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ORIGINAL

August 2, 2000

HAND DELIVERED

Mr. Michael S. Haff
Division of Electric & Gas
Florida Public Service Commission
Room 200G – Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

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Dear Michael:

Pursuant to your letters dated June 8, 2000 and June 23, 2000, respectively, we enclose Tampa Electric Company's responses to your requests for supplemental information on the company's generation expansion plans which will be used to supplement Tampa Electric's Company's 2000 Ten-Year Site Plan filed with the Commission on April 3, 2000.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

cc: Joseph D. Jenkins (w/o enc.)

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TAMPA ELECTRIC COMPANY
SUPPLEMENTAL DATA REQUEST
2000 TEN YEAR SITE PLANS

1. Provide all data requested on the attached forms. If any of the requested data is already included in TECO's *Ten-Year Site Plan*, state so on the appropriate form.

A. Data provided on the attached forms.

Existing Generating Unit Operating Performance

(1)	(2)	(3)		(4)		(5)		(6)	
		Planned Outage Factor (POF)		Forced Outage Factor (FOF) *		Equivalent Availability Factor (EAF)		Average Net Operating Heat Rate (ANOHR)	
Plant Name	Unit No.	Historical	Projected	Historical	Projected	Historical	Projected	Historical	Projected
BIG BEND	1	8.20	7.85	16.50	15.76	75.30	76.39	10,254	10,280
BIG BEND	2	5.58	7.20	14.15	14.11	80.30	78.69	10,135	10,172
BIG BEND	3	9.32	7.28	18.12	17.71	72.57	75.01	10,189	10,234
BIG BEND	4	7.71	6.70	11.79	13.06	80.49	80.24	10,123	10,098
BBCT	1	0.66	3.83	9.80	33.66	89.53	62.51	19,196	16,102
BBCT	2	1.76	5.74	2.57	29.13	95.64	65.13	15,329	16,035
BBCT	3	1.30	3.86	14.60	29.71	84.33	66.43	16,117	15,990
GANNON	1	10.87	7.69	15.43	18.28	73.09	74.03	12,054	11,803
GANNON	2	3.93	8.73	15.90	18.71	79.87	72.56	12,855	12,631
GANNON	3	2.89	8.34	12.94	12.83	84.17	78.82	11,923	11,674
GANNON	4	8.85	8.43	19.52	19.41	71.60	72.16	11,823	11,531
GANNON	5	7.61	8.43	22.43	18.50	69.99	73.07	10,678	10,482
GANNON	6	11.51	7.66	20.52	21.61	67.97	70.73	10,604	10,469
GNCT	1	0.00	3.86	2.20	33.65	97.80	62.49	19,736	16,114
HOOKERS PT. **	1	0.65	10.94	11.22	3.56	88.13	85.49	16,201	18,248
HOOKERS PT. **	2	2.54	5.84	1.06	6.50	96.40	87.67	16,201	16,950
HOOKERS PT. **	3	0.23	5.75	9.43	6.50	90.33	87.75	16,201	18,281
HOOKERS PT. **	4	5.33	5.75	24.51	6.50	70.17	87.75	16,201	17,547
HOOKERS PT. **	5	7.80	5.75	27.14	15.08	64.93	79.17	16,201	18,380
PHILLIPS	1	18.35	0.96	6.45	15.85	75.20	100.00	9,427	9,338
PHILLIPS	2	18.35	1.72	6.45	15.72	75.20	100.00	9,370	9,338
POLK	1	10.02	4.00	12.31	9.98	77.67	86.02	10,506	10,572

NOTE: Historical - average of past three years
Projected - average of next ten years
* Includes full and maintenance outages as well as unplanned unit derations.
** Hookers Point Station is assumed to be retired in January of 2003 for purposes of the study.

Nominal, Delivered Residual Oil Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				Residual Oil (By Sulfur Content)					
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
2000	NOTE: TAMPA ELECTRIC'S OIL FIRED UNITS DO NOT			16.74	264.78		**18.81**	297.60	
2001	BURN RESIDUAL OIL LESS THAN 0.7% SULFUR CONTENT.			17.52	277.12	4.7	**19.60**	310.01	4.2
2002				18.16	287.26	3.7	**20.27**	320.71	3.5
2003				18.64	294.87	2.6	**20.75**	328.20	2.3
2004				19.17	303.31	2.9	**21.23**	335.87	2.3
2005				19.77	312.71	3.1	**21.78**	344.50	2.6
2006				20.39	322.53	3.1	**22.35**	353.54	2.6
2007				21.03	332.64	3.1	**22.94**	362.88	2.6
2008				21.69	343.07	3.1	**23.55**	372.50	2.7
2009				22.36	353.81	3.1	**24.17**	382.43	2.7

NOTE: 2000-2009 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE.

Nominal, Delivered Residual Oil Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				Residual Oil (By Sulfur Content)					
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
Forecast:									
2000	NOTE: TAMPA ELECTRIC'S OIL FIRED UNITS DO NOT			18.30	289.55		19.36	306.27	
2001	BURN RESIDUAL OIL LESS THAN 0.7% SULFUR CONTENT.			19.18	303.44	4.8	20.21	319.68	4.4
2002				19.91	314.91	3.8	20.94	331.32	3.6
2003				20.46	323.61	2.8	21.47	339.68	2.5
2004				21.06	333.24	3.0	22.01	348.25	2.5
2005				21.74	343.95	3.2	22.62	357.85	2.8
2006				22.45	355.14	3.3	23.26	367.93	2.8
2007				23.18	366.69	3.3	23.92	378.36	2.8
2008				23.93	378.60	3.2	24.60	389.13	2.8
2009				24.71	390.88	3.2	25.30	400.26	2.9

NOTE: 2000-2009 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE.

Nominal, Delivered Residual Oil Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				Residual Oil (By Sulfur Content)					
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
Forecast:									
2000	NOTE: TAMPA ELECTRIC'S OIL FIRED UNITS DO NOT			15.86	250.92		**16.82**	266.12	
2001	BURN RESIDUAL OIL LESS THAN 0.7% SULFUR CONTENT.			16.42	259.79	3.5	**17.46**	276.29	3.8
2002				16.84	266.37	2.5	**18.02**	285.07	3.2
2003				17.30	273.69	2.7	**18.40**	291.02	2.1
2004				17.82	281.85	3.0	**18.78**	297.08	2.1
2005				18.35	290.37	3.0	**19.21**	303.95	2.3
2006				18.91	299.15	3.0	**19.67**	311.14	2.4
2007				19.47	307.95	2.9	**20.13**	318.54	2.4
2008				20.04	317.01	2.9	**20.62**	326.17	2.4
2009				20.63	326.33	2.9	**21.11**	334.01	2.4

NOTE: 2000-2009 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil			Natural Gas	
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	c/Therm	Escalation %
Forecast:						
2000	24.21	420.69		275.98	27.60	
2001	25.36	440.65	4.7	285.17	28.52	3.3
2002	26.40	458.74	4.1	291.01	29.10	2.0
2003	27.12	471.40	2.8	299.35	29.94	2.9
2004	27.95	485.82	3.1	305.83	30.58	2.2
2005	28.81	500.71	3.1	314.50	31.45	2.8
2006	29.70	516.08	3.1	324.12	32.41	3.1
2007	30.61	531.94	3.1	334.65	33.47	3.2
2008	31.55	548.30	3.1	345.86	34.59	3.3
2009	32.52	565.19	3.1	357.32	35.73	3.3

NOTE: 2000-2009 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE.

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	c/Therm	Escalation %
Forecast:						
2000	26.32	457.45		300.63	30.06	
2001	27.63	480.24	5.0	310.98	31.10	3.4
2002	28.83	501.03	4.3	317.69	31.77	2.2
2003	29.69	515.98	3.0	327.17	32.72	3.0
2004	30.66	532.92	3.3	334.65	33.47	2.3
2005	31.67	550.45	3.3	344.56	34.46	3.0
2006	32.72	568.58	3.3	355.54	35.55	3.2
2007	33.79	587.32	3.3	367.56	36.76	3.4
2008	34.91	606.71	3.3	380.36	38.04	3.5
2009	36.06	626.75	3.3	393.46	39.35	3.4

NOTE: 2000-2009 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil			Natural Gas	
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	c/Therm	Escalation %
Forecast:						
2000	22.10	384.08		255.64	25.56	
2001	23.10	401.39	4.5	261.85	26.19	2.4
2002	23.99	416.96	3.9	266.79	26.68	1.9
2003	24.60	427.53	2.5	273.79	27.38	2.6
2004	25.30	439.65	2.8	279.76	27.98	2.2
2005	26.02	452.14	2.8	289.84	28.98	3.6
2006	26.76	464.99	2.8	298.33	29.83	2.9
2007	27.52	478.24	2.8	307.64	30.76	3.1
2008	28.30	491.88	2.9	317.55	31.76	3.2
2009	29.11	505.93	2.9	327.66	32.77	3.2

NOTE: 2000-2009 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE.

Nominal, Delivered Coal Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
Forecast:												
2000	32.61	185.29			41.96	174.83			37.56	164.75		
2001	33.19	188.60	1.8	100	42.62	177.58	1.6	100	38.11	167.17	1.5	100
2002	33.80	192.07	1.8	100	43.29	180.36	1.6	100	38.68	169.65	1.5	100
2003	34.43	195.60	1.8	100	43.97	183.19	1.6	100	39.25	172.13	1.5	100
2004	35.05	199.14	1.8	100	44.68	186.16	1.6	100	39.84	174.75	1.5	100
2005	35.69	202.77	1.8	100	45.34	188.93	1.5	100	40.45	177.42	1.5	100
2006	36.34	206.50	1.8	100	46.02	191.75	1.5	100	41.07	180.13	1.5	100
2007	37.02	210.32	1.8	100	46.71	194.62	1.5	100	41.70	182.90	1.5	100
2008	37.71	214.25	1.9	100	47.41	197.53	1.5	100	42.34	185.71	1.5	100
2009	38.38	218.07	1.8	100	48.12	200.50	1.5	100	42.99	188.57	1.5	100

NOTE: 2000-2009 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE.

Nominal, Delivered Coal Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
Forecast:												
2000												
2001												
2002												
2003												
2004												
2005												
2006												
2007												
2008												
2009												

NOTE: TAMPA ELECTRIC DOES NOT FORECAST HIGH COAL PRICES.

Nominal, Delivered Coal Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
Forecast:												
2000												
2001												
2002												
2003												
2004												
2005												
2006												
2007												
2008												
2009												

NOTE: TAMPA ELECTRIC DOES NOT FORECAST LOW COAL PRICES.

Nominal, Delivered Nuclear Fuel and Firm Purchases

(1)	(2)	(3)	(4)	(5)
	Nuclear		Firm Purchases	
Year	c/MBTU	Escalation %	$/MWh	Escalation %
Forecast:				
2000			25.31	
2001			27.95	10.4
2002			27.75	-0.7
2003			27.98	0.8
2004			30.35	8.5
2005			32.88	8.3
2006			30.98	-5.8
2007			32.68	5.5
2008			34.04	4.2
2009			35.93	5.6

NOTE: TAMPA ELECTRIC COMPANY HAS NEVER SERVED ITS LOAD FROM OWNED OR PURCHASED NUCLEAR POWER, AND TAMPA ELECTRIC'S CURRENT EXPANSION PLAN DOES NOT PROJECT A NUCLEAR GENERATING FACILITY.

NOTES: FIRM PURCHASE COSTS INCLUDE FUEL AND VARIABLE O&M COSTS ONLY.

Financial Assumptions
Base Case

AFUDC Rate		7.79	%
Capitalization Ratios:			
	Debt	41.30	%
	Preferred	0.00	%
	Equity	58.70	%
Rate of Return:			
	Debt	8.00	%
	Preferred	0.00	%
	Equity	12.75	%
Income Tax Rate:			
	State	35.00	%
	Federal	5.50	%
	Effective	38.58	%
Other Tax Rate:		3.00	%
Discount Rate:		9.51	%
Tax Depreciation Rate:		MACRS	%

Financial Escalation Assumptions

(1)	(2)	(3)	(4)	(5)
Year	General Inflation %	Plant Construction Cost %	Fixed O&M Cost %	Variable O&M Cost %
2000	2.00	2.00	2.10	2.10
2001	2.20	2.20	2.30	2.30
2002	2.20	2.20	2.30	2.30
2003	2.20	2.20	2.30	2.30
2004	2.20	2.20	2.30	2.30
2005	2.20	2.20	2.30	2.30
2006	2.20	2.20	2.30	2.30
2007	2.20	2.20	2.30	2.30
2008	2.20	2.20	2.30	2.30
2009	2.20	2.20	2.30	2.30

Loss of Load Probability, Reserve Margin,
and Expected Unserved Energy
Base Case Load Forecast
(Base Case Expansion Plan)

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Annual Isolated			Annual Assisted		
Year	EUE/NEL* %	Reserve Margin % (Including Firm Purch.)	Expected Unserved Energy (GWh)	EUE/NEL* %	Reserve Margin* * (%)	Expected Unserved Energy (GWh)
2000	0.46%	19%	91.7	0%	19%	0
2001	0.23%	17%	45.0	0%	17%	0
2002	0.18%	19%	34.8	0%	19%	0
2003	0.16%	18%	32.1	0%	18%	0
2004	0.15%	25%	29.8	0%	25%	0
2005	0.17%	27%	34.1	0%	27%	0
2006	0.14%	28%	28.6	0%	28%	0
2007	0.21%	26%	44.2	0%	26%	0
2008	0.13%	28%	28.1	0%	28%	0
2009	0.10%	29%	21.8	0%	29%	0

* Tampa Electric Company's planning criteria is 1% EUE to NEL and 15% winter reserve margin. In January, 2003 the Company's reserve margin criteria will increase to 20% with a supplyside reserve margin of 7%.

* * Tampa Electric Company's annual isolated values include firm purchases.

2. Illustrate what TECO's generation expansion plan would be as a result of each of the demand and fuel price forecast sensitivities discussed in TECO's Ten-Year Site Plan. Include the cumulative present worth revenue requirements of each sensitivity.

A. Tampa Electric Company's ("Tampa Electric") generating expansion plan did not vary with the fuel price forecast sensitivities discussed in Tampa Electric 's Ten-Year Site Plan. Detailed expansion plan impacts were not completed for the high and low demand sensitivities mentioned in the Ten-Year Site Plan. The cumulative present worth revenue requirements for each fuel sensitivity are listed on the following table.

YEAR	GENERATING EXPANSION PLANS							
	ENVIRONMENTALLY ADJUSTED ALTERNATIVE		GANNON REPOWERING ALTERNATIVE		GANNON NON-REPOWERING REPLACEMENT ALTERNATIVE		PURCHASED POWER ALTERNATIVE	
	PLAN	CPWRR ($000)	PLAN	CPWRR ($000)	PLAN	CPWRR ($000)	PLAN	CPWRR ($000)
2000	HPS CT2B Polk CT (Oct)	392,341	HPS CT2B Polk CT (Oct)	393,941	HPS CT2B Polk CT (Oct)	392,724	HPS CT2B Polk CT (Oct)	398,438
2001	----	767,046	----	770,767	----	763,743	----	784,920
2002	Polk CT (May)	1,124,074	Polk CT (May)	1,130,371	Polk CT (May)	1,125,107	Polk CT (May)	1,160,062
2003	Polk CT (May)	1,473,581	Repower 5 (May) LTRS Gannon 1 & 2	1,493,275	Gannon "F" CC Polk CT LTRS Gannon 1, 2, & 5	1,501,203	Firm purchase to replace Gannon Repowering Alternative	1,546,899
2004	Polk CT (May)	1,820,852	Repower 3 & 4 (May) LTRS Gannon 6	1,870,730	2 ea - Gannon "F" CC LTRS Gannon 3, 4, & 6	1,893,521	Firm purchase to replace Gannon Repowering Alternative	1,952,798
2005	Polk CT (May)	2,219,573	Polk CT	2,223,928	----	2,258,072	Polk CT	2,336,680
2006	----	2,605,349	Polk CT	2,571,670	Polk CT	2,615,812	Polk CT	2,712,434
2007	Future Site CT	2,982,969		2,907,191	Future Site "G" CC	2,952,357		3,073,637
2008	Future Site CT	3,350,624	Polk CT	3,236,616		3,306,707	Polk CT	3,427,145
2009	Future Site CT	3,713,347	Future Site CT	3,562,473		3,646,306	Future Site CT	3,775,900
2010-2018		2,583,408		2,389,496		2,386,200		2,538,545

Notes:

Environmentally Adjusted Alternative: This alternative has an all combustion turbine (CT) expansion plan and assumes installation of environmental equipment to meet the more stringent interpretations of the New Source Review (NSR) standards proposed by the Environmental Protection Agency (EPA). The environmental equipment includes the addition of flue gas desulfurization (FGD) and selective catalytic reduction (SCR) systems on all of the Gannon coal units

Gannon Repowering Alternative: This alternative meets the more stringent interpretations of the NSR standards proposed by the EPA and the requirements of the Consent Final Judgement (CFJ) by repowering Gannon Units 3; 4 with natural gas-fired technology by the end of 2004. This alternative includes installation of SCR systems for all of the CTs used in the repowering. In addition, NOx control technology is installed on the Big Ben coal units beginning in 2007 with completion by the end of 2010.

Gannon Non-Repower Replacement Alternative. This alternative meets the more stringent interpretations of the NSR standards proposed by the EPA by retiring the existing Gannon coal assets by 2004 and replacing the retired generation with on-site combined cycle technology. The replacement units were all equipped with SCRs. In addition, NOx control technology is installed on the Big Bend coal units beginning in 2007 with completion by the end of 2010.

Purchased Power Alternative: This alternative meets the more stringent interpretations of the NSR standards proposed by the EPA by retiring the existing Gannon coal assets by 2004 and purchasing capacity and energy to meet system demand and energy requirements. In addition, NOx control technology is installed on the Big Ben coal units beginning in 2007 with completion by the end of 2010.

3. Provide a table of annual and cumulative present worth revenue requirements for all combinations of units that were evaluated in order to arrive at Tampa Electric's base case generation expansion plan. Include the type and timing of the unit or units that comprise each alternative, and the effect of these units additions on FPC's reliability criteria.

A. The expansion plans, annual and cumulative present worth revenue requirements for all scenarios used to arrive at Tampa Electric's base case generation plan are shown on the following tables.

YEAR	GENERATING EXPANSION PLANS HIGH TRANSPORTATION							
	ENVIRONMENTALLY ADJUSTED ALTERNATIVE		GANNON REPOWERING ALTERNATIVE		GANNON NON-REPOWERING REPLACEMENT ALTERNATIVE		PURCHASED POWER ALTERNATIVE	
	PLAN	CPWRR ($000)	PLAN	CPWRR ($000)	PLAN	CPWRR ($000)	PLAN	CPWRR ($000)
2000	HPS CT2B Polk CT (Oct)	392,341	HPS CT2B Polk CT (Oct)	393,941	HPS CT2B Polk CT (Oct)	392,724	HPS CT2B Polk CT (Oct)	398,438
2001	----	767,046	----	770,767	----	763,743	----	784,920
2002	Polk CT (May)	1,124,197	Polk CT (May)	1,130,493	Polk CT (May)	1,125,229	Polk CT (May)	1,160,184
2003	Polk CT (May)	1,474,086	Repower 5 (May) LTRS Gannon 1 & 2	1,495,647	Gannon "F" CC Polk CT LTRS Gannon 1, 2, & 5	1,503,575	Firm purchase to replace Gannon Repowering Alternative	1,552,078
2004	Polk CT (May)	1,821,882	Repower 3 & 4 (May) LTRS Gannon 6	1,877,953	2 ea - Gannon "F" CC LTRS Gannon 3, 4, & 6	1,900,744	Firm purchase to replace Gannon Repowering Alternative	1,964,173
2005	Polk CT (May)	2,221,241	Polk CT	2,236,471	----	2,270,615	Polk CT	2,354,203
2006	----	2,607,747	Polk CT	2,589,075	Polk CT	2,633,217	Polk CT	2,735,776
2007	Future Site CT	2,986,168		2,929,040	Future Site "G" CC	2,976,428		3,102,424
2008	Future Site CT	3,354,677	Polk CT	3,262,527		3,336,870	Polk CT	3,461,010
2009	Future Site CT	3,718,291	Future Site CT	3,592,096		3,682,039	Future Site CT	3,814,563
2010-2018		2,590,416		2,411,387		2,419,037		2,570,984

Environmentally Adjusted Alternative This alternative has an all combustion turbine (CT) expansion plan and assumes installation of environmental equipment to meet the more stringent interpretations of the New Source Review (NSR) standards proposed by the Environmental Protection Agency (EPA). The environmental equipment includes the addition of flue gas desulfurization (FGD) and selective catalytic reduction (SCR) systems on all of the Gannon coal units

Gannon Repowering Alternative: This alternative meets the more stringent interpretations of the NSR standards proposed by the EPA and the requirements of the Consent Final Judgement (CFJ) by repowering Gannon Units 3; 4 with natural gas-fired technology by the end of 2004. This alternative includes installation of SCR systems for all of the CTs used in the repowering. In addition, NOx control technology is installed on the Big Ben coal units beginning in 2007 with completion by the end of 2010.

Gannon Non-Repower Replacement Alternative: This alternative meets the more stringent interpretations of the NSR standards proposed by the EPA by retiring the existing Gannon coal assets by 2004 and replacing the retired generation with on-site combined cycle technology. The replacement units were all equipped with SCRs. In addition, NOx control technology is installed on the Big Bend coal units beginning in 2007 with completion by the end of 2010.

Purchased Power Alternative: This alternative meets the more stringent interpretations of the NSR standards proposed by the EPA by retiring the existing Gannon coal assets by 2004 and purchasing capacity and energy to meet system demand and energy requirements In addition, NOx control technology is installed on the Big Ben coal units beginning in 2007 with completion by the end of 2010.

YEAR	GENERATING EXPANSION PLANS HIGH GAS							
	ENVIRONMENTALLY ADJUSTED ALTERNATIVE		GANNON REPOWERING ALTERNATIVE		GANNON NON-REPOWERING REPLACEMENT ALTERNATIVE		PURCHASED POWER ALTERNATIVE	
	PLAN	CPWRR ($000)	PLAN	CPWRR ($000)	PLAN	CPWRR ($000)	PLAN	CPWRR ($000)
2000	HPS CT2B Polk CT (Oct)	392,370	HPS CT2B Polk CT (Oct)	393,970	HPS CT2B Polk CT (Oct)	392,754	HPS CT2B Polk CT (Oct)	398,467
2001	----	767,257	----	770,977	----	763,954	----	785,130
2002	Polk CT (May)	1,124,721	Polk CT (May)	1,131,018	Polk CT (May)	1,125,754	Polk CT (May)	1,160,709
2003	Polk CT (May)	1,474,678	Repower 5 (May) LTRS Gannon 1 & 2	1,496,626	Gannon "F" CC Polk CT LTRS Gannon 1, 2, & 5	1,503,122	Firm purchase to replace Gannon Repowering Alternative	1,551,019
2004	Polk CT (May)	1,822,860	Repower 3 & 4 (May) LTRS Gannon 6	1,879,389	2 ea - Gannon "F" CC LTRS Gannon 3, 4, & 6	1,901,733	Firm purchase to replace Gannon Repowering Alternative	1,959,692
2005	Polk CT (May)	2,222,952	Polk CT	2,240,424	----	2,273,993	Polk CT	2,350,637
2006	----	2,610,215	Polk CT	2,596,426	Polk CT	2,639,879	Polk CT	2,734,185
2007	Future Site CT	2,989,586		2,940,332	Future Site "G" CC	2,983,968		3,103,646
2008	Future Site CT	3,359,305	Polk CT	3,278,217		3,345,854	Polk CT	3,465,546
2009	Future Site CT	3,724,349	Future Site CT	3,612,708		3,693,170	Future Site CT	3,822,877
2010-2018		2,973,714		2,471,046		2,461,489		2,619,483

Notes:

Environmentally Adjusted Alternative: This alternative has an all combustion turbine (CT) expansion plan and assumes installation of environmental equipment to meet the more stringent interpretations of the New Source Review (NSR) standards proposed by the Environmental Protection Agency (EPA). The environmental equipment includes the addition of flue gas desulfurization (FGD) and selective catalytic reduction (SCR) systems on all of the Gannon coal units.

Gannon Repowering Alternative: This alternative meets the more stringent interpretations of the NSR standards proposed by the EPA and the requirements of the Consent Final Judgement (CFJ) by repowering Gannon Units 3; 4 with natural gas-fired technology by the end of 2004. This alternative includes installation of SCR systems for all of the CTs used in the repowering. In addition, NOx control technology is installed on the Big Ben coal units beginning in 2007 with completion by the end of 2010.

Gannon Non-Repower Replacement Alternative: This alternative meets the more stringent interpretations of the NSR standards proposed by the EPA by retiring the existing Gannon coal assets by 2004 and replacing the retired generation with on-site combined cycle technology. The replacement units were all equipped with SCRs. In addition, NOx control technology is installed on the Big Bend coal units beginning in 2007 with completion by the end of 2010.

Purchased Power Alternative: This alternative meets the more stringent interpretations of the NSR standards proposed by the EPA by retiring the existing Gannon coal assets by 2004 and purchasing capacity and energy to meet system demand and energy requirements. In addition, NOx control technology is installed on the Big Ben coal units beginning in 2007 with completion by the end of 2010.

4. Identify and discuss any firm power purchases that TECO expects to make from other utilities over the planning horizon. If an unidentified or unconfirmed future, power purchase is part of TECO's generation expansion plan, explain the nature of that purchase.

A. Tampa Electric has a long term purchase power contract for capacity and associated energy from the Hardee Power Station with Hardee Power Partners Limited (a TECO Power Services Corporation). The contract involves a shared-capacity agreement with Seminole Electric Cooperative (SEC), whereby Tampa Electric plans for the full net capability of this capacity during those times when SEC plans for the full availability of Seminole Units 1 and 2 and its entitlement of Crystal River 3. The contracted capacity has a summer rating of 296 MW's and a winter rating of 359 MW's. The contract began in January 1993 and expires in 2012.

Tampa Electric has an additional long-term purchase power contract with Hardee Power Partners Limited to purchase 100% of the output associated with a stand alone combustion turbine. The unit has a summer rating of 72 MW's and a winter rating of 90 MW's. The contract began in May 2000 and expires in 2012.

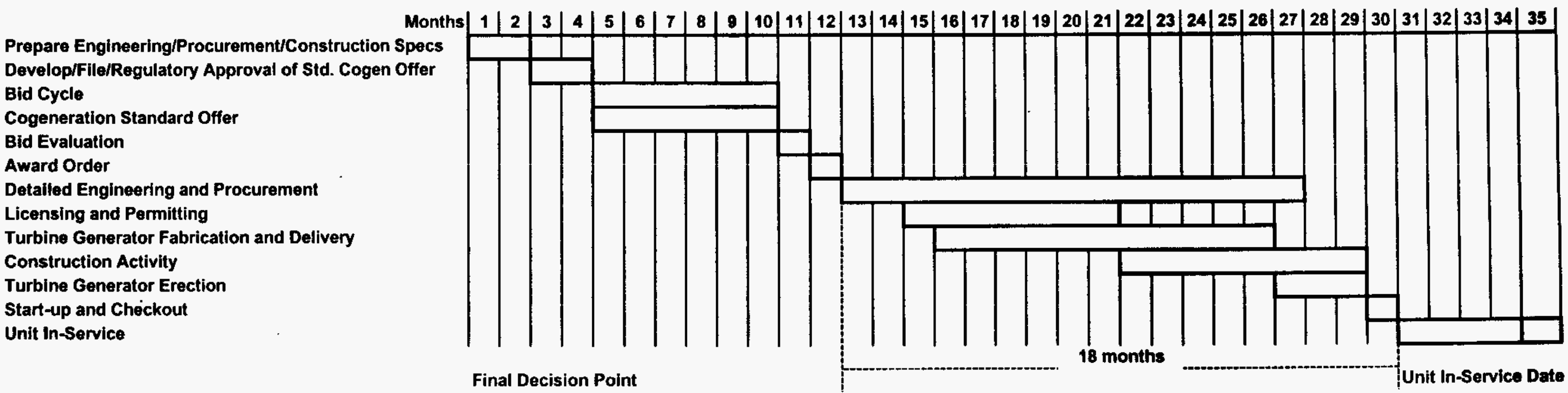
In summer 2000, firm imports from APP = 7 MW's, Farmland = 4 MW's and Okeelanta = 55 MW's are included. Winter 2000 includes firm imports from APP = 15 MW's, Okeelanta = 50 MW's, Reliant = 26 MW, and TEA = 100 MW's. There are no other unidentified future power purchases in Tampa Electric's Ten-Year Site Plan.

In addition to the above purchases, Tampa Electric also has service agreements for the interchange of as-available power with other entities.

5. For each of the generating units contained in TECO's Ten-Year Site Plan, discuss the "drop dead" date for a decision on weather or not to construct each unit. Provide a time line for the construction of each unit, including regulatory approval, final decision point, and vendor order.

A. Tampa Electric estimates a final decision point for procuring and constructing a combustion turbine (CT) unit to be approximately 30 months from the start of contract negotiations. Potential vendors provide Tampa Electric with engineering, construction, and procurement data. The attached timeline shows the typical time frame in which the final decision point, vendor order, and construction occur. Tampa Electric assumes that regulatory approval is not a requirement for the construction of a CT unit and it is not included as an item in the timeline.

Preliminary CT Schedule



6. Identify and discuss all proposed or reasonably expected State and Federal environmental regulations or legislation that impacted TECO's generation expansion plan.

A. To meet Tampa Electric's expected system demand and energy requirements over the next ten years, combustion turbines are planned for service in 2000, 2002, 2005 2006, 2008 and 2009. In addition, Tampa Electric is required to repower Gannon Station from coal to natural gas using combustion turbines in a combined cycle mode in 2003 and 2004. Tampa Electric entered into two separate agreements with the Florida Department of Environmental Protection ("DEP") and the U.S. Environmental Protection Agency ("EPA") which require the elimination of coal-fired combustion and the repowering of two units at Gannon Station. EPA has specified that at least 200 MW of coal-fired generating capacity is to be repowered by May 1, 2003 and that additional coal-fired capacity, which when combined with the initial repowering equals at least 550 MW of capacity, is required to occur by May 1, 2004. The remainder of the coal-fired generation at Gannon is to cease after May 1, 2004 and will be placed in long-term reserve shutdown.

The agreement between EPA and Tampa Electric require Tampa Electric to decide whether to continue to combust coal at more stringent emission limitations at Big Bend or to shut down or repower the Big Bend units. Tampa Electric shall inform the EPA whether it shall continue to fire Big Bend Unit 4 with coal on or before June 1, 2005 and by June 1, 2007 for Big Bend Units 1, 2 and/or 3. New environmental limitations must be met by May 1, 2007 for Big Bend Unit 4 and for the remaining units, increased environmental emission limits are to be met on a phased-in basis beginning May 1, 2007 and completed by May 2010. At this time, Tampa Electric plans to continue to operate its coal-fired generation at Big Bend and anticipates no further change to the expansion plan due to environmental requirements.

7. Provide, on a system-wide basis, historical annual heating degree day (HDD) data for the period 1990-1999 and forecasted annual HDD data for the period 2000-2009.

A. Heating Degree Data

1990	208
1991	389
1992	515
1993	538
1994	358
1995	648
1996	694
1997	369
1998	358
1999	366
2000	869
2001	869
2002	869
2003	869
2004	869
2005	869
2006	869
2007	869
2008	869
2009	869

8. Provide, on a system-wide basis, historical annual cooling degree day (CDD) data for the period 1990-1999 and forecasted annual CDD data for the period 2000-2009.

A. Cooling Degree Data

1990	4077
1991	3895
1992	3323
1993	3403
1994	3793
1995	3688
1996	3484
1997	3748
1998	4043
1999	3682
2000	3027
2001	3027
2002	3027
2003	3027
2004	3027
2005	3027
2006	3027
2007	3027
2008	3027
2009	3027

9. Provide, on a system-wide basis, the historical annual average real retail price of electricity in TECO's service territory for the period 1990-1999. Also, provide the forecasted annual average real retail price of electricity in TECO's service territory for the period 2000-2009. Indicate the type of price deflator used to calculate the historical prices and forecasted real retail prices.

A. Real system-wide average retail $/MWh price of electricity. (CPI-U 82-84=100)

1990	$50.12
1991	$49.46
1992	$48.43
1993	$48.46
1994	$48.97
1995	$46.24
1996	$44.67
1997	$43.64
1998	$42.04
1999	$41.78
2000	$41.28
2001	$40.02
2002	$39.13
2003	$38.52
2004	$37.75
2005	$36.36
2006	$36.17
2007	$35.49
2008	$34.98
2009	$34.50

10. Provide the following data to support Schedule 4 of TECO's Ten-Year Site Plan: the 12 monthly peak demands for the years 1997, 1998, and 1999; and the date on which these monthly peaks occurred.

A. Data to support Schedule 4 of Tampa Electric's Ten-Year Site Plan.

	1997 Demand	Day of Peak
Jan	3439	19
Feb	2445	12
Mar	2442	3
Apr	2512	22
May	3107	27
Jun	3090	18
Jul	3079	3
Aug	3076	18
Sep	2968	17
Oct	2725	1
Nov	2111	1
Dec	2585	15

	1998 Demand	Day of Peak
Jan	2437	29
Feb	2614	10
Mar	2809	13
Apr	2623	2
May	3029	20
Jun	3325	12
Jul	3291	2
Aug	3377	27
Sep	3112	1
Oct	3122	6
Nov	2535	18
Dec	2455	18

	1999 Demand	Day of Peak
Jan	3539	6
Feb	2835	23
Mar	2504	5
Apr	3073	26
May	3015	25
Jun	3199	15
Jul	3493	28
Aug	3562	2
Sep	3180	28
Oct	2954	11
Nov	2437	1
Dec	2732	2

11. Provide a list of each QF, EWG, IPP, or other type of generating entity that, since January 1, 1997, has initiated discussions regarding interconnection to TECO's system.

A. Please see the attached table.

Name and Type of Generating Entity	Name of Generating Plant	Size and Type of Generating Plant	Location of Generating Plant	Initial Contact Date	Formal Application Date	System Impact Study Completion Date	Facilities Study Completion Date	Interconnection Agreement Date
Houston Industries	Unnamed	540 MW Natural Gas Combustion Turbine	Near TEC's Lake Agnes substation, Polk County, FL	02-Dec-97	None	Not Applicable	Not Applicable	Not Applicable
TECO Power Services, Corp. IPP	Hardee CT2B	75 MW Natural Gas Combustion Turbine	Hardee Power Station, Hardee County, FL	25-Jun-99	25-Jun-99	15-Dec-99	Not Applicable	14-Feb-00
Cargill Fertilizer, Inc. QF	Millpoint Unit #2	36 MW Cogenerator	Cargill's Millpoint Facility, Riverview, FL	02-Oct-98	Not Applicable	Not Applicable	Not Applicable	Not Applicable
TECO Power Services, Corp. IPP	Unnamed	479 MW Integrated Coal-Gasification Combine Cycle	Adjacent to IMC-Agrico's New Wales Facility	07-Jan-00	07-Jan-00	Application Withdrawn Prior to Completion	Not Applicable	Not Applicable
Calpine Corporation IPP	Osprey Energy Center	526 MW Natural Gas Combined Cycle	Adjacent to TEC's Recker Substation, Auburndale, FL	01-Oct-99	01-Oct-99	01-Oct-99	Anticipated Aug-00	Not Applicable

12. For each entity reported in Question #11, provide the following information:

a. the size, type, and location of the proposed generator;

b. the date when initial contact was made regarding interconnection;

c. the date when a formal application was made for either interconnection or a System Impact Study;

d. the date the System Impact Study was completed or is anticipated to be completed;

e. if available, the results of the System Impact Study;

f. if applicable, the estimated completion or results of any Facilities Studies performed; and

g. the date when an interconnection agreement was signed, if applicable, indicating the projected in-service date of the facility.

h. copies of all notes from meetings, and other correspondence, between TECO and the entities identified in Question #11.

A. The attached data is in correspondence to Tampa Electric's answer to Data Request No. 11.

13. Describe how TECO prioritizes requests for interconnection and how this process is integrated with utility-owned generation that is planned for the future.

A. For network resources within Tampa Electric's system to serve Tampa Electric's network load, the resource is posted on the OASIS (and time stamped to establish a priority for transmission rights) as soon as it becomes an official part of Tampa Electric's resource plan. Only that portion of the capacity that will be dedicated to serve network load is listed on the OASIS under "Tampa Electric Ten-Year Network Load and Resources." All associated transmission facilities that are required become an official part of Tampa Electric's plan at the time and will be included in the next posting of Tampa Electric's annual 715 FERC filed transmission models. This is considered the base case for any subsequent transmission service request impact studies.

For generation interconnection requests and associated power sales from within Tampa Electric to the outside of Tampa Electric's system, a reservation must be made on the OASIS for a specific amount of capacity on a specific path (to the adjacent control area to which Tampa Electric will deliver the power) for the period of the transaction. This is required for both utility and non-utility generation and must be done prior to any study of transmission capability.

Given the above, impacts of new resources, loads, tie-lines, generation interconnections and reserved transmission services are assessed in the order they are placed in the OASIS "queue." This allows the costs of the transmission upgrades to be charged to the projects causing the need for the new facilities, regardless of whether the impacting project is retailed or wholesale in nature.

14. Provide a list of each distributed generating resource that is currently interconnected to TECO's system. Indicate the size, type, in-service date and location of the resource.

A. There are ten (10) diesel-fired 1.825 and one (1) 1.65 megawatt Caterpillar engines interconnected at eleven different distribution-level substations throughout Tampa Electric's service territory. The engines are rental units and were installed during the month of June 2000 at the following substation locations; Clearview, 11th Avenue, Plant City, State Road 60, Lake Gum, South Eloise, Ruskin, Juneau, Dale Mabry, Mulberry, and Hampton. There is also an 18-kilowatt photovoltaic solar array interconnection at the Museum of Science and Industry which is located in Tampa, FL.

15. Provide a list of each distributed generating resource that has a pending request for interconnection to TECO's system. Indicate the size, type, in-service date, and location of the resource.

A. There will be two (2) 2.9 megawatt natural gas fired engines that will be constructed, owned, operated and maintained by Tampa Electric and will be interconnected to the Tampa Electric electrical grid later this year. These units are being sited at the City of Tampa's wastewater treatment Plant. Air permits are currently pending from the Environmental Protection Agency.

Two (2) 800-kilowatt diesel-fired backup generators located at Nuccio Parkway in Tampa, FL will be interconnected to the grid to provide approximate 1.0 megawatt of peaking power. The project is estimated to be complete by late August.

A residential 1,500 watt photovoltaic solar array will also be interconnected at a private residence in Apollo Beach, FL.

16. Describe any policies or procedures utilized by TECO to address interconnection requests from owners of distributed generating resources.

A. Tampa Electric has filed Docket No. 000758-EI, a tariff with the Florida Public Service Commission to establish a pilot program for interconnection of small (<10 KW) photovoltaic (PV) systems. The pilot will run for three (3) years. Data will be collected on power quality, quantity of energy produced, reliability, and impact on electric grid operations. The tariff incorporates the recently adopted IEEE 929, *Recommended Standard for Utility Interface of Photovoltaic (PV) Systems.*

In addition, a formal policy/procedure is being developed for the interconnection of distributed generation resources that will interconnect at Tampa Electric's electrical distribution system as opposed to its transmission system.