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

RECEIVED-FPSC

00 APR -3 PM 3: 14

RECORDS AND REPORTING

April 3, 2000

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Tampa Electric Company's Ten Year Site Plan

Dear Ms. Bayo:

Enclosed for filing on behalf of Tampa Electric Company are twenty-five (25) copies of the company's January 2000 to December 2009 Ten Year Site Plan.

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,

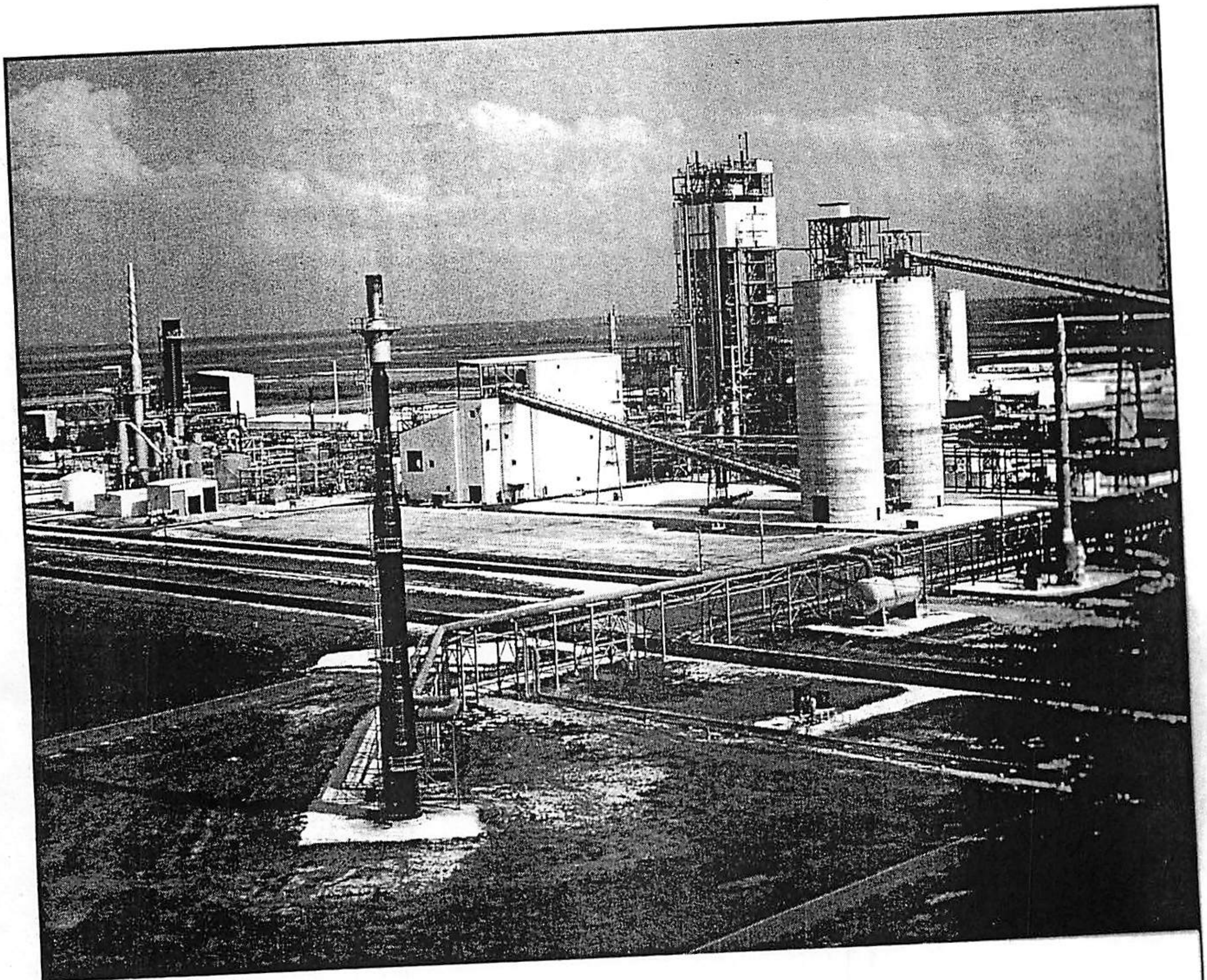
James D. Beasley

JDB/pp
Enclosures

cc: Michael Haff (w/enc.)

DOCUMENT NUMBER-DATE
04062 APR-3 8
FPSC-RECORDS/REPORTING

ORIGINAL



TECO

TAMPA ELECTRIC

TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

JANUARY 2000 TO DECEMBER 2009

DOCUMENT NUMBER-DATE

04062 APR-3 8

TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

January 2000 to December 2009

TAMPA ELECTRIC COMPANY
Tampa, Florida

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TAMPA ELECTRIC COMPANY
CODE IDENTIFICATION SHEET

Unit Type:	CT	=	Combustion Turbine
	CC	=	Combined Cycle
	CG	=	Coal Gasifier
	D	=	Diesel
	FS	=	Fossil Steam
	HRSG	=	Heat Recovery Steam Generator
	IGCC	=	Integrated Gasification Combined Cycle
	ST	=	Steam Turbine
Unit Status:	P	=	Planned
	T	=	Regulatory Approval Received
	LTRS	=	Long Term Reserve Stand-by
Fuel Type:	BIT	=	Bituminous Coal
	C	=	Coal
	PC	=	Petroleum Coke
	HO	=	Heavy Oil (#6 Oil)
	LO	=	Light Oil (#2 Oil)
	NG	=	Natural Gas
	WH	=	Waste Heat
Environmental:	CL	=	Closed Loop Water Cooled
	CLT	=	Cooling Tower
	EP	=	Electrostatic Precipitator
	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	SC	=	Scrubber
	OLS	=	Open Loop Cooling Water System
	OTS	=	Once-Through System
	NO	=	Not Required
Transportation:	PL	=	Pipeline
	TK	=	Truck
	RR	=	Railroad
	WA	=	Water
Other:	N	=	None

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CHAPTER I

DESCRIPTION OF EXISTING FACILITIES

Description of Electric Generating Facilities

Tampa Electric has six generating plants consisting of fossil steam units, combustion turbine peaking units, diesel units and an integrated gasification combined cycle unit. The six generating plants include Big Bend, Gannon, Hookers Point, Dinner Lake, Phillips, and Polk. Big Bend and Gannon consist of both steam-generating units and combustion turbine units.

Tampa Electric currently has eleven coal-fired units. Ten of these units are fired with pulverized coal. Starting in 2003, Tampa Electric will reduce its use of coal with the repowering of Gannon Station with natural gas. After 2005 the four units at Big Bend Station will be the only units in the Tampa Electric system to be fired directly with pulverized coal. Polk unit 1 is fired with synthetic gas produced from gasified coal and other carbonaceous fuels. The Polk unit 1 is an integrated gasification combined cycle unit (IGCC). This technology integrates state-of-the-art environmental processes for creating a clean fuel gas from a variety of feedstocks with the efficiency benefits of combined cycle generation equipment.

Generating units at Hookers Point and Phillips are residual oil fired plants. Dinner Lake is fueled by natural gas and oil and is currently on long term reserve standby. The four combustion turbines at Big Bend and Gannon Stations use distillate oil as the primary fuel. Total net system generation in 1999 was 15,835 GWh.

Schedule 1

TABLE 1-1
Existing Generating Facilities
As of December 31, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt	Commercial	Expected	Gen. Max.	Net Capability	
	Unit		Unit	Fuel		Fuel Transport		Fuel	In-Service	Retirement	Nameplate	Summer	Winter
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Days	Mo/Yr	Mo/Yr	KW	MW	MW
Big Bend		Hillsborough											
		Co. 14/31S/19E									1,998,000	1,843	1,919
	1		FS	C	N	WA	N	0	10/70	Unknown	445,500	416	426
	2		FS	C	N	WA	N	0	4/73	"	445,500	416	426
	3		FS	C	N	WA	N	0	5/76	"	445,500	433	443
	4		FS	C	N	WA	N	0	2/85	"	486,000	442	447
	CT1		CT	LO	N	WA	TK	0	2/69	"	18,000	12	17
	CT2&3		CT	LO	N	WA	TK	0	11/74	"	157,500	124	160
Dinner Lake*		Highland Co.											
		12-055									12,650	11	11
	1		FS	NG	HO	PL	TK	2	12/66	Unknown	12,650	11	11
Gannon		Hillsborough											
		Co. 4/30S/19E									1,319,880	1,132	1,187
	1		FS	C	N	WA	RR	0	9/57	(1)	125,000	114	114
	2		FS	C	N	WA	RR	0	11/58	(1)	125,000	98	98
	3		FS	C	N	WA	RR	0	10/60	(1)	179,520	145	155
	4		FS	C	N	WA	RR	0	11/63	(1)	187,500	159	169
	5		FS	C	N	WA	RR	0	11/65	(1)	239,360	232	242
	6		FS	C	N	WA	RR	0	10/67	(1)	445,500	372	392
	CT1		CT	LO	N	WA	TK	0	3/69	Unknown	18,000	12	17
Hookers Pt.		Hillsborough											
		Co. 19/29S/19E									232,600	196	204
	1		FS	HO	N	WA	N	0	7/48	01/03	33,000	30	32
	2		FS	HO	N	WA	N	0	6/50	01/03	34,500	30	32
	3		FS	HO	N	WA	N	0	8/50	01/03	34,500	30	32
	4		FS	HO	N	WA	N	0	10/53	01/03	49,000	39	41
	5		FS	HO	N	WA	N	0	5/55	01/03	81,600	67	67
Phillips		Highland Co.											
		12-055									42,030	37	37
	1 +		D	HO	N	TK	N	0	6/83	Unknown	19,215	17	17
	2		D	HO	N	TK	N	0	6/83	Unknown	19,215	17	17
	3 **		HRSG	WH	N	N	N	0	6/83	Unknown	3,600	3	3
Polk		Polk Co.											
		2,3/32S/23E									326,299	250	250
	1		IGCC	C	LO	WA/TK	TK	0	9/96	Unknown	326,299	250	250
											TOTAL	3,469	3,608

Note:

* Unit placed on long-term reserve standby 03/01/94.

** Unit on full forced outage with an undetermined return to service date.

\+ Phillip units 1 & 2 returns to service April and May 2000, respectively at 17 MW each in Winter and Summer.

1. Gannon units 1 and 2 are planned for long term reserve stand-by (LTRS) , unit 5 repowered (RP) and renamed Bayside Power Station unit 1 in May 2003.
Gannon unit 6 is planned for long term reserve stand-by (LTRS) and units 3 and 4 repowered (RP) and renamed Bayside Power Station unit 2 in May 2004.

TABLE 1-2
Existing Generating Facilities/Land Use and Investment

	Land Area		Plant Capital Investment ($000)			
Plant Name	**Total Acres**	**In Use Acres**	**Land**	**Structures & Improvements**	**Equipment**	**Total**
Hookers Point Station	25	25	$437	$7,947	$45,512	$53,896
Big Bend Station	1,124	1,124	5,147	157,932	944,809	1,107,888
Francis J. Gannon Station	213	213	1,556	62,455	402,283	466,294
Dinner Lake - Sebring	2	2	15	134	3,487	3,636
Phillips - Sebring	36	36	180	289	59,630	60,099
Combustion Turbine - Gannon	1	1	0	75	1,790	1,865
Combustion Turbines - Big Bend	75	75	834	1,695	20,856	23,385
Miscellaneous Production Services	47	47	94	6,955	1,490	8,539
Polk Power Station	4,347	4,347	18,919	110,780	400,291	530,990
TOTALS			$27,182	$349,262	$1,880,148	$2,256,592

NOTE: Dollar values rounded to the nearest $1,000.

TABLE 1 - 3
Existing Generating Facilities/Environmental
Considerations for Steam Generating Units

Plant Name	Unit		Flue Gas Cleaning			Cooling Type
			Particulate	SO_X	NO_X	
Francis J. Gannon		1	EP	LS	NR	OTS
		2	EP	LS	NR	OTS
		3	EP	LS	(2)	OTS
		4	EP	LS	(2)	OTS
		5	EP	LS	(1)	OTS
		6	EP	LS	(1)	OTS
	CT	1	NR	LS	NR	---
Hookers Point		1	NR	LS	NR	OTS
		2	NR	LS	NR	OTS
		3	NR	LS	NR	OTS
		4	NR	LS	NR	OTS
		5	NR	LS	NR	OTS
Big Bend		1	EP	SC	(1)	OTS
		2	EP	SC	(1)	OTS
		3	EP	SC	(1)	(4)
		4	EP	SC	(3)	(4)
	CT	1	NR	LS	NR	---
	CT	2	NR	LS	NR	---
	CT	3	NR	LS	NR	---
Dinner Lake		1	NR	FQ	NR	OTS
Phillips		1	NR	FQ	(1)	CLT
		2	NR	FQ	(1)	CLT
	HRSG	3	NA	NA	NA	NA
Polk	IGCC	1	NR	AGR	NI	OLS

CLT	=	Cooling Tower	IGCC	=	Integrated Gasification Combined Cycle
CT	=	Combustion Turbine	AGR	=	Acid Gas Removal
EP	=	Electrostatic Precipitator	NI	=	Nitrogen Injection
FQ	=	Fuel Quality	CR	=	Cooling Reservoir
LS	=	Low Sulfur	OLS	=	Open Loop Cooling Water System
SC	=	Scrubber	NA	=	Not Applicable
OTS	=	Once-Through System	NR	=	Not Required
HRSG	=	Heat Recovery Steam Generator			

December 31, 1999 Status

(1) NO_X controlled through unit operation.
(2) NO_X controlled through unit operation and fuel quality.
(3) NOx controlled through unit design and operation.
(4) OTS with fine mesh screens to minimize entrainment.

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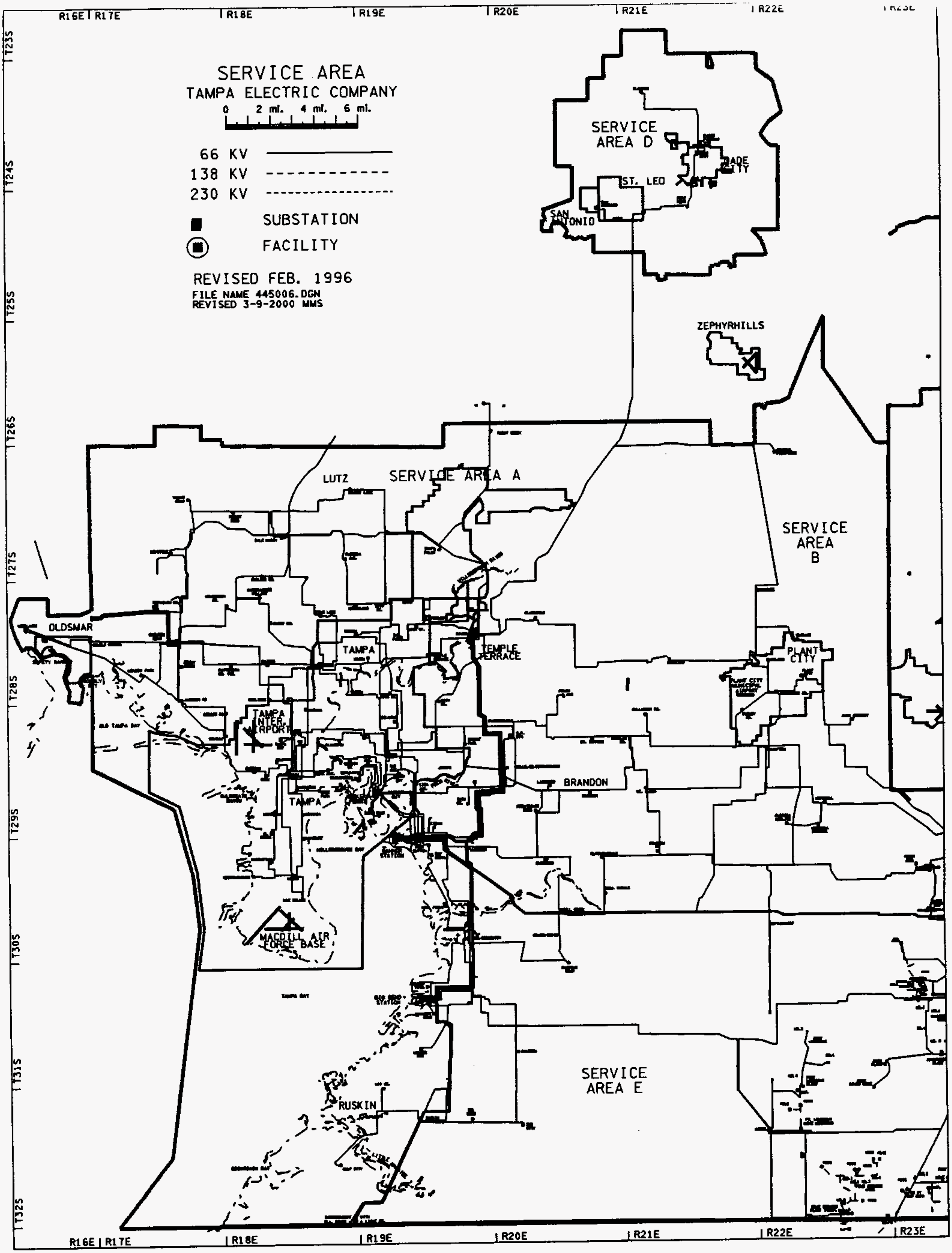
SERVICE AREA
TAMPA ELECTRIC COMPANY
0 2 mi. 4 mi. 6 mi.
66 KV
138 KV
230 KV
SUBSTATION
FACILITY
REVISED FEB. 1996
FILE NAME 445006.DGN
REVISED 3-9-2000 MMS
R16E
R17E
R18E
R19E
R20E
R21E
R22E
R23E
T23S
T24S
T25S
T26S
T27S
T28S
T29S
T30S
T31S
T32S
SERVICE AREA D
DADE CITY
ST. LEO
SAN ANTONIO
ZEPHYRHILLS
LUTZ
SERVICE AREA A
SERVICE AREA B
OLDSMAR
TAMPA
TEMPLE TERRACE
PLANT CITY
TAMPA INTER. AIRPORT
BRANDON
TAMPA
MACDILL AIR FORCE BASE
SERVICE AREA E
RUSKIN

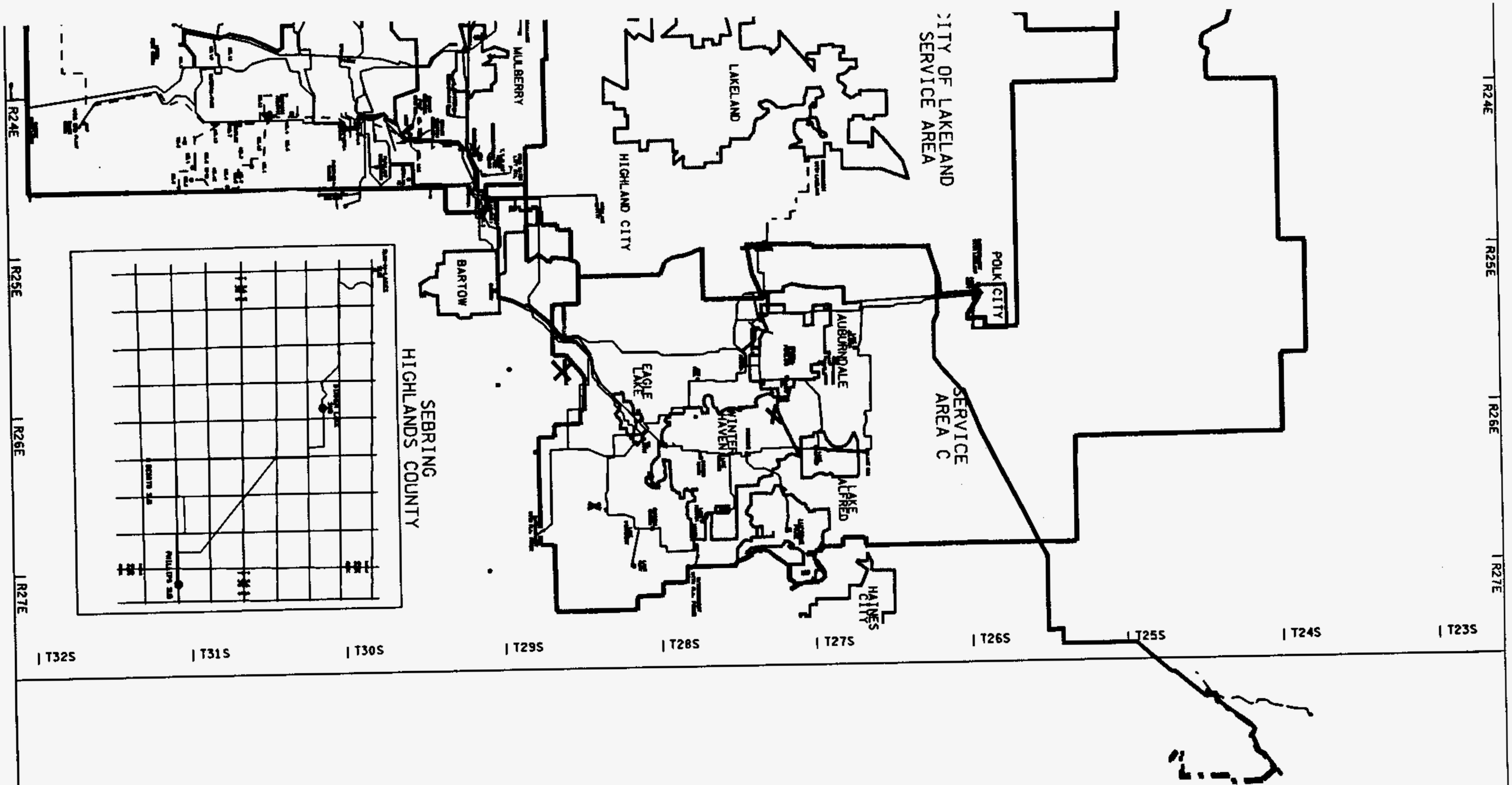

FIGURE I-1

TAMPA ELECTRIC RETAIL CUSTOMER SERVICE AREA

SOURCE: TAMPA ELECTRIC.

TAMPA ELECTRIC COMPANY

TEN YEAR SITE PLAN
FOR ELECTRICAL GENERATING FACILITIES
AND ASSOCIATED TRANSMISSION LINES

FILE NAME 445006.DGN
REVISED 3-9-2000 MMS

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CHAPTER II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

Schedule 2.1

TABLE II-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
(Page 1 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Population**	Members Per Household	GWH	Average* No. of Customers	Average KWH Consumption Per Customer	GWH	Average* No. of Customers	Average KWH Consumption Per Customer
1990	834,054	2.5	5,412	401,172	13,490	4,231	50,287	84,137
1991	843,203	2.5	5,507	407,235	13,523	4,274	50,774	84,177
1992	853,990	2.5	5,560	412,970	13,463	4,333	51,727	83,767
1993	866,134	2.5	5,706	420,051	13,584	4,432	52,492	84,432
1994	879,069	2.5	5,947	427,594	13,908	4,583	53,482	85,692
1995	892,874	2.5	6,352	436,091	14,566	4,710	54,375	86,621
1996	910,855	2.5	6,607	445,664	14,825	4,815	55,479	86,790
1997	928,731	2.4	6,500	456,175	14,249	4,902	56,981	86,029
1998	942,322	2.4	7,050	466,189	15,123	5,173	58,542	88,364
1999	954,758	2.4	6,967	477,533	14,590	5,337	60,089	88,818
2000	966,773	2.4	7,310	487,946	14,981	5,542	61,776	89,711
2001	985,770	2.4	7,539	498,680	15,118	5,720	62,580	91,403
2002	1,001,731	2.4	7,755	508,527	15,250	5,890	63,512	92,738
2003	1,016,680	2.4	7,982	517,179	15,434	6,066	64,078	94,666
2004	1,030,584	2.4	8,230	525,339	15,666	6,246	65,159	95,858
2005	1,043,441	2.4	8,495	533,072	15,936	6,438	66,184	97,274
2006	1,055,482	2.4	8,763	540,431	16,215	6,620	67,159	98,572
2007	1,067,453	2.4	9,001	547,667	16,435	6,804	68,118	99,885
2008	1,080,135	2.4	9,255	555,341	16,665	6,962	69,135	100,702
2009	1,092,053	2.4	9,500	562,755	16,881	7,128	70,118	101,657

December 31, 1999 Status.

* Average of end-of-month customers for the calendar year.
** Hillsborough County population.

Schedule 2.2

TABLE II-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
(Page 2 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				Street &	Other Sales	Total Sales
Year	GWH	Average* No. of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Highway Lighting GWH	to Public Authorities GWH	to Ultimate Consumers GWH
1990	2,818	518	5,440,154	0	41	934	13,436
1991	2,669	515	5,182,524	0	42	963	13,455
1992	2,625	509	5,157,171	0	43	991	13,552
1993	2,236	509	4,392,927	0	45	1,028	13,447
1994	2,278	511	4,457,926	0	46	1,078	13,932
1995	2,362	491	4,810,591	0	51	1,125	14,600
1996	2,305	504	4,573,413	0	53	1,150	14,929
1997	2,465	629	4,027,778	0	53	1,170	15,090
1998	2,520	682	3,695,015	0	54	1,231	16,028
1999	2,223	740	3,004,054	0	52	1,226	15,805
2000	2,566	788	3,256,345	0	54	1,277	16,749
2001	2,662	838	3,176,611	0	55	1,313	17,289
2002	2,687	876	3,067,352	0	57	1,350	17,739
2003	2,597	901	2,882,353	0	59	1,388	18,092
2004	2,634	926	2,844,492	0	60	1,424	18,594
2005	2,627	951	2,762,355	0	61	1,460	19,081
2006	2,645	976	2,710,041	0	63	1,502	19,593
2007	2,620	1001	2,617,383	0	64	1,538	20,027
2008	2,474	1026	2,411,306	0	65	1,576	20,332
2009	2,414	1051	2,296,860	0	66	1,614	20,722

December 31, 1999 Status.

* Average of end-of-month customers for the calendar year.

Schedule 2.3

TABLE II-1
History and Forecast of Energy Consumption and Number of Customers by Customer Class
(Page 3 of 3)

(1) Year	(2) Sales for Resale GWH	(3) Utility Use++ & Losses GWH	(4) Net Energy** for Load GWH	(5) Other* Customers (Average No.)	(6) Total* No. of Customers
1990	0	569	14,005	3,695	455,672
1991	129	695	14,279	3,736	462,260
1992	214	671	14,437	3,790	468,996
1993	246	808	14,500	3,958	477,010
1994	163	636	14,731	4,111	485,698
1995	212	870	15,682	4,241	495,198
1996	399	760	16,088	4,391	506,038
1997	507	731	16,328	4,583	518,368
1998	431	783	17,242	4,839	530,252
1999	533	900	17,238	5,299	543,661
2000	374	866	17,989	5,371	555,881
2001	316	895	18,500	5,475	567,573
2002	284	918	18,941	5,580	578,495
2003	261	935	19,288	5,687	587,845
2004	267	961	19,822	5,787	597,211
2005	273	987	20,341	5,883	606,090
2006	273	1,014	20,880	5,974	614,540
2007	271	1,036	21,334	6,063	622,849
2008	274	1,051	21,657	6,158	631,660
2009	277	1,071	22,070	6,249	640,173

December 31, 1999 Status.

* Average of end-of-month customers for the calendar year.
** Output to line including energy supplied by purchased cogeneration.
++ *Utility Use and Losses include accrued sales.*

TABLE II-2
History and Forecast of Summer Peak Demand
Base Case
(Page 1 of 3)

(1) Year	(2) Total +	(3) Wholesale++	(4) Retail +	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
1990	2,659	0	2,659	311	72	20	4	9	2,279	*
1991	2,750	39	2,711	265	71	23	1	10	2,341	
1992	2,856	50	2,806	294	77	25	3	10	2,401	*
1993	2,951	60	2,891	273	91	28	6	11	2,492	*
1994	2,865	69	2,796	200	97	31	8	11	2,451	*
1995	3,028	81	2,947	170	98	34	8	13	2,624	
1996	3,146	92	3,054	234	98	41	18	16	2,647	
1997	3,167	106	3,061	225	89	45	17	15	2,677	*
1998	3,444	111	3,333	204	99	49	18	18	2,945	
1999	3,636	190	3,446	193	92	53	18	21	3,069	
2000	3,622	174	3,448	247	104	57	25	24	2,991	
2001	3,735	174	3,561	255	105	61	26	27	3,087	
2002	3,844	175	3,669	255	107	64	26	30	3,187	
2003	3,948	175	3,773	242	108	68	27	32	3,296	
2004	4,056	175	3,881	245	109	71	28	35	3,393	
2005	4,185	186	3,999	243	110	73	29	38	3,506	
2006	4,305	186	4,119	245	111	76	30	40	3,617	
2007	4,350	130	4,220	242	112	78	30	42	3,716	
2008	4,447	131	4,316	224	112	80	31	45	3,824	
2009	4,545	131	4,414	217	114	82	31	47	3,923	

December 31, 1999 Status.

- * Not coincident with system peak.
- \+ Includes residential and commercial/industrial conservation.
- ++ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
- \# Commercial/Industrial Load Management includes Standby Generator.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
High Case
(Page 2 of 3)

(1) Year	(2) Total +	(3) Wholesale++	(4) Retail +	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
1990	2,659	0	2,659	311	72	20	4	9	2,279	*
1991	2,750	39	2,711	265	71	23	1	10	2,341	
1992	2,856	50	2,806	294	77	25	3	10	2,401	*
1993	2,951	60	2,891	273	91	28	6	11	2,492	*
1994	2,865	69	2,796	200	97	31	8	11	2,451	*
1995	3,028	81	2,947	170	98	34	8	13	2,624	
1996	3,146	92	3,054	234	98	41	18	16	2,647	
1997	3,167	106	3,061	225	89	45	17	15	2,677	
1998	3,444	111	3,333	204	99	49	18	18	2,945	*
1999	3,636	190	3,446	193	92	53	18	21	3,069	
2000	3,665	174	3,491	257	104	58	25	24	3,023	
2001	3,798	174	3,624	269	106	62	26	27	3,134	
2002	3,929	176	3,753	272	108	65	26	30	3,252	
2003	4,057	176	3,881	261	110	69	27	32	3,382	
2004	4,187	176	4,011	267	111	72	28	35	3,498	
			0							
2005	4,346	188	4,158	267	112	74	29	38	3,638	
2006	4,505	188	4,317	270	114	78	30	40	3,785	
2007	4,577	132	4,445	269	116	80	30	42	3,908	
2008	4,709	133	4,576	250	117	83	31	45	4,050	
2009	4,848	132	4,716	242	118	85	31	47	4,193	

December 31, 1999 Status.

- * Not coincident with system peak.
- \+ Includes residential and commercial/industrial conservation.
- ++ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
- \# Commercial/Industrial Load Management includes Standby Generator.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
Low Case
(Page 3 of 3)

(1) Year	(2) Total +	(3) Wholesale++	(4) Retail +	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
1990	2,659	0	2,659	311	72	20	4	9	2,279	*
1991	2,750	39	2,711	265	71	23	1	10	2,341	
1992	2,856	50	2,806	294	77	25	3	10	2,401	*
1993	2,951	60	2,891	273	91	28	6	11	2,492	*
1994	2,865	69	2,796	200	97	31	8	11	2,451	*
1995	3,028	81	2,947	170	98	34	8	13	2,624	
1996	3,146	92	3,054	234	98	41	18	16	2,647	
1997	3,167	106	3,061	225	89	45	17	15	2,677	*
1998	3,444	111	3,333	204	99	49	18	18	2,945	
1999	3,636	190	3,446	193	92	53	18	21	3,069	
2000	3,448	174	3,274	236	102	53	25	24	2,961	
2001	3,540	174	3,366	242	103	57	26	27	3,040	
2002	3,624	173	3,451	238	105	60	26	30	3,123	
2003	3,701	174	3,527	223	106	63	27	32	3,209	
2004	3,784	174	3,610	224	106	66	28	35	3,285	
2005	3,881	184	3,697	219	106	69	29	38	3,371	
2006	3,976	184	3,792	221	107	71	30	40	3,460	
2007	3,978	128	3,850	215	108	73	30	42	3,520	
2008	4,051	129	3,922	200	108	75	31	45	3,602	
2009	4,120	130	3,990	191	108	76	31	47	3,676	

December 31, 1999 Status.

* Not coincident with system peak.
\+ Includes residential and commercial/industrial conservation.
++ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
\# Commercial/Industrial Load Management includes Standby Generator.

Schedule 3.2

TABLE II-3
History and Forecast of Winter Peak Demand
Base Case
(Page 1 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total +	Wholesale ++	Retail +	Interruptible	Residential Load Management	Residential Conservation =	Comm./Ind. Load Management #	Comm./Ind. Conservation	Net Firm Demand
1989/90	2,914	0	2,914	178	107	183	0	19	2,547 *
1990/91	2,638	0	2,638	227	139	196	0	20	2,056
1991/92	3,043	53	2,990	294	151	207	1	21	2,316
1992/93	3,130	63	3,067	281	168	221	4	23	2,370
1993/94	3,003	69	2,934	181	177	241	7	25	2,303
1994/95	3,539	74	3,465	240	227	270	8	25	2,695
1995/96	3,765	98	3,667	152	245	291	8	25	2,946
1996/97	3,577	109	3,468	228	153	325	18	25	2,719
1997/98	3,186	99	3,087	210	151	350	17	26	2,332
1998/99	3,953	131	3,822	152	250	385	17	28	2,990
1999/00	4,194	131	4,063	224	236	424	24	29	3,126
2000/01	4,390	178	4,212	233	240	453	24	30	3,232
2001/02	4,511	178	4,333	232	243	484	25	31	3,318
2002/03	4,642	179	4,463	221	246	511	25	32	3,428
2003/04	4,774	180	4,594	224	249	537	26	34	3,524
2004/05	4,935	189	4,746	222	251	563	27	35	3,648
2005/06	5,069	190	4,879	224	254	582	27	36	3,756
2006/07	5,157	134	5,023	221	256	602	28	37	3,879
2007/08	5,238	134	5,104	203	258	620	28	38	3,957
2008/09	5,365	135	5,230	197	260	637	29	40	4,067

December 31, 1999 Status.

*	Not coincident with system peak.
+	Includes conservation.
++	Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
#	Commercial/Industrial Load Management includes Standby Generator.
=	Residential conservation includes code changes.

Schedule 3.2

TABLE II-3
History and Forecast of Winter Peak Demand
High Case
(Page 2 of 3)

(1) Year	(2) Total +	(3) Wholesale ++	(4) Retail +	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation =	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1989/90	2,914	0	2,914	178	107	183	0	19	2,547 *
1990/91	2,638	0	2,638	227	139	196	0	20	2,056
1991/92	3,043	53	2,990	294	151	207	1	21	2,316
1992/93	3,130	63	3,067	281	168	221	4	23	2,370
1993/94	3,003	69	2,934	181	177	241	7	25	2,303
1994/95	3,539	74	3,465	240	227	270	8	25	2,695
1995/96	3,765	98	3,667	152	245	291	8	25	2,946
1996/97	3,577	109	3,468	228	153	325	18	25	2,719
1997/98	3,186	99	3,087	210	151	350	17	26	2,332
1998/99	3,953	131	3,822	152	250	385	17	28	2,990
1999/00	4,230	132	4,098	232	237	427	24	29	3,149
2000/01	4,447	178	4,269	245	243	458	24	30	3,269
2001/02	4,597	179	4,418	247	247	491	25	31	3,377
2002/03	4,761	180	4,581	238	251	521	25	32	3,514
2003/04	4,909	180	4,729	243	255	548	26	34	3,623
2004/05	5,100	190	4,910	242	258	579	27	35	3,769
2005/06	5,261	191	5,070	246	262	600	27	36	3,899
2006/07	5,381	134	5,247	245	265	623	28	37	4,049
2007/08	5,506	136	5,370	226	269	644	28	38	4,165
2008/09	5,670	135	5,535	219	271	664	29	40	4,312

December 31, 1999 Status.

*	Not coincident with system peak.
+	Includes residential and commercial/industrial conservation.
++	Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
#	Commercial/Industrial Load Management includes Standby Generator.
=	Residential conservation includes code changes.

Schedule 3.2

TABLE II-3
History and Forecast of Winter Peak Demand
Low Case
(Page 3 of 3)

(1) Year	(2) Total +	(3) Wholesale ++	(4) Retail +	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation =	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1989/90	2,914	0	2,914	178	107	183	0	19	2,547 *
1990/91	2,638	0	2,638	227	139	196	0	20	2,056
1991/92	3,043	53	2,990	294	151	207	1	21	2,316
1992/93	3,130	63	3,067	281	168	221	4	23	2,370
1993/94	3,003	69	2,934	181	177	241	7	25	2,303
1994/95	3,539	74	3,465	240	227	270	8	25	2,695
1995/96	3,765	98	3,667	152	245	291	8	25	2,946
1996/97	3,577	109	3,468	228	153	325	18	25	2,719
1997/98	3,186	99	3,087	210	151	350	17	26	2,332
1998/99	3,953	131	3,822	152	250	385	17	28	2,990
1999/00	4,153	131	4,022	214	234	420	24	29	3,101
2000/01	4,330	177	4,153	221	237	448	24	30	3,193
2001/02	4,428	178	4,250	218	239	477	25	31	3,260
2002/03	4,537	179	4,358	204	242	502	25	32	3,353
2003/04	4,639	179	4,460	204	243	525	26	34	3,428
2004/05	4,777	188	4,589	202	244	550	27	35	3,531
2005/06	4,875	188	4,687	201	246	565	27	36	3,612
2006/07	4,931	134	4,797	198	247	582	28	37	3,705
2007/08	4,983	132	4,851	181	249	597	28	38	3,758
2008/09	5,079	134	4,945	175	249	612	29	40	3,840

December 31, 1999 Status.

*	Not coincident with system peak.
+	Includes residential and commercial/industrial conservation.
++	Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
#	Commercial/Industrial Load Management includes Standby Generator.
=	Residential conservation includes code changes.

Schedule 3.3

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
Base Case
(Page 1 of 3)

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1990	13,565	108	21	13,436	0	569	14,005	60.8
1991	13,592	114	23	13,455	129	695	14,279	60.9
1992	13,697	120	25	13,552	214	671	14,437	58.5
1993	13,603	127	30	13,446	246	808	14,500	57.0
1994	14,103	138	33	13,932	163	636	14,731	61.1
1995	14,798	158	40	14,600	212	870	15,682	55.2
1996	15,167	189	49	14,929	399	760	16,088	53.1
1997	15,354	210	54	15,090	507	731	16,328	57.8
1998	16,334	239	67	16,028	431	783	17,242	55.3
1999	16,162	281	76	15,805	533	900	17,238	55.6
2000	17,139	302	88	16,749	374	866	17,989	54.7
2001	17,709	319	101	17,289	316	895	18,500	54.7
2002	18,190	337	114	17,739	284	918	18,941	54.7
2003	18,571	353	126	18,092	261	935	19,288	54.3
2004	19,100	368	138	18,594	267	961	19,822	54.4
2005	19,611	380	150	19,081	273	987	20,341	54.2
2006	20,145	392	160	19,593	273	1,014	20,880	54.2
2007	20,601	404	170	20,027	271	1,036	21,334	53.9
2008	20,926	414	180	20,332	274	1,051	21,657	53.8
2009	21,336	424	190	20,722	277	1,071	22,070	53.7

December 31, 1999 Status.

** Load Factor is the ratio of total system average load to peak demand.
+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
= Residential conservation includes code changes.

Schedule 3.3

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
High Case
(Page 2 of 3)

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1990	13,565	108	21	13,436	0	569	14,005	60.8
1991	13,592	114	23	13,455	129	695	14,279	60.9
1992	13,697	120	25	13,552	214	671	14,437	58.5
1993	13,603	127	30	13,446	246	808	14,500	57.0
1994	14,103	138	33	13,932	163	636	14,731	61.1
1995	14,798	158	40	14,600	212	870	15,682	55.2
1996	15,167	189	49	14,929	399	760	16,088	53.1
1997	15,354	210	54	15,090	507	731	16,328	57.8
1998	16,334	239	67	16,028	431	783	17,242	55.3
1999	16,162	281	76	15,805	533	900	17,238	55.6
2000	17,362	304	88	16,970	374	925	18,269	55.1
2001	18,041	321	101	17,619	319	960	18,898	54.5
2002	18,638	341	114	18,183	287	991	19,461	54.5
2003	19,138	357	126	18,655	263	1,016	19,934	54.1
2004	19,778	374	138	19,266	273	1,050	20,589	54.2
2005	20,428	387	150	19,891	278	1,084	21,253	54.1
2006	21,114	401	160	20,553	279	1,120	21,952	54.2
2007	21,707	413	170	21,124	278	1,151	22,553	53.9
2008	22,175	425	180	21,570	280	1,176	23,026	54.3
2009	22,751	436	190	22,125	285	1,206	23,616	54.3

December 31, 1999 Status.

** Load Factor is the ratio of total system average load to peak demand.
+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
= Residential conservation includes code changes.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
Low Case
(Page 3 of 3)

(1) Year	(2) Total +	(3) Wholesale++	(4) Retail +	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
1990	2,659	0	2,659	311	72	20	4	9	2,279	*
1991	2,750	39	2,711	265	71	23	1	10	2,341	
1992	2,856	50	2,806	294	77	25	3	10	2,401	*
1993	2,951	60	2,891	273	91	28	6	11	2,492	*
1994	2,865	69	2,796	200	97	31	8	11	2,451	*
1995	3,028	81	2,947	170	98	34	8	13	2,624	
1996	3,146	92	3,054	234	98	41	18	16	2,647	
1997	3,167	106	3,061	225	89	45	17	15	2,677	*
1998	3,444	111	3,333	204	99	49	18	18	2,945	
1999	3,636	190	3,446	193	92	53	18	21	3,069	
2000	3,579	174	3,405	236	102	57	25	24	2,961	
2001	3,672	174	3,498	242	103	60	26	27	3,040	
2002	3,758	173	3,585	238	105	63	26	30	3,123	
2003	3,837	174	3,663	223	106	66	27	32	3,209	
2004	3,921	174	3,747	224	106	69	28	35	3,285	
2005	4,018	184	3,834	219	106	71	29	38	3,371	
2006	4,116	184	3,932	221	107	74	30	40	3,460	
2007	4,119	128	3,991	215	108	76	30	42	3,520	
2008	4,192	129	4,063	200	108	77	31	45	3,602	
2009	4,261	130	4,131	191	108	78	31	47	3,676	

December 31, 1999 Status.

* Not coincident with system peak.
\+ Includes residential and commercial/industrial conservation.
++ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
\# Commercial/Industrial Load Management includes Standby Generator.

Schedule 4

TABLE II-5
Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	1999 Actual		2000 Forecast		2001 Forecast	
Month	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	3,539	1,273	3,741	1,349	3,907	1,398
February	2,835	1,139	3,362	1,231	3,515	1,275
March	2,504	1,214	2,965	1,321	3,106	1,368
April	3,073	1,372	2,896	1,317	3,130	1,369
May	3,015	1,475	3,272	1,600	3,418	1,655
June	3,199	1,604	3,541	1,699	3,648	1,737
July	3,493	1,754	3,509	1,799	3,613	1,833
August	3,562	1,819	3,516	1,814	3,621	1,853
September	3,180	1,596	3,505	1,679	3,609	1,724
October	2,954	1,462	3,242	1,505	3,339	1,541
November	2,437	1,219	3,105	1,302	3,175	1,335
December	2,732	1,311	3,368	1,373	3,443	1,412
TOTAL		17,238		17,989		18,500

December 31, 1999 Status.

NOTE: Peak demand represents total retail and wholesale demand, excluding conservation impacts.

Schedule 5

TABLE II-6
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 1998	Actual 1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	7,811	7,229	7,904	7,644	7,662	6,810	5,783	5,630	5,677	5,734	5,770	5,768
(3)	Residual	Total	1000 BBL	469	507	555	510	513	45	43	56	67	66	74	82
(4)		Steam	1000 BBL	368	471	494	448	458	0	0	0	0	0	0	0
(5)		CC	1000 BBL	101	36	62	62	55	45	43	56	67	66	74	82
(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	401	458	301	452	534	310	274	264	266	264	264	263
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	237	244	231	244	243	225	237	226	227	227	228	227
(11)		CT	1000 BBL	164	214	70	208	291	85	37	37	39	37	37	36
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	0	0	273	1,469	3,022	20,915	40,777	46,304	49,806	51,867	54,066	57,621
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	0	0	0	0	0	17,864	38,082	41,250	42,692	43,710	44,565	46,010
(16)		CT	1000 MCF	0	0	273	1,469	3,022	3,051	2,695	5,054	7,114	8,157	9,501	11,611
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	82	90	254	626	621	586	601	603	606	609	612	611

Schedule 6.1

TABLE II-7
History and Forecast of Net Energy for Load by Fuel Source in GWH
(Page 1 of 2)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1998	Actual 1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Annual Firm Interchange		GWh	413	398	(579)	317	480	546	420	461	492	501	522	543
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal*		GWh	16,502	15,124	16,754	15,320	15,346	13,616	11,435	11,162	11,259	11,374	11,444	11,449
(4)	Residual	Total	GWh	211	207	218	200	197	30	29	38	45	45	50	56
(5)		Steam	GWh	142	184	177	158	159	0	0	0	0	0	0	0
(6)		CC	GWh	68	23	42	42	37	30	29	38	45	45	50	56
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWh	228	249	193	288	328	197	177	170	171	170	171	170
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	166	173	160	169	169	156	164	157	157	157	158	157
(12)		CT	GWh	62	76	33	119	159	41	13	13	14	13	13	13
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	0	0	19	105	238	2,779	5,611	6,280	6,674	6,923	7,167	7,572
(15)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	0	0	0	0	0	2,509	5,369	5,824	6,031	6,182	6,306	6,519
(17)		CT	GWh	0	0	19	105	238	270	242	456	643	740	861	1,053
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWh	234	255	720	1,771	1,758	1,659	1,702	1,707	1,714	1,723	1,731	1,728
(20)	Net Interchange		GWh	(789)	581	249	84	114	(26)	(34)	33	29	107	49	42
(21)	Purchased Energy from Non-														
(22)	Utility Generators		GWh	443	424	412	414	481	486	484	493	493	493	523	510
(23)	Net Energy for Load		GWh	17,242	17,238	17,987	18,499	18,942	19,288	19,825	20,343	20,877	21,335	21,657	22,070

Schedule 6.2

TABLE II-7
History and Forecast of Net Energy for Load by Fuel Source as Percentage
(Page 2 of 2)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1998	Actual 1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Annual Firm Interchange		%	2	2	(3)	2	3	3	2	2	2	2	2	2
(2)	Nuclear		%	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal*		%	96	88	93	83	81	71	58	55	54	53	53	52
(4)	Residual	Total	%	1	1	1	1	1	0	0	0	0	0	0	0
(5)		Steam	%	1	1	1	1	1	0	0	0	0	0	0	0
(6)		CC	%	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	%	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	%	1	1	1	2	2	1	1	1	1	1	1	1
(10)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	%	1	1	1	1	1	1	1	1	1	1	1	1
(12)		CT	%	0	0	0	1	1	0	0	0	0	0	0	0
(13)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	%	0	0	0	1	1	14	28	31	32	32	33	34
(15)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	%	0	0	0	0	0	13	27	29	29	29	29	30
(17)		CT	%	0	0	0	1	1	1	1	2	3	3	4	5
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	1	1	4	10	9	9	9	8	8	8	8	8
(20)	Net Interchange		%	(5)	3	1	0	1	(0)	(0)	0	0	0	0	0
(21)	Purchased Energy from Non-														
(22)	Utility Generators		%	3	2	2	2	3	3	2	2	2	2	2	2
(23)	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100	100

* Values shown may be affected by rounding.

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CHAPTER III

FORECAST OF ELECTRIC POWER DEMAND

Tampa Electric Company Forecasting Methodology

The Customer, Demand and Energy Forecast is the foundation from which the integrated resource plan is developed. Recognizing its importance, Tampa Electric Company employs state-of-the-art methodologies for carrying out this function. The primary objective in this procedure is to blend proven statistical techniques with practical forecasting experience to provide a projection, which represents the highest probability of occurrence.

This chapter is devoted to describing Tampa Electric Company's forecasting methods and the major assumptions utilized in developing the 2000-2009 forecast. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2000-2009 time period.

Retail Load

The Tampa Electric Company retail demand and energy forecast is the result of five separate forecasting methods:

1. detailed end-use model (demand and energy);
2. multiregression model (demand and energy);
3. trend analysis (demand and energy);
4. phosphate analysis (demand and energy); and
5. conservation programs (demand and energy management).

The detailed end-use model, SHAPES, is the company's most sophisticated and primary forecasting model. As shown in Figure III-1, the first three forecasting methods are blended together to develop a demand and energy projection, excluding phosphate load. Phosphate demand and energy is forecasted separately and then combined in the final forecast. Likewise, the effect of Tampa Electric Company's conservation, load management, and cogeneration programs is incorporated into the process by subtracting their expected reduction in demand and energy from the forecast.

1. Detailed End-Use Model

The SHAPES model was developed jointly by Tampa Electric Company, Tech Resources (formerly part of the Battelle Memorial Institute), and New Energy Associates and is the foundation of the demand and energy forecasting process. SHAPES projects annual energy consumption for the service area and load profiles by end-use for typical and extreme (peak) days. The model has two major sections. The first section is the regional economic-demographic model, entitled REGIS, which generates population, households, income, and employment projections which are used in the second part of the model, called SHAPES.

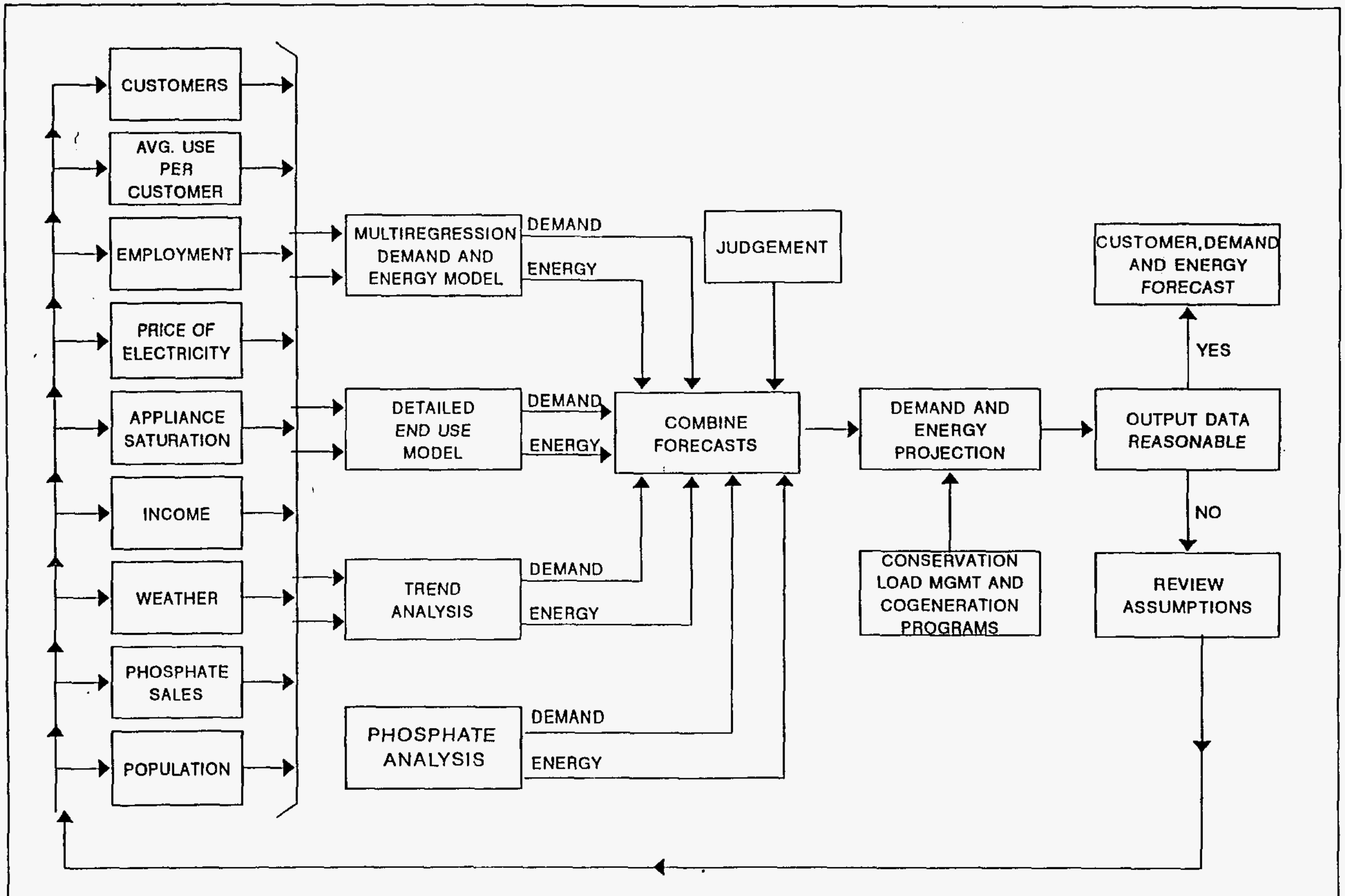


Figure III-1

TAMPA ELECTRIC COMPANY CUSTOMER, DEMAND AND ENERGY FORECAST PROCESS

SOURCE: TAMPA ELECTRIC COMPANY

As an option, the parameters furnished by REGIS may be replaced with other forecasts, such as the University of Florida's population projections. The SHAPES portion of the model consists of two parts: (1) a demand sections, and (2) an energy section. The demand section calculates hourly demands including peak demands based on temperature profiles for normal and extreme conditions. The energy section forecasts residential energy use by appliance, commercial consumption by end-use and building type, and energy used in the industrial and miscellaneous sectors.

REGIS

Since electricity consumption, peak demand, and load shapes depend to a large extent on the nature and level of economic activity, the first step in system demand and energy requirements forecasting is to project the economic and population base of the service area. The economic-demographic model consists of approximately seventeen equations with four major components including migration and demographic, housing, labor, and income.

Population is developed through the migration/demographic component of the model which uses a cohort-survival approach as its foundation. More specifically, Hillsborough County population is partitioned into age groups and "aged" over time through the application of birth and death rates. Migration, the most significant component of population change in the service area, is calculated as a function of the relative economic opportunities in the local area and the general health of the overall economy. The population estimates are converted to residential customers by applying household formation rates to each age group. The housing sector determines the stock of housing that relates to the residential customer forecasts.

The labor market and income components are combined to determine service area employment and income. In the labor sector, employment for four manufacturing categories plus the commercial and governmental sectors is projected. Employment is then combined with the wage equation of the income sector to determine local earnings. Since earnings represent 70 to 75% of total personal income, this is an important input for deriving regional personal income.

SHAPES

The power model is comprised of four major sectors: (1) residential, (2) commercial, (3) industrial, and (4) miscellaneous (governmental, street lighting, and transmission and distribution line losses). This structure emphasizes the projection of hourly demand values by end-use based on month, day type, and temperature. Repeating these calculations for each hour of the day and for all consumption units yields the daily load curve of the system. The energy consumption for any period is calculated by summing demand in each hour in the period for all end-uses.

More specifically, the basic equation upon which the model is based is:

$$D_{ij} = \Sigma\ N_i * C_i * F_{ij}$$

where:

D_{ij} = Demand at hour j by end-use component i;

N_i = Number of use components of type i;

C_i = Connected load per use component i;

F_{ij} = Fraction of connected load of use component i which is operating at hour j.

In the residential sector, the energy consuming units are the major household appliances. A list of the seventeen appliances treated explicitly in the model is provided in Table III-1. The appliance stock in a given year is influenced by the number of households, the mix of dwelling unit types, and family income. The latter two variables are used to derive saturation levels for each appliance which combined with the number of households, results in the total number of units of a given appliance.

Looking at these two factors in more detail, data analysis indicates that saturation levels for certain appliances vary significantly according to housing type. To capture these differences, the occupied housing stock or number of households is partitioned into single family, multi-family, and mobile home categories. In addition, it was determined that certain appliance saturations are related to the individual household's income level. Those appliances having this characteristic included room air conditioners, electric clothes dryers, clothes washers, and dishwashers. Projections of housing mix and per capita income, therefore, were utilized in developing saturation rates for these appliance categories.

To capture the trend of including ranges, central air conditioning, electric water heating, electric space heating or electric heat pumps as standard items in new construction, penetration rates representing the percent of new housing with these features were used to project saturation levels for these appliances. Finally, certain appliances such as television sets and refrigerators have already achieved full saturation. Future saturation levels are similar to present rates except for quality shifts or intercategory adjustments from standard to frost free refrigerators and black and white to color television.

The second major factor in the demand estimation equation is the connected load of the appliance, which was developed from company and industry studies. The last factor in the equation is the use factor or the probability of the appliance operating at a given time.

TABLE III-1. Appliances Treated Explicitly In End-Use Model

Electric Range
Refrigerator - Frost Free
Refrigerator - Standard
Freezer - Frost Free
Freezer - Standard
Dishwasher
Clothes Washer
Electric Dryer
Electric Water Heater
Microwave Oven
TV-Color
TV-Black and White
Lighting
Room Air Conditioner
Central Air Conditioner
Electric Space Heating
Electric Heat Pump
Miscellaneous

SOURCE: Tampa Electric Company

In the model, appliances can be separated into two groups: temperature insensitive and temperature sensitive. Those appliances which are temperature insensitive have use factors which vary by day type, month, and hour. Thus, the usage of these appliances is characterized by 1,152 use factors (12 months x 24 hours x 4 day types). These four day types are Sunday, Monday, Tuesday-Friday, and Saturday. For temperature-sensitive appliances, which include air conditioners, electric space heaters, and electric heat pumps, the monthly use factors are replaced by a set of factors which vary with respect to time and temperature. Therefore, the energy consumption of these appliances is a function of temperature, time, and day type. These temperature-related use factors are combined with monthly temperature probability matrices to calculate energy requirements over that period.

The model is capable of developing a residential as well as a system demand profile for each hour of each day type for all twelve months. In order to calculate peak demand, a temperature profile representing the expected hottest or coldest day must be input into the model. An average day load profile for each month can also be developed by supplying an average temperature for every hour.

The commercial sector of the model forecasts energy and demand by building type by end-use. This sector estimates energy intensity by end-use for each building type in terms of kWh per square foot of floor space. The forecast of building type square footage can be developed within the model using the REGIS employment forecast by building type and estimates of projected floor space per employee.

In addition, end-use saturation rate estimates are developed from surveys of the service area's commercial customers by building type. The original survey of this sector was performed by Xenergy, Inc. during 1994 as part of commission-sanctioned research into the cost effectiveness of commercial DSM programs

From the calculation of energy, commercial demand is determined by allocating annual consumption to the hours of the day through use factors. However, the commercial sector contains both temperature-sensitive and insensitive end-uses. The temperature-sensitive use patterns are a function of temperature and time. Therefore, peak demand is calculated, as in the residential sector, by specifying extreme temperatures to represent severe weather conditions.

The nine end-uses and eleven building types that are included in Tampa Electric's commercial floorspace building type model are listed in Table III-2.

TABLE III-2. Commercial Floorspace Model End-Uses and Building Types

End-Uses:

Air Conditioning	Miscellaneous
Cooking	Refrigeration
Exterior Lighting	Ventilation
Heating	Water Heating
Interior Lighting	

Building Types:

Colleges	Offices
Groceries	Retail
Health Care	Restaurants
Hospitals	Schools
Lodging	Warehouses
Miscellaneous	

The industrial and miscellaneous sectors of the model are less detailed than the residential and commercial customer classes due to a lack of connected load data. The industrial class is disaggregated into four major groups representing different levels of energy intensiveness. These include Food Products (SIC 20); Tobacco, Printing, etc. (SIC 21, 23, 24, 25, 27, 37, 39); Fabricated Metals, etc. (SIC 26, 29, 30, 34, 35, 36, 38); and Basic Industries (SIC 32, 33). In each sector, annual energy consumption is computed by multiplying energy use per employee times projected employment. Monthly energy consumption is calculated by allocating the annual energy to the corresponding month using historic ratios of monthly-to-annual consumption. Once monthly energy is computed, it is further broken down by hour for each of the four day types. That is, a use factor is applied which denotes the fraction of each month's energy that is consumed in a given hour. These use factors were developed from hourly billing data available for major industrial customers in each of the four categories.

The miscellaneous sector includes street lighting, sales to public authorities, and transmission and distribution line losses. For street lighting and public authorities, sales are expressed as a function of the number of residential customers, and demand is calculated using an allocation method similar to the industrial and commercial sectors.

The model also allows for price elasticity adjustments which represent the change in electric consumption resulting from changes in the relative price of electricity. In order to capture the price effect, an adjustment factor is applied to the annual consumption. The adjustment factor for a given year is a time-dependent weighted average of short and long-run elasticity. The general mathematical form of the consumption adjustment equation is as follows:

$$C_n = C_0 * \text{(Price Elasticity Adjustment Factor)}$$

where:

C_n = Consumption at the price level in year n, adjusted for price changes in years 0 to n.

C_0 = Consumption at the base year price level, that is, assuming no price changes.

The Adjustment Factor is given by the following:

Price Elasticity Adjustment Factor

$$\left(\frac{P_1}{P_0}\right)^{E_n} \cdots \left(\frac{P_i}{P_{i-1}}\right)^{E_{n-i+1}} \cdots \left(\frac{P_n}{P_{n-1}}\right)^{E_1}$$

where:

P_i = Price of electricity in period i (i = 1 to n).

E_i = Price elasticity coefficient expressed as a time-dependent weighted average of the short and long-run elasticity coefficients (i = 1 to n)

This relationship can be expressed as follows:

$$E_i = E_S + W_i(E_L - E_S)$$

where:

E_S = Short-run elasticity

E_L = Long-run elasticity

W_i = Weighting factor, $0 \leq W_i \leq 1$; $W_1 = 0$, $W_i = 1$ for $i \geq 12$.

The above relationship warrants two important observations. First, the price elasticity adjustment factor that is applied to a given year incorporates the effects of price changes not only for the given year but also for previous years. Second, the elasticity coefficient that is applied to a given year's price change increases numerically over time, gradually rising from the short-term elasticity value to the long-term. Therefore, each price increase or decrease has a lasting effect on future consumption patterns.

In the residential sector, each of the specific appliances was assigned a short-run and long-run elasticity. This was accomplished by partitioning the major appliances into three groups whose change in consumption due to price changes was considered to be either low, medium, or high (Table III-3). In certain cases, these elasticities were assigned subjectively while in other cases they were based upon studies by National Economic Research Associates (NERA) and the Electric Power Research Institute (EPRI). In addition, the resulting coefficients have the mathematical property that their combined effect, which represents the average residential elasticity coefficient, closely approximates the results of NERA and EPRI research. Therefore, their cumulative effect is in accord with extensive statistical analysis. The elasticity factors used for the commercial and industrial categories were also developed from these studies.

TABLE III-3. Sensitivity of Consumption to Price

Appliances with Low Assumed Price Sensitivity:

Refrigerator	Frost Free Standard
Freezer	Frost Free Standard
TV	Color Black and White

Appliances with Medium Assumed Price Sensitivity:

Electric Range
Clothes Washer
Electric Water Heater
Microwave Oven
Lighting

Appliances with High Assumed Price Sensitivity:

Dishwasher
Electric Dryer
Room Air Conditioner
Central Air Conditioner
Electric Space Heating
Electric Heat Pump

SOURCE: Based on studies by National Economic Research Associates and the Electric Power Research Institute.

Another factor influencing residential energy consumption is the movement toward more energy-efficient appliances. The forces behind this development include market pressures for more energy-efficient technologies and the appliance efficiency standards enacted by the state and federal governments. The efficiency goals affect the usage associated with new additions to the appliance stock.

It should be noted that the base year appliance energy consumption is influenced by both price effects and efficiency improvements. Thus, while some appliances are assumed to be rather price insensitive, their individual consumption levels decrease due to efficiency improvements.

2. Multiregression Demand and Energy Model

The retail multiregression forecasting model is a nine-equation model with two major sections. The energy section forecasts energy sales by the six major customer categories. The demand section forecasts peak load other than phosphate for both summer and winter. The regression technique is a more sophisticated approach than trend analysis as it attempts to examine those factors which influence load.

The selection of appropriate variables to include in the multiregression model equations is an extensive process that begins with the identification of variables that affect demand and energy. Those variables which can not be reasonably quantified or forecast are dismissed from the process. Results from regressions using the remaining variables are evaluated to determine which variables perform best. As a result, the chosen equations are both statistically and theoretically appropriate.

The basic series that make up the regression method are supplied by Tampa Electric Company, the U.S. Bureau of Labor Statistics, the U.S. Bureau of Economic Analysis, the U.S. Geological Survey, the Federal Reserve Board, the National Oceanic and Atmospheric Administration, and the University of Florida's Bureau of Economic and Business Research. All projections of the independent variables in these equations are consistent with those used in the end-use model.

Demand Section

The demand section consists of three regression equations for load other than phosphate. One equation is for the base load which, by definition, is that load on the system that is independent of temperature. The remaining two equations describe the summer peak temperature-sensitive demand and the winter peak temperature-sensitive demand. From regression analysis, the following relationships have been determined.

1.

$$\text{Base Load} = -174.7 + 4.635 * \#\ \text{Residential Customers} \underset{(t = 62.4)}{} - 1835.7 * \$/\text{kWh (lagged 1 year)} \underset{(t = -2.4)}{} + 0.1830 * \text{MA}(2) + 0.3743 * \text{MA}(4)$$

(t = 62.4) (t = -2.4)

$\bar{R}$-Squared = .99 DW = 1.9

2.

$$\text{Temperature Sensitive Demand (Summer)} = (F^\circ - 65)(32.95 + 0.1084 * \#\ \text{A/Cs} - 411.8 * \$/\text{kWh (lagged 2 periods)})$$

(t = 10.3) (t = -3.8)

$\bar{R}$-Squared = .91 DW = 1.7

3.

$$\text{Temperature Sensitive Demand (Winter)} = (65 - F^\circ)(-0.6282 + 0.1297 * \#\ \text{Electric Heaters})$$

(t = 31.9)

$\bar{R}$-Squared = .93 DW = 1.9

The Variables are defined as follows:

Base Load	The temperature-insensitive component of demand (MW).
Temperature-Sensitive Demand	The load component (MW) which is affected by heating or air conditioning on the system.
# Residential Customers	The average number of residential customers (in thousands).
$/kWh	Tampa Electric Company's average cost of electricity per kWh adjusted for inflation.
F° (Summer)	Average 24-hour temperature for the day of the system peak load.
F° (Winter)	Peak hour temperature at the time of the system peak load.
# A/Cs	Number of residential air conditioners (in thousands) calculated by multiplying residential customers by cooling saturation levels.

Electric Heaters — Number of residential electric heaters (in thousands) calculated by multiplying residential customers by electric heating saturation levels.

Energy Section

The Energy Section of the retail multiregression model consists of six equations that estimate future energy by the major Customer classes (residential, commercial, industrial other than phosphate, phosphate, sales to public authorities, and street and highway lighting.) These equations are listed below.

1.

Average Residential Usage = 5787.3 + 71.9 * Chg in Personal Inc. Per Capita (lagged 1 year) - 576.0 * Cts/Kwh (lagged 1 year) + 1.3 * Total Degree Days + 7631.2 * Htg/Cooling Saturation

(t = 2.8) (t= -9.6) (t = 5.3) (t = 20.9)

$\bar{R}$-Squared = .96 DW = 1.7

2.

Commercial Energy Sales = -1473.0 + 14.7 * Residential Customers - 82.8 * Cts/Kwh (lagged 1 yr) + 0.077 * Total Degree Days + 1.318 * MA (1)

(t = 78.0) (t = -5.0) (t = 1.9)

$\bar{R}$-Squared = .99 DW = 1.2

3.

Other Industrial Energy Sales = 311.7 + 6.6 * Ind Prod Index - 28.3 * Chg. in Cts/Kwh (lagged 1 yr) - 135.5 * Trade Dummy Variable

(t = 13.1) (t = -1.8) (t = -8.5)

$\bar{R}$-Squared = .88 DW = 1.7

4.

Phosphate Energy Sales = 1553.7 + 46.2 * U.S. Phosphate Mining - 65.7 * Cts/Kwh (lagged 1 year) + 0.915 * AR (1)

(t = 8.7) (t = -0.9)

$\bar{R}$-Squared = .93 DW = 1.3

5.

$$\text{Sales to Public Authorities} = 520.4 + 3.8 * \underset{(t = 8.4)}{\text{Residential Customers}} - 50.6 * \underset{(t = -1.0)}{\text{Chg in Cts/Kwh}} + .843 * \text{AR (1)}$$

$\bar{R}$-Squared = .99 DW = 1.5

6.

$$\text{Street Lighting} = - 32.4 + 0.108 * \underset{(t = 11.0)}{\text{Population}} = .756 * \text{AR (1)}$$

$\bar{R}$-Squared = .99 DW = 1.7

The Variables are defined as follows:

Population	Hillsborough County Population (in thousands).
Residential Customers	Service Area Residential Customers (in thousands).
Chg in Personal Inc. Per Capita	Percent change in real personal income per capita in Hillsborough County.
Htg/Cooling Saturation	Weighted average of heating and cooling saturation rates.
Total Degree Days	Sum of heating and cooling degree days (billing cycle adjusted).
Ind Prod Index	Industrial Production Index (1992 = 100).
U.S. Phosphate Mining	U.S. mining production (in millions of metric tons).
¢/kWh	Cost per kWh for a given customer class adjusted for inflation.
Chg in ¢/kWh	Percent change in cost per kWh for a given customer class adjusted for inflation.
Trade Dummy Variable	Dummy variable representing import substitution of local basic industries production.

3. Trend Analysis

The role of trend analysis in the Tampa Electric Company forecasting process has changed as the stability of fuel prices and supplies has decreased. The present economic and political environment throughout the world has contributed to changing energy consumption patterns resulting in a need for more sophisticated forecasting techniques. Trending provides a useful check for the more intricate methods used by the company in developing the Customer, Demand, and Energy Forecast.

The primary strength of trend analysis is simplicity. When applied to a series with stable growth patterns, this method is easy to use and is readily understood by those outside the forecasting process. The need for historical data is minimal, compared to other methods, and the need for external forecasts is alleviated as time is the only predictive variable. However, weaknesses are also a function of this simplicity. The use of time as the only explanatory variable limits the ability of the process to reflect changing economic conditions. Given the limitations of this technique, it can still be used to identify time trends, and it provides a familiarity with the data that aids in evaluating forecasts from other methods.

Trend analysis is applied to several variables including:

1. population;
2. residential customers;
3. system peak demand;
4. residential energy sales;
5. commercial energy sales;
6. industrial energy sales;
7. street lighting energy sales;
8. sales to public authorities; and
9. average usage per customer.

The implementation of trend analysis involves establishing a mathematical relationship between the independent variable (time) and the dependent variable. A forecast can be constructed by entering a future year into the equation. Evaluating the data over different time periods allows one to identify changes in the trend over time. Once trend estimates for the various components are established, they can be combined to yield a total sales forecast.

4. <u>Phosphate Demand and Energy Analysis</u>

Because Tampa Electric Company's phosphate customers are relatively few in number, the company's Marketing and Sales Department has obtained detailed knowledge of industry developments including:

1. knowledge of expansion and close-out plans;
2. familiarity with historical and projected trends;
3. personal contact with industry personnel;
4. governmental legislation;
5. familiarity with worldwide demand for phosphate products;
6. knowledge of phosphate ore reserves; and
7. correlation between phosphate rock production and energy consumption.

This department's familiarity with industry dynamics and their close working relationship with phosphate company representatives forms the basis for a survey of the phosphate customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast is based. Further inputs are provided by the multiregression model's phosphate energy equation and discussions with industry experts.

5. <u>Conservation, Load Management and Cogeneration Programs</u>

Tampa Electric has developed conservation, load management and cogeneration programs to achieve five major objectives:

1. to defer capital expansion, particularly production plant construction;
2. to reduce marginal fuel cost by managing energy usage during higher fuel cost periods;
3. to give customers some ability to control their energy usage and decrease their energy costs; and
4. to pursue the cost-effective accomplishment of ten-year demand and energy goals established by the Florida Public Service Commission (FPSC) for the residential and commercial/industrial sectors.
5. To achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act as enacted in guiding conservation policy for utilities in Florida.

The company's current DSM plan contains a mix of proven, mature programs that focus on the market place demand for their specific offerings. The following is a list that briefly describes the company's programs:

1. <u>Heating and Cooling</u> - Encourages the installation of high-efficiency heating and cooling equipment.

2. Load Management - Reduces weather-sensitive heating, cooling, water heating and pool pump loads through a radio signal control mechanism. In addition, commercial and industrial programs exist.

3. Energy Audits - The program is a "how to" information and analysis guide for customers. Five types of audits are available to Tampa Electric customers; three types are for residential class customers and two types for commercial/industrial customers.

4. Ceiling Insulation - An incentive program for existing residential structures which will help to supplement the cost of adding additional insulation.

5. Commercial Indoor Lighting - Encourages investment in more efficient lighting technologies within existing commercial facilities.

6. Standby Generator - A program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.

7. Conservation Value - Encourages investments in measures that are not sanctioned by other commercial programs.

8. Duct Repair - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky ductwork of central air-conditioning systems.

9. Cogeneration - A program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, produce their own electrical requirements and/or sell their surplus to the company.

The programs listed above were developed to meet the FPSC demand and energy goals established in Docket No. 930551-EG. These goals were recently modified by the Commission in Docket No. 971007-EG and the modified goals are a part of this Ten Year Site Plan. In Docket No. 991791-EG, Tampa Electric has before the Commission a new DSM plan designed to meet the new goals. Tampa Electric received Commision approval of this DSM plan on March 28, 2000. The plan contains the above listed programs as well as two new programs, namely, the Commercial Cooling Program and the Residential New Construction Program. The Commercial Cooling Program is designed to incent the installation of high-efficiency DX equipment on commercial buildings. The Residential New Construction Program provides incentives to build residential dwellings at an efficiency level greater than current State of Florida code-compliant baseline construction practices.

In addition, the Energy Answer Home and Street and Outdoor Lighting programs were completed in 1987 and 1990, respectively. The 1999 demand and energy savings achieved by conservation and load management programs are listed in Table III-4.

TABLE III-4
Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal
1995	24.0	36.0	66.7%	2.7	12.0	22.5%	12.2	21.0	58.1%
1996	56.7	72.0	78.8%	10.6	23.0	46.1%	28.3	41.0	69.0%
1997	79.2	107.0	74.0%	16.9	35.0	48.3%	43.6	60.0	72.7%
1998	103.4	142.0	72.8%	23.7	46.0	51.5%	61.2	80.0	76.5%
1999	119.9	177.0	67.7%	28.4	57.0	49.8%	77.7	99.0	78.5%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal
1995	5.1	2.0	255.0%	5.0	7.0	71.4%	11.7	29.0	40.3%
1996	13.1	5.0	262.0%	15.2	13.0	116.9%	27.4	59.0	46.4%
1997	14.4	7.0	205.7%	18.6	20.0	93.0%	42.0	90.0	46.7%
1998	15.7	9.0	174.4%	21.8	27.0	80.7%	55.2	120.0	46.0%
1999	21.5	12.0	179.2%	29.5	34.0	86.8%	68.1	151.0	78.5%

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal
1995	29.1	38.0	76.6%	7.7	19.0	40.5%	23.9	50.0	47.8%
1996	69.8	77.0	90.6%	25.8	36.0	71.7%	55.7	100.0	55.7%
1997	93.6	114.0	82.1%	35.5	55.0	64.5%	85.6	150.0	57.1%
1998	119.1	151.0	78.9%	45.5	73.0	62.3%	116.4	200.0	58.2%
1999	141.4	189.0	74.9%	57.9	91.0	63.7%	145.8	250.0	58.4%

To support the demand and energy savings filed as part of its plan, Tampa Electric Company developed its Monitoring and Evaluation (M&E) plan in response to requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources. Generally speaking, the M&E plan has as its focus two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give Tampa Electric Company insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

Wholesale Load

Tampa Electric's firm long-term wholesale sales consist of sales contracts with the City of Wauchula, the City of Fort Meade, Florida Power Corp., the City of St. Cloud, and the Reedy Creek Improvement District. Since Tampa Electric's sales to Wauchula and Fort Meade will vary over time based on the strength of their local economies, a multiple regression approach similar to that used for forecasting Tampa Electric's retail load has been utilized. Under this methodology, three equations have been developed for each municipality for forecasting energy and peak demand. These equations are shown on the following two pages.

WAUCHULA MULTIREGRESSION EQUATIONS

1.

Average Customer Usage = 3505.128 - 4.5696 * Change in \$/kWh + 0.03290 * Per Capita Income + 1.7670 * Cooling Degree Days + 2.1620 * Heating Degree Days

(t = - 0.7) for Change in \$/kWh; (t = 1.8) for Per Capita Income; (t = 19.6) for Cooling Degree Days; (t = 6.4) for Heating Degree Days

$\bar{R}$-Squared = .94 DW = 1.4

2.

Winter Peak Demand = - 11.6166 + 0.008141 * Total Customers + 0.1862 * Heating Degree Days

(t = 16.7) for Total Customers; (t = 11.2) for Heating Degree Days

$\bar{R}$-Squared = .91 DW = 1.9

3.

Summer Peak Demand = - 6.3040 + 0.005976 * Total Customers + 0.1854 * Cooling Degree Days - 21.4865 * Change in \$/kWh (lagged one month)

(t = 13.5) for Total Customers; (t = 4.5) for Cooling Degree Days; (t = -1.1) for Change in \$/kWh (lagged one month)

$\bar{R}$-Squared = .85 DW = 1.8

The Variables are defined as follows:

Change in \$/kWh	Change in average cost per kWh adjusted for inflation.
Per Capita Income	Real per capita income (seasonally adjusted).
Total Customers	The average number of total customers.
Heating Degree Days	65 degrees less the average 24-hour temperature.
Cooling Degree Days	Average 24-hour temperature less 65 degrees.

FORT MEADE MULTIREGRESSION EQUATIONS

1\.

Average Customer Usage = 3691.8890 – 19.3155 * $/kWh (t = -6.4) + 0.0837 * Change in Per Capita Income (t = 0.9) + 1.1203 * Cooling Degree Days (t = 12.8) + 1.6195 * Heating Degree Days (t = 4.9)

$\bar{R}$-Squared = .89 DW = 1.7

2\.

Winter Peak Demand = - 10.5291 + 0.006888 * Total Customers (t = 4.8) + 0.1313 * Heating Degree Days (t = 4.6)

$\bar{R}$-Squared = .68 DW = 1.8

3\.

Summer Peak Demand = 0.1546 + 0.004033 * Total Customers (t =4.4) + 0.05732 * Cooling Degree Days (t = 1.5) - 37.0750 * $/kWh (t = -3.3)

$\bar{R}$-Squared = .87 DW = 1.6

The Variables are defined as follows:

$/kWh	Average cost per kWh adjusted for inflation.
Change in Per Capita Income	Change in real per capita income (seasonally adjusted).
Total Customers	The average number of total customers.
Heating Degree Days	65 degrees less the average 24-hour temperature.
Cooling Degree Days	Average 24-hour temperature less 65 degrees.

For the remaining wholesale customers, future sales for a given year are based on the specific terms of their contracts with Tampa Electric.

Base Case Forecast Assumptions

Retail Load

1. Detailed End-Use Model

Numerous assumptions are inputs to the detailed end-use model of which the more significant ones are listed below.

1. Population and Residential Customers;
2. Commercial and Industrial Employment;
3. Per Capita Income;
4. Housing Mix;
5. Appliance Saturations;
6. Price Elasticity;
7. Price of Electricity;
8. Appliance Efficiency Standards; and
9. Weather.

Population/Residential Customers

The residential customer forecast is the starting point from which the demand and energy projections are developed. The most important factor in the customer forecast is the service area population estimate. The population estimate is based on Hillsborough County projections supplied by the University of Florida's Bureau of Economic and Business Research (BEBR), which are in the form of high, medium, and low forecasts. The REGIS model is utilized to determine where within the given range population growth is likely to be. For the 2000-2009 period, Hillsborough County population is expected to increase at a 1.4% average annual rate.

Household formation trends supplied by the U.S. Bureau of the Census are applied to the Hillsborough population projections to arrive at Hillsborough County households. Finally, service area household forecasts are determined by adjusting the Hillsborough County figures to reflect the relationship between service area and Hillsborough County residential customers. Since 1970, households in the service area have expanded at a faster rate than population due to a decline in household size. This decline in persons per household has been the result of lower birth rates, higher divorce rates, the postponement of marriage by young adults, and an aging overall population. During the next ten years (2000-2009), persons per household are expected to fall at an annual rate of 0.3%. Therefore, the household growth rate is expected to continue to exceed the population expansion rate in the service area over the next ten years.

Commercial and Industrial Employment

Commercial and industrial employment assumptions are utilized in computing energy and demand in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. REGIS, which interrelates these important variables, ensures this consistency. In addition, forecasts from outside consulting firms also provide input into formulating these assumptions. For the 2000-2009 period, commercial employment is assumed to rise at a 2.0% average annual rate while industrial employment growth of 2.0% per year is expected.

Per Capita Income, Housing Mix, Appliance Saturations

The stock of appliances, which comprises the nucleus of SHAPES' residential sector, is determined by multiplying the number of households by the saturation rate for each appliance. The assumptions for real per capita income growth and housing mix are critical in computing these saturations since many of the appliances are influenced by income levels and the type of housing (single, multi-family, mobile home) in the service area. The housing mix and per capita income growth rates for the local area are based on forecasts from REGIS as well as from outside consulting services. For the 2000-2009 period, real per capita income is expected to increase at a 2.1% average annual rate.

Price Elasticity/Price of Electricity

Price elasticity measures the rate of change in the demand for a product, electricity in this case, that results from a change in its relative price. The expected elasticity effect can be quantified by multiplying this factor by the assumed change in the real price of electricity (See Page III-8). During the 1970s, price elasticity played a major role in slowing demand and energy growth due to the sharp increase in the price of electricity resulting from an explosion in fuel costs. Since 1981, an easing in fuel price pressures has been an important factor in keeping electricity cost changes below the general pace of inflation. Over the next decade, this pattern is expected to continue as the price of electricity should increase at a rate slower than other products and services.

Appliance Efficiency Standards

Another factor influencing residential energy consumption is the movement toward more efficient appliances. The forces behind this development include market pressures for more energy-saving devices and the appliance efficiency standards enacted by the state and federal governments. The efficiency goals affect the usage associated with new additions to the appliance stock.

Weather

Since weather is the most difficult input to project, historical data is the major determinant in developing temperature profiles. For example, monthly profiles used in calculating energy consumption are based on ten years of historical data. In addition, the temperature profiles used in projecting the winter and summer system peak are based on an examination of the minimum and maximum temperatures for the past forty years plus the temperatures on peak days for the past fifteen to twenty years.

2. Multiregression Demand and Energy Model

The multiregression model utilizes assumptions which are common to SHAPES. These assumptions include future inputs for population, residential customers, income, saturation levels for air conditioners/heaters, and the price of electricity. In all cases where the multiregression and SHAPES models use common input variables, the assumptions for these inputs are the same and result in forecasts which are consistent and comparable.

Wholesale Load

Wauchula and Ft. Meade projections are developed from regression equations which, in turn, are driven by forecasts of customers, real per capita income, and the real price of electricity. For the 2000-2009 period, total customers are projected to expand at a 0.8% and 1.1% annual rate, respectively. Also, real per capita income for both cities is projected to grow annually at a pace of 1.6% and 1.4%, respectively.

High and Low Scenario Forecast Assumptions

Retail Load

The high and low peak demand and energy projections represent alternatives to the company's base case outlook. The high band represents a more optimistic economic scenario than the base case (most likely scenario) with greater expected growth in the areas of customers, employment, and income. The low band represents a less optimistic scenario than the base case with a slower pace of service area growth.

The assumptions related to the high, low, and base peak demand and energy cases are presented in Table III-5. For all other assumptions, including weather and price elasticity, the assumptions remain the same as in the base case scenario.

Wholesale Load

Likewise, high and low forecast scenarios are developed for wholesale customers Wauchula and Fort Meade. For these two municipalities, a percent change was applied to the wholesale base case to get the wholesale high and low forecast.

History and Forecast of Energy Use

A history and forecast of energy consumption by customer classification are shown in Table II-1 (Schedules 2.1 - 2.3) and Figure III-2.

Retail Energy

For 2000-2009, retail energy sales are projected to rise at a 2.4% annual rate. The major contributors to growth will continue to be the commercial, governmental, and residential categories. As a group, these three sectors will be increasing at a 2.9% annual rate.

In contrast, industrial sales are expected to decline over this period. Non-phosphate industrial consumption should register an annual gain over the coming years. However, this will be more than offset by a drop in phosphate sales due to an increase in self-service cogeneration and the southward migration of mining activity. This pattern reflects the changing American economy where the service sector is expanding at a rapid pace relative to manufacturing activity.

The combination of service area income growth and a declining real price of electricity has resulted in rising average residential usage in recent years. Over the 2000-2009 period, usage is anticipated to maintain this upward path based on expectations of continuing economic gains and a downward drift in the real price of electricity.

TABLE III-5. Economic Outlook Assumptions (2000-2009) For Retail Load Forecast

	Average Annual Growth Rate		
	BASE CASE	LOW GROWTH SCENARIO	HIGH GROWTH SCENARIO
Residential Customers	1.7%	1.3%	2.1%
Employment	1.4%	1.0%	1.8%
Real Per Capita Income	2.1%	1.6%	2.6%
Real Price of Electricity	-1.4%	-0.9%	-1.9%

Source: Tampa Electric Company

Wholesale Energy

Wholesale energy sales to FPC, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek of 291 GWh are expected in 2000, 299 GWh in 2001 and 267 GWh in 2002. Sales are expected to remain in the 243-264 GWh range for 2003-2009.

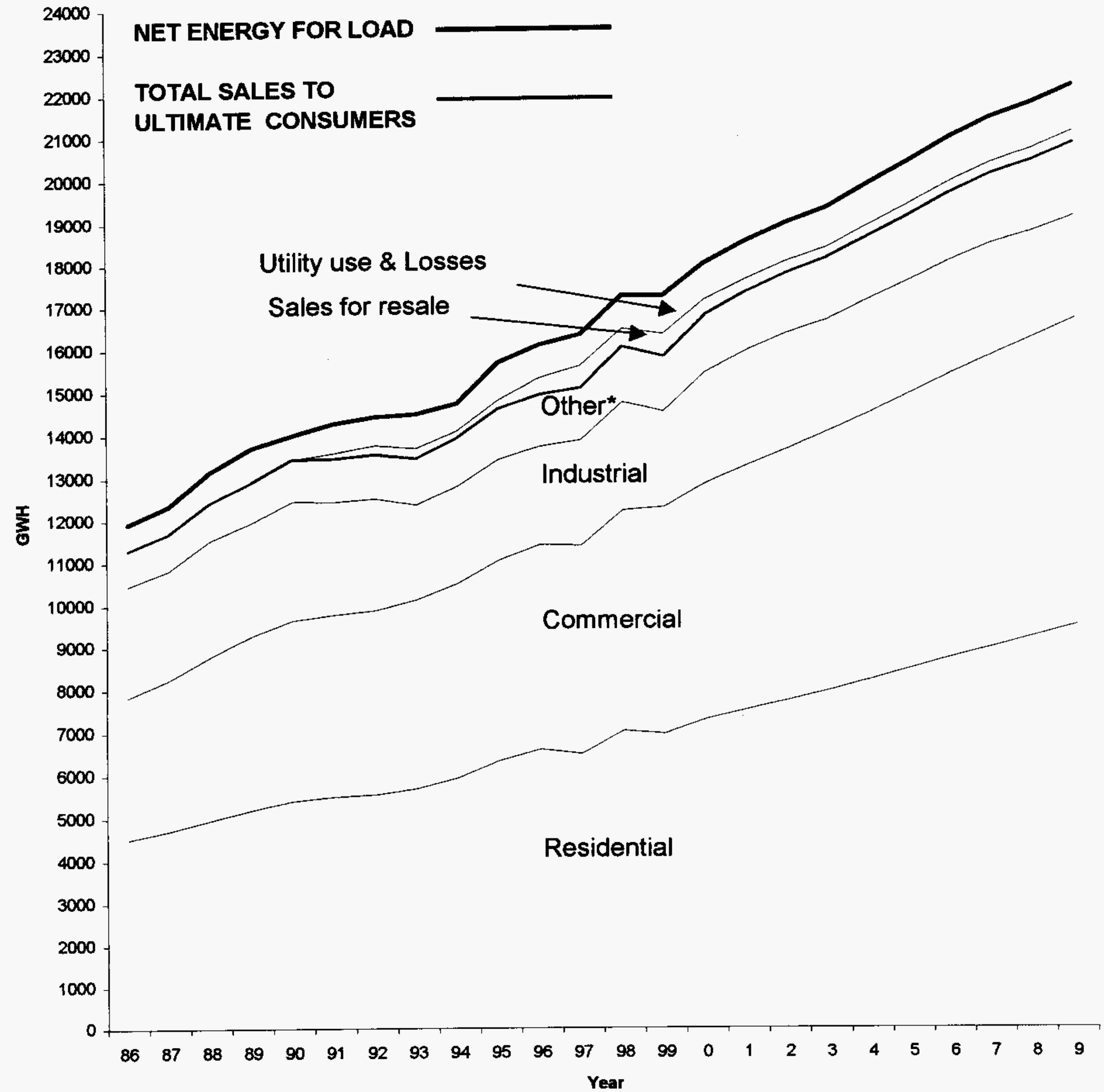
History and Forecast of Peak Loads

Historical and base, high, and low scenario forecasts of peak loads for the summer and winter seasons are presented in Tables II-2 and II-3 (Schedules 3.1 and 3.2), respectively. For the 2000-2009 period, Tampa Electric's base case retail firm peak demand for the winter and summer are expected to advance at annual rates of 3.0% and 3.1%, respectively. In addition, base, high, and low scenario forecasts of NEL are listed in Table II-4 (Schedule 3.3).

Monthly Forecast of Peak Loads for Years 1 and 2

A monthly forecast of retail peak loads (MW) and net energy for load (GWh) for years 1 and 2 of the forecast is provided in Table II-5 (Schedule 4) along with actual for 1999.

FIGURE III-2
HISTORY AND FORECAST OF ENERGY USE

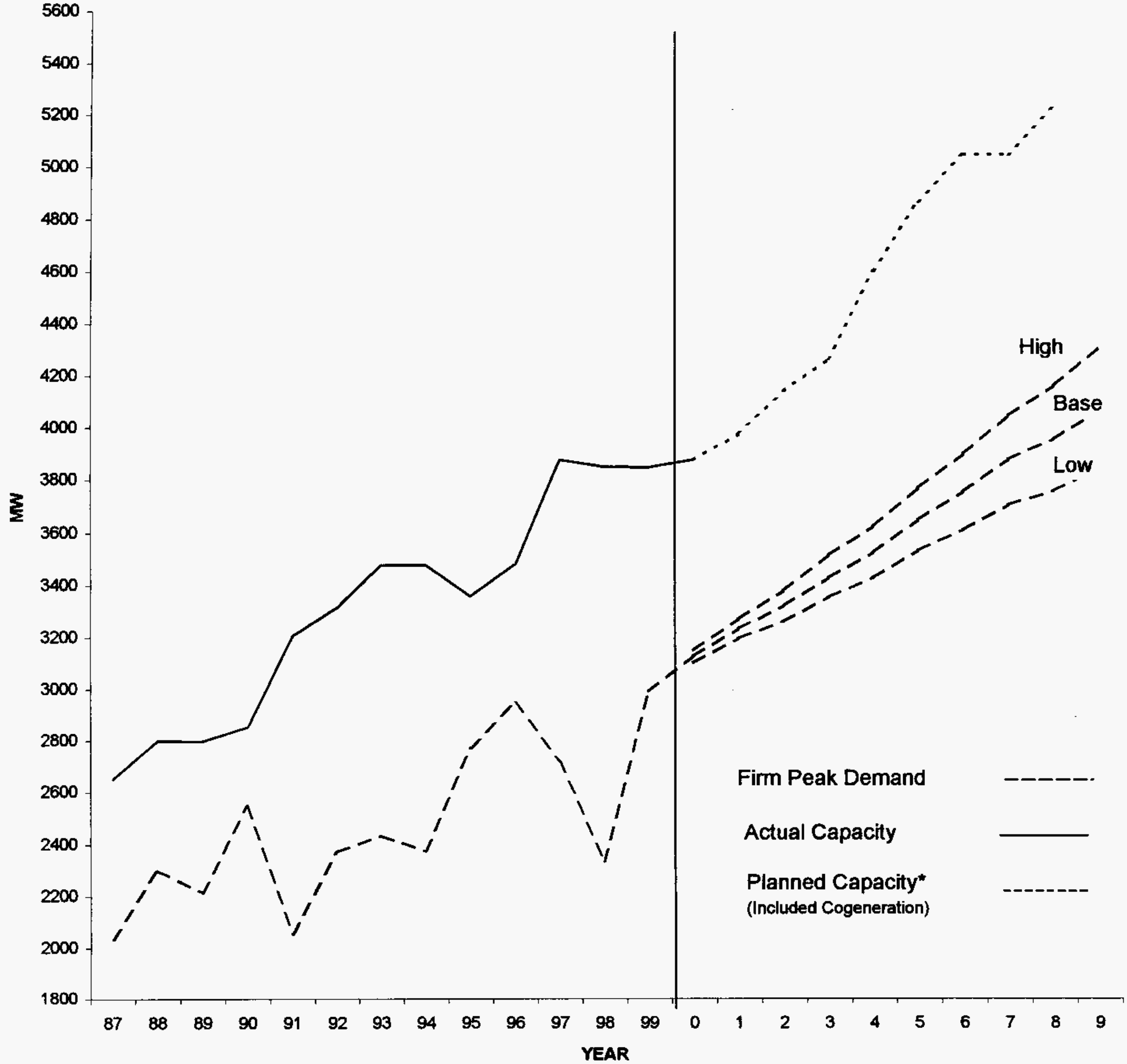


* Street & Highway Lighting and Sales to Public Authorities

TAMPA ELECTRIC COMPANY
Ten-Year Site Plan For Electrical Generating Facilities And Associated Transmission Lines

SOURCE: Tampa Electric Company

FIGURE III-3
HISTORY & FORECAST OF LOAD AND CAPACITY ADDITIONS
WINTER
(Page 1 of 2)

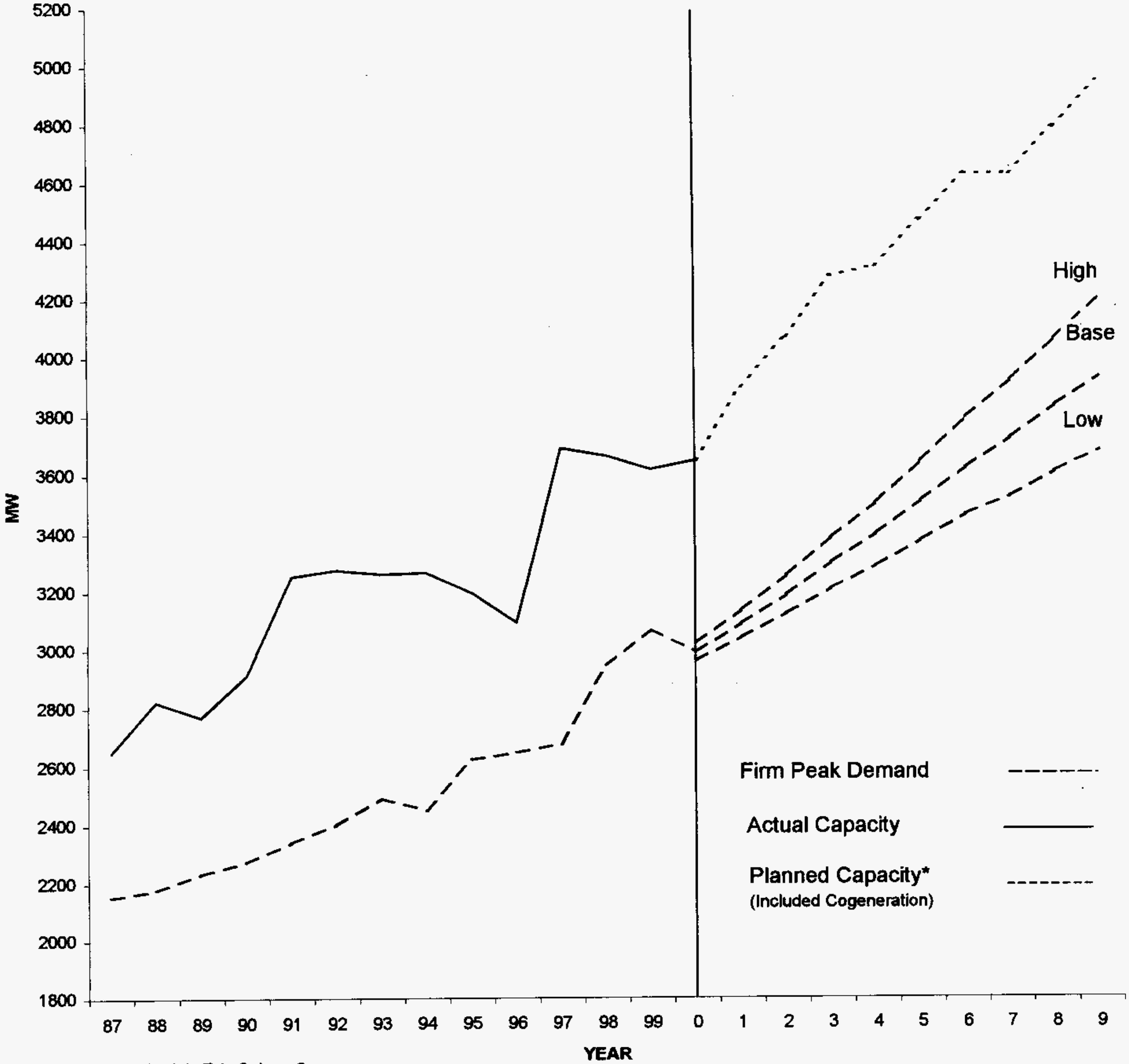


* Agrees with Schedule 7.2, Column6.

TAMPA ELECTRIC COMPANY
Ten-Year Site Plan For
Electrical Generating Facilities
And Associated Transmission Lines

SOURCE: Tampa Electric Company

FIGURE III-3
HISTORY & FORECAST OF LOAD AND CAPACITY ADDITIONS
SUMMER
(Page 2 of 2)



* Agrees with Schedule 7.1, Column6.

TAMPA ELECTRIC COMPANY
Ten-Year Site Plan For
Electrical Generating Facilities
And Associated Transmission Lines

SOURCE: Tampa Electric Company

CHAPTER IV

FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility additions and changes shown in Table IV-3 integrate demand side management programs and alternative generation technologies with traditional generating resources to provide economical, reliable service to Tampa Electric Company's customers. To achieve this objective, various energy resource plan alternatives comprised of a mixture of generating technologies, purchased power, and cost-effective demand side management programs are developed. These alternatives are analyzed with existing generating capabilities to develop a number of energy resource options which meet Tampa Electric's future system demand and energy requirements. A detailed discussion of Tampa Electric Company's integrated resource planning process is included in Chapter V.

The results of the analysis provide Tampa Electric Company with a plan that is cost-effective while maintaining system reliability and balancing other engineering, business, and industry issues. The new capacity additions are shown in Table IV-3. Additional capacity is planned for 2000, based on an analysis of system reliability, the incorporation of the FPSC demand side management goals, projected system demand and energy requirements, purchase power, and the existing Tampa Electric generating system. To meet the 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. These dual-fuel combustion turbines will be fired by natural gas and distillate oil. Additionally, Gannon Units 5 and 3 - 4 are planned to be repowered in 2003 and 2004, respectively, with three CT's and three HRSG's to supply steam to Unit 5 steam turbine and three CT's, and three HRSG's to supply steam to Unit 3 and 4 steam turbines. Gannon Units 1 and 2, and 6 will be put in long-term reserve stand-by in 2003 and 2004. For purposes of this Ten Year Site Plan, Hookers Point Station will be retired in January 2003. Tampa Electric's long-term purchased power contract with Hardee Power Partners Limited has increased beginning in the summer of 2000 to 368 MW summer net capability and 449 MW winter net capability for the entire study period with the addition of a combustion turbine at Hardee Power Station. Some of the assumptions and information that impact the plan are discussed below. Additional assumptions and information are discussed in Chapter V.

Cogeneration

Tampa Electric Company plans for 443 MW of cogeneration capacity operating in its service area in 2000. Self-service capacity of 242 MW (net) is used by cogenerators to serve internal load requirements, 45 MW are purchased by Tampa Electric on a firm contract basis, and 15 MW are purchased on a non-firm, as-available basis. The remaining 141 MW of cogeneration capacity is contracted to other utilities and exports out of Tampa Electric's system. By 2009, the cogeneration capacity within the service area is expected to increase to

459 MW. This total will consist of 262 MW of self-service capacity, 59 MW of firm capacity purchases by Tampa Electric and 13 MW of non-firm as-available purchases by Tampa Electric. The remaining 125 MW of cogeneration capacity is contracted to other utilities and exports out of Tampa Electric's system.

Fuel Requirements

A forecast of fuel requirements and energy sources is shown in Tables II-6 and II-7, respectively. At present, Tampa Electric Company plans to continue to use coal as the primary fuel for most of its generating requirements between 2000 and 2003. A major shift from coal to natural gas will occur with the Gannon repowering project beginning in 2003. This shift will reduce Tampa Electric's generation mix from 88% in 1999 to 55% in 2005. The Polk Unit 1 IGCC utilizes syngas as the primary fuel with No. 2 oil as the back-up. Tampa Electric Company plans to utilize a coal/petroleum coke blend to produce syngas. Tampa Electric Company is currently conducting test burns of coal/petroleum coke blend to produce syngas with environmental permit approval. This blend will result in the IGCC unit being the lowest incremental cost resource on Tampa Electric Company's system. Future combustion turbines will be duel-fueled by natural gas and No. 2 oil.

Title IV of the Clean Air Act

Phase II

Phase II compliance was implemented on January 1, 2000, and the CAAA affects all of the Company's existing and future electric generating units, with the exception of the Phillips Plant and existing combustion turbines. In Phase II, the Company is allocated only 83,882 allowances. In order to assure compliance with Phase II of the CAAA, the Company has considered a wide range of options for further reducing SO_2 emissions from its power plants to the required levels. Based on the limitation, Tampa Electric constructed a Flue Gas Desulfurization (FGD) system for Big Bend 1 and 2, with the scrubber going in service December 1999. Tampa Electric will continue fuel blending at the Gannon units and scrubbing Big Bend with the separate existing FGD systems until the implementation of the resolution with the United States Department of Environmental Protection (EPA) settlement requirements.

Tampa Electric reached resolution of environmental lawsuits by the Florida Department of Environmental Protection (DEP) and the United States Environmental Protection Agency (EPA), through settlements, on December 6, 1999 and February 29, 2000, respectively. These agreements are substantially the same with respect to environmental controls and pollution reductions required for Tampa Electric. The following is a summary of the combined pollutant specific requirements of these settlements.

Repowering of Gannon Station

Tampa Electric is required to repower Gannon Station from coal to natural gas using combustion turbines in a combined cycle mode. Tampa Electric is required to implement the repowering in a stepwise fashion through the repowering of units by May 1, 2003 and then additional units by May 1, 2004. Tampa Electric will then cease all coal combustion at the Gannon Station by December 31, 2004. Those units which are not repowered prior to January 1, 2005 will be available to Tampa Electric as future supply-side resource options, via repowering or conversion to natural gas to meet the growing demand and energy needs of its customers.

Particulate Matter (PM)

Tampa Electric must complete an optimization study on each of the Electrostatic Precipitators (ESP) at Big Bend Station. The optimization study shall recommend the best operational practices to minimize particulate matter emissions from each ESP, and the company must deliver the completed report to EPA for approval. Following approval by EPA, Tampa Electric is required to operate each ESP in conformance with the recommendations of the study.

Following the optimization study, Tampa Electric is required to complete a Best Available Control Technology (BACT) analysis of the ESPs at Big Bend Station and submit it to EPA for approval. Tampa Electric must then complete physical and operational changes as indicated by the optimization and BACT analysis to minimize emissions from each ESP at Big Bend on or before May 1, 2003.

Tampa Electric is also required to install, calibrate, and begin operations of a PM Continuous Emission Monitor (CEM) in the Unit 4 duct on or before March 1, 2002. If Tampa Electric decides to continue to combust coal at Big Bend and is still operating the PM CEM in the Unit 4 Duct, Tampa Electric plans to install one additional PM CEM on a second unit or duct at Big Bend by May 1, 2007.

Sulfur Dioxide (SO_2)

Commencing upon the latter of the date of the consent decree or September 1, 2000, Tampa Electric Company is required to operate the scrubber at all times that either Big Bend Unit 1 or 2 are in operation, except in specific situations. The emissions from Big Bend Units 1 and 2 must be scrubbed with at least 95% removal efficiency. Tampa Electric may operate Big Bend Units 1 and 2 during a scrubber outage if Tampa Electric operates all other units at Big Bend and Gannon Station with fully operational pollution control equipment before operating Big Bend Units 1 and 2 unscrubbed with the following limitations: during calendar year 2000 Big Bend Units 1 and 2 unscrubbed operation is limited to 60 days; from 2001-2012 operating Big Bend 1 and 2 unscrubbed is limited to 45 days annually; and, from 2001-2011 Tampa Electric may operate Big Bend Units 1 and 2 unscrubbed to avoid interrupting power to customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida. Starting in 2013 Big Bend Units 1 and 2 may not operate unscrubbed.

Commencing upon the latter of the date of the consent decree or September 1, 2000, Tampa Electric must operate the scrubber at all times that Big Bend Unit 3 is in operation except in specific situations. The emissions from Big Bend Unit 3 must be scrubbed with at least 93% removal efficiency. After May 1, 2002 until January 1, 2010 emissions from Unit 3 shall be scrubbed with at least 95% removal efficiency when Big Bend Unit 4 is not in operation. Tampa Electric is permitted to operate Big Bend Unit 3 during a scrubber outage if Tampa Electric operates all other units at Big Bend and Gannon Stations with fully operational pollution control equipment before operating Big Bend Unit 3 unscrubbed with the following limitations: during calendar year 2000-2009 operating Big Bend Unit 3 unscrubbed is limited to 30 days annually; and, from 2000-2009 Tampa Electric may operate Big Bend Unit 3 unscrubbed to avoid interrupting power to customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida. Starting in 2010, Big Bend units may not operate unscrubbed. Whenever Big Bend Units operate unscrubbed, they must do so utilizing coal with a sulfur content of 2.2 lb SO_2/mmBtu or less during 2000-2009 for Big Bend Unit 3 and 1.2 lb SO_2/mmBtu during 2010-2012 Big Bend Units 1 and 2.

Tampa Electric is also required to develop and submit to EPA a plan to maximize the availability of the scrubbers treating emissions from Big Bend Units 1, 2 and 3 by considering operation and maintenance changes.

Oxides of Nitrogen (NO_x)

By December 31, 2002, Tampa Electric must spend up to $3 million to attempt to reduce NO_x by 30% below 1998 levels on Big Bend Units 1 & 2 and 15% below 1998 levels on Big Bend Unit 3. Tampa Electric is also required to decide on a methodology to control emissions from all of the Big Bend units by 2007. By May 1, 2005, Tampa Electric must decide whether to install NO_x control, repower or shut down Big Bend Unit 4 and will implement the chosen methodology by June 1, 2007. If NO_x controls are installed, Big Bend Unit 4 must meet a NO_x emission rate of 0.10 lb/mmBtu.

By May 1, 2007, Tampa Electric will decide whether to install NO_x control, repower, or shut down Big Bend Units 1, 2, and 3 and will implement the chosen methodology beginning in 2008 May 1, 2010. If NO_x controls are installed, on either Big Bend 1, 2 or 3, the unit must meet a NO_x emission rate between 0.10 and 0.15 lb/mmBtu. Tampa Electric is also required to develop and submit to EPA a plan to implement $7 to $8 million dollars worth of innovative NO_x control technologies at either the Bayside or Big Bend Stations. This requirement must be implemented by December 31, 2004.

Interchange Sales and Purchases

Tampa Electric's long-term interchange sales include Schedule D, a Partial Requirements service agreement with Florida Power Corporation, a supplemental Schedule D service agreement with the Florida Municipal Power Authority and a Schedule G contract with Seminole Electric Cooperative, Inc. (SEC) for non-firm capacity and energy.

Tampa Electric has a long term purchase power contract for capacity and energy with Hardee Power Partners Limited (a TECO Power Services Corporation). The contract involves a shared-capacity agreement with SEC, whereby Tampa Electric plans for the full net capability of the Hardee Power Station during those times when SEC plans for the full availability of Seminole Units 1 and 2 and the SEC Crystal River Unit 3 allocation, and reduced availability during times when Seminole Units 1 and 2 are derated or unavailable due to planned maintenance. Tampa Electric also has an additional long-term purchase power contract with Hardee Power Partners Limited for 90 MW of firm non-shared winter capacity. The contract begins May 2000 and expires in 2012. A firm capacity sale from Tampa Electric's Big Bend Station Unit 4 is made available, on a limited energy usage basis, to Hardee Power Partners Limited for resale to SEC.

In addition to the above sales and purchases, Tampa Electric also has Schedule J service agreements for the interchanges/sale of as-available power with/to thirteen utilities in Florida and Georgia.

Wholesale power sales and purchases are included in Tables II-2, II-3, II-4, II-5, II-6, II-7, IV-1, and IV-2.

Schedule 7.1

Table IV-1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2000	3,463	455	(299)	46	3,665	3,164	501	16%	0	501	16%
2001	3,624	369	(147)	46	3,892	3,260	632	19%	0	632	19%
2002	3,779	369	(147)	62	4,063	3,360	703	21%	0	703	21%
2003	3837	369	0	62	4,268	3,470	798	23%	0	798	23%
2004	3872	369	0	62	4,303	3,567	736	21%	0	736	21%
2005	4,027	369	0	62	4,458	3,690	768	21%	0	768	21%
2006	4,182	369	0	62	4,613	3,801	812	21%	0	812	21%
2007	4,182	369	0	62	4,613	3,846	767	20%	0	767	20%
2008	4,337	369	0	62	4,768	3,954	814	21%	0	814	21%
2009	4,492	369	0	62	4,923	4,053	870	21%	0	870	21%

NOTE:
1. Per FPSC ruling November 1999 IOU's volunteered for 15% reserve margin to be increased to 20% starting summer 2004.
2. Capacity import includes the purchase agreement with TECO Power Services (TPS) beginning in 1993. Availability of this capacity is subject to back-up requirements for Seminole Electric Cooperative. Capacity import also includes firm transactions in the summer of 2000.
3. Capacity export includes 145 MW of Big Bend 4 which will be sold to TECO Power Services, on a limited basis, for use by Seminole Electric Cooperative. Capacity export also includes firm transactions to FMPA of 150 MW in 2000. Capacities shown in table include losses.
4. The QF column accounts for cogeneration that must be purchased under firm contracts. It also includes the impact of City of Tampa Refuse forced majeure deration of 16 MW for 2000 and 2001.
5. Total installed capacity does not include 11 MW from Dinner Lake unit which was placed on long-term reserve standby (LTRS) 03/01/94, nor 3 MW from Phillips HRSG which is on full forced outage with an undetermined return to service date.
6. Included are the 6 MW of distributive generation with the City of Tampa starting July 2000.
7. Installed capacity includes Hookers Point Station retired as of 01/01/2003 and Gannon Station repowering Units 3, 4 and 5, long term reserve standby (LTRS) of units 1, 2 and 6 and renaming the station to Bayside Power Station in 2003 - 2004.
8. Demand includes effects DSM goals.

* Values may be affected by rounding.

Schedule 7.2

Table IV-2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1999-00	3,594	551	(314)	46	3,877	3,257	620	19%	59	561	17%
2000-01	3,780	450	(299)	46	3,977	3,408	569	17%	0	569	17%
2001-02	3,780	450	(147)	62	4,145	3,495	650	19%	32	618	18%
2002-03	3,756	450	0	62	4,268	3,605	663	18%	0	663	18%
2003-04	4,098	450	0	62	4,610	3,702	908	25%	0	908	25%
2004-05	4,364	450	0	62	4,876	3,836	1,040	27%	0	1,040	27%
2005-06	4,544	450	0	62	5,056	3,944	1,112	28%	0	1,112	28%
2006-07	4,544	450	0	62	5,056	4,013	1,043	26%	0	1,043	26%
2007-08	4,724	450	0	62	5,236	4,091	1,145	28%	0	1,145	28%
2008-09	4,904	450	0	62	5,416	4,202	1,214	29%	0	1,214	29%

NOTE:

1. Per FPSC ruling November 1999 IOU's voluntered for 15% reserve margin to be increased to 20% starting summer 2004.
2. Capacity import includes the purchase agreement with TECO Power Services (TPS) beginning in 1993. Availability of this capacity is subject to back-up requirements for Seminole Electric Cooperative. Capacity import also includes firm transactions in the winter of 1999/2000.
3. Capacity export includes 145 MW of Big Bend 4 which will be sold to TECO Power Services, on a limited basis, for use by Seminole Electric Cooperative. Capacity export also includes firm transactions to New Smyrna Beach of 14 MW in 2000 and FMPA of 150 MW in 2000 and three months of 2001. Capacities shown in tables include losses.
4. The QF column accounts for cogeneration must be purchased under firm contracts. It also includes the impact of City of Tampa Refuse forced majeure deration of 16 MW for 2000 and 2001.
5. Total installed capacity does not include 11 MW from Dinner Lake unit which was placed on long-term reserve standby (LTRS) 03/01/94, nor 3 MW from Phillips HRSG which is on full forced outage with an undetermined return to service date.
6. Included are the 6 MW of distributive generation with the City of Tampa starting July 2000.
7. Installed capacity inlcudes Hookers Point Station retirment as of 01/01/2003 and Gannon Station repowering units 3, 4 & 5, and the long term reserve standby (LTRS) of Units 1, 2 & 6 and renaming the station to Bayside Power Station in 2003 - 2004.
8. Demand includes effects of DSM goals.

* Values may be affected by rounding.

Schedule 8

Table IV-3
Planned and Prospective Generating Facility Additions

Plant Name	Unit No.	Location	Type	Fuel Primary	Fuel Alternate	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW	Fuel Trans. Primary	Fuel Trans. Alternate	Status
Big Bend	CT2	Hills. Co.	CT	LO	N	2/00	6/00	unknown	78,750	4	0	WA	TK	P
Big Bend	CT3	Hills. Co.	CT	LO	N	2/00	6/00	unknown	78,750	4	0	WA	TK	P
Polk	2	Polk Co.	CT	NG	LO	11/99	9/00	unknown	unknown	155	180	PL	TK	P
Polk	3	Polk Co.	CT	NG	LO	10/01	5/02	unknown	unknown	155	180	PL	TK	P
Bayside	1	Hills. Co.	CC	NG	LO	10/01	5/03	unknown	unknown	698	796	PL	TK	P
Bayside	2	Hills. Co.	CC	NG	LO	8/02	5/04	unknown	unknown	711	802	PL	TK	P
Polk	4	Polk Co.	CT	NG	LO	1/03	1/05	unknown	unknown	155	180	PL	TK	P
Polk	5	Polk Co.	CT	NG	LO	1/04	1/06	unknown	unknown	155	180	PL	TK	P
Polk	6	Polk Co.	CT	NG	LO	1/06	1/08	unknown	unknown	155	180	PL	TK	P
Unnamed	1	unknown	CT	NG	LO	1/07	1/09	unknown	unknown	155	180	PL	TK	P

Note:
1. Big Bend CT units 2 and 3 will have a 4 MW summer capacity increase, with the addition of evaprotive cooling on their May 2000 maintenance outages making each units summer capacity 66 MW.
2. Gannon units 1, 2, and 6 are planned for long term reserve stand-by (LTRS). Unit 5 steam turbine will be repowered (RP) with three combustion turbines and renamed Bayside Power Station unit 1. Gannon units 3 and 4 steam turbines will be repowered (RP) with three combustion turbins and renamed Bayside Power Station unit 2.

SCHEDULE 9

TABLE IV-4
(Page 1 of 8)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 2
(2)	CAPACITY	
	A. SUMMER	155
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	NOV 1999
	B. COMMERCIAL IN-SERVICE DATE	SEPT 2000
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NO_X BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	Construction Permits Obtained
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2001)	12%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,580 Btu/kWh

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

TABLE IV-4
(Page 2 of 8)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 3
(2)	CAPACITY	
	A. SUMMER	155
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	OCT 2001
	B. COMMERCIAL IN-SERVICE DATE	MAY 2002
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NO_X BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	Construction Permits Obtained
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2003)	8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,580 Btu/kWh

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

TABLE IV-4
(Page 3 of 8)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE UNIT 1
(2)	CAPACITY	
	A. SUMMER	698
	B. WINTER	796
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	OCT 2001
	B. COMMERCIAL IN-SERVICE DATE	MAY 2003
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	ENGINEERING IN-PROGRESS
(7)	COOLING METHOD	ENGINEERING IN-PROGRESS
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	ENGINEERING IN-PROGRESS
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	Permit Application in-progress
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.9
	FORCED OUTAGE RATE (FOR)	5
	EQUIVALENT AVAILABILITY FACTOR (EAF)	91
	RESULTING CAPACITY FACTOR (2004)	55%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	7,080 Btu/kWh

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL GANNON OR BAYSIDE SITE.

SCHEDULE 9

TABLE IV-4
(Page 4 of 8)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE UNIT 2
(2)	CAPACITY	
	A. SUMMER	711
	B. WINTER	802
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	AUG 2002
	B. COMMERCIAL IN-SERVICE DATE	MAY 2004
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	ENGINEERING IN-PROGRESS
(7)	COOLING METHOD	ENGINEERING IN-PROGRESS
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	ENGINEERING IN-PROGRESS
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	Permit Application in-progress
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.9
	FORCED OUTAGE RATE (FOR)	5
	EQUIVALENT AVAILABILITY FACTOR (EAF)	91
	RESULTING CAPACITY FACTOR (2005)	40%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	7,050 Btu/kWh

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL GANNON OR BAYSIDE SITE.

SCHEDULE 9

TABLE IV-4
(Page 5 of 8)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 4
(2)	CAPACITY	
	A. SUMMER	155
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2003
	B. COMMERCIAL IN-SERVICE DATE	JAN 2005
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	UNDETERMINED
(7)	COOLING METHOD	UNDETERMINED
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2005)	7%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,580 Btu/kWh

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

TABLE IV-4
(Page 6 of 8)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 5
(2)	CAPACITY	
	A. SUMMER	155
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	JAN 2004
	B. COMMERCIAL IN-SERVICE DATE	JAN 2006
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	UNDETERMINED
(7)	COOLING METHOD	UNDETERMINED
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2006)	6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,580 Btu/kWh

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

TABLE IV-4
(Page 7 of 8)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 6
(2)	CAPACITY	
	A. SUMMER	155
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2006
	B. COMMERCIAL IN-SERVICE DATE	JAN 2008
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	UNDETERMINED
(7)	COOLING METHOD	UNDETERMINED
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2008)	6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,580 Btu/kWh

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

TABLE IV-4
(Page 8 of 8)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE SITE UNIT 1
(2)	CAPACITY	
	A. SUMMER	155
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2007
	B. COMMERCIAL IN-SERVICE DATE	JAN 2009
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	UNDETERMINED
(7)	COOLING METHOD	UNDETERMINED
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2009)	7%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,580 Btu/kWh

1 BASED ON IN-SERVICE YEAR.
2 INCLUDES $15 MILLION ESTIMATE FOR NEW SITE

Schedule 10

Table IV-5
Status Report and Specifications of Proposed Directly Associated Transmission Lines

Point of Origin and Termination	Number of Lines	Right-of-Way	Line Length	Voltage	Anticipated Construction Timing (in service by)	Anticipated Capital Investment	Substations	Participation with Other Utilities
So. Gibsonton 230 kV Circuit Addition	1	No new right of way is required	0.3 miles	230 kV	Summer 2002	$.7 million	No new substations	None
SR60 S. Tap Relocation	1	No new right of way is required	0.1 miles	230 kV	Summer 2002	$.2 million	No new substations	None
Barcola - Pebbledale	1	No new right of way is required	TEC 2.7 miles FPC 1.2 miles	230 kV	Fall 2003	TBD	No new substations	Joint Project with FPC
Gannon/Juneau Conversion	1	Possible road right-of-way required	14.5 miles	230 kV	Summer 2003	$13.0 million	Juneau (2) 230/69 kV Transformers	None
Juneau/Ohio	1	Possible road right-of-way required	4.5 miles	230 kV	Summer 2003	$4.0 million	No new substations	None
Dale Mabry to Juneau	1	Possible road right-of-way required	10.5 miles	230 kV	Summer 2004	$6.0 million	No new substations	None
Gannon to Davis	1	No new right of way is required	14.8 miles	230 kV	Summer 2005	$11.0 million	Davis Road 230 kV Switching Station	None
Polk - Lithia	1	Possible expansion of existing right-of-ways	22.0 miles	230 kV	Fall 2006	$15.0 million	Lithia 230 kV Switching Station	None
Lithia - Wheeler	1	No new right of way is required	11.0 miles	230 kV	Summer 2007	$8.5 million	Wheeler 230/69 kV Transformer	None
Lithia - Davis	1	No new right of way is required	14.4 miles	230 kV	Summer 2008	$9.0 million	No new substations	None
Chapman - Davis	1	No new right of way is required	9.0 miles	230 kV	Summer 2009	$7.0 million	No new substations	None

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CHAPTER V

OTHER PLANNING ASSUMPTIONS AND INFORMATION

Transmission Constraints and Impacts

Assessments of Tampa Electric's transmission system performance are based upon planning studies completed in 1999 in support of the company's transmission expansion plan. These studies are performed annually with the results of the study varying due to updates in load projections, planning criteria, operating flexibility and generation expansion plans. Based on existing studies and Tampa Electric's current transmission construction program, Tampa Electric anticipates no transmission constraints on its system which violate the submitted performance criteria contained in the Generation and Transmission Reliability Criteria section of this document.

Expansion Plan Economics and Fuel Forecast

The overall economics and cost-effectiveness of the plan were analyzed as stated in Tampa Electric's Integrated Resource Planning process, discussed in detail later in the chapter. As part of this process, Tampa Electric evaluated various planning and operating alternatives to current operations, with objectives ranging from meeting compliance requirements in the most cost-effective and reliable manner to maximizing operational flexibility and minimizing operational costs. Load forecasts used in the analysis are from the company's 2000 Fuel and Interchange Forecast.

The study was also updated from the most current planning assumptions including minimum reliability criteria of 15 percent firm reserve margin with a minimum 7 percent reserve margin from supply-side resources to 20 percent based on the stipulation between the FPSC and the three Florida investor owned utilities. This was a result of Docket 981890-EU approved in December 1999.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine those alternatives that were the most feasible options, overall. Those alternatives that failed to meet environmental acceptability, economics, technical feasibility, operational criteria, maintainability and reliability were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in the more detailed economic analysis.

Fuel commodity price for actual and forecasted data for the purpose of deriving base, high and low forecast pricing is done by careful analysis of historical, current and previous price forecasts obtained by various consultants and agencies. These sources include the Energy Information Administration, American Gas Association, Cambridge Energy Research Associates, Resource Data International, Coal Markets Weekly, Coal Daily, Energy Ventures Analysis, Inc., and coal, oil, natural gas, and propane pricing publications and periodicals which include: Coal Outlook, Inside FERC, Natural Gas Week, Platt's Oilgram, and the Oil and Gas Journal.

The high and low fuel price projections represent alternative forecasts to the company's base case outlook. The high and low price projection represents the effect of oil and natural gas prices escalating 10% above or below the base case and escalating at a slightly higher or lower escalation rate on a monthly basis for the year 2000. Annual high and low case price projections after 2000 are based on the company's internal general approach using information provided by consultants combined with internal fuel markets analysis.

With a large percentage of fuel utilized by the company being coal, only base case forecasts are prepared for coal fuels. Base case analysis and forecasts include a large number of coal sources and diverse qualities. The individual price forecasts contained within the base forecast capture the market pressures and sensitivities that would otherwise be reflected in high and low case scenarios.

Generating Unit Performance Modeling

Tampa Electric Company models generating unit performance in the Generation and Fuel (GAF) module of PROSCREEN, a computer model developed by New Energy Associates. This module is a tool to evaluate long-range system operating costs associated with particular generation expansion plans. Generating units in the GAF are characterized by several different performance parameters. These parameters include capacity, heat rate, unit derations, planned maintenance weeks, and unplanned outage rates. The unit performance projections that are modeled are based on historical data trends, engineering judgement, time since last planned outage, and recent equipment performance. Specifically, unit capacity and heat rate projections are based on historical unit performance test values which are adjusted as needed for current unit conditions. Planned outage projections are modeled two ways. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on an average of the first five years.

The five-year outage schedule is based on unit-specific maintenance needs, material lead time, labor availability, budget constraints, and the need to supply our customers with power in the most economical manner. Unplanned outage rate projections are based on an average of three years of historical data adjusted, if necessary, to account for current unit conditions.

Financial Assumptions

Tampa Electric makes numerous financial assumptions as part of the preparation for its Ten-Year Site Plan process. These assumptions are based on the current financial condition of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code, an amount for AFUDC is recorded by the company during the construction phase of each capital project. This rate is set by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.

- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the Ten-Year Site Plan.

- The financing cost rates reflect the incremental cost of capital associated with each of the sources of long-term financing.

- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.

- Depreciation represents the annual cost to amortize the total original investment in a plant over its useful life less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the Ten-Year Site Plan represents the average expected life for that type of investment.

Integrated Resource Planning Process

Tampa Electric Company's Integrated Resource Planning process was designed to evaluate demand side and supply side resources on a fair and consistent basis to satisfy future energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders. A flow diagram of the overall process is shown in Figure V-1.

The initial pass of the process incorporates a reliability analysis to determine timing of future needs, and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. In this pass, a demand and energy forecast which excludes incremental DSM programs is developed. Then a supply plan based on the system requirements which excludes incremental DSM is developed. This interim supply plan becomes the basis for potential avoided unit(s) in a comprehensive cost-effective analysis of the DSM programs. Once the cost-effective DSM programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the DSM programs and supply side resources. The same planning and business assumptions are used to develop numerous combinations of DSM and supply side resources that account for variances in both timing and type of resources added to the Tampa Electric Company system.

The cost-effectiveness of DSM programs is based on the following standard Commission tests: the Rate Impact Measure (RIM), the Total Resource Cost (TRC), and the Participants Tests. Using the Commission's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are used in this analysis. All measures that pass the RIM, TRC, and Participants Tests in the DSM analysis are considered for utility program adoption. Each adopted measure is quantified into annual kW/kWh savings and is reflected in the demand and energy forecast. Measures with the highest RIM values are generally adopted first. Tampa Electric Company evaluates DSM measures using a spreadsheet that comports with Rule 25-17.008, F.A.C., the Commission's prescribed cost-effectiveness methodology.

Generating resources to be considered are determined through an alternative technology screening analysis which is designed to determine the economic viability of a wide range of generating technologies for the Tampa Electric Company service area. Geographic viability, weather conditions, public acceptance, economics, lead-time, environmental acceptability, safety, and proven demonstration and commercialization are used as criteria to screen the generating technologies to a manageable number.

The technologies which pass the screening are included in a supply side analysis which examines various supply side alternatives for meeting future capacity requirements. These include modifying existing units by repowering or over-pressure operation and delayed retirements. Other supply resources such as constructing new unit additions, firm power purchases from other generating entities, joint ownership of generating capacity, and modifications of the transmission system to increase import capability are included in the analysis.

Tampa Electric Company uses the PROVIEW module of PROSCREEN, a computer model developed by New Energy Associates, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the time and type of capacity additions which would most economically meet the system demand and energy requirements. Dynamic programming compares all feasible combinations of generating unit additions which satisfy the specified reliability criteria and determines the schedule of additions which have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements used to rank each plan.

A detailed cost analysis for each of the top ranked resource plans is performed using the Capital Expenditure and Recovery module and the Generation and Fuel module of PROSCREEN. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources on our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

TAMPA ELECTRIC COMPANY
INTEGRATED RESOURCE PLAN METHODOLOGY

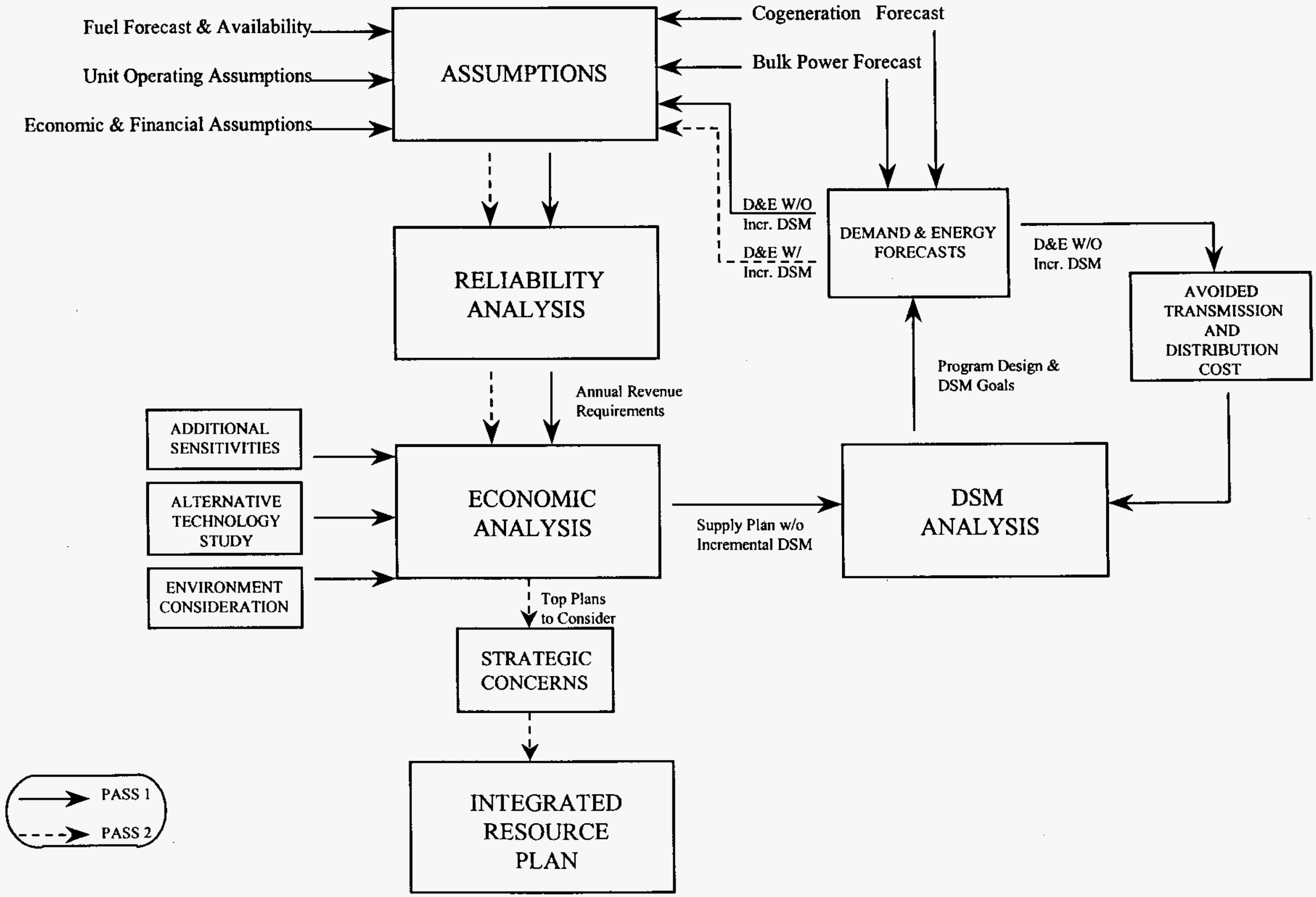


FIGURE VI

Strategic Concerns

Strategic issues which affect the type, capacity, and/or timing of future generation resource requirements are analyzed. These issues such as competitive pressures, environmental legislation, and plan acceptance are not easily quantified. Therefore, a strategic analysis is conducted to compare the overall performance of each alternative resource plan under each issue. The strategic issues and economic analysis are combined to ensure that an economically viable expansion plan is selected which has the flexibility for the company to respond to future technological and economic changes.

To select the most cost-effective plan each alternative resource plan is analyzed on both a quantitative and qualitative basis. The quantitative analysis is based on comparing the cumulative present worth of revenue requirements for each alternative for both the base and sensitivity assumptions. The qualitative analysis considers these previously mentioned strategic issues.

The results of the Integrated Resource Planning process provides Tampa Electric Company with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Table IV-3. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, combustion turbines are planned for September 2000, May 2002, January 2005, 2006, 2008, and 2009. The Gannon repowering is planned for May 2003 and May 2004. All combustion turbines will be dual-fueled by natural gas and distillate oil. For the purposes of this study, Hookers Point Station is assumed to be retired in January of 2003. Tampa Electric's long-term purchase power contract beginning in summer 2000 for Hardee Power Partners Limited has increased with 368 MW summer net capability and 449 MW winter net capability for the entire study period.

Generation and Transmission Reliability Criteria

Generation

As part of the stipulation reached in Docket No. 981890-EU, Generic Investigation into the Aggregate Electric Utility Reserve Margins Planned for Peninsular Florida, the minimum firm Reserve Margin adopted by Tampa Electric has been voluntarily adjusted from 15% to 20%. As part of the stipulation, Tampa Electric agreed to achieve the planned 20% reserve margin criterion over a transition period of four years. Thus, Tampa Electric will reach a planned reserve margin of 20% by the summer of 2004 (Order No. PSC-99-2507-S-EU). In addition, Tampa Electric has further adopted a 7% minimum summer supply-side reserve margin, which will be transitioned into the planning process by the summer of 2004.

Tampa Electric's approach to calculating percent reserves is consistent with that outlined in the settlement agreement incorporated. The calculation of the minimum 20% reserve margin employs an industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and contracted unit sales) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100%. Since the reserve margin calculation assumes no forced outages, Tampa Electric includes the Hardee Power Station in its available capacity. Contractually, Hardee Power Station is planned to be available to Tampa Electric at the time of system peak. Also, the capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from Tampa Electric's available capacity.

Tampa Electric's summer supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the summer firm peak demand, and interruptible and load management loads.

Transmission

The following criteria are used as guidelines by Tampa Electric Company Transmission Planners during planning studies. However, they are not absolute rules for system expansion; the criteria are used to alert planners of potential transmission system capacity limitations. Engineering analysis is used in all stages of the planning process to weigh the impact of system deficiencies, the likelihood of the triggering contingency, and the viability of any operating options. Only by carefully researching each planning criteria violation can a final evaluation of available transmission capacity be made.

Generation Dispatch Modeled

The generation dispatched in the planning models is dictated on an economic basis and is calculated by the Economic Dispatch (ECDI) function of the PSS/E loadflow software. The ECDI function schedules the unit dispatch so that the total generation cost required to meet the projected load is minimized. This is the generation scenario contained in the power flow cases submitted to fulfill the requirements of FERC Form 715 and the Florida Reliability Coordinating Council (FRCC).

Since unplanned and planned unit outages can result in a system dispatch that varies significantly from a base plan, bulk transmission planners also investigate several scenarios that may stress Tampa Electric's transmission system. These additional generation sensitivities are analyzed to ensure the integrity of the bulk transmission system under maximized bulk power flows.

Transmission System Planning Criteria

Tampa Electric follows the FRCC planning criteria as contained in Section V of the FRCC System Planning Committee Handbook. In addition to FRCC criteria, Tampa Electric utilizes company-specific planning criteria. Listed below are the guidelines which are used prior to contingency analysis to identify any inherent system flaws:

<table>
<tr><th colspan="4">Transmission System Loading Limits</th></tr>
<tr><th colspan="2">Transmission System Conditions</th><th colspan="2">Acceptable Loading Limit for Transformers and Transmission Lines</th></tr>
<tr><td colspan="2">All facilities in service</td><td colspan="2">100% or less</td></tr>
<tr><th colspan="4">Transmission System Voltage Limits</th></tr>
<tr><th></th><th>Industrial Substation Buses at point-of-service</th><th>69 kV Buses</th><th>138 kV and 230 kV Buses</th></tr>
<tr><td>All facilities in service</td><td>0.950 - 1.050 pu</td><td>0.900 - 1.050 pu</td><td>0.950 - 1.060 pu</td></tr>
</table>

Single Contingency Planning Criteria

The following two tables summarize the thresholds which alert planners to problematic transmission line and transformers during single contingency scenarios.

Transmission System Loading Limits	
Transmission System Conditions	**Acceptable Loading Limit for Transmission Lines and Transformers**
Single Contingency, pre-switching	115% or less
Single Contingency, after all switching	100% or less
Bus Outages, pre-switching	115% or less
Bus Outages, after all switching	100% or less

Transmission System Voltage Limits			
Transmission System Conditions	**Industrial Substation Buses at point-of- service**	**69 kV Buses**	**138 kV and 230 kV Buses**
Single Contingency, pre-switching	0.925 - 1.050 pu	0.900 - 1.050 pu	0.925 - 1.060 pu
Single Contingency, after all switching	0.950 - 1.050 pu	0.900 - 1.050 pu	0.925 - 1.060 pu
Bus Outages	0.925 - 1.050 pu	0.900 - 1.050 pu	0.925 - 1.060 pu

Available Transmission Transfer Capability (ATC) Criteria

Tampa Electric adheres to the FRCC ATC calculation methodology as well as the principles contained in the NERC ATC Definitions and Determinations document.

Transmission Planning Assessment Practices

Base Case Operating Conditions

Transmission planners ensure that Tampa Electric's transmission system can first and foremost support peak and off-peak system load with no facility overload, voltage violation, or imprudent operating modes. Therefore, the first step in assessing the health of the transmission system is to guarantee that all equipment is within specified continuous loading and voltage guidelines. Consult the previous section for more specific system parameters.

Single Contingency Planning Criteria

The objective of transmission planning is to design a system that can sustain the loss of any single circuit element without loading any transmission line or transformer beyond its rating or resulting in voltage levels that deviate outside of the bandwidths set forth in the Transmission System Planning Criteria section. Any verified criteria violation which cannot be mitigated with an appropriate operating measure is flagged as a limitation on transmission system capacity. Consult the Transmission System Planning Criteria section of this document for more specific system parameters.

Tampa Electric plans on any given piece of transmission system equipment being unavailable for service at some point in time. In addition to Tampa Electric equipment being out of service, Tampa Electric transmission planners plan the system to tolerate the loss of service of equipment outside of Tampa Electric's control area. This mainly consists of bulk transmission system equipment and generation units throughout the state.

Multiple Contingency Planning Criteria

Criteria for multiple contingency conditions are the same as single contingency criteria but are simulated at off-peak load levels. Appropriate double contingencies are investigated at 100% load level when warranted by area load factors. Multiple contingency conditions are also used to gauge the urgency of system deficiencies which are identified during single contingency analysis as cause for concern.

First Contingency Total Transfer Capability Considerations

Bulk transmission planners also use multiple generator/transmission equipment contingency criteria to ensure that Tampa Electric's transmission system import corridors are loaded within approved limits in the event of a Tampa Electric generation shortfall. To accomplish this, statewide dispatches are investigated which load each of Tampa Electric's tie lines to their First Contingency Total Transfer Capability.
Base case and contingency conditions are then imposed to locate any transmission or sub-transmission weaknesses which would require reinforcement under such a scenario. When

necessary, bulk planners identify situations where FCTTC and/or internal system capacities should be increased to raise the capability of a transmission corridor.

FCTTC's which must be observed for Tampa Electric's multi-line corridors are listed below:

Tie Line Corridor	FCTTC
Lake Tarpon-Sheldon 230 kV	1100 MVA
Big Bend-Florida Power & Light 230 kV	1550 MVA

DSM Energy Savings Durability

Tampa Electric Company identifies and verifies the durability of energy savings from its conservation and DSM programs by several methods. First, Tampa Electric Company has established a monitoring and evaluation process where historical analysis identifies the energy savings. These include:

(1) end-use sub-metering of survey samples to identify savings achieved in residential duct repair and commercial indoor lighting programs;

(2) periodic notch test, for residential load management (Prime Time) to confirm the accuracy of Tampa Electric Company's load reduction estimation formulas;

(3) billing analysis of program participants compared to control groups to minimize the impact of weather abnormalities; and

(4) in commercial programs such as Standby Generator and C/I Load Management, the reductions are verified through submetering of those loads under control to determine participant incentives relative to demand and energy savings.

Secondly, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Where programs promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, air distribution system repairs), program standards require they be of a permanent nature. For example, the company's Commercial Indoor Lighting Program requires full-fixture replacement or hard- wiring of fixture replacements.

Supply Side Resources Procurement Process

Tampa Electric Company will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply side resources as well as suppliers of equipment and services will be identified using various data base resources and competitive bid evaluations, and will be used in developing award recommendations to management.

This process will allow for future supply side resources to be supplied from self-build, purchase power, or competitively bid third parties. Consistent with company practice, bidders will be encouraged to propose incentive arrangements that promote development and implementation of cost savings and process improvement recommendations. The procurement process will also demonstrate continued positive efforts by Tampa Electric to include minority, small, and women-owned businesses. Goals will be established and tracked to measure opportunities and awards realized by these firms.

Transmission Construction and Upgrade Plans

Tampa Electric's recently announced plans to repower Gannon Station, with the facility being renamed Bayside Power Station and the planned additional generating units at the Polk Power Station have impacted the prevailing direction of power flow throughout the company's bulk 230 kV system. Bayside Power Station repowering, which will include a net summer increase of approximately 250 MW, will contribute to the bulk flow changes. In addition to the internal impacts created by internal generation expansion plans, external system changes and expansion of generation (both utility and NUG) statewide also have significant impact to our internal bulk transmission flows.

Within the next three years, loads in the Eastern and Plant City Service areas that have traditionally been served by generation at Big Bend and Gannon, are now going to be served by new generation at Polk Power Station. This causes Big Bend and Gannon to redirect more power into the Central and Western Service Areas, resulting in numerous contingency overloads and low voltages. Thus, the first major transmission and substation construction projects are directed at improving the reliability and efficiency of the 230 kV bulk system that transmits power north from Big Bend and Gannon. Gannon's repowering and subsequent additional output emphasizes this northerly flow. Later, as load growth continues and more generation is installed at Polk, additional transmission lines and substations must be built to deliver this new generation into the load centers in Eastern, Central and Western Service Areas.

A detailed list of the construction projects can be found in Chapter IV, Schedule 10. This list represents the latest transmission expansion plan available. However, given the significance of the Gannon Station repowering, this plan is currently being reviewed and updated.

Green Energy Program

Tampa Electric has recently completed an 18kW photovoltaic installation at the Museum of Science and Industry (MOSI) located in Tampa, Florida. This endeavor is the flagship project for the company's proposed Green Energy Program. With customer support of the program, Tampa Electric anticipates adding 32 kW of photovoltaic capacity to our grid by year-end 2004. This addition of 32kW is expected to occur in two separate 16kW installations; one installation in 2001 and one in 2004. This will bring the company's total photovoltaic capacity to 50kW by year-end 2004.

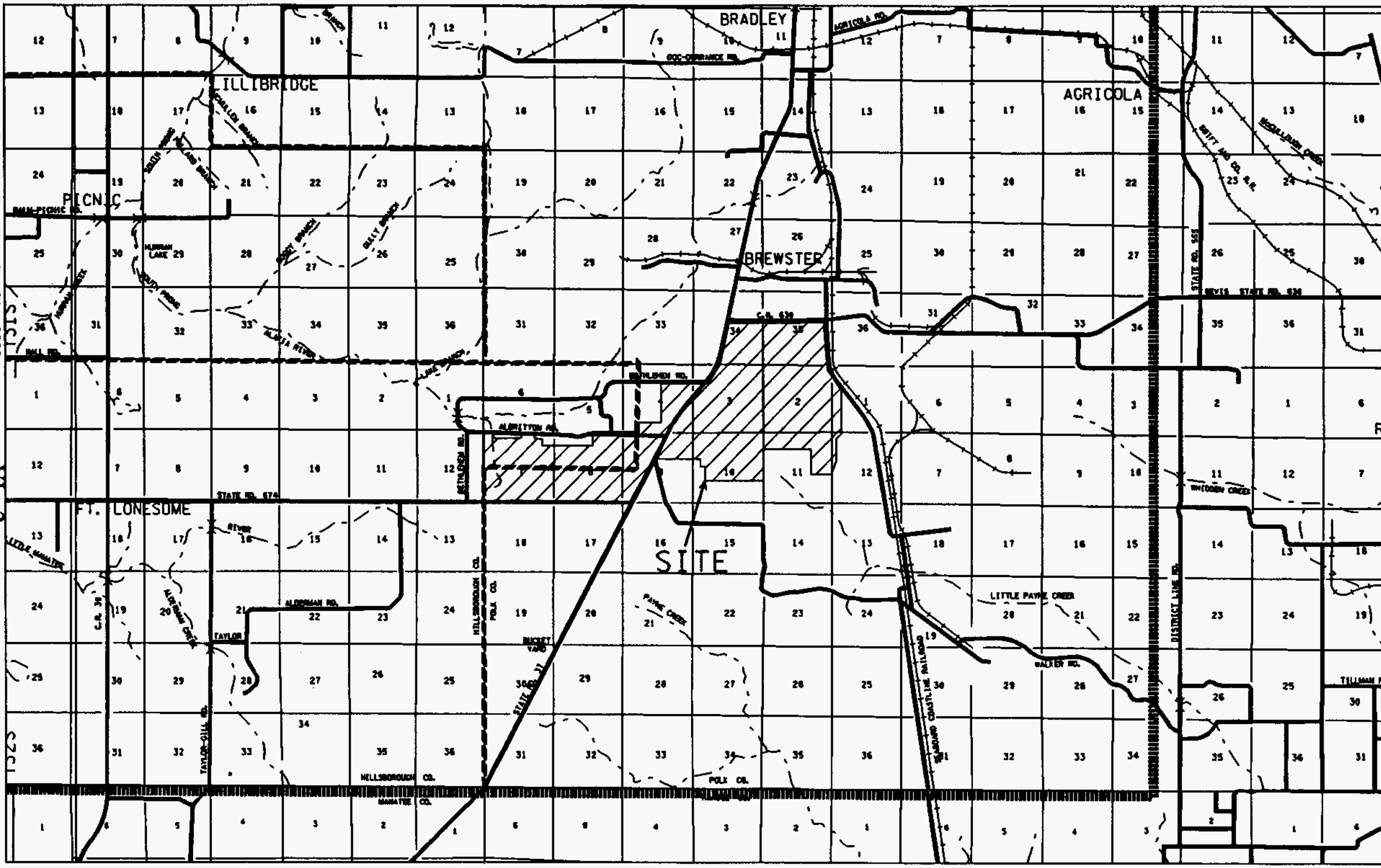
An additional energy source for the Green Energy Program utilizes biomass. Tampa Electric's mix of solar and biomass renewable resources is expected to satisfy the levels of customer subscriptions to the Green Energy Program. The company anticipates a significant portion of biomass energy to be generated at Gannon Station. However, as Gannon is repowered by 2004, the need for replacement facilities to generate "green energy" will exist. Tampa Electric is exploring various long-term options to ensure future availability of renewable energy sources.

CHAPTER VI

ENVIRONMENTAL AND LAND USE INFORMATION

The future generating capacity additions identified in Chapter IV will occur at the existing Polk Power Plant facility. The Polk Power Plant site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-1). This facility is an existing power plant site that has been permitted under the Florida Power Plant Siting Act.

FIGURE VI-1



SITE LOCATION OF POLK POWER STATION

SOURCES: FDOT MAP, FLA, ECT

TAMPA ELECTRIC COMPANY

TEN-YEAR SITE PLAN
FOR ELECTRICAL GENERATING FACILITIES
AND ASSOCIATED TRANSMISSION LINES

FILE NAME 403020.DGN
REVISION 3/9/2000 MMS