quantification of Impact of Adjustments

Comparison of Rates

1.	Dibner Proposed Rate	$ 17.90
2.	Snavely King Recommended Rate	12.86
3.	Difference	$ 5.04

Impact of Adjustments

4.	River Backhaul	$ 2.59
5.	~~Ocean Preference Trade Premium~~ Ocean Backhaul	1.69
6.	~~Ocean Backhaul~~ Ocean Preference Trade Premium	0.53
7.	Terminal Rate	0.23
8.	Total	$ 5.04

Source by Row

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2. Snavely King Recommendation, see Exhibit___(MJM-5).
3. Line 1 - Line 2
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8. Line 4 + Line 5 + Line 6 + Line 7

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(Corrected pg 1 of Hrg. Exh. 99)

Document was filed as confidential by Office of Public Counsel; company will follow up with NOI, claim, or request for confidentiality.

(See DNs 05119-04 + 06655-04)

DOCUMENT NUMBER-DATE
07092 JUN 29 05
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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 031033-EI

In re: Review of Tampa Electric Company's waterborne transportation contract with TECO Transport and associated benchmark.
_____/

CONFIDENTIAL TRANSCRIPT

DEPOSITION OF:	MARTIN DUFF
TAKEN AT THE INSTANCE OF:	CSX Transportation
DATE:	Friday, May 14, 2004
TIME:	Commenced at 9:15 a.m. Concluded at 12:46 p.m.
LOCATION:	Comfort Suites 1026 Apalachee Parkway Tallahassee, Florida
REPORTED BY:	MARY ALLEN NEEL, RPR Notary Public, State of Florida at Large

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AHK 4.20.06. (entire DN)

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2894-A REMINGTON GREEN LANE
TALLAHASSEE, FLORIDA 32308
(850) 878-2221

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FPSC-COMMISSION CLERK

PSC Docket 031033-EI
In Re: TECO Coal Transportation
Exhibit _____
Deposition of Martin Duff

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 100
COMPANY/ WITNESS: 5(27-28) 04 + 6/10/04

APPEARANCES:

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MICHAEL B. TWOMEY, ESQUIRE (Via telephone)
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Tallahassee, Florida 32314-5256

REPRESENTING CSX TRANSPORTATION:

ROBERT SCHEFFEL WRIGHT, ESQUIRE
Landers & Parsons, P.A.
310 West College Avenue
Tallahassee, Florida 32301

APPEARANCES CONTINUED:

REPRESENTING THE COMMISSION STAFF:

MARY ANNE HELTON, ESQUIRE
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

ALSO PRESENT:

CARLOS ALDAZABAL	PENELOPE RUSH
TODD BOHRMANN	ROBERT SANSOM
WILLIAM McNULTY	JOHN STAMBERG
EARL POUCHER	JOANN WEHLE

I N D E X

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Cross-Examination by Mr. Perry	71
Cross-Examination by Mr. Beasley	73
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Recross-Examination by Mr. Beasley	102

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3	11/22/02 e-mail header	59
4	Position Report	63
5	12/11/02 e-mail header	66
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CERTIFICATE OF REPORTER 104

PROCEEDINGS

The following deposition was taken on oral examination, pursuant to notice, for purposes of discovery, for use as evidence, and for such other uses and purposes as may be permitted by the applicable and governing rules. Reading and signing of the deposition transcript by the witness is not waived.

* * *

MR. BEASLEY: At the outset, I would like to propose what we have stipulated to in prior depositions, and that is that the transcript of this deposition will be furnished to Mr. Wright and myself for review and highlighting of confidential information, after which copies could be distributed to those who are signatories to nondisclosure agreements, and also to Office of Public Counsel, who is covered by a Motion for Temporary Protective Order, and with the staff's version being routed to me, and I would immediately file it with the Clerk's Office confidentially with a notice of intent to seek confidential classification. If that's acceptable, we'll proceed under that procedure.

MR. WRIGHT: As in all other instances, we agree.

Thereupon,

MARTIN DUFF

the witness herein, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. WRIGHT:

Q Good morning, Mr. Duff.

A Good morning.

Q My name is Schef Wright. We've met, and you know that I'm an attorney for CSX Transportation in this case.

A Yes.

Q Have you had your deposition taken before?

A No.

Q I know you've been present for some of the other depositions in this case, but I would like to go over a couple of principles or ground rules that we usually follow in depositions. I will try to ask you questions that generally call for a yes or no answer or for a straightforward factual answer. To the extent that it's possible for you to give a yes or no answer or to answer with facts, I would appreciate your doing so, after which you are free to explain your answer to any extent that you deem necessary. Is that okay?

A Yes.

Q Because of the written nature of depositions,

it's important that you give an audible response rather and a nod or a shake of the head.

A I understand.

Q Thank you. If at any time I ask you a question that you don't understand, just say so, and I'll attempt to rephrase it in a way that will enable us to communicate effectively. Okay?

A Okay.

Q At the outset, I would like to ask, did you receive a copy of your deposition notice?

A I'm not really sure. I'm sure I did, but I haven't seen it.

MR. WRIGHT: It's not that important, but I'm going to ask that it be marked as Deposition Exhibit 1.

(Deposition Exhibit 1 was marked for identification.)

BY MR. WRIGHT:

Q Will you please state your name and business address for the record.

A Martin Duff, 702 North Franklin Street, Tampa, Florida.

Q By whom are you employed, and in what position?

A Tampa Electric Company, Fuels and Wholesale Marketing Department. And my position is Fuel

Strategist.

Q For how long have you held that position?

A A little over a year.

MR. WRIGHT: Off for just a second.

(Discussion off the record.)

BY MR. WRIGHT:

Q Do you recall on what date you assumed your current position as Fuel Strategist, or in what month?

A It was late in the fall of 2002.

Q What position did you hold before that?

A Coordinator of Fuels Transportation.

Q For how long did you hold that position?

A Approximately five years.

Q So would I be correct to conclude from your testimony that you started in that position around 1997?

A That's correct.

Q Thank you. To whom do you report presently?

A Karen Bramley.

Q And what is her position?

A Manager of Coal Procurement, I believe.

Q Have you reported to Ms. Bramley since you assumed your current position as Fuel Strategist?

A I believe so. There was a period of time when the organization was a little flatter and we all reported to Joann, but I'm not sure it was before or

after I moved into this position.

Q Thank you. And when you said Joann just now, you meant Joann Wehle?

A Joann Wehle.

Q To whom did you report in your position as -- Coordinator of Fuel Transportation or Coordinator of Coal Transportation? Which was it?

A Fuel.

Q To whom did you report in that position?

A For a period of time, it was Rod Burkhardt, and after that it was Joann Wehle. And there were a couple of other folks that came through between that point.

Q To whom did you directly report in the year 2002?

A I think most of the year it was Joann Wehle.

Q Thank you. Do you recall attending a meeting on May 9, 2002, with CSX Transportation representatives?

A I believe so.

Q To your recollection, what was the purpose of that meeting?

A I believe CSX had requested to come in and discuss the potential to move coal to Tampa Electric by rail.

Q And would that have involved the possibility of CSX's moving coal by rail to Tampa Electric for use at

its Big Bend and Polk Stations?

A I believe that's what they were looking for.

Q Have you reviewed any of the testimony that has been filed in this case by any party?

A Yes.

Q Can you tell me which witnesses' testimonies you have reviewed, please?

A Joann Wehle, Paula -- and I apologize to Paula for not being able to pronounce her last name.

MR. BEASLEY: Guletsky.

A Guletsky. Brent Dibner's, Fred Murrell's, Mr. Stamberg's, Mr. Sansom's.

Q Do you recall whether you reviewed the testimony of Mr. Robert White?

A Oh, yeah. Yes, I did.

Q What were your duties as Coordinator of Fuel Transportation, Mr. Duff?

A Monitor inventories locally. That would be in Tampa, and also at our TECO bulk terminal facility in Davant, Louisiana. Track loadings throughout the month on contracts to ensure that companies were shipping and transportation providers were moving the product.

Q Did you participate in negotiating fuel transportation contracts for Tampa Electric in your role as Coordinator of Fuel Transportation?

A I believe I worked on some -- no. Some oil contracts, but those were delivered to the plant.

Q So you did not participate in negotiating any of the solid fuel transportation contracts for Tampa Electric?

A No, not that I'm aware of or can think of.

Q Do you recall whether you were the first person that CSX Transportation personnel contacted to request the meeting that occurred on May 9, 2002?

A It may have been myself or Cary McBride, who is no longer with the company. We had moved coal by CSX for many years and have always had a business relationship with the folks in Jacksonville, so it wasn't something new that they called us up.

Q Before their requesting the meeting that occurred on May 9th, had they previously made other requests to meet with Tampa Electric to discuss the possibility of carrying coal for use at Big Bend and/or Polk?

A I'm sure we discussed it. Gannon Station was scheduled to be converted to gas, and the tonnage that we historically had moved through them was dwindling, ramping down.

Q So is it a fair characterization of that testimony that there had been discussions, but that you

don't recall specifically when they occurred?

A Yes.

Q Do you recall when approximately CSX requested the meeting or sought the meeting that occurred on May 9, 2002?

A No, not specifically.

Q Were you the primary contact person for CSX regarding setting up that meeting?

A At that time, yes.

Q To the best of your recollection, what occurred at that meeting?

A To the best of my recollection, they discussed the possibility of moving coal into our Polk Station, or possibly Big Bend Station.

Q Do you recall what the outcome in terms of next steps was of that meeting?

A I don't think there was next steps. We listened to them and explained to them that we had a transportation agreement in place, and we appreciated their time and effort.

Q Did you agree to facilitate a site visit for CSXT personnel to the Big Bend Station to gather further information regarding the possibility of delivering coal to Big Bend?

A I agreed to meet with them and show them around

the stations in the context that we had a coal transportation agreement in place.

Q Did you at that time have a coal transportation agreement in place for Polk?

A Yes, sir.

Q And what was that agreement?

A It was a trucking agreement to move the product with CTL Transport out of Mulberry, Florida, from Big Bend to Polk.

Q As of that time, when was that contract due to expire?

A I believe the end of 2003.

Q I've been told, and I couldn't honestly tell you by whom, that that contract has recently been renegotiated and that there is now a new contract in place with CTL. Is that accurate?

A It was rebid, and CTL won the bid, and so a new contract was put in place.

Q And when did that occur?

A The end of 2003.

Q Did CTL have a right of first refusal under its prior contract or any similar right?

A No.

Q In a response a few minutes ago you mentioned that Gannon was closing as a coal plant and being

converted to gas. Do you know when Tampa Electric's decision was made to convert Gannon to gas?

A It was in conjunction with the consent decree, so I'm just going to have to say the late '90s or early 2000, somewhere in that time frame. I'm not sure of the actual date.

Q Do you recall, is it a provision of the consent decree that Gannon would be converted to gas?

A It's my belief that, yes, that's true.

Q So is it your understanding that as of the time the consent decree was executed by Tampa Electric and the relevant governmental agencies -- I'll start over.

A Please.

Q Is it your recollection and your understanding that as of the time the consent decree was executed by Tampa Electric and the relevant governmental agencies, the decision to convert Gannon to gas had been made?

A I'm going to have to ask you to ask me that again. I thought you had already asked me that prior to this.

Q Well, was it your understanding that one of the terms of the consent decree was that Gannon would be converted to gas?

A Yes.

Q Do you recall whether you did in fact meet

with CSX personnel and show them around the Big Bend and Polk Stations?

A Yes.

Q Approximately when did that occur?

A I don't have the dates. It was on, I believe, two or three different occasions.

MR. BEASLEY: Schef, could I interject? You've referred to CSX and CSXT. Can we stipulate that the CSXT is the party you represent?

MR. WRIGHT: Absolutely.

MR. BEASLEY: So any references to CSX mean CSXT?

MR. WRIGHT: Yes, and I appreciate the clarification.

BY MR. WRIGHT:

Q I understood your last answer, Mr. Duff, to indicate that you recall having shown CSXT personnel around the stations on two or three different occasions. Is that accurate?

A I believe so.

Q Can you tell me on approximately what dates those occurred?

A Actually, no.

Q Is it possible that you only did so on one occasion?

A I believe it was more than that.

Q My recollection is that one such visit took place on or about May 31st of 2002. Does that jibe with your memory?

A I would have to look at my records, but I believe so.

Q Do you recall whether you visited both stations on that day or just Big Bend?

A I don't recall.

Q Do you recall who from CSXT came to that meeting?

A It was generally Mike Bullock and Bob White, but on one visit he brought someone else from an engineering firm.

Q Do you recall whether that person was Mr. Richard or Dick Schumann?

A Yes.

Q Did you go to both Big Bend and Polk?

A I believe so.

Q What's your recollection of what occurred when you went to Big Bend on that day, that site visit, whenever it occurred?

A I believe actually we began the day at Polk. If you want me to give it to you in chronological order, that will be fine, or do you want me to go back to Big

Bend?

Q No, I think chronological would be great. I appreciate that.

A They were driving, as was I, and they were coming down from Jacksonville. And Polk is to the east of Tampa, and so we felt it would be better, instead of backtracking, to meet there. So I believe we met them at the gate, drove into the station, and at that point transferred into my van and took a driving tour of the station and looked at the coal unloading facilities there. They were interested in the amount of land, the area, and how our unloading system worked. And at that point, I believe we went to the car, and they got back in their car, and we drove to Tampa, Big Bend Station.

Q Okay. And what happened when you got there, if anything?

A We parked outside the station gate. Once again, they transferred into my car, and we took a driving tour of Big Bend Station, the coal unloading facilities, the docks, the coal yard. They were interested in the existing track and I believe the limestone unloading facility.

Q Do you recall anything else specifically that occurred during that visit?

A No, not specifically.

Q Okay. If you know, at the time of that visit at approximately the end of May of 2002, was Tampa Electric considering the sale of its Polk gasifier or gasification unit?

A There was a consideration of monetizing the gasifier and essentially converting it, as it was qualified to be, into a Section 29 synfuel machine.

Q When you use the phrase "monetizing the gasifier," what does that mean, Mr. Duff?

A The way the rules are written, the IRS rules for a Section 29, that I'm aware of, you cannot sell yourself, essentially, synfuel, that if you were to produce synfuel, you would have to sell it to a third party. So essentially, we would sell the gasifier, and they would produce the synfuel and sell the fuel back to Tampa Electric.

Q The gasifier would produce synfuel?

A Polk Power Station is integrated gasification and combined cycle technology.

Q Yes, sir. That I understand.

Tell me how they produce synfuel, please.

A I'm not a gasification expert, so I'll give you a --

Q 50,000 feet will be fine.

A Essentially, you utilize coal, or in our case,

petroleum coke currently. You grind it into a slurry, so it's liquid coal at that time. You have to have at least a 40% solid solution in the liquid. It then gets pumped into a vessel at greater than 1,700 degrees Fahrenheit, and at that point it is converted into a gas. The gas is then cleaned through a number of different processes to take out the sulfur and any other impurities, and a gas mixture of approximately 40% hydrogen and 60% carbon monoxide is consumed in a combined cycle combustion turbine.

Q Mr. Duff, you were explaining the gasification process, and I think you got to the point of describing what the gaseous fuel that comes out of the gasifier and is then input into the combustion turbines is.

A That's correct. The gas is consumed in the combustion turbines to produce electricity. The hot gas goes through a heat recovery steam generator and also produces generation from a conventional steam turbine.

Q Thank you. So where does the synfuel output of this process occur?

A It's almost two processes. You have your combined cycle generation system, and then you have your gasification system. And the gasification unit was the unit that was going to be sold to an outside entity. I believe we would have operated it under a contract with

them and purchased the synfuel for Tampa Electric.

Q Is the synfuel in this application the gaseous output of the gasifier?

A Yes.

Q Thank you. What fuel or fuels -- are there any requirements, to your understanding of Section 29 of the Internal Revenue Code, as to what fuel or fuels may be used to qualify for the synfuel tax credits?

A Coal.

Q Is it any coal or domestic U.S. coal?

A I don't know that it specifies, but I know it's coal, coal fines.

Q It has to be coal, not pet coke? Is that the important distinction here?

A Yes.

Q Has Polk consumed coal in its career?

A Poke was built as a coal-fired unit and consumed coal for -- time blurs. It was three or four years at the outset.

Q Do you recall what coal or coals it used during that time?

A Yes. There was a number of different test burns that were required by the Department of Energy, who helped contribute the cost of building the clean coal technology gasifier. Pittsburgh 8 was consumed in

it from a number of different mines in that area, Northern Appalachia, for a short period of time.

MR. BEASLEY: Schef, I want to interpose an objection to this line of questioning as being not relevant to the issue of transportation charges that Tampa Electric incurs for its waterborne coal transportation, the same as I did yesterday, and this will be a standing objection.

You may proceed.

MR. WRIGHT: Okay.

A (Continuing) A number of different coals from the Illinois Basin also were consumed.

Q Thank you. In your answer there, between your reference to both Pitt 8 coal and the Illinois Basin coal, you used the phrase "for a short period of time." Was it the Pitt 8 coal that was used for a short period of time or the Illinois Basin that was used for a short period of time, or what?

A I think it began with Pittsburgh 8 coals, and I can think of two different mines we purchased coal from there, and then we began to consume coal from the Illinois Basin. And the vast majority of coal consumed prior to moving to petroleum coke was Illinois Basin coal from the Patriot mine. I can't think of the --

Q I think you mentioned that there were two Pitt

8 mines. What mines were those, if you recall?

A I believe it was Bailey, and I could be wrong. I was just doing transportation at that time. And I don't recall the other one.

Q During the time frame of the meetings that we've been talking about in May and June of 2002, did you discuss with CSXT personnel specific coal sources that would be capable of serving Polk?

A Not that I'm aware of, no.

Q Just so I'm clear regarding a previous answer you gave regarding the phrase "monetizing the gasifier," does that essentially mean selling it to somebody else so that you would then buy the gaseous synfuel from that third party?

A That's correct.

Q Following the -- let me back up. Do you recall specifically any other site visits with CSXT personnel to either Big Bend or Polk after the one that we just discussed?

A I know there were more than that, but specifically, no.

Q Do you remember any specific events that occurred on any other occasion in which they visited either plant?

A Not specifically, no. As I said, we had a

relationship, and we talked on a regular basis.

Q Following the site visit that we did just discuss that you do recall, for the next several months, did you continue to have discussions with CSXT personnel regarding their interest in providing coal transportation services to Tampa Electric?

A I recall that they would call and want to discuss those specific issues, yes.

Q Did they send any correspondence that you recall before October 23, 2002?

A Not that I recall.

Q Any e-mails that you recall?

A I would venture to guess that there was. Like I say, there was a relationship there, and we talked on a regular basis, I think.

Q Do you recall whether you or anyone else at Tampa Electric furnished any plot plans, drawings, or any other descriptive information regarding Big Bend and/or Polk to CSXT?

A That was discussed, and they had requested that, and it was determined that we could go ahead and send them the plot plans, and I believe LaRae Difulgo from our records management sent them something.

Q Thank you. I think you said it was discussed and determined that it would be okay to send them the

plot plants. Who made the decision that that was okay?

A I would assume at that time it was probably Joann.

Q Thank you. Do you recall receiving a proposal from CSX on October 23, 2002, to provide coal transportation by rail services to Tampa Electric?

A Yes.

Q If you recall, was that proposal addressed to yourself?

A I don't recall.

Q Mr. Duff, I'm going to hand you a document that I understand to be a copy of that proposal and ask if you've seen that before. I'll note that it is in fact addressed to Ms. Wehle.

A It appears to be the same document, yes.

Q The same document that you understand CSX to have sent on that date?

A Yes.

Q I understand that there was some concern regarding the origin of this document, in particular, as to whether it had been requested by Tampa Electric or sent on an unsolicited basis by CSX. Do you recall any such concern or issue?

A Uh-huh, yes.

Q What's your recollection of that?

A We requested that they send another cover sheet that it was not requested. We had to my knowledge never requested a proposal from them. They had wanted for some time to give us some kind of proposal, and when they did, to clarify it for our records, we asked them to send another cover sheet.

Q Do you recall whether there were any telephone calls made by Tampa Electric personnel to CSX regarding that issue?

A I'm not sure if it was done on the phone or correspondence by mail. I can't say.

Q Do you know Mr. Hugh Smith?

A Yes, I do.

Q What was his position -- well, was he employed with Tampa Electric Company during this time period?

A I believe so.

Q Do you know what his position was at that time?

A He was our vice president.

Q And by our vice president, does that mean he was over --

A He was over wholesale power and fuels. And I couldn't say at this time what else he was over.

Q Do you know whether he got involved in the issue of who requested or didn't request or originate the proposal from CSXT?

A I wouldn't know.
Q Did Mr. Smith ever discuss this issue with you?
A Not that I recall.
Q Did you discuss this issue with Ms. Wehle?
A I would think so, yes.
Q Do you recall specifically with either?
A Yes.
Q Yes, you recall, and yes, you did?
A Yes, I recall discussing it with Ms. Wehle.
Q If you recall, what did she say about it?
A That she felt that it was an unsolicited offer and not a solicited offer as the cover sheet said, and that we needed to clarify that with CSX.
Q Did you personally review this document, the October 23rd proposal from CSX?
A Yes.
Q Did you consider it to be a bona fide proposal from CSXT?
A I don't think I thought of it that way at all. It was an unsolicited offer. We had no need for transportation services at that time.
Q Did you understand that the proposal offered to provide services through 2008?
A Yes. If that was the date on the document, yes.

Q At that time, your contract with TECO Transport only went through 2003; isn't that correct?

A That's correct.

Q Did you believe that it was a serious proposal by CSXT?

A I believed that since the shutdown of Gannon that they had interest in moving coal to Tampa Electric.

Q Did you believe that it was a serious proposal by CSXT?

A Yes.

Q I'm going to hand you an e-mail that appears to be an exchange of e-mail between yourself and Mr. Mike Bullock and ask you if you recall that.

A Uh-huh. Yes, that's mine.

MR. WRIGHT: I'm going to ask that this be marked as Deposition Exhibit 2.

(Deposition Exhibit 2 was marked for identification.)

MR. BEASLEY: Have you got an extra copy of it?

MR. WRIGHT: I don't, but I'll be happy to get you one. Let's go off.

(Discussion off the record.)

BY MR. WRIGHT:

Q Following Tampa Electric's receipt of the proposal from CSXT on or about October 23, 2002, did you

continue to have discussions with CSXT personnel regarding their interest in transporting coal for Tampa Electric?

A I guess the answer to your specific question would be no. Did we continue to discuss and have open relationships with CSX? Certainly, yes.

Q Did they continue to express their interest to you in transporting coal for Tampa Electric?

A Yes.

Q Did they ask for meetings to discuss the October 23, 2002 proposal with Tampa Electric?

A Yes.

Q Did such a meeting eventually occur?

A Yes.

Q Do you recall whether that meeting occurred on or about March 12, 2003?

A Yes.

Q Did they ask for the meeting to occur earlier than that?

A I believe so.

Q If you know, why didn't the meeting occur before March 12th, when you had received the proposal on or about October 23rd preceding?

A We had a very small shop, and we were probably awfully busy with one thing or another.

Q Do you remember what those other things were?
A Specifically, no.
Q Did you personally do any evaluation of the rates proposed in the October 23rd proposal?
A Did I look at them? Did I evaluate them?
Q Well, my question was evaluate. Did you look at them?
A Sure.
Q Did you evaluate them in terms of comparing them to the rates charged by TECO Transport?
A Yes.
Q Did you prepare any document comparing those rates?
A I don't believe so. We felt they were very aggressive rates, but we were not in the market for fuel transportation.
Q I think we covered this, but just to make sure, isn't it true that as of that time, Tampa Electric's contract with TECO Transport was due to expire on December 31, 2003?
A I believe so.
Q Did you give any consideration to the possibility of negotiating with CSXT for transportation services commencing January 1, 2004?
A That wouldn't have been my call. That's not my

call.

Q Understanding that it would not have been your call, do you recall whether you did so?

A Can you ask the question again?

Q I understand that it would not have been your call as to whether to make that consideration, but do you know whether anybody at Tampa Electric considered it?

A Considered what?

Q The possibility of negotiating with CSXT for coal transportation services commencing January 1, 2004, following the expiration of Tampa Electric's contract with TECO Transport.

A I really couldn't say. I don't think so. I don't know. We don't have fuel unloading facilities for rail, so I'm not sure that we would. We were under a consent decree, and we didn't really know where our tonnage would be going in the next five years.

Q Did CSXT offer to provide funding for rail unloading facilities at Big Bend in connection with its October 23rd proposal?

A I believe so.

Q You mentioned in a previous response that CSXT's rates shown in their October 2002 proposal were aggressive. Is that an accurate restatement of what you

testified to already?

A I think that's what I said.

Q When you say aggressive, does that mean they appeared to you to be relatively low and favorable for the transportation service involved?

A Appeared on their face; that's correct.

Q Did you discuss that perception of yours with anyone at Tampa Electric?

A Not specifically. I can't specifically recall, yes or no.

Q So would it be fair to say that you never made any recommendation to anyone else within Tampa Electric regarding further consideration of CSXT's proposal?

A Yes.

Q When you said that the rates were aggressive, what is your frame of reference for that? In what relationship did they appear to be on their face aggressive and relatively favorable?

A I guess I would say on a dollar per ton basis, without further analysis.

Q And would your review of the proposal have occurred shortly after you received it, in, say, late October or early November of 2002?

A I assume, yes.

Q Would it be your normal practice upon receiving

what appeared to be on its face a favorable offer for any service or commodity to evaluate it and make a recommendation to your superiors?

A Obviously, we would, you know, look at anything. At that time, we weren't in the need for transportation services.

Q But you were about 14 months away from the end of your existing transportation contract, weren't you?

A That would be correct.

Q Let me ask you a hypothetical. If you had a coal contract that was going to expire, say, June 30th of 2005, and a supplier of comparable coal came in and offered you a very attractive price for that coal for delivery starting on July 1, 2005, what would you do?

A I don't think you can make that comparison. A coal contract is not going to require massive infrastructure construction.

Q Well, I'm not asking you for that comparison. I'm asking about your practice in terms of receiving or in relation to receiving what appears to be facially a favorable offer.

A Yes, we would look at it.

Q Would you tell anybody in your chain of command?

A Certainly.

Q Would it be in your normal practice to make a recommendation regarding further negotiations or not in that relation?

A If it wasn't already brought to their attention, I would bring it to their attention. But obviously, this bid was sent to Ms. Wehle.

Q You were copied on it, were you not?

A Yes.

Q To your recollection, what, if any, contact or conversations with CSXT personnel did you have following the meeting that occurred on March 12, 2003? Let's narrow it down to between then and the time Tampa Electric issued its RFP, which I believe occurred on June 27, 2003.

A I really wouldn't be able to tell you. I don't know. Like I said before, we discussed things on a regular basis.

Q Do you recall specifically whether CSX personnel continued to express their interest to Tampa Electric and to you directly in providing coal transportation services for Tampa Electric?

A I think that's a fair assessment.

MR. WRIGHT: Off for a second.

(Discussion off the record.)

BY MR. WRIGHT:

Q Mr. Duff, did you participate in developing the RFP that Tampa Electric issued on June 27, 2003?

A Yes.

Q What was your role and function in developing that RFP?

A I think a team member would be appropriate.

Q As a team member, did you have substantive input into the RFP?

A I had input.

Q Were the responses to be sent to you?

A Yes.

Q Were you the individual at Tampa Electric Company over or under whose signature the proposal was sent out to those who received it?

A That's correct.

Q Did you have input into determining the list of those to whom it was sent?

A Yes.

Q Is that something that would have been more your responsibility than other issues with regard to the RFP issuance?

A No.

Q You will agree, will you not, that CSX was not originally furnished a copy of the RFP?

A It was a waterborne transportation bid. That's

correct.

Q Just to be clear, it's correct that CSXT was not originally furnished a copy of the RFP at issue; correct?

A It was a waterborne transportation solicitation. They were not furnished one. They had recently or sometime in the past sold the waterborne portion of their business.

Q I understand your explanation. I just wanted an answer to my direct question, that's all.

What, if anything, was your role in evaluating the bids submitted in response to the June RFP?

A As a team member.

Q Did you personally perform any actual numeric calculations, analyses, or evaluations of the various bids submitted in response to the June RFP?

A I'm sure I did.

Q You are aware that CSXT did eventually receive a copy of the RFP, are you not?

A Uh-huh.

Q Were you in the loop that led to them being furnished a copy?

A I believe so. I believe I was asked to send them a copy.

Q By whom?

A I would think Karen Bramley.
Q Do you recall when?
A During the open period of the RFP.
Q Does on or about July 15th or 16th ring a bell?
A I wouldn't know, but I'm assuming that's correct.
Q And CSXT did in fact submit two bids on July 31, 2003; is that correct?
A Yes.
MR. WRIGHT: Let's take a break.
(Short recess.)
BY MR. WRIGHT:
Q Mr. Duff, just one follow-up question on the line of questioning I asked you before we took our break. And I believe you answered it, but I just want the record to be clear. Did you prepare any written analysis of the bid proposal that CSXT submitted to Tampa Electric on October 23, 2002?
A No, I don't believe so.
Q Mr. Duff, are you familiar with Tampa Electric Company's Form 423 reports?
A I'm vaguely familiar with them, yes. I mean, there's federal, there's state. We don't produce them in our department. I'm aware of what they are.
Q I'm going to hand you a page that was furnished

by Tampa Electric and purports to be one page out of such a report for Tampa Electric's FPSC Form 423-2 for February 2004. I'll ask you to take a moment and look at that and tell me whether the information contained in that table is generally familiar to you.

A I am familiar with the document. I do not know where the purchase price and the transport charges essentially come from. This gets put together in another department of our company.

Q Are you familiar with the transport charges themselves?

A No, I don't believe I am.

Q Are you familiar with -- or is it your understanding that the information listed in the far left column of that table relates to the mines or coal suppliers from whom Tampa Electric obtains coal?

A Uh-huh.

Q And is it your understanding that the column immediately to the right of that indicates something having to do with districts and states of origin?

A Uh-huh, that's correct.

Q I note that there are two lines on that table that indicate supply from American Coal Company.

A That's correct.

Q Do those come from two different states?

A Yes. It appears one comes from Ohio, and one comes from Illinois.

Q Is the one that comes from Illinois to your knowledge what is commonly known as Galatia coal?

A That's correct.

Q Do you know whether the coal that comes from Ohio is also furnished pursuant to what has been identified in these proceedings at the Galatia contract?

A Line 4?

Q Yes, that's my question.

A Can you give me your question again?

Q Yes. Is that coal also furnished to Tampa Electric pursuant to what has been identified as the Galatia contract?

A If you're asking --

Q Let me ask it a different way.

A I'm not sure what you're asking.

Q Did Tampa Electric Company allow the supplier of the Galatia coal to substitute Ohio coal?

A Yes. Due to the closing of Gannon Station, we had some overhang on the Galatia contract, and we negotiated a spot agreement with American Coal to provide some Powhattan ton for ton -- obviously, they're different prices, different quality coal -- to meet our obligations to American Coal.

Q I also note that there are two lines on that table that indicate purchases from a supplier identified as Dodge Hill. Is that accurate?

A That's correct. Actually, it's four lines.

(Interruption on telephone; discussion off the record.)

BY MR. WRIGHT:

Q Mr. Duff, I note that the coals shown in lines 2 and 5 appear to have Btu contents in the range of 12,700 Btu per pound, and those shown in lines 6 and 7 appear to have coals more in the range of 11,700 Btu per pound. Is that an accurate interpretation?

A Yes, sir.

Q Thank you. Those aren't the same coals, are they?

A No, sir.

Q Do they come from different places?

A Yes, sir.

Q Do you know where the ones shown at lines 6 and 7 come from?

A They come from -- I believe it's the Somerville mine.

Q Is that in Indiana?

A Yes, it is.

Q Just to be clear, is it just an input error

that they're shown as originating in Kentucky?

A I believe so.

Q Why does Tampa Electric buy the coal that it does buy from Somerville?

A It was a negotiated settlement, I believe, with on Dodge Hill on a quality parameter.

MR. BEASLEY: Just for the record, Schef, I want to renew my objection on the grounds that this is not relevant to the issues in this docket. You may proceed.

MR. WRIGHT: Thank you. And we accept your objection as having been made. We don't agree with the substance of it, but if it ever comes up, we'll argue it then.

BY MR. WRIGHT:

Q What quality parameter was it that you referred to in your previous answer?

A I believe it's chlorine.

Q Does the Dodge Hill coal that comes from Kentucky meet the chlorine specification in its contract?

A It does, but it's also on the upper end of the range, and the supplier had requested to send a small portion of the Indiana coal to ensure that he was not out of compliance.

Q So this negotiated arrangement to which you referred in a previous answer was at the request of the supplier to avoid possible penalties for being out of compliance with the chlorine parameter? Is that accurate?

A I believe so.

Q Did Tampa Electric conduct a coal supply solicitation in December of 2003?

A Yes.

Q Did Dodge Hill submit a bid in connection or in response to that solicitation?

A Yes.

Q Was the Dodge Hill coal disqualified because of its chlorine content in that solicitation review?

A I don't believe so. I should say I don't know.

Q Mr. Duff, is it your understanding that the Dodge Hill coal is marketed or sold to Tampa Electric by an entity known as Pigman Sales Company?

A That's correct.

Q I'm going show you a document that appears to be page 1 of 16 of a response by Tampa Electric to the staff's first request for production of documents and ask if you recognize that document.

A Yes.

Q Do you know who prepared that?

A I believe Karen Bramley or myself put it together, kind of a shared document.

Q I would like to ask you, please, to look at Bates page number 32, the first page of the actual response. The bottom half of the table appears to me to list a number of nonconforming coals. Is that an accurate characterization of what that shows?

A Uh-huh, that's correct.

Q And is the Dodge Hill coal, as indicated by the Pigman Sales Company entries in the left-hand column, the coal that you've just been talking about?

A That's correct.

Q And that table shows that that coal as proposed by Pigman in the solicitation we've been discussing is nonconforming; is that accurate?

A To that specific coal solicitation, yes.

Q And what was the spec in that solicitation, if you recall?

A I don't have it off the top of my head.

Q In rough terms, was the coal proposed by Pigman and Dodge Hill there too high in chlorine to meet the spec of the solicitation?

A That particular specification, that's correct.

Q Thank you. What was that solicitation?

A It was -- the name of it is "Solicitation -

Long-Term Contract for Coal for Big Bend, Order No. 4."

Q Was that the solicitation conducted in connection with obtaining a price which the Zeigler Coal Company would have to match pursuant to its contract right of first refusal?

A It could have the opportunity to match.

Q But is that the same solicitation that --

A That's the same one, yes.

Q Has Zeigler been presented with the price that it has to match if it wants to continue the business?

A Yes.

Q On what basis, i.e., FOB mine, FOB rail, or FOB barge, was Zeigler presented with the opportunity to match the price, or on some other basis?

A FOB barge, I believe.

Q FOB barge at the river dock near the mine, or FOB barge at Big Bend, if you know?

A FOB barge, Ohio River.

Q Does Zeigler deliver on the Ohio River?

A Actually, the contract in place calls for delivery to Davant. We would purchase the coal at the terminal.

Q At Davant?

A Yes, sir.

Q I'm just trying to understand then. If Zeigler

was asked to match a price FOB Ohio River, but you buy the coal at Davant, I'm trying to understand the relationship between those two points.

A There's specific contract language that talks to how the RFP is allowed to be performed, and I believe we have the ability to ask for it FOB barge. But I can't speak to it any more than that.

Q Has Zeigler offered to match the price that Tampa Electric has presented to it?

A No.

Q Mr. Duff, I'm not sure that we communicated effectively in response to a previous question. Is it your understanding that Zeigler delivers to the Ohio River or that it delivers to the Mississippi?

A We purchase it in Davant. Currently it doesn't -- we purchase it at Davant.

Q I understand that you purchase it at Davant, but is your testimony still what you said a couple of minutes ago, that the bid that Zeigler was asked to match was FOB Ohio River?

A Yes.

Q Okay. I understand that, and I understand your testimony that you purchase the Zeigler coal at Davant. Do you know whether Zeigler delivers to the Ohio or to the Mississippi, and if so, which?

A It delivers through Cora River Dock on the upper Mississippi River and flows to the lower Mississippi and then to Davant. So, no, it does not go onto the Ohio in its current --

Q Just so I understand, even though Zeigler delivers to the Mississippi, Tampa Electric has offered them to match the price delivered on the Ohio; is that right?

A That's my -- yes, yes.

Q Would Zeigler have the opportunity under the match offer that has been presented to it by Tampa Electric to supply coal from another mine besides that from which it has historically provided coal to Tampa Electric?

A Yes, I believe they have sourcing options.

Q Do you know what their sourcing options for delivery to the Ohio are?

A No.

Q Has Zeigler been offered the opportunity bid FOB rail?

A Not that I'm aware of, no.

Q Thank you. I'll take that document back, if I may.

Mr. Duff, I'm going to hand you two pages of a document produced to CSXT by Tampa Electric with Bates

numbers 184 and 185 on them that are labeled "2004 Purchases by Commodity/Contract Summary." Do you recognize that document?

A Yes.

Q I want to ask you about the entries in the first block on page 184 under which it says "Standard H." What does "Standard H" mean in that context?

MR. BEASLEY: I renew my objection with respect to this document and any questions relating to it on the grounds that it's not relevant. This is a waterborne coal transportation proceeding. You may proceed.

MR. WRIGHT: You can answer.

A We refer to it as standard high, high Btu, high sulfur.

Q Can the coals listed there under "Standard H" be burned in all four Big Bend units when their scrubbers are operating?

A Those coals are purchased for Big Bend 1, 2, and 3.

Q Understanding that they are purchased for Big Bend 1, 2, and 3, can they be burned in Big Bend 4?

A I wouldn't be able to attest to that.

Q I wanted to ask you about the fourth and fifth lines under "Standard H" that refer to SYAF - Synfuel.

Are those products associated with the Black Beauty mine?

A No, sir.

Q What is the origin of those fuels?

A They're from a mine owned by the Black Beauty Company.

Q Do you know the name of the mine?

A I think it's Arclar.

Q Does Arclar --

MR. BEASLEY: Can I ask you a question off the record?

MR. WRIGHT: Sure.

(Discussion off the record.)

BY MR. WRIGHT:

Q Does Arclar have any affiliation with Illinois Fuels or the Illinois Fuels Company?

A No.

Q Is Tampa Electric presently, i.e., during the year 2004, purchasing or planning to purchase coal from the Illinois Fuels Company?

A No.

Q Does Tampa Electric have a contract with Illinois Fuels?

A Illinois Fuels defaulted on a contract of ours.

Q When did that occur?

A I would say early 2003.

Q And do I interpret your testimony to be that as a result of that default, your contract with Illinois Fuels has been terminated?

A I'm not sure of the -- we essentially went out into the marketplace -- when they stopped shipping, we went into the marketplace and purchased coal to replace that coal, and we were able to cover it. But the contract, we still have rights under the contract if they were to ship out of that mine.

Q So do I understand your testimony correctly to be that the contract itself still exists as far as you know, but you aren't getting any coal from it? Is that right?

A I don't know. I wouldn't know enough about after you get into the legal piece of that.

Q Okay. If you know, was this a solicitation for the replacement coal that you mentioned by which Tampa Electric is covered?

A Yes.

Q When did that occur?

A Well, I can't say for sure if we performed a solicitation or if we just purchased the coal. I'm sorry.

Q So the correct answer to my previous question is, "I don't know"; is that correct?

A That's correct.

Q Okay. I'll take those back from you.

I have a follow-up question on some previous questions and answers we had with regard to the Dodge Hill contract. I believe you said that you amended -- well, you said you settled or renegotiated some terms of your contract with Dodge Hill. Is that correct so far?

A That's correct.

Q Was there an actual amendment to the contract?

A Yes, I believe so.

Q Approximately when was that executed?

A Sometime in the last six months.

Q When their scrubbers are operating, can Tampa Electric Company burn high sulfur Illinois Basin coals at all four Big Bend units?

A Yes.

Q When their scrubbers are operating, can Tampa Electric burn high sulfur Pitt 8 coals at all four Big Bend units?

A They can burn high sulfur Pitt 8 coal, I believe, in 1, 2, and 3. Big Bend 4 has been under a contract since its inception with the Zeigler contract, and exclusively that coal has been put in that unit. So

I really don't have that much knowledge of what we could put into Unit 4.

Q Do you know whether Tampa Electric has test burned Pitt 8 in Big Bend 4?

A I don't know.

Q Mr. Duff, are you familiar with a report submitted to the Federal Energy Regulatory Commission known as FERC 580?

A I'm aware of the term, and I'm probably as aware of that report as I am the Florida FERC 423.

Q Do you have anything to do with preparing Tampa Electric's 580 filings?

A Nope.

Q Mr. Duff, I'm going to hand you the same pack of documents I handed you a little bit ago. It's Tampa Electric's response to the staff's first request for production of documents. It's that same pack of documents that I think relates to proposals received in response to the December 2003 solicitation. And I'll ask you to look at what's identified as page 5 of 16, as well as Bates number page 36.

A Okay.

Q If you would look at the very last line of the small table that's shown on that page, does that show that the company received a proposal from an entity

known as Solar Sources and that that was disqualified?

A Yes.

Q And was it disqualified because it was bid FOB rail?

A Yes.

Q Thank you. I'll take that back.

Mr. Duff, I'm going to hand you a copy of a document furnished by Tampa Electric in response to a production request propounded by CSX Transportation. It appears to be a comparison of CSXT's October 23, 2002 proposal and the two proposals submitted by CSXT in response to Tampa Electric's June 2003 solicitation.

I'll give you as much time as you want to look at it, but my first question is, do you recognize that document?

A I do recognize the document.

Q Did you prepare that document?

A No, I did not.

Q Do you know who did?

A I believe Karen Bramley did.

Q Do you know when it was prepared?

A No, I do not.

Q Do you have any idea when it was prepared?

A I think the last proposal was sometime after July of 2003.

Q And other than that, you don't know; is that correct?

A Not exactly, no.

Q Just to drive it down to the extent we can, other than that it was prepared after July of 2003, do you have any idea when it was prepared?

A No.

Q Mr. Duff, I'm going to hand you a document that has been furnished by Tampa Electric in response to CSX Transportation's fourth request for production, and it includes a table that is headed "Impact of Capital Infrastructure for Rail Facilities on Existing Rates, Cost Per Ton on Five-Year Contract," the cover sheet and the table itself. I'll just give you a moment to take a look at it and ask you first do you recognize it.

A Actually, no, I don't.

Q Do you recall ever having seen it before?

A No, I don't believe I have.

Q Mr. Duff, I'm going to hand you a copy of a document that has been identified as Exhibit 6 to Ms. Wehle's deposition that was taken on Wednesday of this week. Do you recognize that document?

A No, I don't.

Q Do you recall ever having seen it before?

A No, I don't.

Q Do you recall ever having seen any similar document before?

A It's just an analysis sheet.

Q Well, have you seen a analysis sheet comparing adjusted rail bid rates and water transportation rates?

A There was something from last year's docket that was prepared by Mr. McNulty that was similar to this, I believe, but other than that, I don't know.

Q I'll take that one back.

Just to be clear, I'm going to hand you my redacted version of the page 2 of three of document number 3, which is a part of Exhibit JGW-1 to Ms. Wehle's testimony submitted in this docket and ask you if you've seen that one before, in either its redacted or unredacted format.

A I think that's what I was referring to, I believe. I can't say for sure.

Q Okay. With regard to the original unredacted version of this, did you have any role in preparing the table?

A Not that I'm aware of, no.

Q Just to be clear with regard to the time frames covered by previous answers that you've given in this deposition, I believe I previously asked you if after receiving CSXT's proposal on October 23, whether you

performed any written analysis, any evaluation, anything like that of that proposal, and I believe you said no; is that correct?

A That's correct.

Q And my question for you is, did you ever perform any written evaluation, analysis, spreadsheet, or anything of the like with regard to CSXT's October 23, 2002 proposal?

A Formal analysis, no.

Q Well, did you do anything in writing with respect to that proposal?

A No.

Q Did you ever do anything in writing, including a computer spreadsheet, with respect to CSXT's July 2003 bid submitted in response to Tampa Electric's RFP?

A I'm sure there was nothing formal, no.

Q Well, understanding that it wasn't formal, did you do anything in writing, like a computer spreadsheet or handwritten calculations comparing --

A I probably did.

Q Do you recall any specific instances in which you might have done any such exercise?

A No.

Q Do you know whether any such documents still exist that you would have personally prepared?

A If there was anything prepared, it was supplied in the production of documents.

Q Mr. Duff, I'm going to hand you a document that is part of Tampa Electric Company's response to CSXT's seventh request for production that is headed "Calculation of TECO's Fuel Cost Savings Using Powhattan Coal vs. Pitt 8 Coal," bearing Bates number 289.

MR. BEASLEY: Same objection as to relevance.

BY MR. WRIGHT:

Q Do you recognize that document, Mr. Duff?

A No.

MR. WRIGHT: Jim, are you objecting to the relevance of that document that compares --

MR. BEASLEY: Yes.

THE WITNESS: No, not this specific document.

BY MR. WRIGHT:

Q When you say not this specific document --

A No, not that document.

Q Okay. Did you ever prepare any similar document to this?

A No.

Q Do you know who prepared this document?

A I believe that was Karen Bramley.

Q Okay. Did you consult with her in her

preparation of it?

A Our offices are next to each other. We consult pretty much all day.

Q Do you recall specifically whether you consulted with her in regard to this document?

A No, not that I know of. She very well may have asked me questions that I responded to. I don't know.

MR. WRIGHT: Could we take a short break, please?

MR. BEASLEY: Okay.

(Short recess.)

BY MR. WRIGHT:

Q Mr. Duff, thank you very much for your time this morning. I have one follow-up question on the questions I've asked you previously, and it relates to the line of questioning I asked you about whether you prepared any document comparing the delivered cost of coal by rail versus the delivered cost of coal by water. My question is this: If you prepared such a document, what was its nature?

A It would have been comparing transportation costs, one venue against the next.

Q Just transportation costs as opposed to all costs of particular coals delivered by water versus delivered by rail?

A I don't have enough experience to accurately perform an analysis on a rail bid. I'm not up to speed on rail cost adjustment factors and how they operate, unadjusted, adjusted, so I would not be qualified to do that at this particular point.

Q I think you've said you don't recall having specifically done such an analysis. Is that accurate?

A Yes, that's accurate.

Q And if you did -- I just want to clarify your answer given about one minute ago. If you did, would it have just been comparing the transportation costs, rail versus water?

A I think so.

MR. WRIGHT: Thank you very much for your time, Mr. Duff. We have no more questions. I believe Mr. Vandiver does, so I'm going to move.

CROSS-EXAMINATION

BY MR. VANDIVER:

Q Good morning, Mr. Duff.

A Good morning.

Q I think I met you earlier. My name is Rob Vandiver. I'm with the Office of Public Counsel.

When did your career at Tampa Electric begin?

A 1980.

Q And what did you do when you began at Tampa

Electric?

A I was a laborer in power plants.

Q And what was your next job at Tampa Electric?

A I worked in the environmental department performing --

Q And can you walk me through your career?

A I worked in the lab performing fuel analysis for a period of time. I performed environmental testing.

Q What year was that?

A For the next 15 years, 14 years, until I moved into the fuels department, I work exclusively in laboratory services providing air analysis, stack testing, combustion testing, continuous emission monitoring and auditing, any number of services that are related to emissions and the operation of the boilers.

Q And is that when you became Fuels Coordinator in 1997? Was that your next job?

A That's correct.

Q And in that position, are you one of the -- or in that Fuels Coordinator position, were you one of the primary employees of Tampa Electric that dealt with on a day-to-day basis TECO Transport?

A That's correct.

Q And do you remain one of the primary employees

of Tampa Electric who deals with TECO Transport on a day-to-day basis?

A My replacement is Dan Akins, and he works on a day-to-day basis much more so than I do.

Q And how often in your present position do you deal with TECO Transport?

A That's hard to say. Maybe weekly.

Q Weekly?

A (Nodding head affirmatively.)

Q Okay. Does everyone in your group deal with TECO Transport on a regular basis?

A There would be no need really for me to on a regular basis. I mean, it's a very small group. I'm --

Q And who is in your group?

A Joann Wehle is the director. Karen Bramley is the manager. There's me, and then there's Dan Akins.

Q And does Dan report to you?

A No. He reports to Karen.

Q You both report to Karen?

A That's correct.

Q Who is Bill Gleaton?

A Bill Gleaton is the coordinator. I don't know what his title is. I would say vessel coordinator at TECO Transport. He coordinated the transportation of the ocean side.

Q Is he the primary interface at TECO Transport for Tampa Electric on the ocean side?

A That's a fair assessment, yes.

MR. VANDIVER: Okay. I want to hand you a memorandum. I think this is not a confidential document. And I would like to get that marked as an exhibit. I'm going to pass it around. I've got some copies for your counsel and so forth. You can pass that down. Thanks a lot.

(Deposition Exhibit 3 was marked for identification.)

BY MR. VANDIVER:

Q I think this has been marked as Exhibit 3. Now, this is a memorandum, and it's dated November 22, 2002; is that correct?

A Yes.

Q And the subject is "vessel projection"; is that correct?

A Yes.

Q And it's from Bill Gleaton to -- I counted 19 individuals here. And they're not all individuals. There's reference to GTC Warehouse and GTC RoutineMaint. I think that would be Routine Maintenance; is that correct?

A I wouldn't know. I'm assuming like you.

Q So you don't know what GTC stands for?
A (Shaking head negatively.)
Q Okay. You're shaking your head.
A I'm sorry. No, I do not.
Q But I counted 19 different recipients of this e-mail.
MR. BEASLEY: If you could, just make it a question, Rob.
MR. VANDIVER: Okay.
BY MR. VANDIVER:
Q Would you accept that subject to check?
A Yes.
Q Do you know these individuals up here? Do you know Dan Akins?
A Yes.
Q Is he an employee of Tampa Electric?
A He is Coordinator of Fuels Transportation. That's correct.
Q Okay. Thank you. Who is Misty Bartholomew?
A She's a dispatcher with TECO Bulk Terminal.
Q Another TECO or Tampa Electric employee?
A No.
Q Okay. Who does Misty Bartholomew work for?
A TECO Bulk Terminal.
Q Okay. And Laura Bennett?

A TECO Bulk Terminal.

Q Let's go down the list here.

A Layne Bennett, TECO Bulk Terminal; myself, Tampa Electric; Michelle Gagliano, TECO Bulk Terminal. I'm not sure about this GTC Warehouse. Howard Hanson, I believe he works at Big Bend Station.

Q That would be a Tampa Electric employee?

A That would be a Tampa Electric employee.

Pennie Little is TECO, in shipping. Chris Miller is a dispatcher, TECO Bulk Terminal. I don't know Ian Palmer. Ursula Smith-Perry, I don't know her. And Loong-Shen Tsai is an engineer at TECO Bulk Terminal.

Q Okay. What is TECO Bulk Terminal?

A It's the transfer and storage facility at Milepost 55 on the lower Mississippi River.

Q Okay. So that's another separate entity from Tampa Electric?

A It's part of TECO Transport.

Q Okay. Very well, sir. And just for my information, I notice that this e-mail is not routed through the Internet or anything. Is there a common e-mail system between TECO Transport and Tampa Electric?

MR. BEASLEY: Objection to the form. Go ahead.

A It's a common --

Q So there's a common e-mail system between TECO Transport and Tampa Electric?

A It's a TECO Energy Internet, I believe is how it operates, but I don't --

Q So there's a common directory? In other words, you can --

A Yes, that's correct.

Q So you can get all the names from one system.

Okay. Do you have common dialing behind the PBX?

A I don't know what that means.

Q In other words, can you five-digit dial TECO Transport within the TECO building down there on Franklin Street?

A You can with TECO Ocean Shipping. You cannot with TECO Barge Line or TECO Bulk Terminal.

Q Okay. Now, this e-mail had some attachments to it. How often do you get this report?

MR. BEASLEY: If I could inquire. There are no attachments to the document you handed us.

MR. VANDIVER: I'm about to hand it to you.

BY MR. VANDIVER:

Q Is this the attachment that goes with this e-mail? I'm about to hand it to you. It's a

confidential document. It's not on yellow paper. I'm going to have Mr. Poucher hand it to you. And I would like to have this marked as an exhibit as well.

A No, it's not.

(Deposition Exhibit 4 was marked for identification.)

BY MR. VANDIVER:

Q Okay. Is this a regular report that you receive?

A This is referred to as a position report, and when I was in the position, it would come on a daily basis. It's called actually the 8:00 a.m. position report, and it will give you a position of all the ocean vessels' locations.

Q Okay. And you would receive this on a daily basis in your former position, but not in your present position?

A That's correct.

Q Now, I believe you said that you had looked at the testimony of Mr. Dibner; is that correct?

A Yes.

Q Okay. Now, I'm going to hand you a document. I don't need to have this marked as an exhibit, but I want to ask if you agree with Mr. Dibner's assessment here. Mr. Dibner has two different numbers on this, but

this is Bates stamped 116 and page 64 of Mr. Dibner's report. And I believe that's labeled "The Core Fleet of Tampa Electric's Ocean Shipping Fleet." And I believe there he recites that those are the primary ships that carry TECO coal, and I want to ask if you agree with that assessment.

A I believe that's how he did it.

Q And is that an accurate depiction of the primary ships that carry the TECO coal into Tampa Bay?

A Uh-huh, yes.

Q Now, this report that we were just discussing that's Bates stamped 7685 that we just had marked as an exhibit, this is a broader scale than some of these core fleets that we were just discussing, isn't it?

A This document is not produced for Tampa Electric.

Q Okay. It's a --

A This is an internal document of TECO Shipping, and at some point in time we had asked to be included on the routing just to help with our scheduling at Big Bend Station and at Gannon Station for the arrival of vessels.

Q I see. This is delivered to Tampa Electric employees just for informational purposes; is that correct?

A I don't know that it's given to Tampa Electric -- that characterization -- it was given to myself, and I think now it's given to Dan Akins. It's not given to this same list. It's not tied to this first document.

Q Okay. I'm going to hand you another e-mail and ask if this smaller distribution list is the list that this report goes to.

A No. I'm sorry.

Q That's all right. I just want to get straight who this 8:00 a.m. shipping report goes to.

A We try to give the stations the best information available so they can schedule manpower to be available to unload vessels when they get there. In some of our coordination meetings, at some point in time, I probably asked for what's the best, most accurate documentation of when a boat is going to get there, and I think at that time they offered this to us.

Q Okay. What's the distribution of this Bates stamp 7685 report within Tampa Electric? Do you know?

A I believe when I was in the transportation position it was me and a fellow named Cary McBride, who is now not with the company. I have the job that he held at that time, and he was my backup.

Q Okay.

A And then we would utilize this to update our

fuels management system. The plant would receive from the fuels management system the arrival time, expected arrival times.

Q And in the course of getting this, obviously, here at the top, the Peggy Palmer is within your core fleet, and that was useful information to you because that was carrying your coal. And down here at the bottom, I believe the C. Fagan would be the Cynthia Fagan, and that ship was in Capetown, which was useless information to you.

A That's correct.

MR. BEASLEY: Rob, could you ask a question, please, and not testify?

MR. VANDIVER: All right, sir.

BY MR. VANDIVER:

Q Where is Dadong? Do you know?

A No, I don't. I wish my geography was better.

Q Me too. But this broader information, some of this ship information includes TECO ships that were not relevant to the core fleet for coal that is carried to Tampa Electric; is that correct?

MR. BEASLEY: I think he has already said that it is.

A Yes.

(Deposition Exhibit 5 was marked for

identification.)

BY MR. VANDIVER:

Q Now, I believe you have the 7032 Bates stamp there at the bottom as well, and that is from Bill Gleaton to Dan Akins, Martin Duff, and Cornel Smith.

A That's correct.

Q Okay. And that is the Wednesday, December 11, 2002 memorandum, and that just says "schedule." Is this yet another document of TECO Ocean Shipping, or is this perhaps the river shipping?

A No. It would be another document for TECO Ocean Shipping, based on that it came from Bill Gleaton, and he works for TECO Ocean Shipping.

Q Okay. And it's not one of these documents. I want to show you that document and ask if that goes with this memorandum.

A I believe so.

Q All right, sir. And that's another report that you get from TECO Transport that you received in the regular course of business?

A That's correct.

MR. BEASLEY: Rob, let me ask you, just for clarification, what is this document? I mean, you're handing him loose documents. Were they attached when you got them, or were they --

MR. VANDIVER: They were in the same stack.

MR. BEASLEY: But this one, the numbering is before what purports to be a transmittal memorandum. The thing doesn't say anything to connect it up with this. That's my point. You know, I don't want the witness answering about something where there's no way for him to conclude that this document relates to this document.

MR. VANDIVER: He was the one that was getting the reports. I'm just trying to tie them together. I'm not trying to trick him or anything. We have the --

MR. BEASLEY: That's my point.

MR. VANDIVER: We can take a break and let him look at the entire stack.

MR. BEASLEY: My point is that the attachment has a lower Bates stamp page number than the --

MR. VANDIVER: The point is well taken. We can take a break and let him look at the entire stack if you like.

MR. BEASLEY: If that's what you want to do. I just don't want the witness to be confused about it.

MR. VANDIVER: And I don't want to confuse him either, Jim. I'm just trying to ascertain the reporting from TECO Transport to Tampa Electric, and

he --

MR. BEASLEY: I don't know that a pile of loose papers is going to accomplish that.

MR. VANDIVER: Oh, here we go. Here's 7033. They're in consecutive order.

BY MR. VANDIVER:

Q Would that appear to be the same page, the report that accompanies that memorandum?

A Yes.

Q And is that another one of the regular reports that's transmitted from TECO Transport to Tampa Electric?

A It's transmitted to the people on the list. It's not -- there's just a couple of people on that list. One of those individuals is TECO Bulk Terminal, the transportation coordinator and their backup.

Q Okay. Do you deal with Bill Gleaton? Is he the sole individual you deal with at TECO Transport?

A Like I said, I -- the answer would be no. Bill Gleaton I don't deal with on on a daily basis generally anymore. That it would be the transportation coordinator.

Q Okay. Who do you deal with at TECO Transport on a regular basis in your present position?

A I generally don't on a regular basis.

Q All right. Do you know how many employees there are at TECO Transport?

A Actually, no, I don't.

Q Who trained you to do your job, your original job at transportation coordinator?

A I worked with Cary McBride for some time.

Q And did you train your successor?

A I worked with Dan. Like I said, there are three or four people in our group, and we all pretty much work together. Yes, I --

Q Okay. But you trained your successor?

A Yes.

Q And did you develop a written SOP for his job?

A No.

Q Okay. Is there a written SOP for your job?

A I don't believe there is.

Q Do you have a TECO Transport telephone directory?

A We have an Internet has a telephone directory on it.

Q Is TECO Transport still on the seventh floor of the building?

A I think their corporate offices are on the seventh floor.

MR. VANDIVER: That's all the questions I

have. Thank you very much.

(Discussion off the record.)

CROSS-EXAMINATION

BY MR. PERRY:

Q Mr. Duff, my name is Tim Perry. I represent the Florida Industrial Power Users Group, and I just have a few questions for you.

Are you familiar with the terms of Tampa Electric's waterborne solicitation from 2003?

A Yes.

Q Do you know if that solicitation contains a preference for an integrated bid as opposed to a segmented bid?

A I'm trying to think of the terms or the wording. Yes. But it also did say we would evaluate --

Q In your experience, have you ever handled any type of contractual arrangements where the delivery of any type of fuel was on a non-integrated basis?

A Not that I can think of, no.

Q So all the fuel delivery contracts were on an integrated basis?

A That's correct.

Q During Tampa Electric's waterborne transportation solicitation process, did you ever meet with representatives of the ACBL?

A Prior to the close or --

Q At any time.

A ACBL requested to come in after it closed and after we had told them they were not selected, and we sat down and talked to them.

Q Do you remember approximately the date when they contacted you?

A Not off the top of my head.

Q Did you meet with them?

A Uh-huh, yes.

Q Do you remember what you discussed?

MR. BEASLEY: That question has already been asked and answered earlier today. Go ahead.

A I think we just discussed his bid, his offer. And he was very cordial and expressed an interest in business then and in the future.

Q Did they provide you with -- well, who did you meet with?

A I can't think of fellow's name right now.

Q Did he provide you with any written materials?

A No.

Q Did you relay what you had discussed in the meeting to anyone at Tampa Electric or to Brent Dibner?

A I believe Karen Bramley was in the meeting, and I think the two of us talked about it at the time.

Q Did you discuss your meeting with Mr. Dibner?

A Not that I'm aware of. I don't necessarily recall that.

MR. PERRY: Okay. That's all the questions I have.

MR. BEASLEY: Any other questions?

CROSS-EXAMINATION

BY MR. BEASLEY:

Q Mr. Duff, you were asked some questions about CSXT's desire to provide rail transportation to Tampa Electric; is that right?

A That's correct.

Q My question to you is whether you have any concern about CSXT's actual ability to provide the service that it is offering.

A Yes.

Q Could you please explain your concerns?

A For instance, this past week, I was at a conference, and Mike Sullivan gave a paper. Mike Sullivan is the VP of Coal, Southeast Region, I guess.

Q Which conference was that?

A Eastern Fuel Buyers.

Q Where was that conducted?

A It was in Orlando the end of last week, Wednesday, Thursday, and Friday, I believe. I'm not

sure. The 7th through the 9th, I believe.

Q What was Mr. Sullivan's presentation about?

A Mr. Sullivan's presentation was about the railroad's capacity to do any more -- to perform any more business. It was essentially an apology to all the Eastern Fuel Buyers. It began with an apology to all the Eastern Fuel Buyers for their lack of service to their utility clients. His quote, one of his quotes was something along the line that he was apologizing due to the fact that not a single buyer has had a train loaded, because everybody had come up to him and told him that they didn't have any coal. He was being facetious, obviously. But he went on to talk about the problems CSX was currently having and the problems they expected to have in the future due to the rate structures, and essentially that they needed to increase their rates to put the needed capital infrastructure in place so they could supply the amount of business they currently have.

Q I want to hand you a document entitled "Coal & Energy" dated May 7, 2004. Have you seen that publication before?

A Yes. I saw this this past Monday, I believe.

Q Could you read me the highlighted portion of that article?

MR. WRIGHT: I'm going to object to the extent

that this may be hearsay.

MR. BEASLEY: It may be hearsay, but it corroborates the witness's testimony.

MR. WRIGHT: I didn't say he couldn't answer. I just wanted to have my objection on the record as to its hearsay status, just in case.

MR. BEASLEY: Sure.

A Mike Sullivan, Assistant Vice President, Utility South, for CSX.

Q This is it here.

A During the 33rd Eastern Fuel Buyers Conference in Orlando, Florida, Mike Sullivan, Assistant Vice President, Utility South, for CSX told attendees the railroad's coal business encompassed very strong deliveries in the Southeast this quarter, but it's fallen short of customer demand.

CSX recently loaded one day a staggering 6,200 cars. "Not one of them, apparently, is being loaded in this market because everyone I ran into here said they couldn't get any coal," Sullivan said.

"Basically, our deliveries fell short of demand," Sullivan said, and the railroad needs to up shipments about one train/day "to satisfy where people want to be."

"Inventories are lower than summer target

levels," Sullivan said, and even when customers have healthy inventories, "we miss one train, we get intense pressure to get that train loaded."

Any problem with a particular train "backs everything up," Sullivan said. The railroad is attempting to tackle the problem through crew additions, train length changes, helper changes, siding improvements, yard configuration optimization, collapsed maintenance programs, no maintenance for now to help keep traffic flowing, a new policy designed to make sure reservations are consistent with what can be loaded in a week and a 90-minute slot plan."

MR. WRIGHT: May I have a copy of that document, please?

MR. BEASLEY: Sure.

BY MR. BEASLEY:

Q Did you interact with other representatives at the Eastern Fuel Buyers Conference?

A I did. I spoke to Bob White.

Q I'm talking about other representatives of coal shippers.

A Oh, I'm sorry. Yes, a number of people, who basically confirmed what has been said in the industry press, that nobody is getting supplied coal as needed and required from CSX basically this spring.

MR. WRIGHT: Same objection to that question and answer. It's hearsay.

MR. BEASLEY: Noted.

BY MR. BEASLEY:

Q You said this was the Eastern Fuel Buyers Conference. Was the commodity about which Mr. Sullivan's presentation concerned coal?

A Strictly coal and synfuel, that's correct.

Q So the entire presentation related to delivery problems with coal?

A That's correct.

Q And synfuel.

A That's correct.

Q How many shippers did you talk to while you were there at the conference?

A I would say at least five, maybe less than 10, though.

Q How many of them had complaints that they expressed to you about deliveries of coal?

A Every one that received rail coal.

MR. WRIGHT: Same objection. And if it's okay with you, Jim, I'll just make it a continuing objection.

MR. BEASLEY: Sure. That's fine.

MR. WRIGHT: I think it's clear that the

witness is relating statements by others.

MR. BEASLEY: Sure.

BY MR. BEASLEY:

Q Did Tampa Electric itself have a contract with CSXT for the delivery of coal to its Gannon Station?

MR. WRIGHT: Objection. Vague.

A Tampa Electric has received coal from CSX since I believe the early '60s at Gannon Station.

Q And when did that service by CSXT conclude?

A I believe 2000 or 2001, due to the projected shutdown of Gannon Station, or conversion.

Q In your capacity as the Fuels Transportation Coordinator for Tampa Electric, did you deal with CSXT virtually each time CSXT made a delivery to Gannon Station by rail?

A That's correct.

Q So you were, I take it, familiar with the service provided by CSXT to Tampa Electric for the deliveries to Gannon?

A Yes, I was.

Q How would you describe the level of service provided by CSXT?

A Poor, at best. It was difficult to receive slottings.

Q What is a slotting?

A A time frame in which you're going to be given a train to be loaded at a particular mine. And then once you did receive a slotting, would the train show up at the mine? And once the train showed up at the mine and was loaded, the projection of when it would arrive at the station would not be tremendously accurate.

Q How would you get those projections?

A We really -- we basically got to the point where we would put it into the system that they would be there two days after it was loaded or three days after it was loaded. I don't remember if it was two or three. And you would basically wait until they brought the train. There was no significant methodology for updates on where the trains were and when they would be there.

Q Did that present any operational problems from your perspective?

A Well, it's difficult to schedule manpower to be onsite to discharge a train when you don't know when it's going to get there.

Q Was that just an every once in a while type of problem, or was it a regular recurring problem?

A In my experience, it was a recurring problem.

Q Over the last several years that CSXT provided rail deliveries to Gannon Station, would you say that the level of service improved or declined?

A It declined along with our tonnage. We were on a flight path lowering the tonnage from at one time in the early '90s -- it was prior to me being in the position, but it was, I believe, as high as 1.5 million tons at Gannon Station. I believe when I began the position, it was around a million tons. In the last year, the contract was, I believe, 200,000 tons.

Q Did you mention Mr. Sullivan talking about rates at the coal buyers conference that you attended?

A Yes. In his discussion or his paper, I guess, that he put on -- he was a featured speaker at the conference. His discussion of rates was the fact that CSX needed to increase rates over time so they would have the capital to upgrade their infrastructure.

One of the things he talked specifically about was a location, I believe Corbin, where 80% of the cars and trains will -- it's kind of a pinch point for them, where everything comes through that's going into the Southeast. It appears that some of the significant problems they are having is moving the coal out of the coal fields through that Corbin location, which is south of the Central Appalachian District, and getting them into the Southeast.

Q Was there any discussion about coal exporting at that conference and any impact that might have on

deliveries to domestic coal power plants?

A Not necessarily from CSX. Maybe they did mention it. Essentially, the import market has --

Q Import or export?

A I'm sorry. The export market has over the last five or seven years dwindled to nearly nothing. In 2004, end of 2003, the international coal market -- I think some of the folks talked about the Chinese and the demand for some raw materials and how everything interrlates. But essentially the international coal market, the price of the commodity has increased dramatically, which has given American coal producers an opportunity that they have not had over the last number of years, and that opportunity is to export coal.

Amongst the other utility buyers, there was a concern that when the international market gets heated and there's an opportunity for shippers to take their coal offshore, that they seem to get shorted at those times from CSX and that CSX will run their trains -- despite this demand they talked of, there is a demand for it to get to some of the eastern ports and loaded off for international shipments.

Q Was the concern one currently, that that's happening?

A Yes.

Q You testified that you looked at the October 23, 2002 proposal that CSXT presented to Tampa Electric; is that correct?

A That's correct.

Q And you also looked at the response that CSXT submitted to the June 27, 2003 Tampa Electric RFP?

A That's correct.

Q How do the rates proposed in those two proposals compare?

A Well, on their face, the number was -- I think I characterized it as aggressive. But when you --

Q I mean, were they the same or different rate proposals?

A I believe they were the same rate proposal.

Q Okay. When you mentioned aggressive, how do you use that term?

A Well, the price per ton appeared to be low. But when you factored in all the other additional items, they still evaluated higher than the TECO Transport numbers that we've asked them to match.

Q You were asked about coal supply solicitations put out in December of last year. Do you know what the supply time frame is to be met by the responses to those solicitations?

A I believe it was 2005 through 2014.

Q You were also asked some questions about Polk Power Station and the use of Pitt 8 coal versus pet coke at that station. Do you recall that discussion?

A Yes.

Q Can you tell me any differences in Btu value between pet coke and Pitt 8 coal?

A Generally pet coke is between 13,000 and 14,000 per million Btu, whereas Pitt 8 coal can run anywhere from 12,000 to 13,200.

Q Btu per pound?

A Btu per pound. I'm sorry. Million Btu per pound.

MR. WRIGHT: Btu per pound.

THE WITNESS: I'm sorry. Pet coke generally runs between 13,000 Btu per pound and 14,000 Btu per pound, and Pitt 8 generally runs between -- my experience is 12,000 to 13,200, 13,300.

BY MR. BEASLEY:

Q So the pet coke has a better Btu value?

A That's correct.

Q How do they compare pricewise, if you know?

A On a price per ton basis?

Q Yes.

A Currently the high sulfur Pittsburgh 8 quotes that they list in Coal & Energy and those types of

publications is around $34 or $35, either in a rail car or in a barge. Petroleum coke, our last shipment of petroleum coke purchased, which I believe was in April, was $8.50 a ton.

Q So the Pitt 8 coal is about three times as expensive as the pet coke? Is that a fair assessment?

A That's correct.

Q How about the transportation cost? Which costs more to get to Tampa Electric, Polk Power Station, pet coke or Pitt 8?

A Currently petroleum coke would be the less expensive option into Polk Power Station.

Q What is your goal at Polk Power Station regarding the percentage of pet coke that you hope to be able to use in that facility?

A Currently we're consuming a 60-40 blend of coal and petroleum coke. We're in the process of working with the State DEP on increasing the ability to raise that percentage up to -- at a minimum, the next step we believe will be 80%, with the hope at some point to go to 100%. If it went to 100%, we would have to make some modifications to -- petroleum coke has very little ash, and the system that we have, the gasifier needs a percentage of ash. And we would have to develop a methodology to inject some ash, probably from our other

stations, Big Bend possibly, into the fuel mix to get to 100% petroleum coke.

Q From the standpoint of your ratepayers, do you think it would be a better deal to just scrap that pet coke and burn Pitt 8 coal at Polk Power Station?

A No, I do not.

Q You were asked some questions about the testimony of CSXT witness Robert White in this proceeding. Do you recall that?

A I'm sorry. Could you ask that again?

Q You were asked some questions about Mr. White's testimony for CSXT in the proceeding.

A That's correct.

MR. WRIGHT: I'm going to object to any specific questions. I think I only asked him if he -- I don't believe I asked him a single substantive question about it.

BY MR. BEASLEY:

Q Did you review the testimony of Mr. White? I think you were asked that.

A Yes, I did.

Q What were your reactions to his testimony when you read it?

A I was upset. I don't know if "upset" is the right word. I felt that the meetings between Mike

Bullock, Bob White, and myself were mischaracterized as contentious, acrimonious, when they were anything but. I believe on the first visit they came down, we went to dinner and had a nice discussion, and then the subsequent trip was cordial. I understood what they were trying to do, and they seemed to understand what our limitations were. We were honest and forthright with them about where we were and what our intentions were. And his characterizations of our meetings were just wrong. They're just basically not true.

Q Do they accurately reflect the meetings based on your recollection?

A No.

Q You know Mr. White? I think you said you did.

A Yes.

Q Have you had a chance to inquire of him or confront him with your concerns about his testimony?

A Actually, I did talk to him at the Eastern Fuel Buyers meeting.

Q How did he react?

A He apologized for the characterization in his testimony.

Q Did he say what his motivations were?

A He specifically said that you have to do what you have to do to keep your job.

MR. BEASLEY: Thank you, sir. I would like to ask that the Coal & Energy document be marked as an exhibit.

MR. WRIGHT: Subject to my objection to it as possible hearsay.

(Deposition Exhibit 6 was marked for identification.)

REDIRECT EXAMINATION

BY MR. WRIGHT:

Q I have some questions regarding the questions that Mr. Beasley just asked you.

In response to an earlier question regarding Mr. Sullivan's presentation, you stated that Mr. Sullivan indicated that CSXT expected to have difficulty performing additional business in the future. Did he specify over what time period he thought that might continue?

A No, he didn't. Other presenters were putting their papers on the web site, and to my knowledge, CSX has refused to put their paper on the web site. So I would like to read it, but I'm not sure.

Q Do you recall whether he said whether there was a point in time at which they expected the current situation to be alleviated such that they could handle more coal?

A It was predicated on increased rates, if I remember correctly, and that their rate structure had to change and be increased if they wanted -- you know, it was essentially that if we get rate increases, we can put more capital on the ground, and all these problems will go away.

Q Well, I understand your explanation. My question for you was and is, did he mention a specific time in which or at about which he expected the situation to be alleviated as you have described it?

A Not that I remember, no.

Q I think when you read from the document, you used the phrase or read the phrase "a staggering 6,200 cars." Do you know enough about the rail industry to know whether that's a very large number of cars for CSX to load in one day?

A I don't know. I also don't know where those cars are going, if they're going for export or if they're going for utility customers.

Q Is Tampa Electric Company a member of the Eastern Fuel Buyers Conference?

A Yes, we are.

Q Do you know what Tampa Electric Company's role in the Eastern Fuel Buyers Conference is?

A We generally have not had a role historically.

This year, we joined with three other municipals in the state and helped sponsor the conference.

Q Did your sponsorship of the conference give you a role in determining the program of the conference?

A I'm not -- I was not involved in that. I think Karen is the person that --

Q In response to some questioning by Mr. Beasley, you mentioned some difficulty getting slotting, as I recall. Is that accurate so far?

A That's correct.

Q When you use the term "slotting," does that refer to CSX's making available of a train?

A That's what I was referring to, yes.

Q Do you know whether slotting has anything to do with the mine's loading a train?

A It's -- well, as in any other transportation of commodities, the train needs to be loaded as soon as it's taken to the source. If the source doesn't load it, it's going to back things up. If the train is late or, for instance, it's loaded but there's no power to move it, the mine is stuck, and they can't move any more coal until that train is out of there.

Q If the train is on time and the mine or supplier decides not to load that train, is that beyond the railroad's control?

A Sure, yes.

Q Do you know anything about the reservation process for trains at coal mines?

A Not specifically, no.

Q Do you know whether on any given day there are a certain number of reservations for coal loading at coal mines?

A I would assume that's correct.

Q Do you know what, if any, relationship that bears to the ability of the mine to load coal?

A I don't understand your question.

Q Well, suppose the mine has got five reservations and the capability of loading two trains. What happens?

A Then you're going to have three backed up. But in the current market, where the coal prices in the Central Appalachian District has doubled, I would think that coal miners would be very interested in having their coal shipped to consumers as quickly as possible.

Q I'm sure they are. Do you have any reason to think that the railroad has any interest other than to ship coal to consumers as quickly as possible?

A Only if they have new obligations to move it to export terminals that they have not been utilizing over the last five years.

Q Who decides which coal gets loaded onto these trains, the coal mine or the railroad?

A I believe the coal mine would do that.

Q You mentioned in response to some questions by Mr. Beasley a pinch point at Corbin. Was that in the context of CSX's hopes or plans to improve conditions to alleviate that pinch point?

A In relation to rate increases, they would have the money to fix those kind of problems.

Q Going back to the questions I asked you a minute ago about reservations, do you recall anything specific about CSXT's new policy regarding reservations?

A No.

Q Did any of the shippers with whom you spoke that you mentioned asserted they are being shorted by CSXT also assert to you that they are being shorted by their mines?

A No.

Q In response to questions by Mr. Beasley, you made reference to when you compare the rates plus all the adders that go onto the rail rates, they're more expensive than water transportation. I want to compare that to a response you gave to questioning by me this morning, in which you said that you're not competent to evaluate a rail bid. Are you backing off your statement

that you're not competent to evaluate a rail bid?

A No. But the analysis was done by other folks to show that that's how it evaluated out.

Q To which analysis are you referring?

A I believe there was some analysis in Ms. Wehle's rebuttal testimony, if I'm correct.

Q But you didn't do any of that, did you?

A No, sir.

Q In response to the same question, I believe -- I'm going to ask another question first. If you know, when was the analysis that's shown in Ms. Wehle's testimony of which you just spoke prepared?

A No, I don't.

Q Following on where I was, I believe you stated that the rail rates, with the adjustments that somebody at Tampa Electric thinks are appropriate taken into account, the prices are higher than those that you asked CSXT to match. Did you ask CSXT to match any charges by TECO Transport?

A No. I made a mistake. I'm not sure when that was said.

Q All I can tell you is that's what I wrote down at the time, and that's why I wanted to ask you about it, because I have never heard of you having asked CSXT to match any TECO Transport prices.

A No.

Q So to the best of your knowledge, Tampa Electric has never asked CSXT to match any TECO Transport prices?

A No.

Q In response to questioning by Mr. Beasley, you mentioned that Pitt 8 coal is about $34 to $35 a ton. My question for you is, for what percent sulfur would that be?

A Three and a half percent, 3%.

Q What's the price for, let's say, 5-1/2 to 6% sulfur Pitt 8 coal?

Let me ask you a clarifying question. Probably not nearly to degree that you have, I have looked at a number of the coal trade publications in recent times. I have frequently --

MR. BEASLEY: Object. You're testifying. Ask a question.

MR. WRIGHT: I was -- well, I'll try this.

BY MR. WRIGHT:

Q Is it typical to see the coal prices stated in terms of pounds of SO2 per million Btu or in terms of percent?

A It's not typical either way. Some publications list it as percent. Some publications list

it as pounds per million.

Q Okay. What's the price for 5-1/2 to 6% sulfur Pitt 8 coal?

A You would have to do a market survey or a solicitation, but in those publications, I would think somewhere between $28 and $34.

Q I'm going to hand you a copy of the Argus Coal Daily dated May 7, 2004, and ask you to look at a table that appears in the upper left-hand corner of page 3 of eight.

A (Examining document.)

Q That shows the prices stated in pounds of SO2 per million Btu, doesn't it?

A That's correct.

Q Will you agree that there's a linear relationship between that and the percent sulfur in coal?

A That's correct.

Q So can you tell me, looking at that information, what you think the price of 6% sulfur coal would be?

A This price list -- I had just told you 27 to 34. This is dated May 7th. I've been out of the office for a couple of weeks, so bear with me. It's showing 12,500, 6 pound coal, which would relate somewhere into

the 3-1/2, 3 pound coal, as $25, but it's also showing that it has dropped $2 in the previous week, so that would --

Q Okay. Do you have any knowledge of future projected prices of Pitt 8 coal?

A One of the things about Pittsburgh coal, it is extremely volatile, as opposed to where Tampa Electric purchases the vast majority of their coal, and that's the Illinois Basin.

I have a document here, if I could show this -- I don't know how this works.

MR. BEASLEY: This is an exhibit.

THE WITNESS: Oh, okay. Northern Appalachia, 13,000 Btu coal -- this is May 7th -- 3.6 pounds, FOB barge, $42.

MR. WRIGHT: Okay. Is that --

MR. BEASLEY: That's your copy to keep.

BY MR. WRIGHT:

Q You had some conversations with Mr. Beasley regarding pet coke. Are you aware of other power plants in Florida that burn petroleum coke other than Polk?

A Are you asking Mr. Beasley or me?

Q I'm asking you.

A I thought you were addressing Mr. Beasley.

Q I probably mumbled, and I apologize for that.

I said in response to some questions by Mr. Beasley, you made some remarks regarding petroleum coke.

A Seminole Electric consumes petroleum coke. Both plants in Jacksonville, JEA and Northside -- I continue to get those two plants confused, but they both consume significant quantities of petroleum coke. Lakeland Electric consumes petroleum coke. I couldn't say if anybody else does or not.

Q When you said JEA, did you mean the St. Johns River Power Park units?

A That's what I meant by getting them confused. There's two stations up there. There's St. Johns River Power Park, and then there's -- I'm not sure what the other one is called. There's two facilities.

Q If you know, isn't it true that Seminole Electric receives all of its petroleum coke by rail from CSX Transportation?

A That's my understanding.

Q If you know, how does Lakeland receive its petroleum coke?

A By truck.

Q If you know, how does JEA receive its petroleum coke that it uses at its units?

A I believe by vessel.

Q Do you know whether JEA receives any pet coke

by rail?

A No, I don't know.

Q You mentioned in your characterization of Mr. White's testimony that the meetings were contentious and acrimonious. Those were the words you used, I believe. Is that accurate so far?

A The words I --

MR. BEASLEY: I believe he said they weren't acrimonious or contentious.

THE WITNESS: They were not.

BY MR. WRIGHT:

Q I'm sorry. I probably mumbled again. I think that you characterized Mr. White's testimony as characterizing the meetings as contentious and acrimonious. Is that accurate?

A Yes.

Q As you sit here today, can you show me where in Mr. White's testimony he characterized those meetings as you just did, as you characterized his testimony?

A Well, line 21, page 6 -- I'll just read this paragraph. "We then followed Mr. Duff by automobile from Polk to Big Bend. We parked our vehicle outside the plant and toured Big Bend Station."

MR. BEASLEY: Why don't you start up here.

THE WITNESS: Okay.

A (Continuing) This is on line 13 of page 6. "Did CSXT representatives visit Big Bend and Polk?"

"Yes. On May 21, 2002, Mr. Richard Schumann of RAS Engineering, an independent engineering firm that CSXT occasionally hires on a consulting basis, visited the Polk and Big Bend sites. We were met at Polk in the morning and taken on a brief tour of the facility by Martin Duff. We were not introduced to any staff people at the plant, nor were we given any written material about Polk. We toured the site with Mr. Duff and discussed several potential scenarios to serve the plant by rail. The tour of the station lasted about 30 minutes.

"We then followed Mr. Duff by automobile from Polk to Big Bend. We parked our vehicle outside of the plant and toured the Big Bend Station in Mr. Duff's automobile. We were not introduced to any plant personnel or given any written material about the plant. Mr. Duff was able to answer general questions, but was not fully versed in technical specifications of the plant. We were interested in specific issues related to the infrastructure needs, such as belt sizes, belt speeds, hopper size and rated capacity of the existing limestone pit dump, which CSX was considering using as the receiving pit for rail deliveries of coal. At the

time of the visit, the tracks below the dump pit had been removed in order to lay pipe for the desalinization plant located adjacent to the station. We asked about plans to restore the tracks after the pipes had been laid, and Mr. Duff replied that they would be restored. We left Mr. Duff after a tour of about 45 minutes and at that time requested that TECO provide as-built drawings of the plant so that CSXT could begin its design work."

This discussion where they say they were not introduced to any staff at the plant, nor were they given any written material about the plant, there would be no reason to introduce them to the staff. And, yes, they were given information about the plant.

There's another characterization in here, I'm not sure where, where they were not allowed to get out of their cars, walk around, climb on equipment. They were not there to do that. They were not in steel-toed boots. They were not in work clothes. His characterization that he was to come down and do something other than look at the station is inaccurate, and that's what I felt was misconstrued on his part.

Q Well, I didn't hear -- can you tell me right there anything that's contentious or acrimonious about what went on that day?

A I guess the entirety of the testimony against

my experience to me comes across as acrimonious.

Q Okay. Did you introduce either Mr. White or Mr. Schumann to any staff, Tampa Electric personnel at Polk?

A No.

Q Did the tour last approximately 30 minutes?

A That's probably an accurate description.

Q In your testimony this morning you characterized it as a driving tour.

A That's correct.

Q Does that mean you stayed in the car pretty much the whole time?

A That's correct.

Q Did you give them written materials about Polk Station?

A I think we had pamphlets about the clean coal technology project. And I guess I won't testify to it, but I believe generally everybody that goes through there we give plant documents to. It's kind of our flagship plant.

Q Are those in the nature of what might be called public relations or educational pamphlets for lay persons who visit the plant?

A Exactly.

Q Do you recall whether you gave them any other

written materials regarding the plant?

A No.

Q Did you introduce them to any Tampa Electric personnel at Big Bend?

A No.

Q Did you give them any written materials regarding Big Bend?

A Not that I can recall.

Q Is Mr. White's characterization of the tour as having lasted about 45 minutes accurate as far as you know?

A I think so.

Q Did you all get out of the car at Big Bend?

A We did get out of the car over by desalinization plant so Bob could have a smoke. But other than that, no, they were not allowed out of the car.

Q Did you tell Mr. White that it was Tampa Electric's plan at that time to restore the tracks that you referred to?

A No. I wouldn't be privy to that kind of knowledge. That would be a plant decision. I don't make those kind of decisions.

Q Well, I understand that you don't make those decisions, but you might have heard or had some

understanding of what the plan was, mightn't you?

A (Gesturing.)

MR. WRIGHT: That's all I have.

RECROSS-EXAMINATION

BY MR. BEASLEY:

Q Just one question. Did you do everything that the CSXT representatives asked you to do when they visited Polk and Big Bend Station?

A Yes.

MR. BEASLEY: Thank you. We would like to read and sign the deposition.

(Deposition concluded at 12:46 p.m.)

CERTIFICATE OF OATH

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, Notary Public in and for the State of Florida at Large:

DO HEREBY CERTIFY that on the date and place indicated on the title page of the foregoing transcript, an oath was duly administered by me to the designated witness before testimony was taken.

WITNESS my hand and official seal this 17th day of May, 2004.

MARY ALLEN NEEL, RPR
2894-A Remington Green Lane
Tallahassee, Florida 32308

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, MARY ALLEN NEEL, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter transcribed under my supervision; and that the foregoing pages numbered 1 through 102 are a true and correct transcription of my stenographic notes.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, or relative or employee of such attorney or counsel, or financially interested in the action.

DATED THIS 17th day of May, 2004.

MARY ALLEN NEEL, RPR
2894-A Remington Green Lane
Tallahassee, Florida 32308
(850) 878-2221

ERRATA SHEET

I have read the transcript of my deposition, pages 1 through 102, and hereby subscribe to same, including any corrections and/or amendments listed below.

6-2-04
Date

Signature

Page	Line	Correction or Amendment	Reason for Change
40	10	Strike Q & A in lines 10-15	
41	9	Strike Q & A in lines 9-25	
42	1	Strike Q & A in lines 1-25	
43	1	Strike Q & A in lines 1-25	
44	1	Strike Q & A in lines 1-23	
49	23	Strike Q & A in lines 23-25	
50	1	Strike Q & A in lines 1-4	
61	9	Change "TECO, in Shipping" to "TECO Ocean Shipping"	
62	4	Change "Internet" to "Intranet"	typo
70	19	Change "Internet" to "Intranet"	typo
95	1	Change pound to percent	typo

Date of Deposition

Reporter

EXHIBIT NO. 101

DOCKET NO. 031033-EI

CERTIFIED COPIES OF PUBLIC SERVICE COMMISSION RECORDS

PARTY: CSX TRANSPORTATION

DESCRIPTION: CERTIFIED COPIES OF SELECTED PAGES (FPSC Form 423-2(b)) REGARDING TRANSPORTATION CHARGES TO GANNON STATION FROM TAMPA ELECTRIC COMPANY'S FORM 423 REPORTS FROM 1994 THROUGH 2001

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 101
COMPANY/ CSX
WITNESS: Excerpts from TECO's 423 report 1994-2001
DATE 05/27-28/04

COMMISSIONERS:
BRAULIO L. BAEZ, CHAIRMAN
J. TERRY DEASON
LILA A. JABER
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

STATE OF FLORIDA

DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES
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Public Service Commission

CERTIFICATE

I, BLANCA S. BAYÓ, Director of the Division of the Commission Clerk and Administrative Services, Florida Public Service Commission, do hereby certify that the attached are true and correct copies of Tampa Electric Company's FPSC Forms 423 as listed and described below:

May 1994, Declassified Form (07099-94)
June 1994, Declassified Form (08281-94)
July 1994, Declassified Form (09446-94)
August 1994, Declassified Form (10274-94)

May 1995, Declassified Form (06732-95)
June 1995, Declassified Form (07721-95)
July 1995, Declassified Form (09123-95)
August 1995, Declassified Form (10137-95)

May 1996, Declassified Form (07384-96)
June 1996, Declassified Form (08606-96)
July 1996, Declassified Form (09768-96)
August 1996, Declassified Form (10984-96)

July 1998, Redacted and Declassified Forms (10041-98 and 10040-98)
August 1998, Redacted and Declassified Forms (11539-98 and 11538-98)

May 1999, Redacted and Declassified Forms (08362-99 and 08364-99)

May 2000, Declassified Form (08541-00)
June 2000, Declassified Form (09818-00)
July 2000, Declassified Form (11616-00)
August 2000, Declassified Form (13071-00)

(continued on next page)

May 2001, Redacted and Declassified Forms (08648-01 and 08647-01)
June 2001, Redacted and Declassified Forms (10073-01 and 10072-01)
July 2001, Redacted and Declassified Forms (11536-01 and 11535-01)
August 2001, Redacted and Declassified Forms (13104-01 and 13103-01)

as shown in the records of the Commission.

WITNESS my hand and the seal of the Florida Public Service Commission this 9th day of June, 2004.

BLANCA S. BAYÓ

By: _____
Kay Flynn, Chief
Bureau of Records

(SEAL)

** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: May Year: 1994

2. Reporting Company: Tampa Electric Company

3. Plant Name: Electro-Coal Transfer Facility - Gannon Station (1)

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Supervisor, Regulatory Accounting (813) - 228 - 1609

5. Signature of Official Submitting Form: L. L. Lefler, Vice Pres. & Controller

6. Date Completed: July 15, 1994

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Transport Mode (e)	Tons (f)	(2) Effective Purchase Price ($/Ton) (g)	Add'l Shorthaul & Loading Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Waterborne Charges: Other Related Charges ($/Ton) (o)	Total Transportation Charges ($/Ton) (p)	Delivered Price Transfer Facility ($/Ton) (q)
1.	Gatliff Coal	9,KY,235	Union & Webster Cnty, KY	R&B	32,702.39	$40.295	$0.000	$7.793	$0.000	$14.110	$0.000	$0.000	$0.000	$0.000	$21.903	$62.198
2.	Gatliff Coal	8,TN,013	Campbell Cnty, TN	R&B	24,629.61	$40.295	$0.000	$8.110	$0.000	$3.480	$0.000	$0.000	$0.000	$0.000	$11.590	$51.885
3.	Gatliff Coal	19,WY,5	Campbell Cnty, WY	R&B	57,748.88	$5.299	$0.000	$14.370	$0.000	$2.860	$0.000	$0.000	$0.000	$0.000	$17.230	$22.529
4.	Sugar Camp	10,IL,059	Gallatin Cnty, IL	R&B	3,043.70	$26.120	$0.000	$0.000	$0.000	$2.960	$0.000	$0.000	$0.000	$0.000	$2.960	$29.080

(1) As Electro-Coal Transfer Facility is a central storage site for coal prior to its delivery to the power plant, the coal from suppliers noted on this schedule is usually delivered to Gannon Station but could ultimately be delivered to Big Bend Station.

(2) Tampa Electric purchases coal F.O.B. shipping point or F.O.B. destination.

FPSC FORM 423-2(b) (2/87)

SPECIFIED CONFIDENTIAL

** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: May Year: 1994
2. Reporting Company: Tampa Electric Company
3. Plant Name: Gannon Station
4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Supervisor, Regulatory Accounting (813) - 228 - 1609
5. Signature of Official Submitting Form: L. L. Lefler, Vice Pres. & Controller
6. Date Completed: July 15, 1994

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Transport Mode (e)	Tons (f)	Effective Purchase Price ($/Ton) (g)	Add'l Shorthaul & Loading Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Waterborne Charges: Other Related Charges ($/Ton) (o)	Total Transportation Charges ($/Ton) (p)	FOB Plant Price ($/Ton) (q)
1.	Transfer Facility	N/A	Davant, La.	OB	217,150.00	$53.617	$0.000	$7.765	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$7.765	$61.382
2.	Gatliff Coal	8,KY,235	Whitley Cnty, KY.	UR	106,495.00	$40.295	$0.000	$17.268	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$17.268	$57.563
3.	AK Steel Corp	N/A	Ashville Cnty, KY	TR	262.00	$45.000	$0.000	$60.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$60.000	$105.000

FPSC FORM 423-2(b) (2/87)

SPECIFIED CONFIDENTIAL

** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: May Year: 1995

2. Reporting Company: Tampa Electric Company

3. Plant Name: Electro-Coal Transfer Facility - Gannon Station (1)

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Manager Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: L. L. Lefler, Vice Pres. & Controller

6. Date Completed: July 14, 1995

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Transport Mode (e)	Tons (f)	(2) Effective Purchase Price ($/Ton) (g)	Add'l Shorthaul & Loadin Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Other Related Charges ($/Ton) (o)	Total Transportation Charges ($/Ton) (p)	Delivered Price Transfer Facility ($/Ton) (q)
1.	Gatliff Coal	8,KY,235	Union & Webster Cnty, KY	R&B	6,559.45	$40.450	$0.000	$7.480	$0.000	$8.940	$0.000	$0.000	$0.000	$0.000	$16.420	$56.870
2.	Gatliff Coal	8,TN,013	Campbell Cnty, TN	R&B	7,701.45	$40.450	$0.000	$7.480	$0.000	$8.940	$0.000	$0.000	$0.000	$0.000	$16.420	$56.870
3.	Kerr McGee	10,IL,165	Saline Cnty, IL	RB	56,059.00	$27.790	$0.000	$0.000	$0.000	$8.170	$0.000	$0.000	$0.000	$0.000	$8.170	$35.960

(1) As Electro-Coal Transfer Facility is a central storage site for coal prior to its delivery to the power plant, the coal from suppliers noted on this schedule is usually delivered to Gannon Station but could ultimately be delivered to Big Bend Station.

(2) Tampa Electric purchases coal F.O.B. shipping point or F.O.B. destination.

FPSC FORM 423-2(b) (2/87)

SPECIFIED CONFIDENTIAL

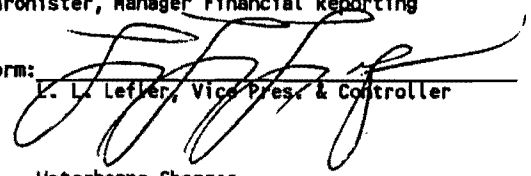
** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: May Year: 1995
2. Reporting Company: Tampa Electric Company
3. Plant Name: Gannon Station

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Manager Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: 
E. L. Lefler, Vice Pres. & Controller

6. Date Completed: July 14, 1995

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Transport Mode (e)	Tons (f)	Effective Purchase Price ($/Ton) (g)	Rail Charges: Add'l Shorthaul & Loadin Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Other Related Charges ($/Ton) (o)	Total Transportation Charges ($/Ton) (p)	FOB Plant Price ($/Ton) (q)
1.	Transfer Facility	N/A	Davant, La.	OB	178,865.00	$43.660	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$9.170	$52.830
2.	Gatliff Coal	8,KY,235	Whitley Cnty, KY	UR	88,426.00	$40.450	$0.000	$17.472	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$17.472	$57.922
3.	Gatliff Coal	8,KY,195	Pike Cnty, KY	UR	17,959.00	$40.450	$0.000	$19.651	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$19.651	$60.101

FPSC FORM 423-2(b) (2/87)

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FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: May Year: 1996

2. Reporting Company: Tampa Electric Company

3. Plant Name: Electro-Coal Transfer Facility - Gannon Station (1)

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Manager Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: E. A. Townes, Assistant Controller

6. Date Completed: July 15, 1996

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Trans-port Mode (e)	Tons (f)	(2) Effective Purchase Price ($/Ton) (g)	Add'l Shorthaul & Loading Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Other Related Charges ($/Ton) (o)	Total Transpor-tation Charges ($/Ton) (p)	Delivered Price Transfer Facility ($/Ton) (q)
1.	Kerr McGee	10,IL,165	Saline Cnty, IL	RB	108,940.00	$26.081	$0.000	$0.000	$0.000	$7.718	$0.000	$0.000	$0.000	$0.000	$7.718	$33.799
2.	Mapco	10,IL,059	Gallatin Cnty, IL	RB	6,351.50	$31.530	$0.000	$0.000	$0.000	$7.835	$0.000	$0.000	$0.000	$0.000	$7.835	$39.365
3.	Powder River Coal	19,WY,5	Campbell Cnty, WY	R&B	112,703.98	$4.090	$0.000	$12.900	$0.000	$7.725	$0.000	$0.000	$0.000	$0.000	$20.625	$24.715
4.	Sugar Camp	10,IL,059	Gallatin Cnty, IL	RB	43,089.00	$23.000	$0.000	$0.000	$0.000	$7.835	$0.000	$0.000	$0.000	$0.000	$7.835	$30.835

(1) As Electro-Coal Transfer Facility is a central storage site for coal prior to its delivery to the power plant, the coal from suppliers noted on this schedule is usually delivered to Gannon Station but could ultimately be delivered to Big Bend Station.

(2) Tampa Electric purchases coal F.O.B. shipping point or F.O.B. destination.

FPSC FORM 423-2(b) (2/87)

** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: May Year: 1996

2. Reporting Company: Tampa Electric Company

3. Plant Name: Gannon Station

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffray Chronister, Manager Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: E. A. Townes, Assistant Controller

6. Date Completed: July 15, 1996

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Trans-port Mode (e)	Tons (f)	Effective Purchase Price ($/Ton) (g)	Add'l Shorthaul & Loading Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Other Related Charges ($/Ton) (o)	Total Transpor-tation Charges ($/Ton) (p)	FOB Plant Price ($/Ton) (q)
1.	Transfer Facility	N/A	Davant, La.	OB	77,949.00	$32.345	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$8.663	$41.008
2.	Gatliff Coal	8,KY,235	Whitley Cnty, KY	UR	74,538.00	$41.690	$0.000	$17.764	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$17.764	$59.454
3.	Gatliff Coal	8,KY,195	Pike Cnty, KY	UR	23,200.00	$41.690	$0.000	$18.574	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$18.574	$60.264
4.	Modern Recycling	N/A	Lee Cnty, FL	TR	173.00	$15.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$15.000
5.	Florida Tire Recycling	N/A	St. Lucie Cnty, FL	TR	984.00	$32.340	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$32.340

FPSC FORM 423-2(b) (2/87)

** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: August Year: 1998

2. Reporting Company: Tampa Electric Company

3. Plant Name: Electro-Coal Transfer Facility - Gannon Station (1)

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Manager Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: Phil L. Barringer, Assistant Controller

6. Date Completed: October 15, 1998

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Transport Mode (e)	Tons (f)	(2) Effective Purchase Price ($/Ton) (g)	Add'l Shorthaul & Loading Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Other Related Charges ($/Ton) (o)	Total Transportation Charges ($/Ton) (p)	Delivered Price Transfer Facility ($/Ton) (q)
1.	Sugar Camp	10,IL,059	Gallatin Cnty, IL	RB	65,374.40	$26.190	$0.000	$0.000	$0.000	$7.493	$0.000	$0.000	$0.000	$0.000	$7.493	$33.683
2.	Jader Fuel Co	10,IL,165	Saline Cnty, IL	RB	30,783.40	$25.070	$0.000	$0.000	$0.000	$7.493	$0.000	$0.000	$0.000	$0.000	$7.493	$32.563
3.	Kennecott	19,WY,5	Campbell Cnty, WY	R&B	113,701.00	$3.650	$0.000	$12.400	$0.000	$7.323	$0.000	$0.000	$0.000	$0.000	$19.723	$23.373
4.	Sugar Camp	10,IL,059	Gallatin Cnty, IL	RB	51,495.00	$23.720	$0.000	$0.000	$0.000	$7.493	$0.000	$0.000	$0.000	$0.000	$7.493	$31.213
5.	American Coal	10,IL,165	Saline Cnty, IL	RB	87,068.00	$26.850	$0.000	$0.000	$0.000	$7.323	$0.000	$0.000	$0.000	$0.000	$7.323	$34.173
6.	Teco Coal - Distressed Coal (2)	UK	UK	UK	561.00	$25.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$25.000

(1) As Electro-Coal Transfer Facility is a central storage site for coal prior to its delivery to the power plant, the coal from suppliers noted on this schedule is usually delivered to Gannon Station but could ultimately be delivered to Big Bend Station or Polk Station.

(2) Tampa Electric purchases coal F.O.B. shipping point or F.O.B. destination.

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** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
ORIGIN, TONNAGE, DELIVERED PRICE AND AS RECEIVED QUALITY

1. Reporting Month: August Year: 1998

2. Reporting Company: Tampa Electric Company

3. Plant Name: Gannon Station

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Manager Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: Phil L. Barringer, Assistant Controller

6. Date Completed: October 15, 1998

Line No. (a)	Supplier Name (b)	Mine Location (c)	Purchase Type (d)	Transport Mode (e)	Tons (f)	Effective Purchase Price ($/Ton) (g)	Total Transport Charges ($/Ton) (h)	FOB Plant Price ($/Ton) (i)	As Received Coal Quality: Sulfur Content % (j)	As Received Coal Quality: BTU Content (BTU/lb) (k)	As Received Coal Quality: Ash Content % (l)	As Received Coal Quality: Moisture Content % (m)
1.	Transfer Facility	N/A	N/A	OB	136,265.00	$29.115	$8.358	$37.473	1.12	10,627	6.45	18.22
2.	Gatliff Coal	8,KY,195	LTC	UR	89,828.00	$43.710	$18.630	$62.340	1.39	12,972	8.10	5.65
3.	Gatliff Coal	8,KY,235	LTC	UR	39,710.00	$43.710	$18.879	$62.589	1.12	12,341	8.33	9.00

FPSC FORM 423-2 (2/87)
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** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
ORIGIN, TONNAGE, DELIVERED PRICE AND AS RECEIVED QUALITY

1. Reporting Month: May Year: 1999

2. Reporting Company: Tampa Electric Company

3. Plant Name: Electro-Coal Transfer Facility - Gannon Station (1)

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Director Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: Phil L. Barringer, Vice President Controller

6. Date Completed: July 15, 1999

Line No. (a)	Supplier Name (b)	Mine Location (c)	Purchase Type (d)	Trans-port Mode (e)	Tons (f)	Effective Purchase Price ($/Ton) (g)	Total Transport Charges ($/Ton) (h)	Delivered Price Transfer Facility ($/Ton) (i)	As Received Coal Quality: Sulfur Content % (j)	BTU Content (BTU/lb) (k)	Ash Content % (l)	Moisture Content % (m)
1.	Sugar Camp	10,IL,059	LTC	RB	77,059.70	$26.341	$5.670	$32.011	2.60	12,759	8.26	7.13
2.	Jader Fuel Co	10,IL,165	LTC	RB	12,533.90	$25.300	$5.670	$30.970	3.11	12,864	10.45	4.77
3.	Jader Fuel Co	10,IL,165	S	RB	13,412.60	$23.850	$5.670	$29.520	3.00	12,794	10.69	4.44
4.	American Coal	10,IL,165	LTC	RB	90,837.00	$27.300	$4.330	$31.630	1.07	12,175	6.32	11.27
5.	Sugar Camp	10,IL,059	S	RB	12,905.80	$24.500	$5.670	$30.170	3.07	12,633	10.08	5.94

(1) As Electro-Coal Transfer Facility is a central storage site for coal prior to its delivery to the power plant, the coal from suppliers noted on this schedule is usually delivered to Gannon Station but could ultimately be delivered to Big Bend Station or Polk Station.

FPSC FORM 423-2 (2/87)

** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: May Year: 1999

2. Reporting Company: Tampa Electric Company

3. Plant Name: Gannon Station

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Director Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: Phil L. Barringer, Vice President Controller

6. Date Completed: July 15, 1999

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Trans-port Mode (e)	Tons (f)	Effective Purchase Price ($/Ton) (g)	Add'l Shorthaul & Loading Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Other Related Charges ($/Ton) (o)	Total Transpor-tation Charges ($/Ton) (p)	FOB Pl Price ($/To (q)
1.	Transfer Facility	N/A	Davant, La.	OB	92,845.00	$25.475	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$9.800	$35.2
2.	Gatliff Coal	8,KY,235	Whitley Cnty, KY	UR	18,311.00	$44.560	$0.000	$19.160	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$19.160	$63.7
3.	Gatliff Coal	8,KY,195	Whitley Cnty, KY	UR	19,244.00	$44.560	$0.000	$19.160	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$19.160	$63.7

FPSC FORM 423-2(b) (2/87)

** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: May Year: 2000

2. Reporting Company: Tampa Electric Company

3. Plant Name: Electro-Coal Transfer Facility - Gannon Station (1)

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Director Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: Jeffrey Chronister, Director Financial Reporting

6. Date Completed: July 14, 2000

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Trans-port Mode (e)	Tons (f)	(2) Effective Purchase Price ($/Ton) (g)	Add'l Shorthaul & Loading Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Other Related Charges ($/Ton) (o)	Total Transpor-tation Charges ($/Ton) (p)	Delivered Price Transfer Facility ($/Ton) (q)
1.	Sugar Camp	10,IL,059	Gallatin Cnty, IL	RB	20,500.60	$25.367	$0.000	$0.000	$0.000	$7.760	$0.000	$0.000	$0.000	$0.000	$7.760	$33.127
2.	Sugar Camp	10,IL,059	Gallatin Cnty, IL	RB	35,357.30	$25.705	$0.000	$0.000	$0.000	$7.420	$0.000	$0.000	$0.000	$0.000	$7.420	$33.125
3.	Jader Fuel Co	10,IL,165	Saline Cnty, IL	RB	58,110.00	$25.650	$0.000	$0.000	$0.000	$7.420	$0.000	$0.000	$0.000	$0.000	$7.420	$33.070
4.	American Coal	10,IL,165	Saline Cnty, IL	RB	84,303.00	$27.850	$0.000	$0.000	$0.000	$5.650	$0.000	$0.000	$0.000	$0.000	$5.650	$33.500
5.	Sugar Camp	10,IL,059	Gallatin Cnty, IL	RB	73,000.30	$23.488	$0.000	$0.000	$0.000	$7.420	$0.000	$0.000	$0.000	$0.000	$7.420	$30.908
6.	Duke Energy Merchants, LLC	19,WY,009	Converse Cnty, WY	RB	60,003.80	$5.040	$0.000	$13.160	$0.000	$5.650	$0.000	$0.000	$0.000	$0.000	$18.810	$23.850
7.	Kennecott Energy Company	19,WY,009	Converse Cnty, WY	RB	60,190.50	$4.630	$0.000	$13.160	$0.000	$5.650	$0.000	$0.000	$0.000	$0.000	$18.810	$23.440
8.	Jader Fuel Co	10,IL,165	Saline Cnty, IL	RB	9,374.50	$24.694	$0.000	$0.000	$0.000	$7.420	$0.000	$0.000	$0.000	$0.000	$7.420	$32.114
9.	American Coal	10,IL,165	Saline Cnty, IL	RB	24,467.00	$25.600	$0.000	$0.000	$0.000	$7.500	$0.000	$0.000	$0.000	$0.000	$7.500	$33.100

(1) As Electro-Coal Transfer Facility is a central storage site for coal prior to its delivery to the power plant, the coal from suppliers noted on this schedule is usually delivered to Gannon Station but could ultimately be delivered to Big Bend Station or Polk Station.

(2) Tampa Electric purchases coal F.O.B. shipping point or F.O.B. destination.

FPSC FORM 423-2(b) (2/87)

** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: May Year: 2000

2. Reporting Company: Tampa Electric Company

3. Plant Name: Gannon Station

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Director Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: Jeffrey Chronister, Director Financial Reporting

6. Date Completed: July 14, 2000

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Trans-port Mode (e)	Tons (f)	Effective Purchase Price ($/Ton) (g)	Add'l Shorthaul & Loading Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Other Related Charges ($/Ton) (o)	Total Transpor-tation Charges ($/Ton) (p)	FOB Plan Price ($/Ton) (q)
1.	Transfer Facility	N/A	Davant, La.	OB	111,807.00	$27.865	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$10.577	$38.442
2.	Premier Elkhorn	9,KY,195,133	Pike & Letcher Cnty, KY	UR	45,494.00	$22.000	$0.000	$16.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$16.000	$38.000

FPSC FORM 423-2(b) (2/87)

** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: May Year: 2001

2. Reporting Company: Tampa Electric Company

3. Plant Name: Electro-Coal Transfer Facility - Gannon Station (1)

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Director Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: Jeffrey Chronister, Director Financial Reporting

6. Date Completed: July 16, 2001

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Trans-port Mode (e)	Tons (f)	(2) Effective Purchase Price ($/Ton) (g)	Add'l Shorthaul & Loading Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Other Related Charges ($/Ton) (o)	Total Transpor-tation Charges ($/Ton) (p)	Delivered Price Transfer Facility ($/Ton) (q)
1.	Sugar Camp	10,IL,059,165	Gallatin & Saline Cnty, IL	RB	47,119.30	$26.202	$0.000	$0.000	$0.000	$7.600	$0.000	$0.000	$0.000	$0.000	$7.600	$33.802
2.	Sugar Camp	10,IL,059,165	Gallatin & Saline Cnty, IL	RB	69,663.10	$25.844	$0.000	$0.000	$0.000	$7.950	$0.000	$0.000	$0.000	$0.000	$7.950	$33.794
3.	Jader Fuel Co	10,IL,165	Saline Cnty, IL	RB	5,050.10	$26.000	$0.000	$0.000	$0.000	$7.600	$0.000	$0.000	$0.000	$0.000	$7.600	$33.600
4.	Jader Fuel Co	10,IL,165	Saline Cnty, IL	RB	14,280.70	$24.550	$0.000	$0.000	$0.000	$7.600	$0.000	$0.000	$0.000	$0.000	$7.600	$32.150
5.	American Coal	10,IL,165	Saline Cnty, IL	RB	54,886.00	$28.270	$0.000	$0.000	$0.000	$5.790	$0.000	$0.000	$0.000	$0.000	$5.790	$34.060
6.	Triton	19,WY,005	Campbell Cnty, WY	RB	92,006.00	$8.500	$0.000	$11.990	$0.000	$5.790	$0.000	$0.000	$0.000	$0.000	$17.780	$26.280
7.	Lodestar	9,KY,225	Union Cnty, KY	RB	34,570.00	$28.000	$0.000	$0.000	$0.000	$7.600	$0.000	$0.000	$0.000	$0.000	$7.600	$35.600

(1) As Electro-Coal Transfer Facility is a central storage site for coal prior to its delivery to the power plant, the coal from suppliers noted on this schedule is usually delivered to Gannon Station but could ultimately be delivered to Big Bend Station or Polk Station.

(2) Tampa Electric purchases coal F.O.B. shipping point or F.O.B. destination.

FPSC FORM 423-2(b) (2/87)

CONFIDENTIAL

** SPECIFIED CONFIDENTIAL **

FPSC Form 423-2(b)

MONTHLY REPORT OF COST AND QUALITY OF COAL FOR ELECTRIC PLANTS
DETAIL OF TRANSPORTATION CHARGES

1. Reporting Month: May Year: 2001

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3. Plant Name: Gannon Station

4. Name, Title & Telephone Number of Contact Person Concerning Data Submitted on this Form: Jeffrey Chronister, Director Financial Reporting (813) 228 - 1609

5. Signature of Official Submitting Form: Jeffrey Chronister, Director Financial Reporting

6. Date Completed: July 16, 2001

Line No. (a)	Supplier Name (b)	Mine Location (c)	Shipping Point (d)	Transport Mode (e)	Tons (f)	Effective Purchase Price ($/Ton) (g)	Add'l Shorthaul & Loading Charges ($/Ton) (h)	Rail Charges: Rail Rate ($/Ton) (i)	Rail Charges: Other Rail Charges ($/Ton) (j)	Waterborne Charges: River Barge Rate ($/Ton) (k)	Waterborne Charges: Trans-loading Rate ($/Ton) (l)	Waterborne Charges: Ocean Barge Rate ($/Ton) (m)	Waterborne Charges: Other Water Charges ($/Ton) (n)	Other Related Charges ($/Ton) (o)	Total Transportation Charges ($/Ton) (p)	FOB Plant Price ($/Ton) (q)
1.	Transfer Facility	N/A	Davant, La.	OB	172,295.00	$31.743	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$10.098	$41.841
2.	Consol of Kentucky	9,KY,225	Union Cnty, KY	UR	35,446.00	$22.000	$0.000	$16.350	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$16.350	$38.350
3.	Teco Coal	8,KY,195,133	Pike & Letcher Counties, KY	UR	8,988.00	$37.600	$0.000	$16.350	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$16.350	$53.950

FPSC FORM 423-2(b) (2/87)

CONFIDENTIAL

CSXT UTILITY SOUTH: 2004 TONS vs. 2003 & 2004 TONS vs. PLAN THROUGH APRIL 2004

CONSIGNEE	2003	Plan
All CSXT Florida Destinations	112%	106%
Progress Fuels Corp.	115%	109%
Duke Power	92%	115%
Progress Energy Carolinas	125%	136%
Santee Cooper	101%	99%
Southern Company	100%	100%
South Carolina Electric & Gas	155%	111%
Total Utility South	107%	106%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 102
COMPANY/ Mike Twomey, Esq.
WITNESS. CSX Comparison Delivered Coal 2003-2004
DATE: 5/27-28/04

CONFIDENTIAL

Document Number: 06780-04
Order Number:
Fine/Settlement: N
Pages: 0
Suffix: EI
Co. Name: Tampa Electric Company

Filing Date: 06/18/2004
Is/Was Confidential: N
Type: (•) Other
( ) Motion
( ) Order

DESCRIPTION

GCL/C. Keating - Memo dated 6/18/04 forwarding duplicate copy of confidential late-filed Exh. 103 (DN 06781-04) to CCA for appropriate handling. [duplicate DN 06732-04]

103 (Late-filed) Recalculation of CSXT bid prices for RCAFU and fuel surcharge since July 2003 bid to TECO

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 103
COMPANY/ TECO
WITNESS: Recalculation of CSXT Bid Prices
DATE: 05/27-28/04

CONFIDENTIAL

Document Number: 06657-04
Order Number:
Fine/Settlement: N
Pages: 0
Suffix: EI
Co. Name: Tampa Electric Company

Filing Date: 06/16/2004
Is/Was Confidential: Y
Type: (•) Other
( ) Motion
( ) Order

DESCRIPTION

(CONFIDENTIAL) Hearing Exhibit No. 104 (8/28/02 letter to Mr. White from Mr. Shuman) from 5/27-28/04 and 6/10/04 hearing.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 104
COMPANY/ TECO
WITNESS: Letter to Mr. White from Mr. Shuman
DATE: 05/27-28/04

TECO'S APPROVED WATERBORNE TRANSPORTATION BENCHMARKS
VS. ACTUAL RAIL AND WATERBORNE COSTS TO GANNON STATION, 1994-2001

			ACTUAL[1]	
Docket No.	Year	Benchmark[2]	Rail Cost	Waterborne Cost[3]
020001	2001	$23.87/Ton	$16.35/Ton[4]	$19.99/Ton[4]
010001	2000	$26.23/Ton	$16.00/Ton[4]	$20.33/Ton[4]
000001	1999	$25.85/Ton	$19.16/Ton[4]	$18.23/Ton[4]
990001	1998	$28.14/Ton	$18.63/Ton[4]	$19.78/Ton[4]
980001	1997	NA[5]	NA	NA
970001	1996	$25.35/Ton	$17.76/Ton[4]	$20.60/Ton[4]
960001	1995	$27.08/Ton	$17.47/Ton[4]	$25.59/Ton[4]
950001	1994	$25.70/Ton	$17.27/Ton[4]	$19.34- $29.60/Ton[4]

[1] Source: Non-confidential (declassified) FPSC 423's for 1998-2001.

[2] FPSC Orders

[3] Includes estimated cost to get coal from the mine onto the river barge.

[4] 1998 August; 1999 May; 2000 May; 2001 May; 1996 May; 1995 May; 1994 May

[5] 1997 Not Available

Not Admitted

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 105
COMPANY/ OPC
WITNESS. Benchmark Comparison
DATE: 5/22-28/04

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 031033-EI EXHIBIT NO. 106
COMPANY/ TECO
WITNESS: Update to EMC estimate
DATE 05/27-28/04 (BS-4)

5/18/04

TO: ENERGY VENTURES ANALYSIS, INC.
ATTN: MR. JOHN STAMBERG FAX #(703)276-9541
FROM: RANDY BAIRD, MHS SYSTEMS BUSINESS MANAGER
FMC TECHNOLOGIES

DEAR MR. STAMBERG,

FIRSTLY, MY APOLOGIES FOR THIS HAND-WRITTEN NOTE AND ADDENDUM TO FMC TECHNOLOGIES BUDGET CONVEYOR PROPOSAL (RB03260401) DATED MARCH 2004.
I AM CURRENTLY ON A BUSINESS TRIP AND HAVE ENCOUNTERED SOME PROBLEMS WITH MY NEW IBM LAPTOP. I UNDERSTAND YOUR NEED FOR AN URGENT AND TIMELY RESPONSE, HENCE THIS HANDWRITTEN CORRESPONDENCE. I WILL FOLLOW WITH A REVISED BUDGETARY QUOTE WITH CLARIFICATIONS UPON MY RETURN. I WAS ABLE TO DEVELOP SOME BID CLARIFICATION IN THE OFFICE PRIOR TO LAPTOP FAILURE IN FIELD. COPIES ATTACHED

FIRST, SOME POINTS OF NOTE ON THE ORIGINAL PROPOSAL:

1) FMCTI BASED THE BUDGETARY QUOTE MOSTLY BASED UPON THE VERBAL SPECIFICATIONS PROVIDED TO FMCTI FROM ENERGY VENTURES ANALYSIS,

- CLEAN COAL, 50 lbs/cu.ft., 0-3"
- HORIZONTAL CONVEYORS (NO-LIFT), 18' CLEARANCE UNDER TRUSS. TRUSS SPANS 30' ON BENTS TOTAL LENGTH.
- 2 30' CLOSED SECTIONS (1 PER CONVEYOR)
- GRAVITY TAKE-UPS (SIDE-MOUNTED TOWERS)
- ELECTRICAL LIGHTING FULL LENGTH.

- CV1 2500 ST/HR, 3300', 54" BW WITH 35° IDLERS
- CV2 1500 ST/HR, 2100', 42" BW WITH 35° IDLERS.

2) SINCE THIS WAS A BUDGETARY, CAPITAL PLANNING QUOTE FMCTI MADE THE FOLLOWING DESIGN ASSUMPTIONS AS SPELLED OUT IN THE SUBMITTED BUDGETARY QUOTE:

- 5 on 10 IDLER SPACING
- CEMA C DESIGN IDLERS
- SINGLE-COAT INDUSTRIAL ENAMEL ON STRUCTURAL STEEL
- NON-UNION LABOR FOR CONSTRUCTION
- CUSTOMER TO PROVIDE FOUNDATION ENGINEERING AND CIVIL, INCLUDING FOUNDATION INSTALLATION.
  FMCTI WOULD PROVIDE STARTERS FOR DRIVES AND WALKWAY LIGHTING ONLY (AND RELEVANT ELECTRICAL DESIGN FOR THIS SUPPLY).

3) AS NOTED IN QUOTE: <u>BUDGETARY PRICING SUMMARY SECTION:</u>
NOTE: PRICING PROVIDED AS BUDGETARY ONLY. EXACT PRICING WILL REQUIRE FURTHER SCOPE DEVELOPMENT, SPECIFICATION REVIEW, AND SITE ANALYSIS. FINAL PRICING TO OCCUR PRIOR TO ORDER ACCEPTANCE.

BASED UPON OUR CONVERSATIONS OF 5/16/04 AND 5/17/04, I AM PROVIDING THE ATTACHED BID CLARIFICATIONS AND A PRICE ADDER FOR THE REQUESTED CHANGES.
THE BUDGETARY QUOTE NOW INCLUDES:

1) FOUNDATION ENGINEERING DESIGN AND FOUNDATION CONSTRUCTION (LESS ALL CIVIL WORK ⇒ EXCAVATION, BACK-FILL, AND UTILITY LOCATION)

2) ALL ELECTRICAL ENGINEERING AND SCOPE SUPPLY OF ATTACHED BID CLARIFICATIONS (DATED 5/18/04)

3) DESIGN TO USE CEMA D DESIGN FMCTI IDLERS 6" ROLLS. 4 ON 10 CENTER DESIGN.

4.) ALL STRUCTURAL STEEL TO BE GALVANIZED PER SCOPE OF ATTACHED BID CLARIFICATIONS (DATED 5/18/

5) NEMA 4 ELECTRICAL DESIGN

6.) INCLUDES HEAD DISCHARGE CHUTE BOXES AS REQUIRED BY APPROPRIATE DESIGN.

NOTE: WE CONTINUE TO QUOTE A 54" CV1 CONVEYOR PER EVA'S SPECIFICATION. A 60" CONVEYOR COULD BE PROVIDED ALLOWING A LOWER CONVEYOR SPEED. PRICE IMPLICATIONS WOULD OCCUR, BUT BE MINIMAL.
THIS WOULD ALLOW A 600'/MIN CONVEYOR SPEED. CV2 COULD BE INCREASED TO 48" WITH THE SAME RESULTS (FUNDAMENTALLY).

NOTE: 7.) ELECTRICAL AND COMPONENTS / WIRING ARE QUOTED AS NON-CLASSIFIED. EXPLOSION-PROOF CLASSIFICATIONS WILL REQUIRE A PRICE RE-BID. FMCTI HAS NOT BEEN NOTIFIED OF ANY CLASSIFICATION REQUIREMENTS.

NOTE: 8.) [redacted] BUDGETARY QUOTE IS BASED ON CUSTOMER SUPPLY OF SIZED 460/60/3ϕ POWER. NO HIGH-VOLTAGE STEPPING IS ACCOUNTED FOR IN BID.

AS STATED, A FORMAL REVISION TO THE ORIGINAL BUDGETARY QUOTE (RB03260401) WILL BE MADE UPON MY RETURN AND SUBMITTED TO ENERGY VENTURES ANALYSIS.

FOR THE INCLUSION OF ITEMS #1, 2, 3, 4, 5, 6 AS NOW REQUIRED, A PRICE ADDER TO ORIGINAL SUBMISSION IS AS FOLLOWS:

— ORIGINAL PRICE FOR SUPPLY OF ITEMS #1, 2, 3 OF RB03260401

$5,851,000.00

-15% to +20%

($4,680,000) to ($4,728,650)

— REVISED PRICE TO INCLUDE ITEMS # 1-6 OF THIS 5/18/04 ADDENDUM

15%

$6,736,814.00

RANGE CONSTRICT DUE TO RECENT SPECIFICATION CLARIFICATION

-10% to +15%

($6,063,133) to (7,747,336

1 Found engr.
3 Elec Eng
3 D Adlers
3 4H Alla
4 Halvorsen
6 Ruschmeyer Bar

ALL TERMS & CONDITIONS OF RB03260401 APPLY TO THIS ADDENDUM.

THANK YOU FOR THE CONTINUED OPPORTUNITY.
I LOOK FORWARD TO FURTHER DIALOG AND CLARIFICATIONS ON THIS IMPORTANT PROJECT.

SINCERELY,

RANDY BAIRD
IMHS SYSTEMS BUSINESS MANAGER
PH: (724) 479-4687
FX: (724) 479-4681

724. 9.0 9578

EVA. BID CLARIFICTIONS 5/18/04

Our proposal is based on the Information provided and attached clarifications.

Conveyor Specifics

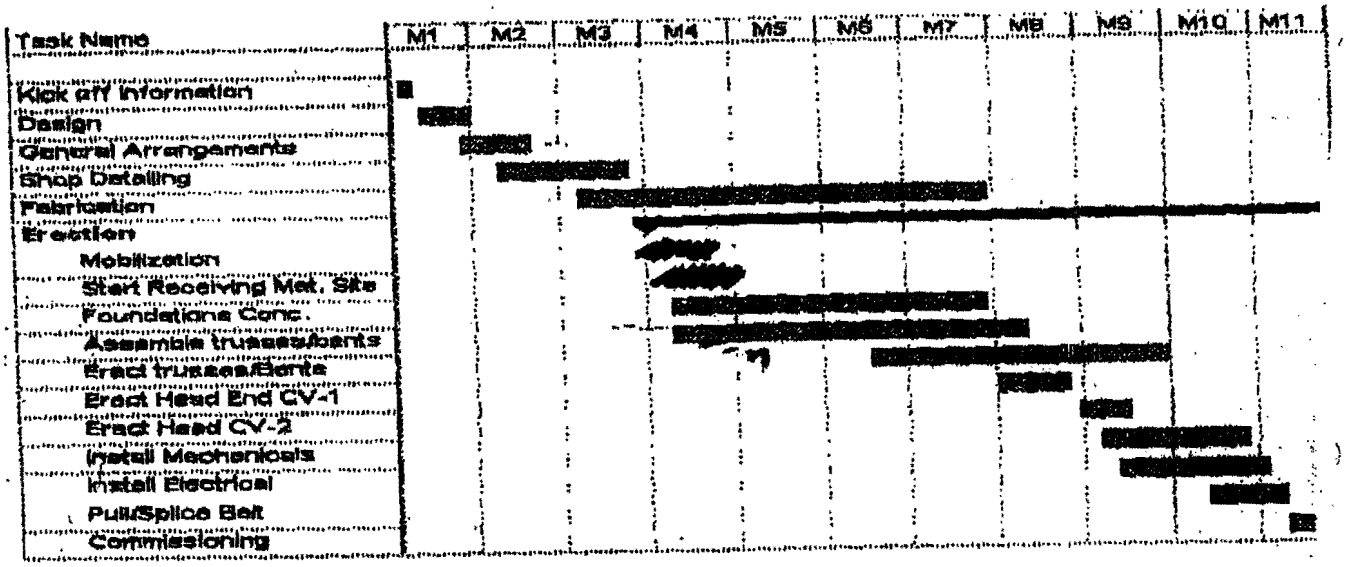
Conveyor	Main CV-1	Secondary CV-2
Des. Tonnage	2500 stph	1500 stph
Belt Width	54 in.	42 in.
Belt Speed	700 fpm.	700 fpm.
Length	3,300 ft.	2,100 ft.
Elevation Change	0 ft.	0 ft.

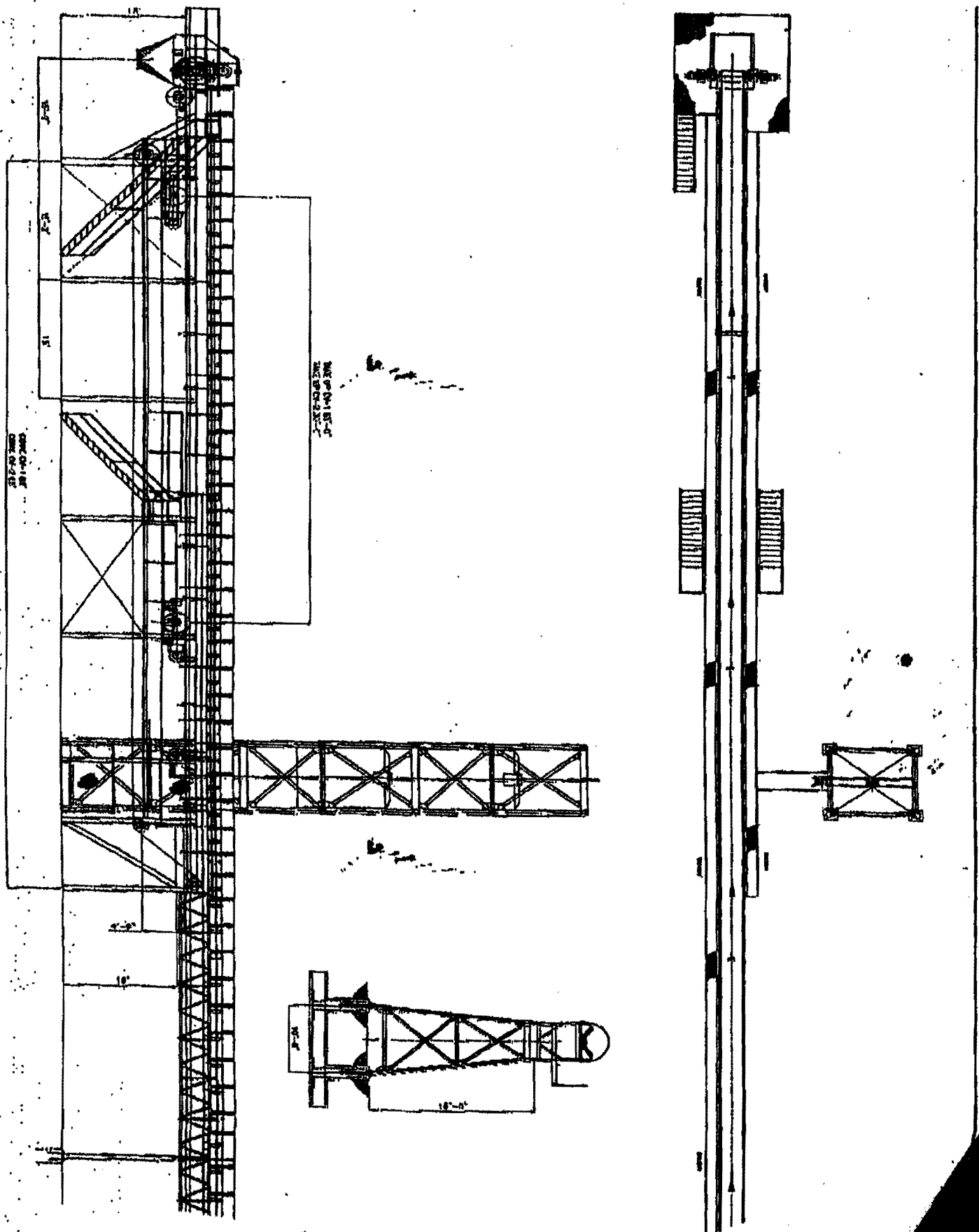
Conveyors are to be elevated with 18 ft. clearance to ground along the entire length, with a continuous walkway on one side and full covers along the entire length.

Pricing

Item Description	Budget Price
Engineering Structural/Mechanical	$ [redacted]
Electrical - Engineering/ Supply/Installation	$ [redacted]
Fabrication/Delivery and supply ww/hoods/T-UP hardware	$ [redacted]
Installation Concrete Foundations	$ [redacted]
Erection Structural/Mechanical/Belting	$ [redacted]
Total Budget	$ [redacted]

Estimated Schedule





General

Our bid has been based on the understanding that FMC will supply:

- FMC TI will provide power drive packages and associated hardware.
- FMC TI will provide conveyor belting, and vulcanized spliced kits.
- FMC TI will provide: idlers, belt cleaners and plows, pulleys and bearings, and necessary hardware.
- FMC TI to provide motor starters.

Modifications to the original assumptions, final conveyor profile, site investigation, soils report, may impact quotation price shown.

Scope of work.

• SHOULD FMCTI NOT BE REQUIRED TO PROVIDE THE POWER/TRANSMISSION COMPONENTS, THE STRUCTURAL PRICING WILL BE IMPACTED. THE QUOTE PROVIDED IS A BUNDLED PACKAGE. SEGMENTATION WILL IMPACT PRICING.

Engineering:

Engineering covers the design of the conveying system.

- Foundation design, and drawings.
- Design conveyor steel components, conveyor profiles and general arrangement drawings. General arrangement drawings to be submitted for approval.
- Shop detail and erection drawings.
- Client to provide control points, and surveying.
- Engineering pricing does not include any travel or any associated expenses.

Electrical

- Design covers conveyor control logic programming, schematic and assembly drawings, and specifications for conveyor electrical components.
- Supply the following conveyor electrical components:
  - Area and walkway lighting.
  - Pull cord, plug chute, belt speed and belt alignment switches.
  - Start up horns and strobes.
  - Programmable logic controllers for respective conveyors.
  - Push buttons and enunciator panels for respective conveyors.
  - Cabling and conduit to connect all [redacted] supplied electrical and safety components to the head and/or tail of the respective conveyors only. (cabling along conveyors to be run in rigid conduit)
- Install and commission electrical components.

Fabrication:

Fabricate and supply fabricated steel in accordance with design and shop detail drawings, and deliver to site. This bid is based on galvanizing the structural components.

Erection:

Mobilize, unload trucks, supply necessary labor and equipment required to: pour foundations, install all structural steel and mechanical components, install all electrical equipment, pull and vulcanize belts, provide commissioning labor to cover commissioning of supplied components and provide training to operators.

Bid Design Assumptions:

- The wind velocity for bid calculations was based on 120 mph.
- Allowable bearing load for foundations 3000 psf, foundations approximately 4.5 to 5 ft. deep
- Two 30 ft. enclosed conveyor sections to go over roadways have been allowed for.
- Steel structure to be galvanized.
- Stair access to conveyor walkway from ground level provided every 1000 ft along belt line.
- Truss expansion joints have been provided at 500 ft. intervals, with twin trestle (bent supports).
- Walkways have been provided along one side of the conveyor, the drive heads and loading areas will have twin walkways for access to horizontal take-up carriage and loading boots.
- 180 deg. Fixed hoods have been allowed for along the entire conveyor length.
- For estimating shipping, it was assumed that the site was located in the central part of Florida.
- Pull cord switches have been provided at 200 ft. intervals along belt line.
- Start up horns with strobes have been provided at 500 ft. intervals along belt line.
- Walkway lights have been provided at 75 ft. intervals along belt line.
- Customer to provide surveys along the conveyor belt line.

Specific Components

1. Reducers: It is assumed that all reducers will be supplied as shaft mounted (Dodge TXT or equivalent reducers)
2. Pulleys: It is assumed that all pulleys will be supplied with bearings fitted to shafts based on the mechanical design drawings.
3. Fixed 120 deg. covers for the entire length of the conveyor have been included.
4. All structural steel will be galvanized.
5. Walkways are supplied on one side of the truss with a head and tail wrap-around platform. The walkways will be galvanized Gripstrut, galvanized hold down clips, and galvanized splice plates all fabricated for field installation.
6. Nuts, bolts, and washers: Galvanized, sized for the load conditions.
7. Electrical Components General: The electrical design and supply of components is based on NEMA 4 enclosure classification. The bid assumes that the electrical components and wiring shall be non-classified.
8. No allowance has been made for the provision of MCC buildings for conveyor electrical.
9. Walkway and area lighting at the head and tail ends and along conveyor walkways have been included in our supply and installation; price based on 150w 480V HPS stanchion fixed on 75 ft. centers.
10. Guards and Handrails: Provided, per our interpretation of OSHA. Handrails fabricated from 1 ¼" schedule 40 galvanized pipe.
11. Discharge Chutes/Skirt boards and inlet connections: Skirt boards are constructed from ¼" plate with 3/8" AR40 steel liners where material flow comes in contact with chutes and or loading boots, except in areas where rock-boxes form dead material. Inspection ports are standard. Loading boots and chutes will be designed to meet or exceed CEMA recommendations.
12. No allowance has been made for dust suppression or extraction.
13. No allowance has been made for fire suppression or equipment.
14. Electrical switch brackets, lighting stanchions have been included in our bid.

15. Customer to provide Soils Report. Foundation costs may be impacted based upon Soils Report. (Foundations have been estimated on 3000 psf.)

16. Customer to be responsible for excavation for foundations and pumping of ground water if necessary. Our bid has assumed that the customer will be responsible for backfilling foundations and provide foundation base layer and backfill material.

17. Environmental: No allowance has been made for environmental mitigation, abatement, permitting, licensing or any associated costs, that might be required or necessary with the execution of this project.

18. Construction Labor and equipment required has been included in this bid.

19. It is assumed that Owner will provide a secured fenced lay-down area, large enough to accommodate all structural, mechanical and delivered items, for storage and safe keeping.

20. Our bid has included the unloading of trucks for components supplied [redacted]

21. It is assumed that the client will provide access to workers, subcontractors, cranes, erection equipment, delivery trucks (includes concrete) with access to areas worked, in a timely manner to suit the construction schedule. It has been assumed that the ground conditions will allow standard vehicles and trucks to access the construction areas at all times.

22. FMCTI [redacted] will not be responsible for locating underground services, and the relocation of underground or above ground services is not included in our bid.

23. It is assumed that the construction site will be provided with electrical power to site offices, adequate water supplies, etc., necessary for the construction activities.

24. It is assumed that potable water will be made available.

25. The proposed schedule has not made any allowance for inclement weather, latent conditions that might be discovered during the execution of this contract.

26. Our scope has included qualified staff for 8 days of commissioning for the supplied equipment, any equipment required will be billed based on our schedule of rates. We have not included technical representatives that could be needed to commission the major mechanical components if required. The costs associated with the commissioning personnel from the various vendors if required, will be billed on a cost plus basis.

27. Field services or equipment over and above our scope of works will be extra based on our schedule of rates.

28. Estimated schedule will have to be confirmed, it is dependent on the work at hand and on award date. We have not made allowance in the schedule for holidays.

29. Spare and Critical components and special tool list will be submitted at a later date

30. US, Federal, State charges/taxes, permits have not been included in our pricing.

[redacted]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Review of Tampa Electric Company's 2004-2008 Waterborne Transportation Contract with TECO Transport and Associated Benchmark	)	DOCKET NO. 031033-EI
	)	FILED: June 17, 2004

CSX TRANSPORTATION'S NOTICE OF FILING
LATE-FILED HEARING EXHIBIT NO. 107

CSX Transportation ("CSXT"), pursuant to the instructions of the Chairman at the conclusion of the hearing in the above-referenced docket, hereby gives notice of filing and files its Late-Filed Hearing Exhibit No. 107.

Respectfully submitted this 17th day of June, 2004.

LANDERS & PARSONS

Robert Scheffel Wright
Florida Bar No. 966721
John T. LaVia, III
Florida Bar No. 853666
310 West College Avenue (32301)
Post Office Box 271
Tallahassee, Florida 32302
Phone: 850/681-0311
FAX: 850/224-5595

Counsel for CSX Transportation

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 107
COMPANY/ CSX
WITNESS. Late-Filed Hearing Ex. No. 107
DATE: 05/27-28/04

DOCUMENT NUMBER-DATE
06730 JUN 17 04
FPSC-COMMISSION CLERK

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that the original and one copy of the foregoing has been filed with the Clerk's Office, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399 and that a true and correct copy of the foregoing has been served by U.S. Mail or hand delivery (*) this 17th day of June, 2004, on the following:

Wm. Cochran Keating, Esq.*
Jennifer Rodan, Esq.
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

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Florida Industrial Power Users Group
c/o John W. McWhirter, Jr., Esq.
McWhirter Reeves
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Florida Retail Federation
John Rogers, Esq.
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Ms. Angela Llewellyn
Regulatory Affairs
P.O. Box 111
Tampa, FL 33601-0111

Michael B. Twomey, Esq.*
P.O. Box 5256
Tallahassee, FL 32314-5256

TECO Transport Company
c/o Benjamin Hill III/Landis Curry III
Hill Ward Law Firm
P.O. Box 2231
Tampa, FL 33601-2231

Attorney

STONE & WEBSTER ENGINEERING CORPORATION

TABLE C.-4A WL.-50 CONVEYOR PHYSICAL DATA

	NO.1 CONVEYOR	NO.2 CONVEYOR
LENGTH	18.5 FT.	54 FT.
WIDTH	64 IN.	60 IN.
SPEED	0-950 FPM	0-1000 FPM
*CAPACITY	4000 TPH	4000 TPH
DRIVE	HEAD PULLEY	HEAD PULLEY
POWER	HYDROSTATIC MOTOR	HYDROSTATIC MOTOR
IDLERS	IMPACT/FLAT	IMPACT/TROUGH
TAKEUP	HYDRAULIC	HYDRAULIC
ALIGNMENT	HYDRAULIC	HYDRAULIC

*RECLAIM CAPACITY IS REDUCED TO 3000 TPH WHEN THE WL-50 IS BEING POWERED BY IT'S AUXILIARY DIESEL ENGINE

CHECKED	TITLE	SCALE:	
CORRECT	WL-50 CONVEYOR PHYSICAL DATA	DATE: 15 NOVEMBER 82	
APPROVED		SKETCH NUMBER	C-4A

(2) (3) (4) (5)

PSC Docket No. 031033-EI
In Re: TECO Coal Transportation
Exhibit No. LFE 107
Page from TECO Manual re: Conveyor Specs

CONFIDENTIAL

Document Number: 06658-04
Order Number:
Fine/Settlement: N
Pages: 0
Suffix: EI
Co. Name: Tampa Electric Company

Filing Date: 06/16/2004
Is/Was Confidential: Y
Type: (•) Other
( ) Motion
( ) Order

DESCRIPTION

(CONFIDENTIAL) Hearing Exhibit No. 108 (late-filed deposition Exhibit No. 1 from witness Paula Guletsky) from 5/27-28/04 and 6/10/04 hearing. [See DNs 05822-04, 05954-04, 05987-04, 06012-04, 06208-04, and 06491-04]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 108
COMPANY/ CSX
WITNESS: Paula Guletsky late-file Exhibit No 1.
DATE: 05/27-28/04

Tampa Electric Company
Docket No. 031033-EI
Late Filed Deposition Exhibit of
Paula Guletsky
No. 1
Page 1 of 17

CONFIDENTIAL

"Conveyor Cost Estimates"

CONFIDENTIAL
DECLASSIFIED
RBB 4.20.06 (entire DOC)

declas 4-20-06
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 108
COMPANY/ WITNESS: CSX
DATE: 5/27-28/04 + 6/10/04

DOCUMENT NUMBER-DATE
06058 JUN 14
FPSC-COMMISSION CLERK

PSC Docket No. 031033-EI
In Re: TECO Coal Transportation
Exhibit _____
Guletsky LFDE No. 1 - Conveyor Cost
Estimates

CONFIDENTIAL

Project No. 09476-020

Confidential

Benchmark Analysis of Belt Conveyor Cost Guidelines
Tampa Electric

Roberts & Schaefer Company						
Width (in)	Lift (ft)	Length (ft)	Equipment Cost ($)	Equipment Cost ($/ft)	S&L Model Equipment Cost ($/ft)	% Difference
60	56	267	310,000	1,161	1,156	-0.47
60	56	267	310,000	1,161	1,360	14.60

FMC Material Handling Systems						
Width (in)	Lift (ft)	Length (ft)	Equipment Cost ($)	Equipment Cost ($/ft)	S&L Model Equipment Cost ($/ft)	% Difference
42	53	204	494,935	2,426	2,502	3.03

1. The S&L Belt conveyor cost model provides data for nine belt widths. Each belt width has cost data for three conveyor lengths (i.e. the longer the conveyor the lower the price per linear foot). Eight different conveyor arrangements are costed for the 27 cases (216 data points).
2. The R&S quote is benchmarked against two different cost categories. This equipment is being retrofit into an existing facility such that the main support will be obtained from existing steel structures. The first benchmark represents the cost for an at grade conveyor with hoods. The second adds conveyor gallery steel and trusses. We would expect the cost to be bracketed within these two cost categories.
3. Data pages provided with the quotations are attached. *Information not pertinent* to the cost benchmarking has been removed.
4. *This benchmark* information is confidential.

Paula Dudzisky
Ben Williams
Sam Madan

CONFIDENTIAL

Date: March 10, 2004

PROPOSAL DATA FOR
COAL HANDLING SYSTEM

NAME OF BIDDER: FMC Energy Systems

1. NET WEIGHTS (not shipping weight) (lb.) as follows:

2. BELT CONVEYORS AND FEEDERS

Conveyor/Feeder Designation Number:						
2.1 Width	(in)	42				
2.2 Capacity	(TPH)					
2.3 Speed	(fpm)					
2.4 Lift	(ft)	53				
2.5 Length along belt line	(ft)	204				
2.6 Type of take-up		Gravity				
2.7 Take-up travel	(ft)	4.5				
2.8 Pulley manufacturer		Dodge				
2.9 Type of hubs		HE				

(Revised 4-15-04)

CONFIDENTIAL

Date: March 10, 2004

PROPOSAL DATA FOR
COAL HANDLING SYSTEM

NAME OF BIDDER: FMC Energy Systems

2.10 Bearing manufacturer		[Dodge]
2.11 Type of bearing		[USAF-Roller]
2.12 Shifting material		[1045]
2.13 Pulley and Shaft Diameters		
a. Drive	(in)	[24]
b. Tail	(in)	[20]
c. Snub	(in)	[N/A]
d. Bend	(in)	[16]
e. Take-up	(in)	[20]
f. Tripper	(in)	[N/A]
2.14 Pulley Lagging:		
a. Type of drive pulley		[Herringbone]
b. Type of snub and bend pulleys		[Plain]
2.15 Idlers:		
a. Troughing:		
a1. Manufacturer		[FMC Energy Systems]
a2. Catalog number and type		[C3628S, 35 Deg.]
a3. CEMA rating and roll size		[C, 6"]
b. Return:		
b1. Manufacturer		[FMC Energy Systems]
b2. Catalog number and type		[C3617S, C]
b3. CEMA rating and roll size		[C, 6"]
c. Training idlers:		
c1. Manufacturer		[FMC Energy Systems]
c2. Catalog number and type for:		
c2.1 Troughing		[C3632S, Pos. Action]
c2.2 Return		[C3220S, Pos. Action]
c3. CEMA rating and roll size		[C, 6"]
d. Impact Idlers:		
d1. Manufacturer		[FMC Energy Systems]
d2. Catalog number and type		[C3630S, Rubber]
d3. Catalog number and CEMA rating and roll size		[C, 6"]

Date: March 10, 2004

PROPOSAL DATA FOR
COAL HANDLING SYSTEM

NAME OF BIDDER: FMC Energy Systems

2.16 Belt

a. Manufacturer		[Goodyear]
b. Trade name		[Plylon Plus]
c. Length, including splice	(ft-in)	[458'-0"]
d. Splice allowance length included	(ft-in)	[7'-0", Single Length]
e. P.I.W.:		
e1. Calculated maximum		[193]
e2. Allowable (mechanical splice rating)		[250]
f. Number of plies		[2]
g. Fabric type		[Nylon]
h. Cover:		
h1. Top cover thickness	(in)	[0.250]
h2. Bottom cover thickness	(in)	[0.0625]
i. Weight per foot length	(lb/ft)	[9.3]

2.17 Conveyor/Feeder Speed Reducer:

a. Manufacturer		[Sew Eurodrive]
b. Type and model		[MC3PLSF06]
c. Horsepower		
c1. Required by driven equipment (hp)		[87]
c2. Reducer mechanical rating	(hp)	[204]
c3. Reducer thermal rating	(hp)	[160]
c4. Required at motor shaft	(hp)	[125]
d. Service factor		[1.63]
e. Speed		
e1. Input	(rpm)	[1800]
e2. Output	(rpm)	[77]

2.18 Backstop or Brake:

a. Manufacturer		[Form Sprag]
b. Type and model		[Longlife LLH-800
c. Rated torque	(ft/lb)	[11,500]
d. Service factor		[Per Motor Breakdown Torque
e. Maximum speed	(rpm)	[108]

2.19 Coupling:

CONFIDENTIAL

Date: March 10, 2004

PROPOSAL DATA FOR
COAL HANDLING SYSTEM

NAME OF BIDDER: FMC Energy Systems

a. Manufacturer		[Transfluid]
b. Type and model		
b1. Reducer input		[Fluid, 17KCM]
b2. Reducer output		[Gear, F4]
c. Rated torque	(ft/lb)	[18,375]
d. Bore:		
d1. Reducer input	(in)	[1.189]
d2. Reducer output	(in)	[5.118]
2.20 Quantity of belt cleaning devices on each conveyor/feeder:		
a. Primary belt scrapers		[1]
b. Secondary belt scrapers		[1]
c. Snub pulley cleaners		[---]
d. V-plow cleaners		[2]

CONFIDENTIAL

Date: March 10, 2004

PROPOSAL PRICES FOR
COAL HANDLING SYSTEM

NAME OF BIDDER: FMC Energy Systems

1.0	EQUIPMENT PRICE - (For complete WORK as covered by the Technical Specification) Ex Works, point of manufacture.	
1.1	Firm price for Coal Handling System complete with all accessories.	
1.2	Mandatory installation, commissioning and startup spare parts and consumables.	
	1.2.1 Taxes at 5%	
1.3	Total Firm Price	$3,633,525.00
1.4	Bidder to identify above Ex Works location(s)	Included in Sec. 9 of Proposal
2.0	TOTAL FIRM PRICE BREAKDOWN - Price breakdown for design, fabrication, furnish and delivery of the following equipment and material. (Total to equal 1.1)	
2.1	Two (2) belt feeders in transfer house 4	
2.2	Two (2) belt feeders in Unit 3 transfer conveyor bay	
2.3	Two (2) ring granulators	
2.4	Conveyors	$494,935.00
2.5	Conveyors	
2.6	Two (2) traveling trippers including festooned cable system, rails	
2.7	Two (2) crusher bypass gates including manual operated Limitorque	
2.8	Rod gates	
2.9	Tripper floor slot seal belt and mechanism	
2.10	Conveyor drive components	
2.11	Chutework and skirt boards	
a.	Transfer from transfer hopper belt feeders to conveyors	
b.	Transfer from conveyor 13A to 14A and from conveyor to	Included in Item 2.4
c.	Balance chutework	Included in Individual Conveyor / Feeder Sections
2.12	Dust collector, exhaust fans, dampers, rotary air lock, diverter gate, ductwork, supports, stairs	
2.13	Cyclone, separator, rotary air lock, diverter gate	

CONFIDENTIAL

Date: March 10, 2004

PROPOSAL PRICES FOR
COAL HANDLING SYSTEM

NAME OF BIDDER: FMC Energy Systems

2.14—h		
2.15		
2.16		
2.17		
2.18		
2.19	Conveyors gallery steel, siding, bulk heads	[Included in Item 2.4]
2.20	Trolleys and hoists	[—]
2.21	Electrical	
2.22		
2.23		
2.24	List equipment and material (itemized) not included above	[See Below]
a.	Electrical Engineering	
b.	Start-Up Spares	
c.	Miscellaneous	
d.		[—]
e.		[—]
f.		[—]
g.		[—]
h.		[—]
2.25	Total (equal to 1.1)	[$3,460,500.00] Plus taxes $173,025.00

3.1		
3.2		
3.3		

Other Options

CONFIDENTIAL

Date: March 10, 2004

PROPOSAL PRICES FOR
COAL HANDLING SYSTEM

NAME OF BIDDER: FMC Energy Systems

3.4	**Budget Price for Erection Based on Non-Union Labor**	(ADD $1,920,000.00 to Item 1.3)
3.6		
3.7		
3.8		
4.0	SHIPPING	
4.1	Lump sum price for delivery:	ADD $23,611.00 to Item 1.3
a.		
b.		
5.0		
5.1		
5.2		
6.0	SPARE PARTS	
6.1	Price for maintenance spare parts	To be attached by Bidder (Included in this section of this Proposal)
7.0	SERVICE ENGINEER	
7.1	Price per working day for field service engineer	Refer to page titled "Technical Services - Field Representatives" included in this section of proposal
7.2	Price per working day for start-up engineer	Refer to page titled "Technical Services - Field Representatives" included in this section of proposal
7.3	Transportation expense for one round trip to the project site	Refer to page titled "Technical Services - Field Representatives" included in this section of proposal

PP-3

UNLOADING CONVEYOR MODIFICATIONS
COAL HANDLING SYSTEM UPGRADES

PROPOSAL DATA

NAME OF BIDDER: Roberts & Schaefer Company

INSERT ALL INFORMATION WITHIN BRACKETS

NET WEIGHTS (Not shipping weights) (lb):

Equipment	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Total net weight (sum of all Items) (lb)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]

MAJOR EQUIPMENT DATA, corresponding to specified design conditions

| | | | | | | | |

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Sargent & Lundy

Belt Conveyor / Feeder Data:	Conveyor
Bearing Manufacturer	[Dodge]
Type of bearing	[SRP Spherical]
Shafting Material.....	[C1045]
Pulley diameter (Drive).....(in)	[24]
Shaft diameter (Drive).....(in)	[7.5]
Pulley diameter (tail).....(in)	[20]
Shaft diameter (tail).....(in)	[6.5]
Pulley diameter (snub) .....(in)	[20]
Shaft diameter (snub) .....(in)	[3-15/16]
Pulley Lagging:	
Type for drive pulley.....	[1/2" HBGL]
Type for snub and bend pulley.....	[1/2" Plain]
Troughing Idlers:	
Manufacturer.....	[Rexnord]
Catalog number and type.....	[60-D6400 45°]
CEMA rating and roll size.....	[D6]
Return Idlers:	
Manufacturer.....	[Rexnord]
Catalog number and type.....	[60-D6040 Flat]
CEMA rating and roll size.....	[D6]
Training Idlers:	
Manufacturer.....	[Rexnord]
Catalog number and type for troughing	[60-D6412 45°]

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Sargent & Lundy

Belt Conveyor / Feeder Data:	Conveyor
Catalog number and type for return	[60-D6052 Flat]
CEMA rating and roll size	[D6]
Hood and Chute Work.....	[New Hood & Chute]
Hood and Chute Work thickness... (in)	[1/4"]
Type of liner.....	[St. Steel]
Liner thickness .....(in)	[3/16"]
Belt:	
Manufacturer.....	[G.A. Duck]
Trade Name.....	[Power Plus]
Length, including splice(ft-in)	[585]
Splice allowance length included (ft-in)	[1x6']
P.I.W.:	[259]
Calculated Maximum	[600]
Allowable (mechanical splice rating)..	[4]
Number of plies.....	[Polyester]
Fabric type.....	
Cover:	[3/16]
Top cover thickness.....(in)	[1/16]
Bottom cover thickness .....(in)	[18.0]
Weight per foot length.....(lb/ft)	

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	Conveyor
Belt Conveyor / Feeder Data:	
Speed reducer	
Manufacturer.....	[Falk]
Type and model.....	[Para-M1170DH2]
Horsepower:	
Required by driven equipment.....(hp)	[257.2]
Reducer mechanical rating.....(hp)	[532]
Reduce thermal rating .....(hp)	[378]
Required at motor shaft.....(hp)	[273.6]
Service factor	[1.52]
Speed:	
Input ..... (rpm)	[1750]
Output..... (rpm)	[121.6]
Backstop or Brake:	
Manufacturer.....	[Falk]
Type and model.....	[NRT]
Rated torque ..... (ft/lb)	[1095, 28000]
Service factor	[1.5]
Maximum speed..... (rpm)	[300]
Coupling:	
Manufacturer.....	[Falk]
Type and model.....	[Fluid]
Reducer input.....	[1584HFD]
Reducer output.....	[1140T10]
Rated torque .....(ft/lb)	[21,069]
Bore reducer input.....(in)	[2.5591]

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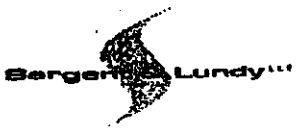

	Convevor
Belt Conveyor / Feeder Data:	
Bore reducer output.....(in)	[5.118]
Quantity of belt scrapers	[2]

Safety Switches:

Manufacturer.....	
Model number.....	
NEMA enclosure type.....	
Quantity.....	

	Conveyor
ELECTRICAL DATA	
Conveyor Motors	[ ]
Manufacturer	[Reliance]
Type.....	[Induction (SC)]
Enclosure.....	[TEFC-Washdown]
Horsepower Rating.....	[350]

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ELECTRICAL DATA	Conveyor
Voltage, phase, frequency	[460/3/60]
Speed at full load	[1750]
Type of bearings	[A/F]
Insulation Class	[F]
Temperature rise (by resistance) above 50°C ambient of the windings when operating at rated hp continuously	[80]
Service factor at rated hp	[1.15]

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UNLOADING CONVEYOR MODIFICATIONS
COAL HANDLING SYSTEM UPGRADES
POWER STATION

PROPOSAL PRICES

NAME OF BIDDER: Roberts & Schaefer Company

INSERT ALL INFORMATION WITHIN BRACKETS

1.	FIRM LUMP SUM PRICE, for the complete work covered by Specification based on meeting all conditions on the Bid Documents, unless exceptions are specifically listed and identified as such in the Proposal. Without limitation, it is understood that this price is firm, and not subject to adjustment due to changes in cost of labor or materials, or to any other factor, except changes in the scope of work or other causes specifically stated in the Contract (Sum of Items 1.1 through 1.4)	[	
1.1	Amount included in the above Firm Lump Sum Price (Item 1) for Equipment & Material	[	
1.2	Amount included in the above Firm Lump Sum Price (Item 1) for field labor associated with installation of equipment and material and modification to existing structures	[	
1.3	Amount included in the above Firm Lump Sum Price (Item 1) for Construction Management including start-up personnel	[	[
1.4	Amount included in the above Firm Lump Sum Price (Item 1) for Freight	[	[

		EQUIPMENT AND FREIGHT COSTS	INSTALLATION COST
2.	AMOUNT included in the above Firm Lump Sum Price (Item 1) for the following equipment:		
2.1	.....	[	
2.2	.....	[	
2.3	.....	[	
2.4	.....	[	
2.5	Conveyor	[$310,000]	[$190,000]
2.6	.....		
2.7	.....	[	
2.8	Existing Building Modifications	[	
2.9	SCR for Conveyors	[	]
2.10	Field Devices	[	
2.11	Conveyor Head End Repairs	[	
2.12	Reclaim Hopper 18	[	]
2.13	Tripper Modifications	[	]
2.14	Conveyor Belt Scale		]
2.15	Engineering Design	[$ 350,000]	[$ Not applicable]
2.16	Remaining Items		

2.17 Start-Up Assistance	[$10,000]	[$30,000]
SUB TOTAL OF ITEM 2.0	[ ]	

TAXES ON THE MATERIAL PORTION OF THE CONTRACT

3.1 Contractor shall confirm that sales tax has been included in the bid price by writing: "Sales tax included".....

4.0 BID VALIDITY

4.1 Bidder hereby agrees that his proposal shall remain valid for acceptance by Ow3ner for a period of 90 days from the bid.

Due date..... (Answer Yes/No)

5. The following constitutes the terms and conditions for Time and Material Rates:

5.1 Materials including freight and taxes, if applicable, shall be invoiced .....

5.2 Subcontractors' work shall be invoiced at: .....

5.3 AZCO INC. equipment shall be invoiced:

5.4 Rental rates shall include insurance, property tax, interest, depreciation cost, cost of repairs and equipment operating costs. .....

5.5 Equipment must be in first class condition when arriving on job site.....

5.6 Owner will not be responsible for repairs of equipment.

5.7 Labor charged to Owner. .....

5.8 Third party rental equipment costs : .....

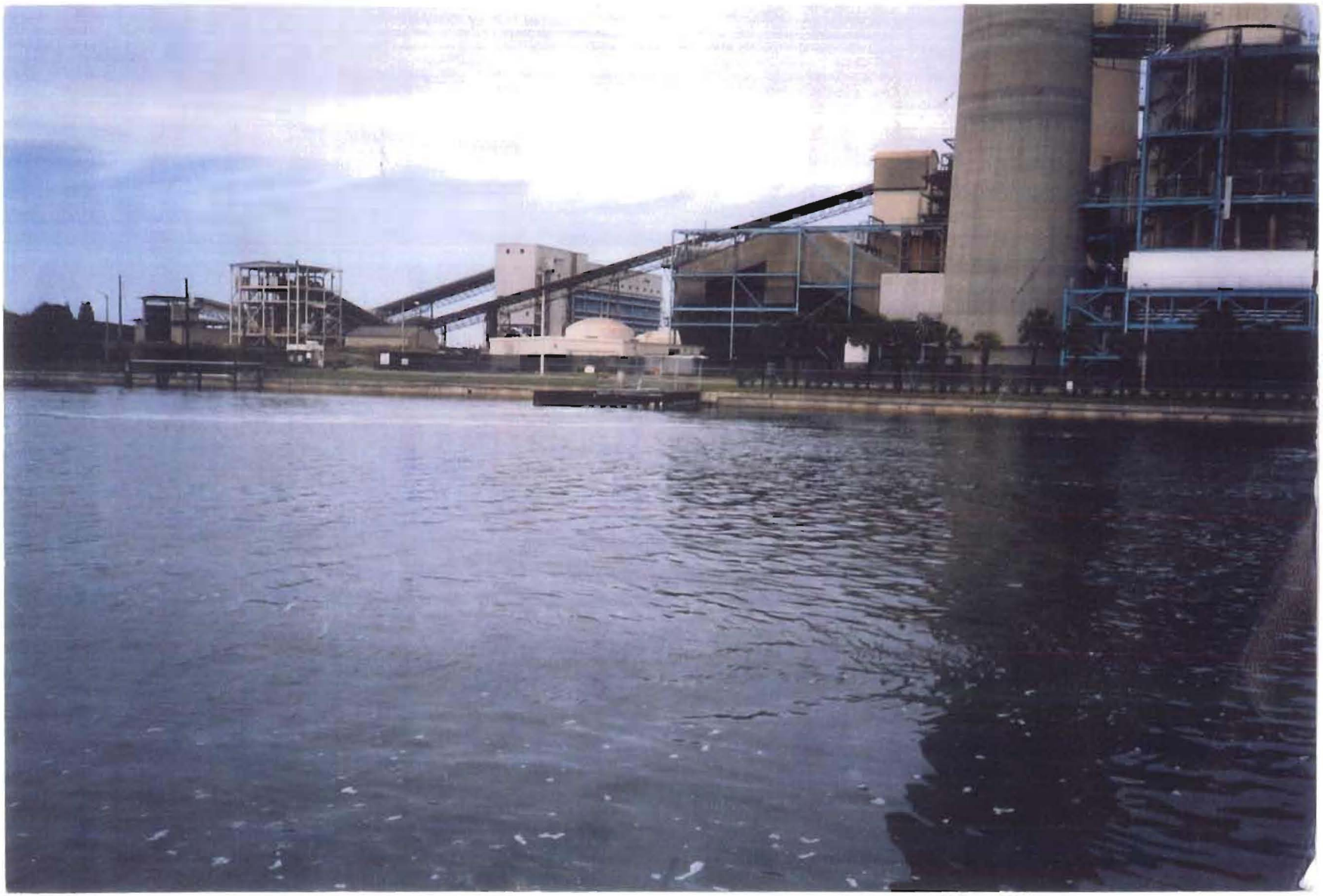
Third party equipment must be in first class condition when arriving on job site. Owner will not be responsible for repairs. .....

5.9 Consumables Costs:

5.10 Small tools costs with a value of one-thousand dollars ($1000.00) or less are: .....

5.11 Where applicable per union agreement costs for travel and worker subsistence, including taxes.....

5.12 Unless Contractor can demonstrate that extra work is the sole cause of schedule extension, there should be no charge for extended overheads and/or project manager/superintendent costs on extra work.....



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO 109
COMPANY/ CSX
WITNESS. Conveyor Photographs
DATE: 05/27-28/04

PSC Docket 031033-EI
In Re: TECO Coal Transportation
Exhibit 109
Conveyor Photographs

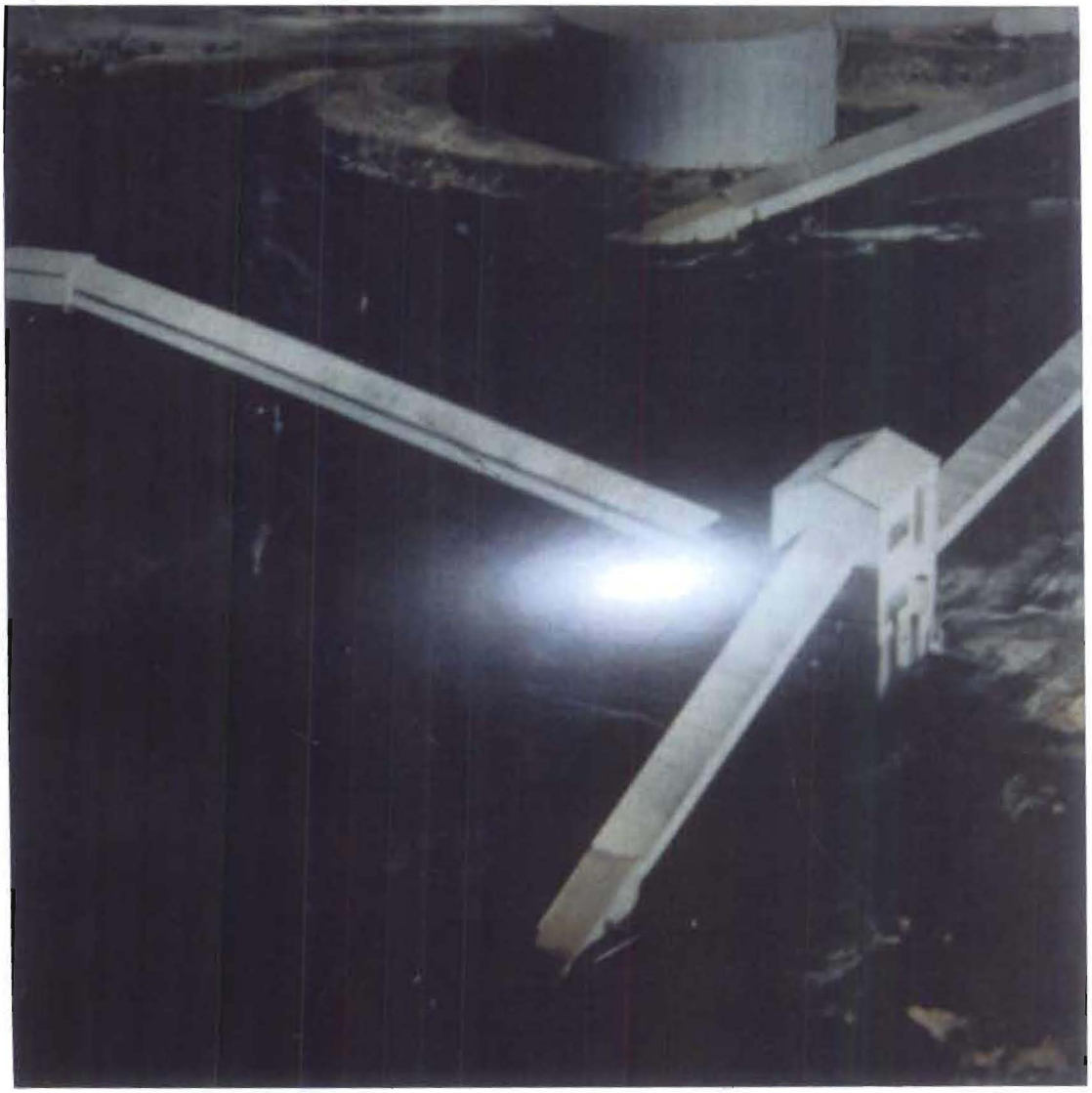


Exhibit No. 110
Tampa Electric Company
Docket No. 031033-EI

Heller 8 Week RFP

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 031033-EI EXHIBIT NO. 110
COMPANY/ OPC
WITNESS: Heller 8 Week RFP
DATE: 5/27-28/04

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 031057-EI

DIRECT TESTIMONY OF JAMES N. HELLER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is James N. Heller. I am currently President of Hellerworx, Inc. at 4803 Falstone Avenue, Chevy Chase, Maryland 20815.

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. I have prepared Exhibit JNH-1, which describes my education and experience. By way of background, I received a Bachelor of Science degree in electrical engineering from Northwestern University in 1970. I was a member of the Eta Kappa Nu and Tau Beta Pi engineering honorary societies. In 1972, I received a Masters in Business Administration from the Harvard Business School.

Upon graduation, I began work with the U.S. Environmental Protection Agency's Office of Water Quality, Planning and Standards in Washington, D.C. While at EPA, I was responsible for the development of industrial water pollution control effluent guidelines. I served as Section Chief of a group responsible for the review of these guidelines and for the development of computer-based tools to assist management in the analysis of progress in the water pollution control programs.

In 1975, I joined Energy and Environmental Analysis, Inc., in Arlington, Virginia, a firm that provided consulting services primarily to agencies of the Federal government. I became Director of Management Studies, and was responsible for conducting a wide range of analyses in areas relating to air and water pollution control, automobile energy consumption, energy conservation, coal markets, and rail transportation. Clients served included the U.S. Department of Energy, U.S. Environmental Protection Agency, Executive Office of the President, President's Commission on Coal, U.S. Congress' Office of Technology Assessment, and various coal producers.

In 1980, I joined Teknekron, Inc. of Berkeley, California as a senior analyst. I was responsible for performing a number of coal market and transportation studies for both railroads and coal producers. These studies included evaluation of the coal market implications of the merger of the Norfolk & Western and Southern Railways, and a number of market evaluations for potential coal property acquisitions.

After leaving Teknekron in 1981, I formed the Fieldston Company, Inc., and began providing consulting services for energy producers, shippers, utilities, and government agencies. Fieldston participated in numerous studies on matters related to energy markets, plant-siting studies, all forms of transportation, production costs, port studies, and government policy development.

Fieldston also developed a publications business centered on the coal and railroad industries, and environmental compliance. Publications included the Coal Transportation Report, the Fieldston Coal Transportation Manual, Coal Daily, Rail Business, Clean Air Compliance Review, Air Daily, and Intermodal Business.

My personal publications include Coal and Profitability: An Investor's Guide, published by McGraw-Hill, which I co-authored in 1979 with Charles A. Mann. In 1984, I authored the book Coal Transportation and Deregulation: An Impact Analysis of the Staggers Act, a book jointly published by Serif Press and the Energy Bureau. I speak frequently at conferences on coal transportation and supply matters.

In November 1998, I sold Fieldston Company to Hagler Bailly, Inc., a publicly traded, international consulting firm. Hagler Bailly maintained the consulting business of Fieldston and sold the publications business. In July of 2002, I resigned from PA Consulting and continued my consulting activities under Hellerworx, Inc.

I had also co-founded Fieldston Transportation Services Company (FTS) in 1995 providing railcar management, leasing and maintenance services to shippers and short line carriers. In 1998, we sold FTS to Detroit Edison (DTE).

I have worked as a consultant in the energy, environmental, and transportation industries for more than 25 years. Through my professional experience, I have become knowledgeable about fuel markets, fuel contracts, fuel transportation agreements and power markets among other subjects. My clients have included numerous electric utilities, including Progress Energy, energy producers, transportation companies, various government agencies and the Electric Power Research Institute. I have presented testimony on a number of occasions before regulatory commissions, state and federal courts, and arbitration panels in the U.S. and abroad. I have been accepted as an expert in matters related to energy and transportation markets and have offered testimony a number of times.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by Progress Energy Florida, Inc. (PEF) to address the question of what policies and procedures Progress Fuels Corporation (PFC) should follow in soliciting and evaluating bids for waterborne coal transportation services (WCTS).

III. APPROPRIATE POLICIES AND PROCEDURES FOR SOLICITATION AND EVALUATION OF COAL TRANSPORTATION BIDS

Q. WHAT SHOULD BE PFC'S APPROACH TO WCTS CONTRACTING?

A. Mr. Pitcher describes the approach that the company intends to follow in conducting the upcoming solicitations.

The parameters in the RFP will specify PFC's volume, flexibility and service requirements, so the responses should provide sufficient information for PFC to distinguish among the offers. The pricing, service provisions, equipment, staff capabilities, and financial condition of each offer will be evaluated. The solicitation process and evaluation criteria should be comprehensive and transparent so that the results will be viewed as reasonable regardless of the outcome. To this end, my testimony discusses the processes used by others for developing and disseminating RFPs; screening and evaluating bids; and, selecting the successful bidders. Mr. Pitcher describes the specific PFC strategy and processes.

Q. WHAT METHODOLOGY DID YOU FOLLOW IN DETERMINING WHAT CONSTITUTE REASONABLE PROCEDURES FOR SOLICITING AND AWARDING BUSINESS FOR THE WATERBORNE ROUTE?

A. As part of my ongoing work, I have developed, evaluated or analyzed the policies, procedures and RFPs used by other companies to solicit bids for coal transportation services (e.g. rail, transloading, barge and ship). I have also discussed the processes for soliciting and evaluating bids with various coal transportation providers and electric generators, including studies conducted in the coal transportation area for the Electric Power Research Institute (EPRI). Based on this information and experience I have recommended processes for soliciting and evaluating bids for WCTS for PEF.

Q. WHAT DO YOU UNDERSTAND TO BE THE PFC FUEL PROCUREMENT POLICY REGARDING WCTS?

A. PFC is tasked with transporting an adequate supply of fuel that meets all legal and environmental requirements to Crystal River at the lowest cost consistent with PEF's obligation to provide adequate and reliable service to its customers. Mr. Pitcher discusses the review and approval mechanisms that PFC intends to follow in collecting and evaluating bids. These processes allow for sufficient oversight and review by parties outside the fuel department to ensure that bids will be evaluated reasonably and fairly.

Q. WHAT PROCESSES WILL PFC USE TO SECURE WATERBORNE TRANSPORTATION SERVICES?

A. Most companies use formal solicitations and informal bid and negotiation processes to secure the lowest possible transportation costs. In this case, PFC intends to use a formal solicitation process consistent with the recommendations of the FPSC staff. To maximize competition, the bid process will allow vendors to bid on any or all of the parts with no preference for an integrated bid. The process will also allow venders flexibility in the bid options to ensure that PFC can take advantage of

opportunities to minimize delivered fuels prices while maximizing system reliability and flexibility.

IV. PROCEDURES

Q. HOW SHOULD THE COMPANY DETERMINE THE QUANTITIES OF COAL TO BE OFFERED UNDER THE WCTS SOLICITATION?

A. Typically the generating company will forecast its range of unit burn requirements for multiple years. The fuels group will then match current and projected coal and transportation contract commitments to a range of burn requirements, identify the uncommitted tonnage and develop a plan to fuel the units reliably at the lowest delivered coal price.

PFC's dilemma is how to build sufficient flexibility into its transportation agreements so as not to commit to and pay for transportation services it may not use, while at the same time to obtain firm commitments from the transportation vendors to ensure that adequate transportation capacity is available to transport all of the required coal to the units. Solving this dilemma is essentially a risk allocation matter where PFC attempts to develop contracts that provide for sufficient flexibility so that tonnage levels can vary over a wide enough range to meet the potential needs of the units while minimizing the costs to be paid for that flexibility.

PFC operates a complex coal supply transportation network aimed at serving a single plant site. PFC must coordinate rail and water deliveries from multiple US and foreign sources. PFC must also ensure that coals are properly blended, and that inventories are maintained at remote terminals in addition to the plants site. The transportation system involves the coordination of inland river tugs and barges, cross-

Gulf tug-barge sets and oceangoing vessels. The water transportation system, therefore, must be capable of handling substantial volume fluctuations.

Q. SHOULD THE CONTRACT TERM BE THE SAME FOR ALL OF THE SOLICITATIONS?

A. Not necessarily. It may be easier to administer agreements and to handle coordination issues if certain parts of the WCTS have matching terms, but not necessarily all. For example, the rates offered by a particular vendor may fluctuate depending upon the vendor's other commitments, or the need to invest in equipment to fulfill this contract. For one vendor a shorter-term contract might yield rates that are more attractive while another vendor might offer more attractive rates for the same service with a longer term agreement.

Q. HOW SHOULD THE COMPANY DETERMINE THE TERM OF THE SOLICITATION?

A. The term of the solicitation typically balances the desire for short-term flexibility and market responsiveness with the economic benefits that may result from a longer-term commitment. For example, to capture anticipated productivity gains, PFC may seek to use a shorter-term contract or a periodic market re-pricing mechanism rather than simply BLS type indices. However, bidders seeking to support new equipment purchases or acquisitions may be discouraged from bidding unless they can be assured of sufficient cash flow to recoup their capital investment under the initial contract term. Contract terms may vary depending upon the bids received and the competitive conditions in the various markets at the time of the solicitation.

Q. HOW SHOULD PFC IDENTIFY POTENTIAL TRANSPORTATION SUPPLIERS?

A. PFC should select potential inland waterway operators based on available lists of companies that have or could reasonably acquire the dry cargo capability and provide the towboats necessary to perform the service between central Appalachian coal docks and Gulf transfer facilities. The names of and information about these operators are available from existing lists maintained by the company, market intelligence, industry publications (e.g. *Sparks Barge Fleet Profile*), and general industry knowledge.

Because of industry consolidation over the past decade, the top three operators now control over 50% of the dry bulk fleet, and one of these, ACBL, is in bankruptcy. PFC will be able to solicit multiple operators; however, it will have a limited number of creditworthy operators capable of handling this business.

With regard to gulf transfer facilities, three terminals in the New Orleans area and one in Mobile have the potential to load jumbo barges, receive Panamax vessels and provide ground storage. In addition, new facilities are being developed in Tampa that could also provide an opportunity for coal transfer and storage.

In New Orleans, TECO Bulk Terminal and IMT were designed to handle the TECO and PEF businesses respectively. The more recently built IC Marine terminal may have the capability to handle all or part of the traffic. McDuffie Coal Terminals in Mobile also provides the potential for gulf transfer depending upon the coal source. McDuffie is well suited for foreign imports, but not for CAPP coals that move by barge on the Mississippi River. In Tampa, Kinder Morgan is developing a new coal terminal, as is Drummond. PFC must consider the necessity of and location for blending CAPP and foreign coals in selecting dock locations.

What are CAPP coals?

With regard to cross-Gulf shipping services currently, the two largest providers are Dixie Fuels Ltd, and TECO Ocean Shipping. However, other companies provide ocean shipping services and should be included in a solicitation. PFC should also be open to other creative techniques for meeting the PEF waterborne coal need reliably and at minimum cost (e.g. use of multiple operator and facility combinations). However, new firms may have difficulty penetrating the market because of substantial equipment requirements, the advantage that incumbent operators have because of existing backhaul business, and the channel limitation at Crystal River that precludes use of deep draft vessels. The vessel restrictions at Crystal River that result from the channel depth, channel restrictions and unloading constraints are severe.

Q. HOW SHOULD THE COMPANY CONDUCT THE SOLICITATIONS?

A. Mr. Pitcher describes the manner in which PFC will conduct the solicitations and perform the evaluations. He also describes the proposed time schedule. The approach as described should provide for comprehensive coverage of potential bidders, allow ample notification that allows bidders to respond and assemble equipment if necessary, and provide sufficient guidance so that bidders understand the terms and conditions that PFC seeks.

However, in addition to informing vendors about the process, PFC must convince bidders that PFC is genuinely interested in developing the least cost, reliable transportation system without unduly favoring current vendors or affiliates. A key component of developing that credibility is to follow the transparent evaluation process that the Company has proposed.

Q. HOW MUCH TIME SHOULD BE ALLOWED FROM THE TIME THAT THE RFPS ARE SENT UNTIL THE SUBMISSIONS ARE DUE?

A. Typically, the time to respond to an RFP may range from two to eight weeks depending upon the complexity of the request and the prior familiarity of the suppliers with the bid requirements. This bid request should probably allow eight weeks for the cross-Gulf response given the magnitude and complexity of the requirement. Less time should be required by those bidding on the terminal and barge segments because these bid requirements are less unique.

Q. HOW SHOULD PFC EVALUATE THE RESPONSES?

A. PFC should strive to make the bidding and evaluation processes as transparent as practicable. In conformance with FPSC guidelines and its own fuel policies, PFC should clearly present its solicitation process and evaluation criteria. Evaluation criteria should include price package, operational capability, safety record, environmental record, financial stability, reliability, past performance, flexibility, and management integrity. To the extent that evaluation criteria involve quantitative responses, the process may be viewed as more objective; however, some parameters will be inherently difficult to quantify. As a practical matter, PFC may adjust prices and renegotiate terms as part of the final negotiations with the successful bidder or bidders to obtain the best possible deal.

Q. WHAT KEY TERMS AND ELEMENTS WOULD YOU EXPECT TO BE INCLUDED IN THE BARGE AND OCEAN TRANSPORT CONTRACTS?

A. I would expect the following terms to be included:

- Shipper – state guarantor, if any.
- Recitals/Intent – state the intentions of each contracting party and purpose/need for the contract agreement.

- Commodity/Annual Tonnage – state whether tons are fixed and if not, state nature of shipper's commitment, e.g. requirements, and the basis for the estimate of tonnage; also prepare "what ifs" referencing the potential for tonnage changes during each specified period or during the term of the contract. The "dead freight" issue is particularly important. If PFC makes a minimum annual volume commitment and then fails to meet those minimums, it is likely to be assessed a charge for freight it does not ship.
- Services contracted for – state specific jobs define locations and job performance tolerances; possibly identify remedial obligations.
- Area-to Area – state principal origins and destinations; identify any changes that may occur during the contract term and under what permissible circumstances; ensure that additional points can be covered.
- Shipping schedule/Service schedule and frequency – specify tons per month, level shipments, ratability, frequency of regular services, and requirements for special or non-routine activities.
- Operating assumptions – specify barge or equipment type, dedicated/ exclusive use equipment, unit tows, and backhaul involvements.
- Performance obligations – specify for each party to include loading/unloading facilities, personnel responsible, etc. Also, determine ability to use subcontractors.
- Demurrage terms – specify use of credit system or payments for delay, and number of free days allowed.

- Term & Termination conditions - specify extendibility terms and/or renewal options.
- Prices/pricing/rates - specify whether using flat or incentive rates. Pricing should consider the value of using marginal pricing on incremental tonnage after meeting baseload tonnage requirements.
- Price Adjustments – specify permissibility of adjustments under specified conditions, time frequency, notification requirements, approval requirements, and nature of pricing caps if any. If formula or index adjustments are used, specify the basis and if any portion is to be held fixed.
- Payment terms –specify methods allowed (e.g. electronic).
- Cancellation & Default – identify permissible actions and conditions for implementation of default or cancellation.
- Insurance – specify indemnification, requirements and damage responsibility.
- Force Majeure – identify circumstances/causes excusing performance and obligations to mitigate, whether makeup is required, and financial obligations while force majeure exists, including notice requirements, etc.
- Weight Determination/Service performance criteria – state methods for determination and obligations for inadequate performance; consider incentives for excellence.
- Exclusivity – identify supplier's rights including whether this is the sole service provider or carrier; identify non-exclusivity if that is the case.
- Guarantees – state any guarantees for performance of service or tonnage; corporate parent or fiduciary involvement if necessary.

- Indicate any other material or unusual information to be included in the contract.

Q. WHAT KEY TERMS AND ELEMENTS WOULD YOU EXPECT TO BE INCLUDED IN THE TRANSLOADING CONTRACTS?

A. I would expect the following terms to be included:

- Shipper – state guarantor, if any.
- Recitals/Intent – state the intentions of each contracting party and purpose/need for the contract agreement.
- Commodity/Annual Tonnage – state whether tons are fixed and if not, state nature of shipper's commitment, e.g. requirements, and the basis for the estimate of tonnage; also prepare "what ifs" referencing the potential for tonnage changes during each specified period or during the term of the contract.
- Services contracted for – state specific jobs, define locations and job performance tolerances; possibly identify remedial obligations.
- Terminal equipment to be used in this movement – this would include loading and unloading equipment for barges and ships, mobile equipment, reclaim equipment, number of berths and minimum draft.
- Shipping schedule/Service schedule and frequency – specify tons per month, level shipments, ratability, frequency of regular services, and requirements for special or non-routine activities.
- Ground storage – specify availability and possible dedication. Also, specify number of piles and maximum storage allocation for this movement.
- Sampling equipment – specify availability for testing inbound and outbound coals and for monitoring during loading and unloading.

- Fleeting capability - include fleet locations, availability of barge storage space, availability of harbor boats.
- Performance obligations – specify for each party to include loading/unloading facilities, personnel responsible, etc. Also, determine ability to use subcontractors.
- Demurrage terms – specify use of credit system or payments for delay, and number of free days allowed.
- Term & Termination conditions - specify extendibility terms and/or renewal options.
- Prices/pricing/rates - specify whether using flat or incentive rates. Pricing should consider the value of using marginal pricing on incremental tonnage after meeting baseload tonnage requirements.
- Price Adjustments – specify permissibility of adjustments under specified conditions, time frequency, notification requirements, approval requirements, and nature of pricing caps if any. If formula or index adjustments are used, specify the basis and if any portion is to be held fixed.
- Payment terms –specify methods allowed (e.g. electronic).
- Cancellation & Default – identify permissible actions and conditions for implementation of default or cancellation.
- Insurance – specify indemnification, requirements and damage responsibility.
- Force Majeure – identify circumstances/causes excusing performance and obligations to mitigate, whether makeup is required, and financial obligations while force majeure exists, including notice requirements, etc.

- Weight Determination/Service performance criteria – state methods for determination and obligations for inadequate performance; consider incentives for excellence.
- Exclusivity – identify supplier's rights including whether this is the sole service provider or carrier; identify non-exclusivity if that is the case.
- Guarantees – state any guarantees for performance of service or tonnage; corporate parent or fiduciary involvement if necessary.
- Identify any other material or unusual information to be included in the contract.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE PROCESS THAT PFC SHOULD USE IN SOLICITING BIDS?

A. Yes. While I understand that the FPSC would like PEF to switch to market rates as soon as feasible, I think that PFC management should be given discretion over timing to ensure that market conditions are most favorable for PFC at the time of the solicitation. Central Appalachian coal prices are at historically high levels as shown in Exhibit JNH-2. Compliance coal prices spiked in 2001 and then declined though not to the pre-2001 levels. Currently, market prices have again hit historically high levels, and there is considerable difference of opinion about how long prices will remain at current levels. Ocean shipping rates are also at historically high levels as shown in Exhibit JNH-3 and expected to come down only gradually.

The high central Appalachian coal prices are a function of a number of factors including reserve depletion, environmental restrictions that have delayed new mine openings, and high natural gas prices that have increased coal burns. The high ocean freight rates are driven largely by Chinese demand for ocean freight to provide inputs for their rapidly growing steel industry coupled with a lack of new vessel builds.

Changes in market factors can occur suddenly (as shown in the 2001 coal price spike) and PFC management should have discretion to approach the market when they deem it to be most appropriate.

Since it appears that costs to the customer over the duration of the contract may be higher than if the solicitation were conducted under more stable market conditions, FPSC should give PFC management sufficient latitude as to when the solicitation is conducted to achieve the most favorable results.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

EXHIBIT JNH-1

RESUME OF
JAMES N. HELLER

HELLERWORX, INC.
4803 Falstone Avenue
Chevy Chase, Maryland 20815

Current Position

Jamie Heller is the founder and president of Hellerworx, Inc. Hellerworx was developed to provide strategic and economic consulting services to electric generators, energy producers and transportation companies. Mr. Heller is an expert in fuel, energy, environmental and transportation issues. His specialties include fuel market analysis, transportation market analysis, electric utility planning and electric power market analysis, analysis of environmental compliance options, utility fuel procurement, energy property valuation, and litigation support. Mr. Heller has served as an arbitrator, and as an expert witness before various state commissions, federal district and state courts, arbitration panels in the U.S. and overseas, the Surface Transportation Board and the Federal Energy Regulatory Commission. He has made numerous speeches and presentations before various conferences and seminars in the U.S. and abroad. His comments have appeared in various trade publications.

Consulting Specialties

Strategic planning. Estimating fuel production and transportation costs. Fuel price and transportation rate forecasting. Negotiating fuel and transportation agreements. Evaluating alternative Clean Air Act compliance strategies. Siting new energy facilities. Transportation procurement planning. Transportation management studies. Providing litigation and regulatory support. Conducting market assessments and forecasts. Performing reserve acquisition analyses. Evaluating equipment purchases. Energy supply planning.

Prior Professional Experience

- **PA Consulting (October 2000-July 2002). Senior Partner.** As Senior Partner within the PA Management Group worked on launching the Environmental and Resource Analytics practice within PA. The practice provided strategic and analytical services to clients in the electric generation, fuel and transportation markets; performed various studies and modeling activities related to compliance with environmental regulations; and conducted environmental risk assessments. The principal areas of focus were environmental compliance with Clean Air Act standards, providing fuel and environmental analyses in support of electric generating unit asset acquisition and financing activities, and a major effort to support Firestone Tire in its dispute with Ford Motor Company and NHTSA.
- **Hagler Bailly (October 1998-October 2000). Senior Vice President.** Served as head of Hagler Bailly's fuels and environment practice area and an expert in coal, energy, and transportation issues. His activities supported the firms forecasting and analysis of electric power, fuel and transportation markets and various clean air compliance issues. In October 2000, PA Consulting purchased Hagler Bailly.

- **Fieldston Company, Inc. and Fieldston Publications, Inc. (1981-1998). Founder and President.** Founded The Fieldston Companies in 1981 to provide energy and transportation consulting services to the energy supply, transportation and electric utility sectors. The 60+ person staff provided expert assistance to the fuels supply, transportation and electric generation industries in hundreds of commercial matters. The publication staff developed and published leading business periodicals in the coal, rail transportation and environmental fields. A joint venture company, Fieldston Transportation Services, provided rail transportation and railcar maintenance services to various shippers and short line rail carriers. In 1998, Mr. Heller sold the consulting and publishing companies to Hagler Bailly, and the transportation services company to DTE.
- **Teknekron, Inc. of Berkeley, Calif. (1979–1980). Senior Analyst.** Strategic planning, market analyses, rail merger studies, transportation market analysis and rate estimation, plant siting, and public policy development.
- **Energy and Environmental Analysis, Inc. (1975-1979). Director of Management Studies.** Directed coal market and transportation studies for railroads and coal producers. Conducted economic evaluation of air and water regulations. Developed energy efficiency plans. Clients included U.S. Department of Energy, Executive Office of the President, U.S. Presidential Commission on Coal, U.S. Congress Office of Technology Assessment, and various coal producers.
- **Office of Water Quality Planning and Standards (U.S. Environmental Protection Agency) (1972–1975). Section Chief.** Developed and promulgated industrial water pollution control guidelines.

Books

James N. Heller and Charles A. Mann. *Coal and Profitability: An Investor's Guide.* McGraw-Hill, 1979.

James N. Heller. *Coal Transportation and Deregulation: An Impact Analysis of the Staggers Act.* Serif Press and the Energy Bureau, 1984.

Education

Harvard Business School — Master of Business Administration, 1972

Northwestern University — Bachelor of Science, Electrical Engineering, 1970

Honors

Member, Eta Kappa Nu and Tau Beta Pi Engineering Honorary Societies

Exhibit JNH-2

Central Appalachian Coal Prices
NYMEX Coal 1987-2004)

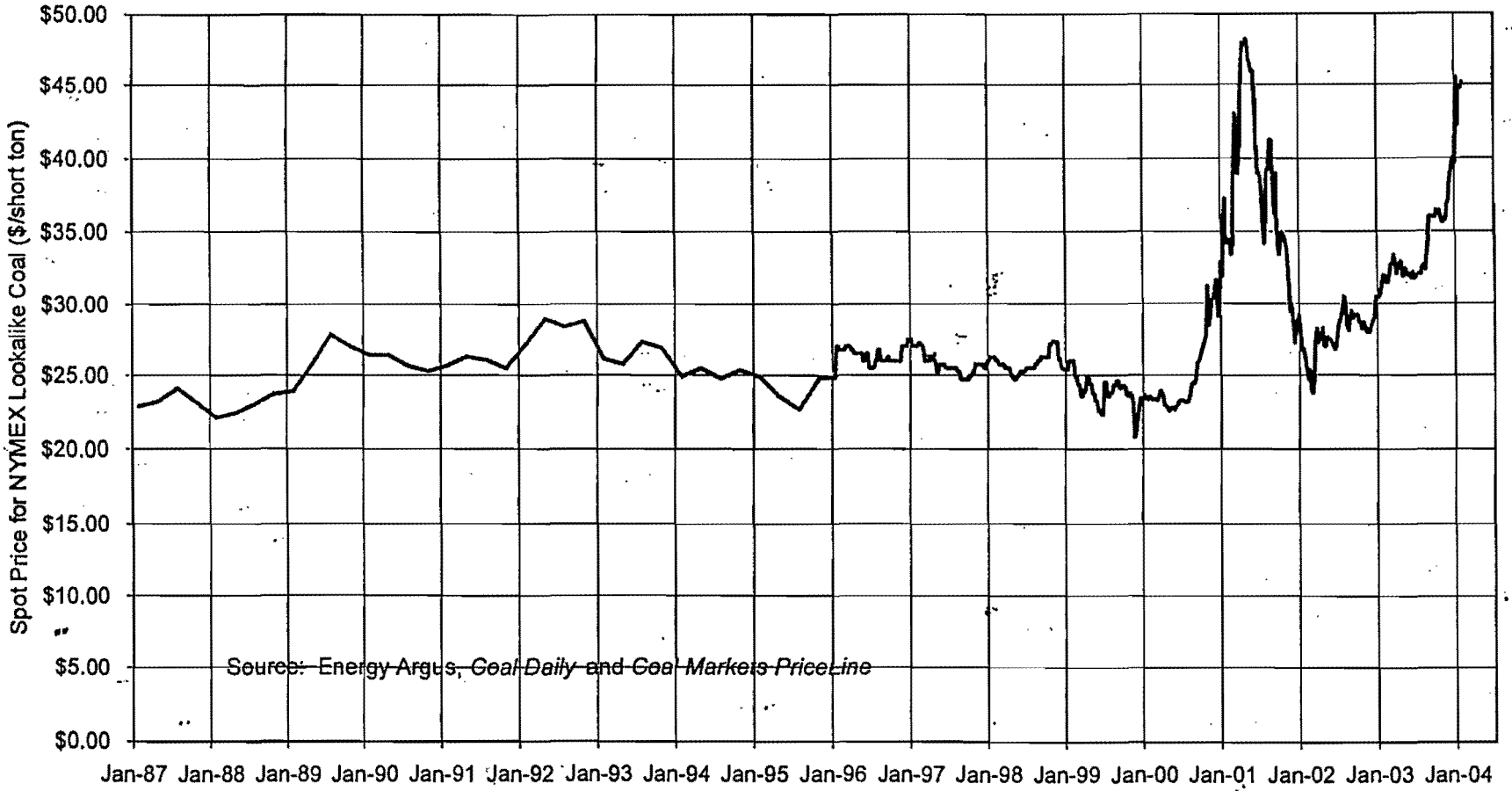
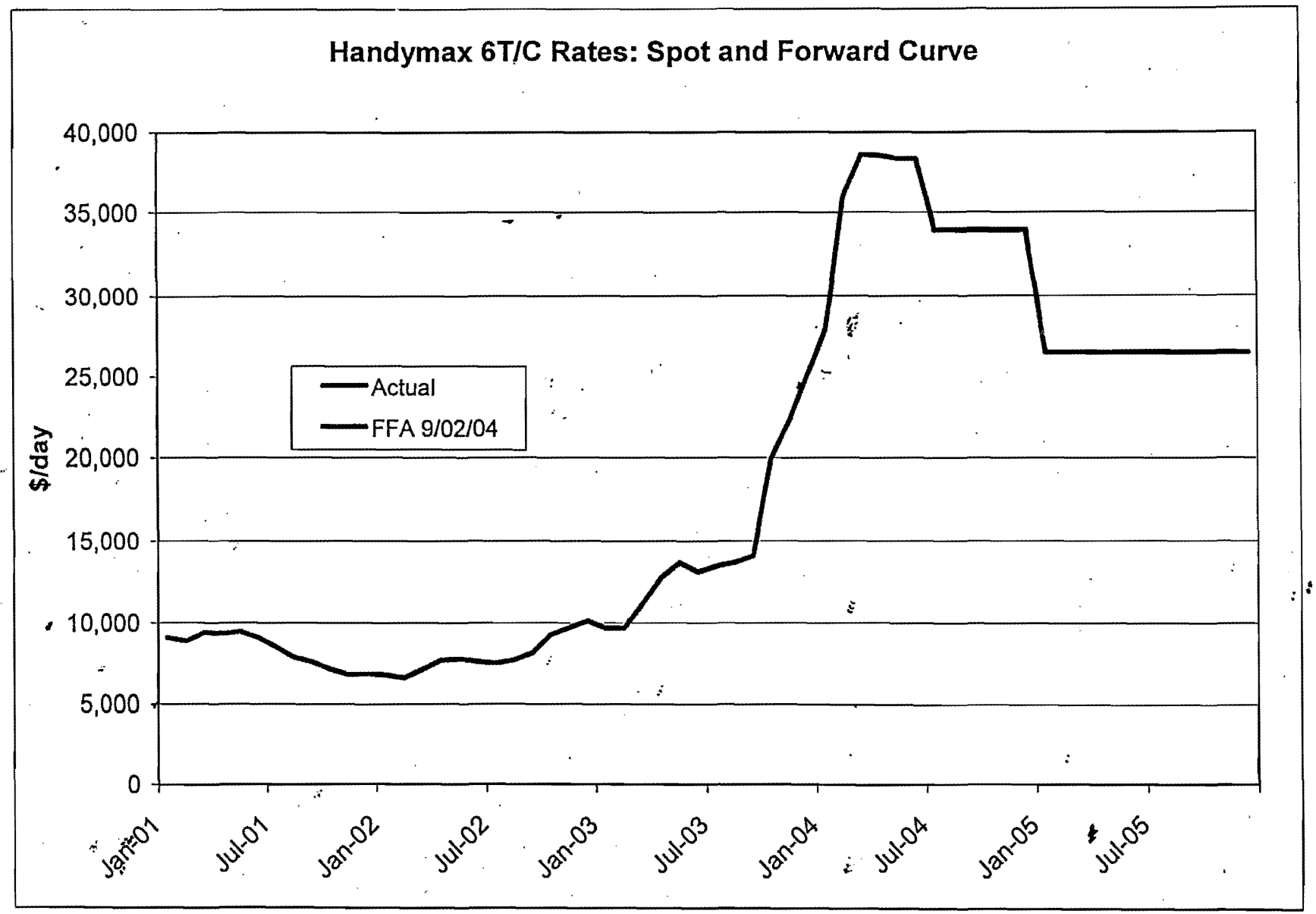


Exhibit JNH-3

Handymax Historical and Forecasted Rates



BID SOLICITATION WB-2004

Solid Fuel Transportation and Terminal Services

GENERAL

The Wholesale Marketing & Fuels Department of Tampa Electric is inviting proposals to provide waterborne transportation services for the movement of solid fuel (defined as coal, synfuel, and petroleum coke) from mid-west supply sources convenient to the Mississippi River and Ohio River systems for final delivery to Tampa Electric's generating stations near Tampa, Florida. Tampa Electric prefers proposals for integrated waterborne transportation services, however proposals for segmented services will be considered. Terminal facilities should be accessible to Mississippi River barge traffic and capable of receiving and discharging inland river barges from domestic suppliers and Panamax sized vessels for offshore coal. Proposals should represent the entire requirements stated herein of Tampa Electric's domestic waterborne solid fuel transportation services. The specifics of this request and the bidding procedures to be followed are outlined below.

QUANTITY AND TERM

Tampa Electric anticipates that the quantity of required inland river, terminal and ocean transportation services will be as listed in the following table:

Contract Years 2004-2006

Transportation Mode	Minimum Annual Quantities Tons	Maximum Tons
Inland River	3,250,000	5,000,000
Terminal	3,250,000	5,000,000
Ocean	4,000,000	5,500,000

Contract Years 2007-2008
(without a Consent Decree Trigger Event)

Transportation Mode	Minimum Annual Quantities Tons	Maximum Tons
Inland River	3,250,000	5,000,000
Terminal	3,250,000	5,000,000
Ocean	4,000,000	5,500,000

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 031033-EI EXHIBIT NO. 111
COMPANY/ FIPUG
WITNESS. RFP TECO (WB-2004)
DATE: 05/22-28/04

Contract Years 2007
(with a Consent Decree Trigger Event)

Transportation Mode	Minimum Annual Quantities Tons	Maximum Tons
Inland River	2,000,000	4,000,000
Terminal	2,000,000	4,000,000,
Ocean	3,000,000	4,500,000

Contract Years 2008
(with a Consent Decree Trigger Event)

Transportation Mode	Minimum Annual Quantities Tons	Maximum Tons
Inland River	1,000,000	3,000,000
Terminal	1,000,000	3,000,000
Ocean	2,000,000	3,500,000

Should Tampa Electric fail, for reasons other than force majeure, to tender solid fuel in any calendar year for the Minimum Annual Quantities, carrier shall be entitled to payment, as liquidated damages and not as a penalty, a dead freight charge for each ton of solid fuel not tendered for such service. Accordingly, please provide a rate for dead freight on Attachments A and B, respectively.

Compliance with Consent Decree. Tampa Electric is required to advise the EPA, on or before May 1, 2005 with respect to Big Bend Unit 4, and on or before May 1, 2007 with respect to Big Bend Units 1, 2 and 3 (or any combination of them), whether each such unit (i) will be shut down, (ii) will be re-powered, (with natural gas as primary fuel) or (iii) will continue to be fired by coal. Tampa Electric shall be entitled in its sole discretion to choose among the compliance options available to it under the Consent Decree. If Tampa Electric chooses compliance option (i) or (ii), (herein defined as "Consent Decree Trigger Event") Tampa Electric may reduce its annual minimum tonnage requirements for 2007 and 2008, respectively by giving notice at any time after tendering the Notice to EPA with respect to such Unit. Such notice shall be effective ninety (90) days after receipt thereof by Carrier, or one hundred eighty (180) days prior to the effective date of any restrictions upon the combustion of coal arising out of the Consent Decree and Tampa Electric's choice of compliance option, whichever occurs later. If Tampa Electric chooses compliance option (iii) above, then the annual tonnage requirements shall remain at the existing tonnage level.

The quantity of Terminal services may include up to 1.0 million tons of international deliveries with the remaining tons coming domestic sources.

Notice of annual tonnage declarations and monthly shipping schedules will be provided by Tampa Electric by September 30 of each contract year for the following calendar year. Tampa Electric shall have the right to make monthly shipment variances of plus or minus 20% throughout the contract year. The term is from January 1, 2004 through December 31, 2008.

PRICING

Pricing for both River and Ocean shipments shall be composed of a fixed component, variable component and a fuel component. Terminal pricing shall be a fixed component only. Proposals should include bidder's preferred escalation methodology. The variable and fuel components shall be subject to quarterly adjustment with 4th quarter 2003 serving as the base period. Payment terms are (30) thirty days net from receipt of proper invoice. Services shall only be billed upon completion of those services as described below:

Inland River	after discharge of coal at the terminal
Terminal/Ocean	after discharge of coal at the generating station

River barge weights shall be based upon origin weights consistent with each coal supply agreement. For terminal services and ocean movements, weights shall be determined on destination weights. Pricing should include a minimum of three (3) free days at loading and three (3) free days at discharge to load and discharge river barges. Ocean vessels will include a minimum of twenty-four (24) hours free time to load or unload vessels at the terminal. Pricing should include a minimum of forty-eight (48) free hours to unload ocean barges at the generating station. Tampa Electric will not be responsible for demurrage at the terminal. Tampa Electric may be responsible for demurrage at the origin and/or the generating station. Such vessel demurrage shall be calculated and paid quarterly on a cumulative credit / debit system. Accordingly, please include all demurrage rates on Attachment B.

CONTRACT PROVISIONS

The winning bidder will be expected to enter into a contract that will, among other things, include the following provisions.

Required River and Ocean Transportation Services

The fixed and variable component charges must represent all charges other than fuel. Such charges shall include, but not be limited to, all port charges, fleeting charges, switching fees, emergency vessel services, existing taxes and any other charges associated with the transportation of solid fuel. Carrier shall bear the risk of cargo loss. Tampa Electric will reserve the right to expedite solid fuel shipments at no additional cost in critically low inventory situations. Carrier shall be required to report shipment information and tonnage reconciliation by fuel type on a daily, weekly and monthly basis.

Carrier shall be responsible for meeting all regulatory requirements e.g., Coast Guard, Responsible Carrier Program, environmental and others.

Required Terminal Transportation Services

The fixed and variable component charges must represent all charges other than fuel. Such charges shall include, but not be limited to, all port charges, fleeting and constructive placement charges, switching fees, emergency vessel services, wharfage services, docking / undocking services, trimming services, launch boat services, maintenance crane services, tractor cleaning services, stockpile storage fees, existing taxes, and any other charges associated with the unloading, loading, storage and transportation of solid fuel. Ground storage facilities will be utilized to provide surge capacity such that Tampa Electric's local inventories can be maintained at acceptable levels. Tampa Electric shall require the Terminal to maintain adequate storage for up to 1.4 million tons and up to 8 individual storage piles. Stockpile maintenance, compaction, and inventory accounting (physical inventories) should be considered routine terminal services, and include prevention and control of spontaneous combustion within stockpiles as part of routine stockpile maintenance. Sampling and weighing services should be provided for both inbound and outbound shipments. Precise blending services of multiple fuel types is required to meet performance and environmental requirements at Tampa Electric's generating stations. Standard application of dust suppressant is required for all outbound shipments and shall be included as part of the fixed terminal charge. The minimum discharge rate for unloading Panamax sized vessels of solid fuel should be 900 tons per hour. The terminal shall bear the risk of cargo loss and any demurrage charges from river and ocean vessels which exceed the free time allowed in the solicitation. Cargoes of segregated multiple fuel types will be required. The terminal shall provide daily inventory and position reports. The terminal shall be responsible for meeting all regulatory requirements e.g., Coast Guard, environmental, and others. Tampa Electric will reserve the right to switch or change the composition of previously scheduled cargoes on short notice in critical situations. Attachment C lists the unloading generating station's capabilities and limitations.

MISCELLANEOUS PROVISIONS

The contract will contain other commercially reasonable terms and conditions customarily found in contracts for similar services, including but not limited to, provisions dealing with standards of performance, risk allocation, insurance levels, force majeure, events of default, remedies, and others.

Tampa Electric will require an electronic interface to upload data into our fuels management system. At a minimum, vessel number, contract number, date loaded, shipped weight, and destination need to be made available at carrier's expense.

BIDDING PROCEDURES

In order to ensure that proposals are responsive to Tampa Electric's needs and provide a uniform basis for evaluation, bidders are requested to provide the information on the attached Transportation Proposal Form, complete rate quotes on Attachments A & B and send Sealed Bid Packages to:

Bid Proposal WB-2004
Street Address
Tampa Electric Company
702 North Franklin Street, Plaza 5
Tampa, Florida 33602

P.O. Box Address
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

Failure to properly mark bid reference number WB-2004 on the exterior of the sealed envelope could result in non-consideration of the bid.

Bid packages must be received at the Wholesale Marketing & Fuels Department no later than 12:00 p.m. (EDST) on August 1, 2003. Bids received after this date will not be evaluated or considered and returned to the bidder. The bidder shall be responsible for the completeness and accuracy of all information contained in and used in preparation of its proposal and for having supplied all necessary information. Bid packages that are incomplete may not be evaluated. Revised proposals, if any, must be received before the closing deadline for evaluation.

Any award will be based on Tampa Electric Company's overall evaluation process and not on price alone. The evaluation will include price, ability to supply sufficient barge, towing and storage capacity, financial stability, credit worthiness and other pertinent factors. Field inspections and audits by Tampa Electric personnel or Tampa Electric's designated representative(s) may be required to verify the accuracy of information provided in proposals. Tampa Electric reserves the right to reject any and all proposals which in Tampa Electric's sole judgment are determined to not be in its best interest.

Bid proposals shall remain open for a period of two months beyond the closing date of this solicitation. Proposals represent a firm offer to supply Transportation and Terminal services at the prices and under the terms provided in your proposal, subject to the execution and delivery of a contract, the first draft of which will be provided by Tampa Electric Company. Should you have questions or desire to schedule a presentation, please call Martin Duff at 813.228.1596.

Waterborne Transportation Proposal Form

Tampa Electric Company
Wholesale Marketing & Fuels

PART 1

Company Name:_____

Mailing Address:_____

_____

_____

_____

Authorized Representative:_____

Phone Number:_____ Fax Number:_____

E-mail Address:_____

Corporate Affiliations (Include parent, subsidiary and affiliated companies):

_____

_____

_____

_____

_____

Facility Locations:

_____

_____

_____

_____

_____

WATERBORNE TRANSPORTATION PROPOSAL FORM (Continued)

RIVER TRANSPORTATION
PART 2

Towing Equipment Description (Include name, age, rated horsepower, towing capability, and other pertinent information):

Barge Fleet Description (Include design, configuration, type, size, style ownership, number of barges and other pertinent information):

Insurance Coverage Description (types of coverage, insureds coverage limits, carrier, policy numbers and expiration dates, etc.):

WATERBORNE TRANSPORTATION PROPOSAL FORM - PART 2 (Continued)

Major Customer Listing (Include company name, tonnage lifted in 2001 and 2002, Contact and Phone number):

Subcontractors (Include company name, contact, phone number, and description of services rendered):

Financial Information (provide last five years of audited financial statements and other relevant information):

TERMINAL FACILITIES
PART 3

Terminal Equipment Description (Include unloading and loading equipment, reclaim equipment, mobile equipment, rated capacities, average performance capabilities and other pertinent information):

Terminal Ground Storage Description (Include schematic or diagram of storage capacity):

Sampling Equipment (Include a description of inbound and outbound capabilities):

WATERBORNE TRANSPORTATION PROPOSAL FORM - Part 3 (Continued)

Weighing Equipment (Include a description of belt scale capabilities inbound and outbound):

Fleeting Equipment (Include a description of harbor boats and other fleeting equipment):

Insurance Coverage Description (types of coverage, insureds coverage limits, carrier, policy numbers and expiration dates, etc.):

WATERBORNE TRANSPORTATION PROPOSAL FORM - Part 3 (Continued)

Major Customer Listing (Including company name, tonnage lifted in 2001 and 2002, Contact and Phone number):

Subcontractors (Include company name, contact, phone number, and description of services rendered):

Financial Information (provide last five years of audited financial statements, bank references and other relevant information):

WATERBORNE TRANSPORTATION PROPOSAL FORM (Continued)

GULF TRANSPORTATION
PART 4

Ship or Ocean Barge Fleet Description (Include design, configuration, type, size, style, cargo capacity and other pertinent information):

Insurance Coverage Description (types of coverage, insureds coverage limits, carrier, policy numbers and expiration dates, etc.):

Major Customer Listing (Including company name, tonnage lifted in 2001 and 2002, Contact and Phone number):

WATERBORNE TRANSPORTATION PROPOSAL FORM - Part 4 (Continued)

Subcontractors (Include company name, contact, phone number, and description of services rendered):

_____

_____

_____

_____

_____

Financial Information (provide last five years of audited financial statements and other relevant information):

_____

_____

_____

_____

_____

Signature:

_____
(Signature of person having proper authority to legally obligate the Transportation Company)

Title:

_____

Date:

_____

Attachment A

RIVER TRANSPORTATION CHARGE

LOCK 53 POOL OHIO RIVER	VARIABLE	FIXED	FUEL	TOTAL
Cook Coal Terminal - MP 948 OH				
Mound City - MP 976 OH				
TENNESSEE RIVER				
BRT - MP 23 TR				
Kentucky Lakes Dock - MP 24 TR				
SMITH LAND POOL OHIO RIVER				
Empire Dock - MP 896 OH				
Rigsby & Barnard - MP 881 OH				
Kanipe Enterprises - MP 872 OH				
Caseyville - MP 872 OH				
Hamilton - MP 852 OH				
UNIONTOWN POOL OHIO RIVER				
Overland Terminal - MP 842 OH				
Mount Vernon - MP 828 OH				
Southern Indiana - MP 794 OH				
GREEN RIVER				
Green Coal - MP 11 GR				
Patriot - MP 32 GR				
Sebree - MP 43 GR				
Pyramid - MP 94 GR				
Ken Mine - MP 98 GR				
NEWBURGH POOL OHIO RIVER				
Yankeetown - MP 773 OH				

Owensboro - MP 750 OH	_____	_____		
New Hope - MP 734 OH	_____	_____	_____	_____
CANNELTON POOL OHIO RIVER				
Jefferson River Port - MP 618 OH	_____	_____	_____	_____
MELDAHL POOL OHIO RIVER				
Transcontinental Terminals - MP 406 OH	_____	_____	_____	_____
UPPER MISSISSIPPI RIVER				
Cora - MP 99 UMR	_____	_____	_____	_____
Kellogg - MP 125 UMR	_____	_____	_____	_____
Cahokia - MP 178 UMR	_____	_____	_____	_____

PROPOSED ESCALATION METHODOLOGY:

VARIABLE

FUEL

DEMURRAGE RATE

TAMPA ELECTRIC COMPANY
DOCKET NO. 031033-EI
FIPUG'S 1st REQUEST FOR POD

Attachment B

TERMINAL CHARGE

TOTAL

OCEAN TRANSPORTATION CHARGE

VARIABLE	FIXED	FUEL	TOTAL

DEMURRAGE RATE:

DEAD FREIGHT RATES:

RIVER TRANSPORTATION SERVICES

TERMINAL SERVICES

OCEAN TRANSPORTATION SERVICES

Attachment C

UNLOADING PORT FACILITIES - CAPABILITIES AND LIMITATIONS

A. Tampa Electric's Big Bend Station on Hillsborough Bay, Tampa, Florida.

1. Draft Limitation: 33 feet.
2. Maximum Vessel Dimensions: 650 feet length; and vessels over 600 feet must be shifted at the dock during unloading. 85 feet beam.
3. Airdraft: Maximum airdraft is 47 feet. Vessel may have to be ballasted during unloading to maintain this maximum.
4. Minimum Hatch Size: 38' width x 50' length; greater size highly desirable.
5. Discharging Equipment: Dravo ladder bucket machine and Traveling Clamshell Crane.
6. Expected Average Unloading Rate: 2000 net tons per hour, excluding delays caused by vertical interference from vessel booms, masts and superstructures.
7. Draft Surveying: If it is necessary to make a draft survey of the delivering vessel in loaded conditions, such survey is to be made while the vessel is standing in deep water before she comes into the dock.

B. EXCEPTIONS: Vessel of slightly different maximum dimensions may be accommodated provided that mutual agreement has been reached between the Seller and Tampa Electric and/or Tampa Electric's unloading contractor prior to loading and also prior to any commitments on the part of the Seller to utilize such vessels.

TOTAL COST FOR 1,000 KILOWATT HOURS - RESIDENTIAL ELECTRIC SERVICE

Effective April 15, 2004 - December 31, 2004

	Florida Power & Light Company	Progress Energy Florida, Inc.	Tampa Electric Company	Gulf Power Company	Florida Public Utilities Co. Marianna	Florida Public Utilities Co. Fernandina Beach
Base Rate	$40.22	$41.18	$51.92	$49.30	$23.73	$23.73
Fuel Cost Recovery	$37.50	$34.58	$39.39	$24.72	$40.56	$29.68
Energy Conservation Cost Recovery	$1.45	$1.74	$1.11	$0.76	$0.54	$0.54
Environmental Cost Recovery	$0.13	$0.61	$1.44	$1.36	N/A	N/A
Capacity Cost Recovery	$6.25	$8.77	$2.67	$1.94	N/A	N/A
Gross Receipts Tax	$0.88	$2.23	$2.48	$2.00	$1.66	$1.38
Total Monthly Bill	**$86.43**	**$89.11**	**$99.01**	**$80.08**	**$66.49**	**$55.33**

A TRUE COPY
ATTEST _____
Chief Bureau of Records

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 031033-EI EXHIBIT NO. 112
COMPANY/ Mike Twomey, Esq.
WITNESS: Residential Competitive Rates
DATE: 05/27-28/04