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ORIGINAL

990000

April 1, 1999

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 Tampa Electric Company's January 1999 to December 2008 Ten-Year Site Plan for Electric Generating Facilities and Associated Transmission Lines.

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

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AFA ___
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TECO

TAMPA ELECTRIC

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

JANUARY 1999 TO DECEMBER 2008

445.002 2/99

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

January 1999 to December 2008

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
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.

Generation by coal continues to be the most economical fuel alternative for satisfying Tampa Electric's energy requirement. Tampa Electric has eleven coal-fired units. Ten of these units are fired with pulverized coal while the Polk unit is fired with synthetic gas produced from gasified coal and other carbonaceous fuels. The Polk unit 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 1998 was 17,174 GWh.

Schedule 1

TABLE 1-1
Existing Generating Facilities
As of December 31, 1998

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days	(10) Commercial In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen. Max. Nameplate KW	(13) Net Capability Summer MW	(14) Net Capability Winter MW
Big Bend		Hillsborough											
		Co. 14/31S/19E									1,998,000	1,838	1,924
	1		FS	C	N	WA	N	0	10/70	Unknown	445,500	421	431
	2		FS	C	N	WA	N	0	4/73	"	445,500	421	431
	3		FS	C	N	WA	N	0	5/76	"	445,500	428	438
	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	114	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	1,107	1,167
	1		FS	C	N	WA	RR	0	9/57	Unknown	125,000	99	99
	2		FS	C	N	WA	RR	0	11/58	"	125,000	93	93
	3		FS	C	N	WA	RR	0	10/60	"	179,520	145	155
	4		FS	C	N	WA	RR	0	11/63	"	187,500	169	179
	5		FS	C	N	WA	RR	0	11/65	"	239,360	227	232
	6		FS	C	N	WA	RR	0	10/67	"	445,500	362	392
	CT1		CT	LO	N	WA	TK	0	3/69	"	18,000	12	17
Hookers Pt.		Hillsborough											
		Co. 19/29S/19E									232,600	204	212
	1		FS	HO	N	WA	N	0	7/48	01/03*	33,000	32	34
	2		FS	HO	N	WA	N	0	6/50	01/03*	34,500	32	34
	3		FS	HO	N	WA	N	0	8/50	01/03*	34,500	32	34
	4		FS	HO	N	WA	N	0	10/53	01/03*	49,000	41	43
	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	3,447	3,601

* This is currently being reviewed by Tampa Electric Company.

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

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

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

Plant Name	Land Area Total Acres	Land Area In Use Acres	Plant Capital Investment ($000) Land	Structures & Improvements	Equipment	Total
Hookers Point Station	25	25	$437	$7,963	$45,287	$53,687
Big Bend Station	1,124	1,124	5,147	157,203	868,356	1,030,706
Francis J. Gannon Station	213	213	1,556	61,635	393,013	456,204
Dinner Lake - Sebring	2	2	15	134	3,487	3,636
Phillips - Sebring	36	36	180	289	59,379	59,848
Combustion Turbine - Gannon	1	1	0	75	1,785	1,860
Combustion Turbines - Big Bend	75	75	834	1,695	20,878	23,407
Miscellaneous Production Services	47	47	94	6,939	5,797	12,830
Polk Power Station	4,347	4,347	18,919	110,915	394,089	523,923
TOTALS			$27,182	$346,848	$1,792,071	$2,166,101

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

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

Plant Name	Unit	Flue Gas Cleaning: Particulate	Flue Gas Cleaning: SO_x	Flue Gas Cleaning: NO_x	Cooling Type
Francis J. Gannon	1	EP	LS	NR	OTS
	2	EP	LS	NR	OTS
	3	EP	LS	NR	OTS
	4	EP	LS	NR	OTS
	5	EP	LS	NR	OTS
	6	EP	LS	NR	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	(1)	NR	OTS
	2	EP	(1)	NR	OTS
	3	EP	SC	(2)	(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	(2)	CLT
	2	NR	FQ	(2)	CLT
	HRSG 3	NA	NA	NA	NA
Polk	IGCC 1	NR	AGR	NI	OLS

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

December 31, 1998 Status.

(1) Coal blending of Big Bend units 1 and 2 will be replaced with a scrubber in 2000 to comply with Phase II of CAAA.
(2) NO_x controlled through unit operation.
(3) NO_x controlled through unit design and operation.
(4) OTS with fine mesh screens to minimize entrainment.

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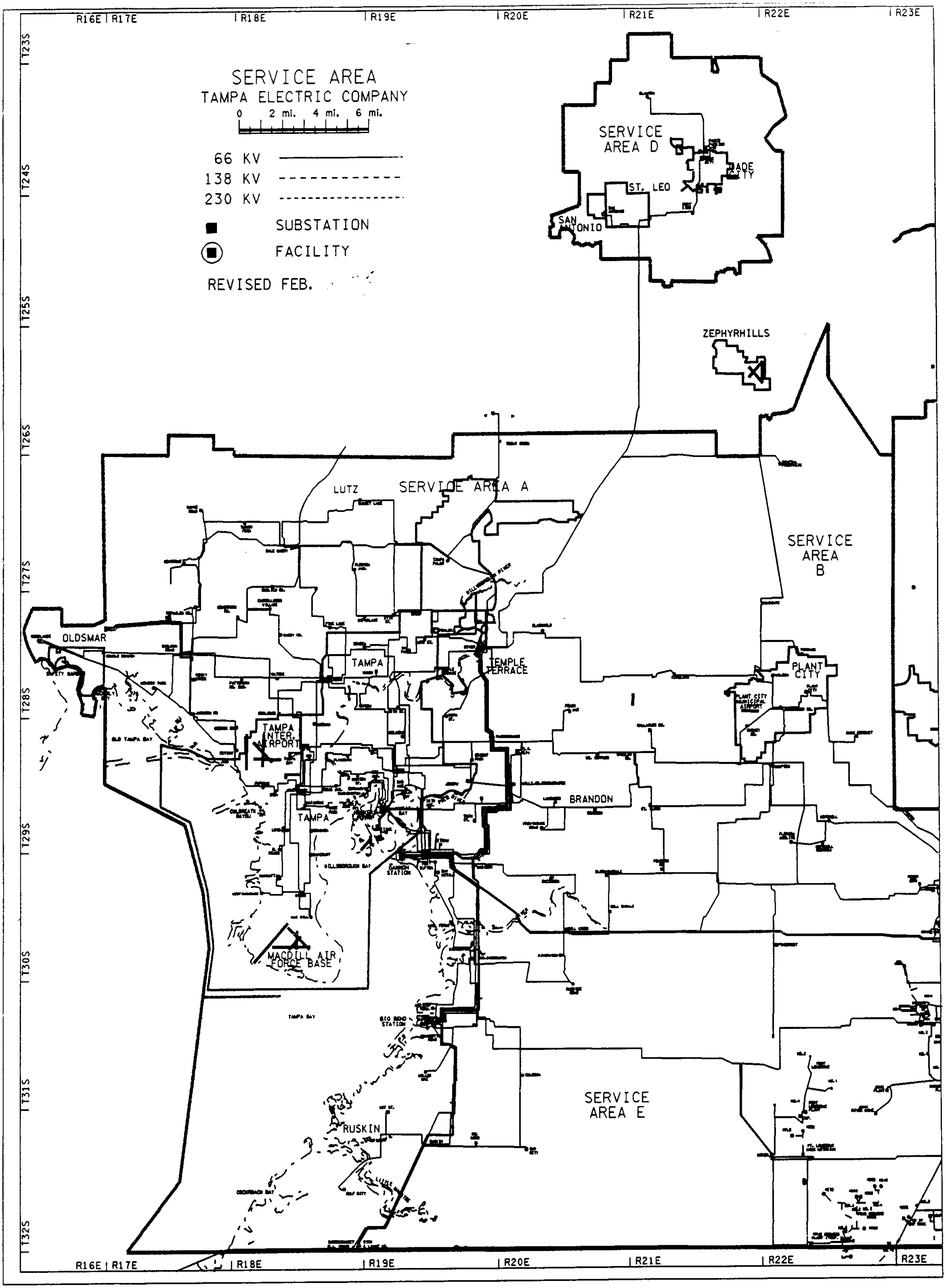
SERVICE AREA
TAMPA ELECTRIC COMPANY
0 2 mi. 4 mi. 6 mi.
66 KV
138 KV
230 KV
SUBSTATION
FACILITY
REVISED FEB.
R16E
R17E
R18E
R19E
R20E
R21E
R22E
R23E
T23S
T24S
T25S
T26S
T27S
T28S
T29S
T30S
T31S
T32S
SERVICE AREA D
DADE CITY
ST. LEO
SAN ANTONIO
ZEPHYRHILLS
LUTZ
SERVICE AREA A
SERVICE AREA B
OLDSMAR
TAMPA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

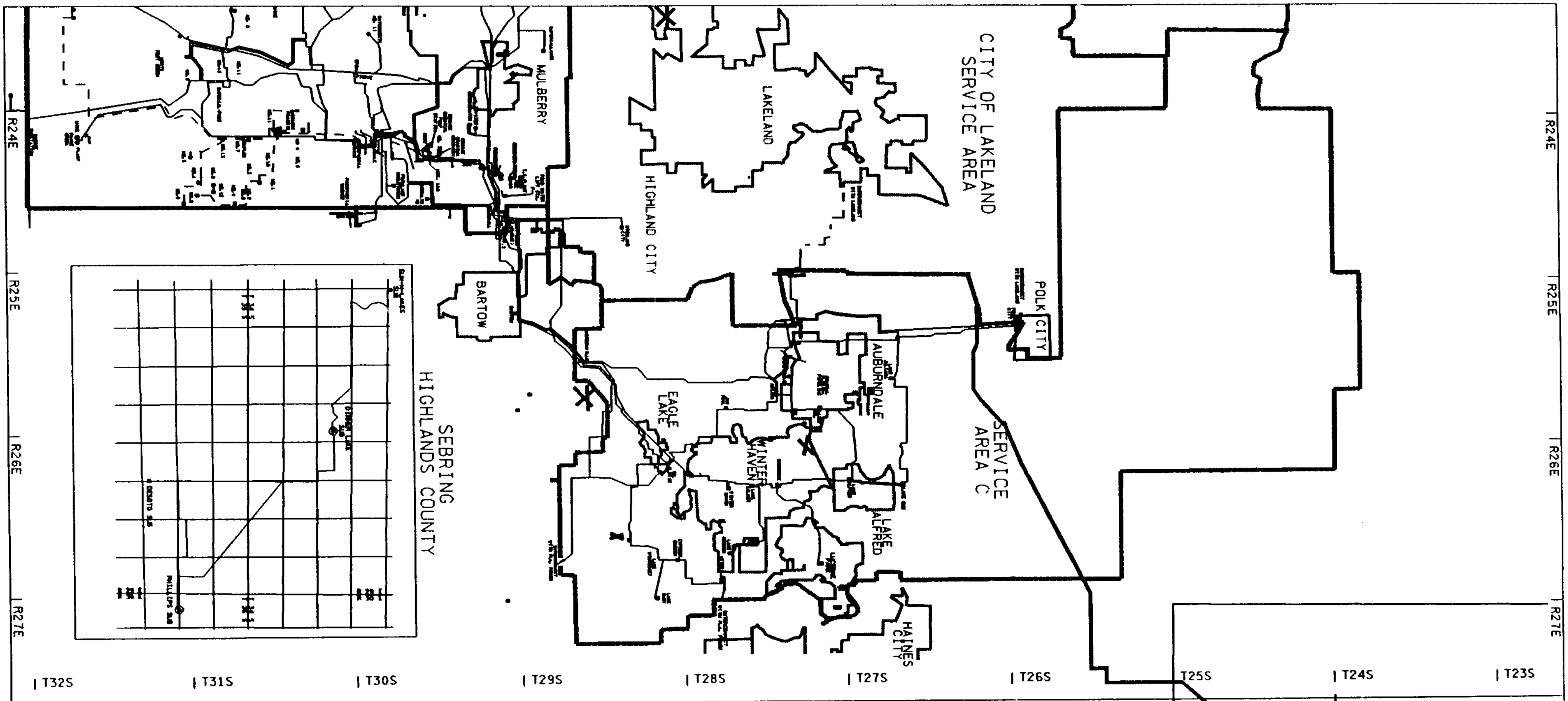

FIGURE I-1

TAMPA ELECTRIC RETAIL CUSTOMER SERVICE AREA

SOURCE: TAMPA ELECTRIC.

TAMPA ELECTRIC COMPANY

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

I - 6

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CHAPTER II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

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2. Table II-2: History and Forecast of Summer Peak Demand
3. Table II-3: History and Forecast of Winter Peak Demand
4. Table II-4: History and Forecast of Annual Net Energy for Load
5. Table II-5: Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month
6. Table II-6: History and Forecast of Fuel Requirements
7. Table II-7: History and Forecast of Net Energy for Load by Fuel Source

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
1989	822,621	2.5	5,214	393,278	13,258	4,062	49,780	81,599
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	944,689	2.4	7,050	466,189	15,123	5,173	58,542	88,364
1999	964,345	2.4	7,068	475,958	14,850	5,269	59,564	88,459
2000	986,239	2.4	7,300	486,104	15,017	5,493	60,493	90,804
2001	1,006,167	2.4	7,490	496,132	15,097	5,713	61,594	92,753
2002	1,025,335	2.4	7,704	505,574	15,238	5,923	62,752	94,387
2003	1,042,326	2.4	7,952	514,538	15,455	6,101	63,875	95,515
2004	1,058,678	2.4	8,209	523,101	15,693	6,285	64,948	96,770
2005	1,073,895	2.4	8,487	531,290	15,974	6,468	65,975	98,037
2006	1,088,493	2.4	8,757	539,188	16,241	6,651	66,964	99,322
2007	1,102,801	2.4	8,985	546,990	16,426	6,826	67,955	100,449
2008	1,116,970	2.4	9,235	554,743	16,647	6,999	68,941	101,522

* Average of end-of-month customers for the calendar year.
** Hillsborough County population.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

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						
Year	GWH	Average* No. of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
1989	2,672	536	4,985,075	0	40	907	12,896
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	16,027
1999	2,416	692	3,491,329	0	57	1,248	16,057
2000	2,524	692	3,647,399	0	59	1,283	16,660
2001	2,522	692	3,644,509	0	61	1,318	17,104
2002	2,418	692	3,494,220	0	64	1,353	17,462
2003	2,432	692	3,514,451	0	66	1,388	17,938
2004	2,435	692	3,518,786	0	68	1,423	18,420
2005	2,445	692	3,533,237	0	70	1,458	18,928
2006	2,444	692	3,531,792	0	73	1,493	19,418
2007	2,436	692	3,520,231	0	75	1,528	19,850
2008	2,257	692	3,261,561	0	78	1,563	20,133

* Average of end-of-month customers for the calendar year.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

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
1989	0	809	13,705	3,563	447,157
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	17,241	4,839	530,252
1999	402	850	17,309	4,770	540,984
2000	324	882	17,866	4,865	552,154
2001	324	906	18,334	4,961	563,379
2002	327	924	18,713	5,055	574,073
2003	333	949	19,220	5,146	584,251
2004	329	974	19,723	5,233	593,974
2005	337	1,001	20,266	5,316	603,273
2006	338	1,028	20,784	5,396	612,240
2007	298	1,050	21,198	5,476	621,113
2008	302	1,065	21,500	5,555	629,931

* 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.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

Schedule 3.1

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	
1989	2,583	0	2,583	315	71	19	2	9	2,233	*
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	3,426	128	3,298	222	101	53	24	21	2,877	
2000	3,546	129	3,417	233	103	57	25	24	2,975	
2001	3,661	130	3,531	233	104	61	26	27	3,080	
2002	3,755	130	3,625	219	106	65	27	30	3,178	
2003	3,860	130	3,730	220	107	68	27	32	3,276	
2004	3,959	125	3,834	219	108	71	28	35	3,373	
2005	4,070	131	3,939	221	109	74	29	37	3,469	
2006	4,176	132	4,044	222	110	77	30	40	3,565	
2007	4,260	112	4,148	222	111	79	31	42	3,663	
2008	4,350	112	4,238	201	112	82	31	45	3,767	

* 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.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

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	
1989	2,583	0	2,583	315	71	19	2	9	2,233	*
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	3,466	129	3,337	229	102	53	24	21	2,908	
2000	3,604	130	3,474	242	104	57	25	24	3,022	
2001	3,744	130	3,614	246	106	62	26	27	3,147	
2002	3,860	130	3,730	234	107	66	27	30	3,266	
2003	4,001	131	3,870	238	110	69	27	32	3,394	
2004	4,127	127	4,000	239	111	72	28	35	3,515	
2005	4,271	132	4,139	245	113	76	29	37	3,639	
2006	4,417	133	4,284	246	114	79	30	40	3,775	
2007	4,534	113	4,421	249	115	81	31	42	3,903	
2008	4,665	115	4,550	225	117	84	31	45	4,048	

* 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.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
Low Case
(Page 3 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	2,583	0	2,583	315	71	19	2	9	2,233	*
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	3,383	128	3,255	214	101	53	24	21	2,842	
2000	3,490	128	3,362	223	102	57	25	24	2,931	
2001	3,576	128	3,448	220	102	60	26	27	3,013	
2002	3,640	129	3,511	202	103	64	27	30	3,085	
2003	3,728	130	3,598	200	105	67	27	32	3,167	
2004	3,791	125	3,666	199	105	70	28	35	3,229	
2005	3,876	130	3,746	199	106	72	29	37	3,303	
2006	3,949	130	3,819	197	106	75	30	40	3,371	
2007	4,000	110	3,890	195	106	77	31	42	3,439	
2008	4,053	110	3,943	176	107	80	31	45	3,504	

* 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.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

Schedule 3.2

TABLE II-3
History and Forecast of Winter 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
1988/89	2,769	0	2,769	242	127	168	1	17	2,270 *
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	3,185	99	3,086	210	151	350	17	26	2,332
1998/99	4,041	131	3,910	200	222	381	16	27	3,064
1999/00	4,191	131	4,060	212	239	409	24	28	3,148
2000/01	4,339	133	4,206	212	243	438	24	29	3,260
2001/02	4,465	133	4,332	199	246	466	25	30	3,366
2002/03	4,599	134	4,465	200	249	491	25	31	3,469
2003/04	4,724	129	4,595	199	251	516	26	32	3,571
2004/05	4,863	134	4,729	201	254	539	27	33	3,675
2005/06	4,993	136	4,857	201	256	562	27	34	3,777
2006/07	5,103	116	4,987	202	258	584	28	35	3,880
2007/08	5,211	116	5,095	183	260	605	28	36	3,983

* 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.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

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
1988/89	2,769	0	2,769	242	127	168	1	17	2,270 *
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	3,185	99	3,086	210	151	350	17	26	2,332
1998/99	4,076	131	3,945	205	224	384	16	27	3,089
1999/00	4,253	132	4,121	221	242	414	24	28	3,192
2000/01	4,414	133	4,281	224	247	444	24	29	3,313
2001/02	4,563	134	4,429	212	250	475	25	30	3,437
2002/03	4,724	134	4,590	215	255	502	25	31	3,562
2003/04	4,891	130	4,761	218	258	530	26	32	3,697
2004/05	5,057	136	4,921	221	261	555	27	33	3,824
2005/06	5,222	136	5,086	223	265	581	27	34	3,956
2006/07	5,379	118	5,261	225	268	606	28	35	4,099
2007/08	5,531	118	5,413	205	271	630	28	36	4,243

* 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.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

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	
1988/89	2,769	0	2,769	242	127	168	1	17	2,270	*
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	3,185	99	3,086	210	151	350	17	26	2,332	
1998/99	4,004	131	3,873	195	220	378	16	27	3,037	
1999/00	4,130	131	3,999	203	236	405	24	28	3,103	
2000/01	4,256	132	4,124	200	239	432	24	29	3,200	
2001/02	4,356	132	4,224	185	241	457	25	30	3,286	
2002/03	4,469	133	4,336	184	243	480	25	31	3,373	
2003/04	4,565	128	4,437	181	244	503	26	32	3,451	
2004/05	4,674	134	4,540	182	245	523	27	33	3,530	
2005/06	4,776	134	4,642	180	247	544	27	34	3,610	
2006/07	4,846	114	4,732	178	248	563	28	35	3,680	
2007/08	4,938	114	4,824	162	249	581	28	36	3,768	

* 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.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

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 % **
1989	13,013	102	15	12,896	0	809	13,705	57.7
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	16,333	239	67	16,027	431	783	17,241	58.3
1999	16,404	267	80	16,057	402	850	17,309	54.4
2000	17,048	295	93	16,660	324	882	17,866	54.2
2001	17,533	323	106	17,104	324	906	18,334	54.1
2002	17,929	348	119	17,462	327	924	18,713	53.8
2003	18,441	373	130	17,938	333	949	19,220	53.8
2004	18,960	398	142	18,420	329	974	19,723	53.8
2005	19,504	422	154	18,928	337	1,001	20,266	53.9
2006	20,027	445	164	19,418	338	1,028	20,784	54.0
2007	20,491	467	174	19,850	298	1,050	21,198	54.0
2008	20,807	489	185	20,133	302	1,065	21,500	53.6

** 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.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

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 % **
1989	13,013	102	15	12,896	0	809	13,705	57.7
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	16,333	239	67	16,027	431	783	17,241	58.3
1999	16,606	269	80	16,257	403	861	17,521	54.6
2000	17,366	298	93	16,975	326	899	18,200	54.4
2001	17,956	327	106	17,523	327	928	18,778	54.4
2002	18,471	353	119	17,999	330	953	19,282	54.2
2003	19,123	380	130	18,613	336	986	19,935	54.3
2004	19,792	406	142	19,244	334	1,019	20,597	54.2
2005	20,486	432	154	19,900	344	1,054	21,298	54.4
2006	21,183	457	164	20,562	346	1,089	21,997	54.5
2007	21,825	481	174	21,170	306	1,121	22,597	54.4
2008	22,296	505	185	21,606	311	1,144	23,061	54.0

** 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.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

Schedule 3.3

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
Low Case
(Page 3 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 % **
1989	13,013	102	15	12,896	0	809	13,705	57.7
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	16,333	239	67	16,027	431	783	17,241	58.3
1999	16,200	265	80	15,855	401	840	17,096	54.6
2000	16,731	292	93	16,346	321	866	17,533	54.4
2001	17,099	319	106	16,674	321	883	17,878	54.2
2002	17,383	343	119	16,921	323	896	18,140	53.9
2003	17,763	367	130	17,266	328	914	18,508	53.8
2004	18,142	390	142	17,610	324	933	18,867	53.6
2005	18,531	412	154	17,965	331	951	19,247	53.7
2006	18,927	434	164	18,329	332	971	19,632	53.8
2007	19,230	454	174	18,602	290	985	19,877	53.7
2008	19,409	474	185	18,750	293	993	20,036	53.1

** 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.
Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

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)
	1998 Actual		1999 Forecast		2000 Forecast	
	Peak Demand	NEL	Peak Demand	NEL	Peak Demand	NEL
Month	MW	GWH	MW	GWH	MW	GWH
January	2,437	1,225	3,633	1,320	3,754	1,362
February	2,614	1,125	3,292	1,196	3,402	1,234
March	2,809	1,259	2,844	1,278	2,938	1,321
April	2,623	1,249	2,769	1,283	2,860	1,328
May	3,029	1,518	3,111	1,528	3,216	1,575
June	3,325	1,787	3,352	1,621	3,465	1,673
July	3,291	1,689	3,320	1,696	3,430	1,749
August	3,377	1,752	3,327	1,717	3,439	1,770
September	3,112	1,562	3,322	1,627	3,433	1,681
October	3,122	1,525	3,038	1,435	3,140	1,482
November	2,535	1,285	2,920	1,260	3,009	1,299
December	2,455	1,266	3,214	1,348	3,313	1,389
TOTAL		17,242		17,309		17,863

Includes effects of the DSM goals for 2000.
Values may be effected by rounding.

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 1997	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	8,021	7,811	8,144	8,032	7,940	7,923	8,038	8,111	8,223	8,235	8,340	8,471
(3)	Residual	Total	1000 BBL	427	469	680	922	680	708	136	144	157	178	179	176
(4)		Steam	1000 BBL	345	368	604	818	585	610	0	0	0	0	0	0
(5)		CC	1000 BBL	82	101	76	104	95	98	136	144	157	178	179	176
(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	319	401	364	512	594	623	733	841	1,086	1,316	1,408	1,460
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	250	237	229	244	245	245	245	245	244	244	244	245
(11)		CT	1000 BBL	70	164	135	268	348	378	488	596	842	1,072	1,164	1,215
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	0	0	0	0	1,329	1,474	2,450	3,867	5,153	5,945	7,561	8,318
(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	0	0	0	0	0	0	0
(16)		CT	1000 MCF	0	0	0	0	1,329	1,474	2,450	3,867	5,153	5,945	7,561	8,318
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	111	82	128	481	732	728	737	733	735	731	737	739

* Values shown may be affected by rounding.
** All values exclude ignition.

Schedule 6.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1997	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Annual Firm Interchange		GWh	(125)	413	68	(897)	(3)	329	463	520	610	709	689	720
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal*		GWh	17,033	16,502	17,144	16,681	15,753	15,734	15,970	16,163	16,326	16,351	16,537	16,865
(4)	Residual	Total	GWh	188	211	287	390	292	304	90	96	105	119	119	117
(5)		Steam	GWh	136	142	237	320	229	239	0	0	0	0	0	0
(6)		CC	GWh	52	68	51	69	63	65	90	96	105	119	119	117
(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	202	228	211	267	343	355	425	481	611	733	788	824
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	178	166	163	174	175	175	175	175	175	175	175	175
(12)		CT	GWh	24	62	47	93	168	180	250	306	436	559	614	649
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	0	0	0	0	112	125	210	350	474	547	700	758
(15)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(17)		CT	GWh	0	0	0	0	112	125	210	350	474	547	700	758
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWh	310	234	367	1,377	2,096	2,085	2,110	2,099	2,106	2,093	2,111	2,117
(20)	Net Interchange		GWh	(1,734)	(789)	(1,182)	(431)	(744)	(723)	(557)	(479)	(456)	(258)	(237)	(394)
(21)	Purchased Energy from Non-														
(22)	Utility Generators		GWh	453	443	415	479	483	505	509	491	491	491	491	491
(23)	Net Energy for Load		GWh	16,328	17,241	17,310	17,865	18,333	18,714	19,220	19,722	20,267	20,784	21,198	21,499

* Values shown may be affected by rounding.

Schedule 6.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1997	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Annual Firm Interchange		%	(1)	2	0	(5)	(0)	2	2	3	3	3	3	3
(2)	Nuclear		%	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal*		%	104	96	99	93	86	84	83	82	81	79	78	78
(4)	Residual	Total	%	1	1	2	2	2	2	0	0	1	1	1	1
(5)		Steam	%	1	1	1	2	1	1	0	0	0	0	0	0
(6)		CC	%	0	0	0	0	0	0	0	0	1	1	1	1
(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	1	2	2	2	2	3	4	4	4
(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	1	1	2	2	3	3	3
(13)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	%	0	0	0	0	1	1	1	2	2	3	3	4
(15)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	%	0	0	0	0	0	0	0	0	0	0	0	0
(17)		CT	%	0	0	0	0	1	1	1	2	2	3	3	4
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	2	1	2	8	11	11	11	11	10	10	10	10
(20)	Net Interchange		%	(11)	(5)	(7)	(2)	(4)	(4)	(3)	(2)	(2)	(1)	(1)	(2)
(21)	Purchased Energy from Non-														
(22)	Utility Generators		%	3	3	2	3	3	3	3	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 1999-2008 forecast. The data tables in Chapter II outline the expected customer, demand, and energy values for the 1999-2008 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.

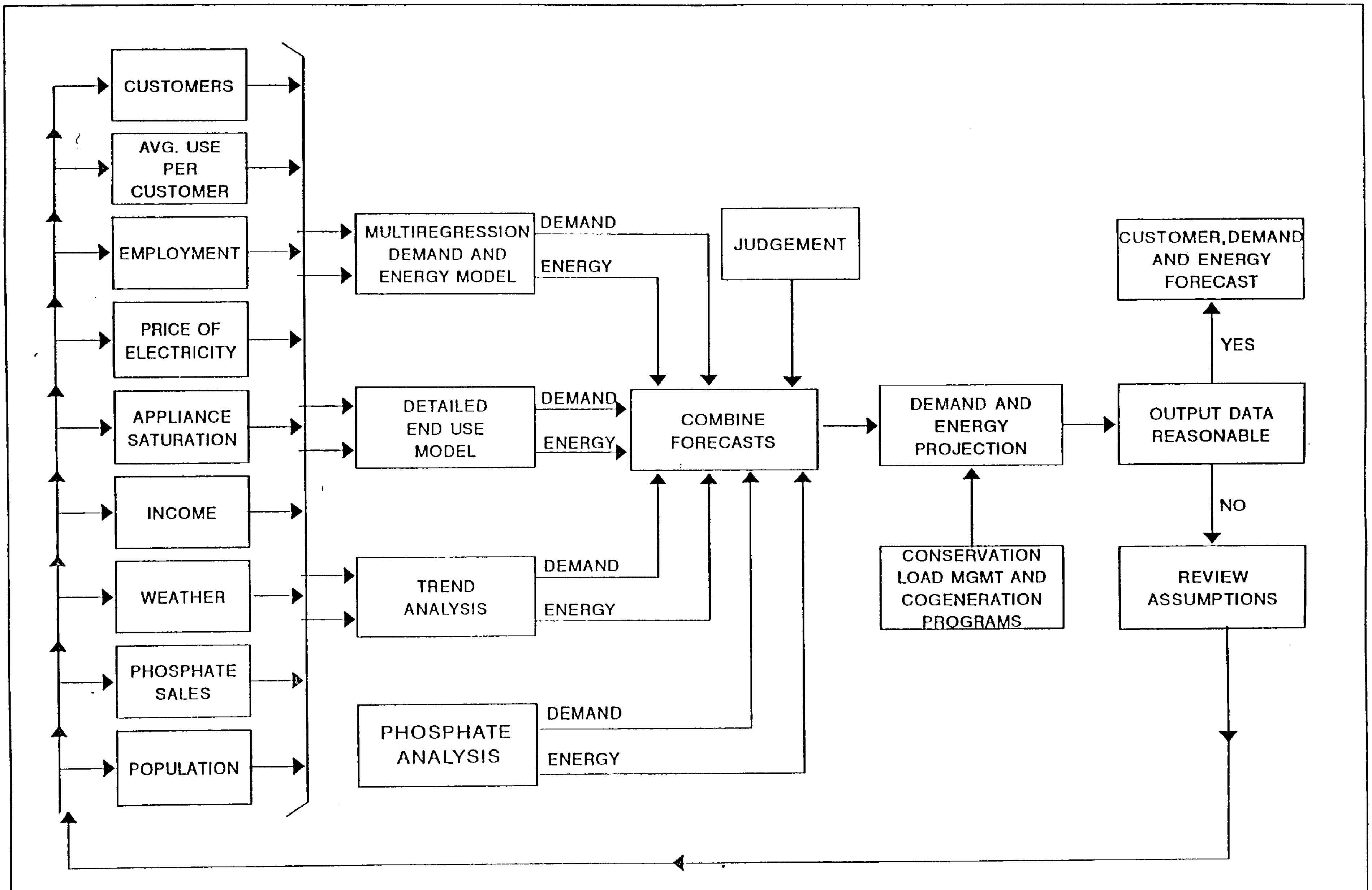


FIGURE III-1

Figure III-1

TAMPA ELECTRIC COMPANY CUSTOMER, DEMAND AND ENERGY FORECAST PROCESS

SOURCE: TAMPA ELECTRIC COMPANY

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

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

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

$$\left(\frac{P_1}{P_0}\right)^{\varepsilon_n} \cdots \left(\frac{P_i}{P_{i-1}}\right)^{\varepsilon_{n-i+1}} \cdots \left(\frac{P_n}{P_{n-1}}\right)^{\varepsilon_1}$$

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

<u>Appliances with Low Assumed Price Sensitivity:</u>

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

<u>Appliances with Medium Assumed Price Sensitivity:</u>

Electric Range
Clothes Washer
Electric Water Heater
Microwave Oven
Lighting

<u>Appliances with High Assumed Price Sensitivity:</u>

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.

Base Load = 70.159 + 4.3389 * # Residential Customers - 3707.9 * ¢/kWh (lagged 1 year)

(t = 35.8) (t = -3.7)

$\bar{R}$-Squared = .97 DW = 1.9

2.

Temperature Sensitive Demand (Summer) = (F° - 65) (20.718 + 0.1106 * # A/Cs - 244.53 * ¢/kWh (lagged 2 periods))

(t = 25.5) (t = -4.9)

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

3.

Temperature Sensitive Demand (Winter) = (65 - F°) (-0.9842 + 0.13284 * # Electric Heaters)

(t = 24.2)

$\bar{R}$-Squared = .89 DW = 1.4

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 = 6045.7 + 51.226 * Chg in Personal Inc. Per Capita (lagged 1 year) (t = 2.3) - 563.6 * ¢/kWh (lagged 1 year) (t = -8.9) + 1.06167 * Total Degree Days (t = 4.5) + 8362.9 * Htg/Cooling Saturation (t = 19.1)

$\bar{R}$-Squared = .94 DW = 1.7

2.

Commercial Energy Sales = -75.95 + 13.813 * Residential Customers (t = 23.2) - 583.0 * ¢/kWh (lagged 1 year) (t = -4.1)

$\bar{R}$-Squared = .99 DW = .94

3.

Other Industrial Energy Sales = 334.44 + 5.933 * Ind Prod Index (t = 7.7) - 88.7825 *Chg. in ¢/kWh (lagged 1 year) (t = -1.7) - 138.1 * Trade Dummy Variable (t = -6.2)

$\bar{R}$-Squared = .70 DW = 1.7

4.

Phosphate Energy Sales =1135.2 + 51.242 * U.S. Phosphate Mining (t = 10.3) - 331.39 * ¢/kWh (lagged 1 year) (t = -3.3)

$\bar{R}$-Squared = .84 DW = 1.0

5.

Sales to Public Authorities	= 530.50 + 2.4514 * Residential Customers - 251.11 * Chg in ¢/kWh		
		(t = 10.9)	(t = -4.4)

$\bar{R}$-Squared = .98 DW = 1.1

6.

Street Lighting	= - 29.073 + 0.10370 * Population	
		(t = 34.8)

$\bar{R}$-Squared = .98 DW = .70

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 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. Phosphate Demand and Energy Analysis

Because Tampa Electric Company's phosphate customers are relatively few in number, the 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.

These departments' 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. Conservation, Load Management and Cogeneration Programs

Tampa Electric has developed conservation, load management, and cogeneration programs to achieve four 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.

The company's current DSM plan contains a mix of proven, mature programs that focus on the market place demand for their specific offerings. Additionally, we have developed residential and commercial mail-in audits designed to more economically target customers who have the potential to benefit significantly from our energy management programs. The following is a list that briefly describes the company's programs:

1. Heating and Cooling - 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, a commercial/industrial program is in effect.

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

8. Duct Repair - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky heating and cooling air ducts.

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.

In addition, the Energy Answer Home and Street and Outdoor Lighting programs were completed in 1987 and 1990, respectively.

The 1998 demand and energy savings achieved by our 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%

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%

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%

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 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 = 3025.4 - 4.2441 * Change in ¢/kWh (t = - .98) + 0.05997 * Per Capita Income (t = 3.0) + 1.7935 * Cooling Degree Days (t = 19.6) + 2.5064 * Heating Degree Days (t = 7.0)

$\bar{R}$-Squared = .94 DW = 2.0

2.

Winter Peak Demand = - 11.427 + 0.00812 * Total Customers (t = 16.1) + 0.17877 * Heating Degree Days (t = 10.7)

$\bar{R}$-Squared = .90 DW = 1.8

3.

Summer Peak Demand = - 6.8121 + 0.0060109 * Total Customers (t = 11.4) + 0.20840 * Cooling Degree Days (t = 4.8) - 0.2670 * Change in ¢/kWh (lagged one month) (t = -1.4)

$\bar{R}$-Squared = .85 DW = 1.5

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 = 1008.4 - 66.786 * ¢/kWh + 0.1100 * Change in Per Capita Income
(t = -2.1) (t = 2.1)
+ 1.1327 * Cooling Degree Days + 1.5189 * Heating Degree Days
(t = 12.5) (t = 4.7)

$\bar{R}$-Squared = .87 DW = 1.9

2.

Winter Peak Demand = - 11.523 + 0.0072114 * Total Customers + 0.14632 * Heating Degree Days
(t = 5.1) (t = 4.7)

$\bar{R}$-Squared = .79 DW = 1.6

3.

Summer Peak Demand = - 2.0035 + 0.0043383 * Total Customers + 0.10790 * Cooling Degree Days
(t = 5.0) (t = 2.6)
- 0.29532 * ¢/kWh
(t = -2.8)

$\bar{R}$-Squared = .87 DW = 1.7

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 1999-2008 period, Hillsborough County population is expected to increase at a 1.7% 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 (1999-2008), persons per household are expected to fall at an annual rate of 0.3 percent. 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 1999-2008 period, commercial employment is assumed to rise at a 2.3% average annual rate while industrial employment growth of 1.5% 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 1999-2008 period, real per capita income is expected to increase at a 1.8% 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 1999-2008 period, total customers are projected to expand at a 1.4% and 1.2% annual rate, respectively. Also, real per capita income for both cities is projected to grow annually at a pace of 1.4% 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 1999-2008, retail energy sales are projected to rise at a 2.3% 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 2.8% 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 1999-2008 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 (1999-2008) For Retail Load Forecast

	Average Annual Growth Rate		
	BASE CASE	LOW GROWTH SCENARIO	HIGH GROWTH SCENARIO
Residential Customers	1.8%	1.4%	2.2%
Employment	1.5%	1.1%	1.9%
Real Per Capita Income	1.8%	1.3%	2.3%
Real Price of Electricity	-1.5%	-1.0%	-2.0%

Source: Tampa Electric Company

Wholesale Energy

Wholesale energy sales to FPC, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek of 402 GWh are expected in 1999, 324 GWh in 2000 and 324 GWh in 2001. Sales are expected to remain in the 298-338 GWh range for 2002-2008.

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 1999-2008 period, Tampa Electric's base case retail firm peak demand for the winter and summer are expected to advance at annual rates of 2.9% and 3.0%, 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 1998.

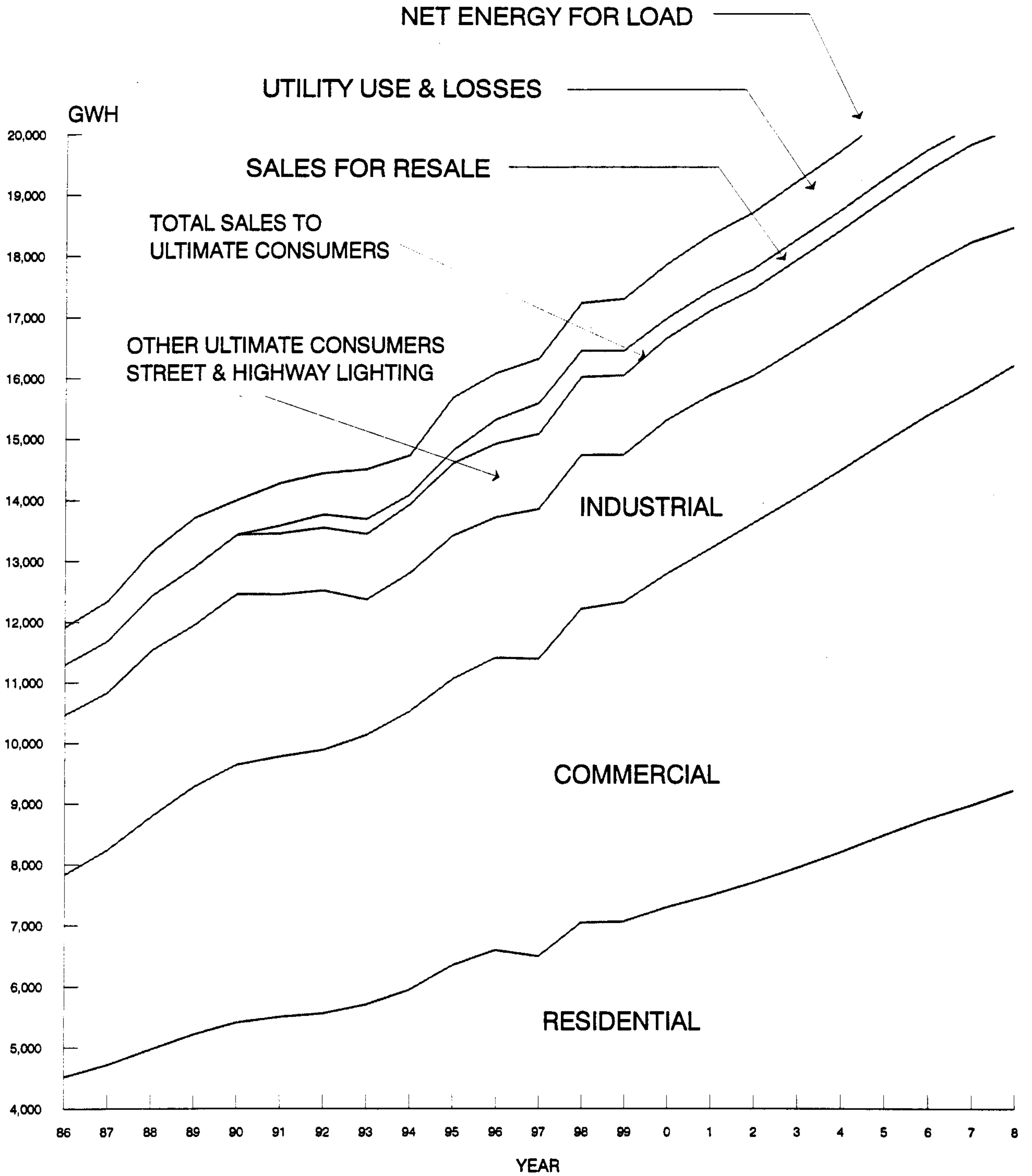


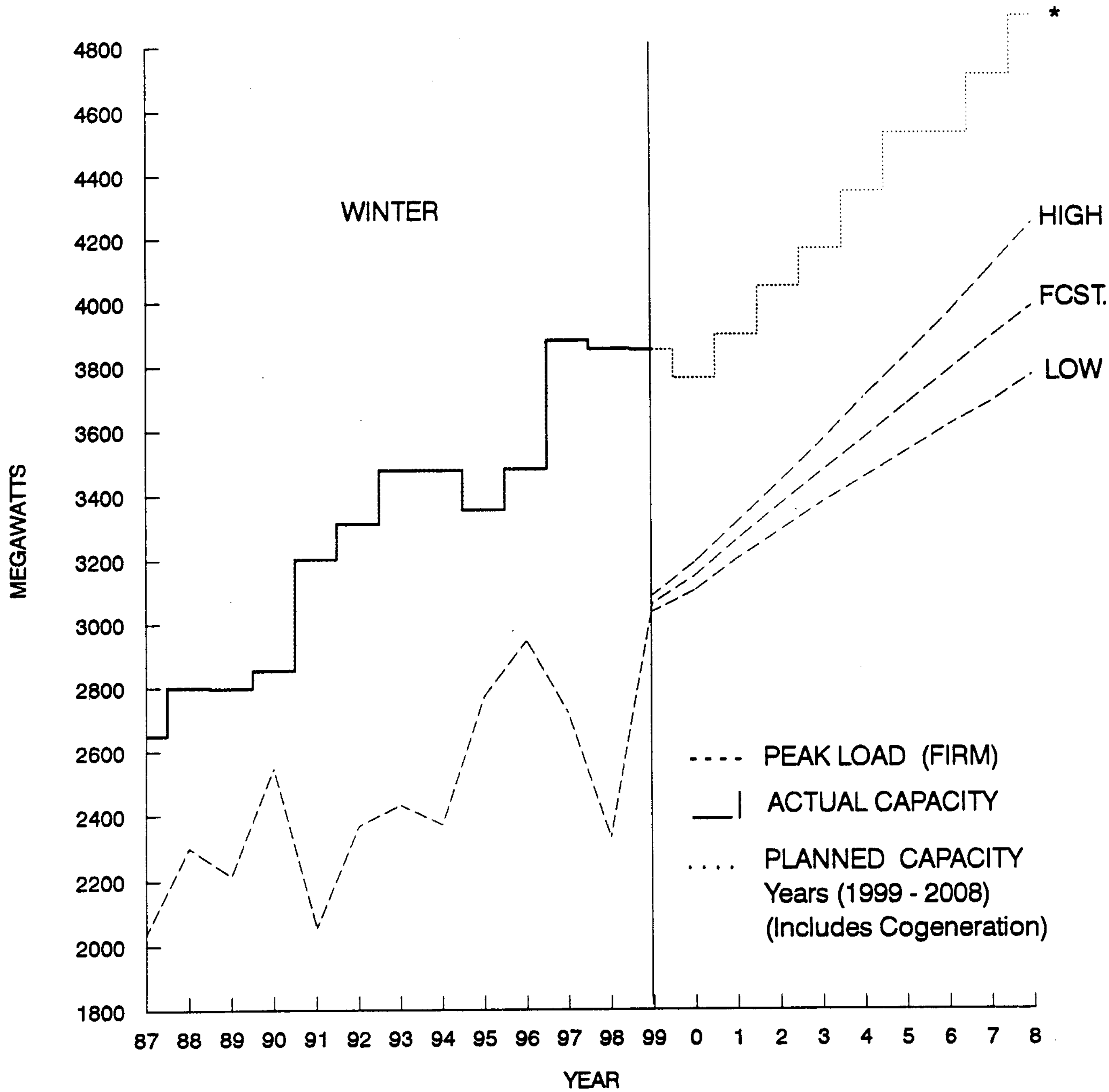
Figure III-2

HISTORY AND FORECAST OF ENERGY USE

SOURCE: TAMPA ELECTRIC COMPANY

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

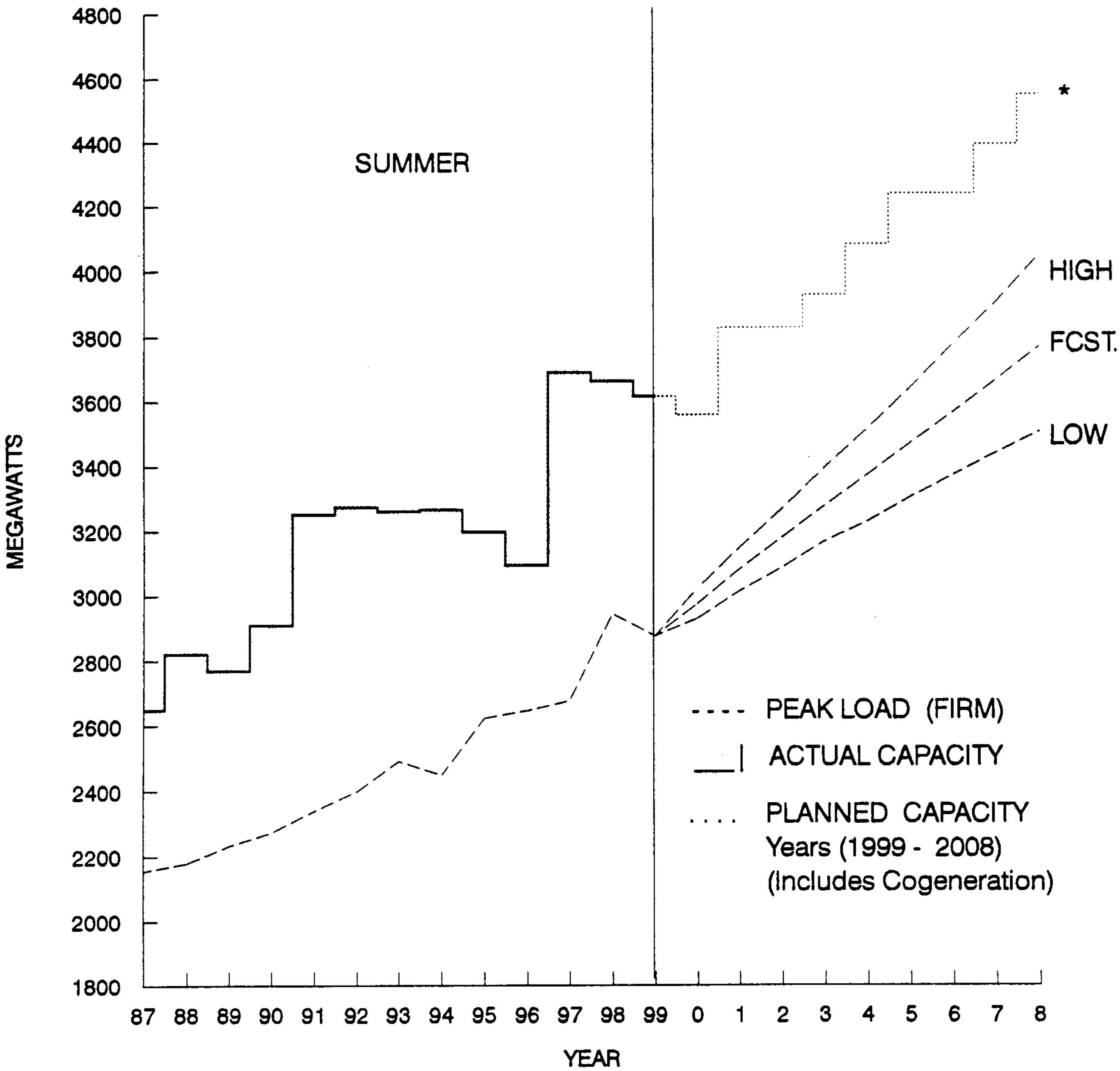
FIGURE III-3 HISTORY & FORECAST OF LOAD AND CAPACITY ADDITIONS
Page 1 of 2



* AGREES WITH SCHEDULE 7.2, COL.. 6.

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

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



* AGREES WITH SCHEDULE 7.1, COL 6.

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

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 2001, 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 2001, 2003, 2004, 2005,2007, and 2008. These dual-fuel combustion turbines will be fired by natural gas and distillate oil. For purposes of this study, Hookers Point Station is assumed to be retired in January 2003, and Tampa Electric's long-term purchase power contract with Hardee Power Partners Limited remains at 297 MW summer net capability and 360 MW winter net capability for the entire study period. 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 442 MW of cogeneration capacity operating in its service area in 1999. Self-service capacity of 240 MW (net) is used by cogenerators to serve internal load requirements, 62 MW are purchased by Tampa Electric on a firm contract basis, and 9 MW are purchased on a non-firm as-available basis. By 2008, the cogeneration capacity within our service area is expected to increase to 459 MW. This total will consist of 262 MW of self-service capacity, 62 MW of firm capacity purchases by Tampa Electric, and 7 MW of non-firm as-available purchases by Tampa Electric. During 1999, Tampa Electric has entered into transmission wheeling agreements with four of its cogeneration customers, supplying a total of 154 MW of firm contract capacity to two other utilities in the state. By 2008, this total is expected to decrease to 145 MW.

Fuel Requirements

A forecast of fuel requirements and energy sources is shown in Tables II-6 and II-7, respectively. As shown in these tables, Tampa Electric Company plans to continue to use coal as the primary fuel for most of its generating requirements. Alternative fuels were considered and have been incorporated when appropriate to achieve a low cost fuel strategy which benefits Tampa Electric's customers while meeting environmental emissions requirements. The Polk Unit 1 IGCC utilizes syngas as the primary fuel with No. 2 oil as the back-up. The syngas will be produced from five demonstration fuels during the first three years of commercial operation to satisfy their demonstration requirements. The demonstration fuels include coal and a coal/petroleum coke blend. Following the demonstration period, Tampa Electric Company plans to utilize a coal/petroleum coke blend to produce syngas. This blend will result in the IGCC unit being the lowest incremental cost resource on Tampa Electric Company's system.

Clean Air Act Amendments of 1990

The Clean Air Act Amendments of 1990 (CAAA) has as its primary goal the reduction of annual SO_2 emissions nationwide by 10 million tons below 1980 levels. To achieve these reductions, the law mandates a two-phase program which establishes annual SO_2 tonnage emission limits for fossil fuel-fired power plants. Under Phase I of the CAAA compliance plan, SO_2 emission limitations were placed on Tampa Electric's Big Bend Units 1, 2, and 3. These units were granted a combined total of 80,085 SO_2 allowances. Phase I compliance was implemented by the January 1, 1995 deadline largely through increasing the use of low sulfur coal at the affected plants, increasing purchases of emission allowances, and subsequently, by linking Big Bend 3 to the FGD system then serving Unit 4. The Company then voluntarily made Big Bend 4 subject to the Phase I requirements of the CAAA. Unit 4 was granted a total of 6,400 additional allowances for Phase I, giving Tampa Electric a total of 86,485 Phase I allowances.

Phase II compliance must be implemented by January 1, 2000, and 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 will be allocated only 83,882 allowances. In order to assure compliance with Phase II of the CAAA, the Company has meticulously considered a wide range of options for further reducing SO_2 emissions from its power plants to the levels mandated by the CAAA. Although careful consideration has been given to compliance options which would address both SO_2 and NO_X emission, it is clear that no cost effective, commercially proven technology exists for addressing SO2 and NO_X emissions as part of a single solution. Based on this analysis of compliance alternatives, Tampa Electric is constructing a FGD system at Big Bend 1 and 2. Tampa Electric will continue fuel blending at the Gannon units and scrubbing Big Bend 3 and 4 with the separate existing FGD system. These compliance measures provide the most prudent and cost effective means of meeting Tampa Electric's CAAA SO_2 compliance obligations.

Interchange Sales and Purchases

Tampa Electric interchange sales include Schedule D and Partial Requirements (PR) service agreements with several utilities 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. A firm capacity sale from Tampa Electric's Big Bend Station Unit No. 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
1999	3,433	402	(282)	62	3,615	3,006	609	20%	145	464	15%
2000	3,459	353	(300)	62	3,574	3,104	470	15%	16	454	15%
2001	3,614	297	(147)	62	3,825	3,210	615	19%	0	615	19%
2002	3,614	297	(147)	62	3,825	3,309	516	16%	0	516	16%
2003	3,565	297	0	62	3,924	3,406	518	15%	0	518	15%
2004	3,720	297	0	62	4,079	3,497	582	17%	0	582	17%
2005	3,875	297	0	62	4,234	3,599	635	18%	0	635	18%
2006	3,875	297	0	62	4,234	3,695	539	15%	0	539	15%
2007	4,030	297	0	62	4,389	3,774	615	16%	0	615	16%
2008	4,185	297	0	62	4,544	3,878	666	17%	0	666	17%

NOTE:

1. 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.
2. 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 19 MW in 1999 and New Smyrna Beach - J 10 MW in 2000. Capacities shown in table include losses.
3. Tampa Electric plans to fulfill the firm D transactions to FMPA via firm power purchases in 1998-99 and from in-house generation thereafter.
4. The QF column accounts for cogeneration that will be purchased under firm contracts.
5. Total installed capacity does not include 11 MW from Dinner Lake unit which was placed on long-term reserve standby 03/01/94, nor 3 MW from Phillips HRSG which is on full forced outage with an undetermined return to service date.
6. Demand includes effects of the DSM Goals for 2000.
7. Year 2000 includes a firm purchase of 56 MW as a portion of the planned import capacity.

* 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
1998-99	3,587	465	(265)	62	3,848	3,195	653	20%	34	619	19%
1999-00	3,592	436	(314)	62	3,776	3,279	497	15%	16	481	15%
2000-01	3,772	360	(300)	62	3,894	3,393	501	15%	0	501	15%
2001-02	3,772	360	(147)	62	4,046	3,499	547	16%	0	547	16%
2002-03	3,740	360	0	62	4,162	3,603	559	16%	0	559	16%
2003-04	3,920	360	0	62	4,342	3,700	642	17%	0	642	17%
2004-05	4,100	360	0	62	4,522	3,809	713	19%	0	713	19%
2005-06	4,100	360	0	62	4,522	3,913	609	16%	0	609	16%
2006-07	4,280	360	0	62	4,702	3,996	706	18%	0	706	18%
2007-08	4,460	360	0	62	4,882	4,099	783	19%	0	783	19%

NOTE:

1. 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.
2. 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 13 MW in 1999 and 14 MW in 2000. Capacities shown in table include losses.
3. Tampa Electric plans to fulfill the firm D transactions to FMPA via firm power purchases in 1998/99 and from in-house generation in 2000 - 3/2001.
4. The QF column accounts for cogeneration that will be purchased under firm contracts.
5. Total installed capacity does not include 11 MW from Dinner Lake unit which was placed on long-term reserve standby 03/01/94, nor 3 MW from Phillips HRSG which is on full forced outage with an undetermined return to service date.
6. Demand includes effects of the DSM Goals for 2000.
7. Year 2000 includes a firm purchase of 76 MW as a portion of the planned import capacity.

* 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
Polk	2	Polk Co.	CT	NG	LO	1/99	1/01	unknown	unknown	155	180	PL	TK	P
	3	Polk Co.	CT	NG	LO	1/01	1/03	unknown	unknown	155	180	PL	TK	P
	4	Polk Co.	CT	NG	LO	1/02	1/04	unknown	unknown	155	180	PL	TK	P
	5	Polk Co.	CT	NG	LO	1/03	1/05	unknown	unknown	155	180	PL	TK	P
	6	Polk Co.	CT	NG	LO	1/05	1/07	unknown	unknown	155	180	PL	TK	P
	7	Polk Co.	CT	NG	LO	1/06	1/08	unknown	unknown	155	180	PL	TK	P

SCHEDULE 9

TABLE IV-4
(Page 1 of 6)

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	JAN 1999
	B. COMMERCIAL IN-SERVICE DATE	JAN 2001
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(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)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	17.5
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,131 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	303.49
	DIRECT CONSTRUCTION COST ($/kW)	290.04
	AFUDC AMOUNT ($/kW)	11.27
	ESCALATION ($/kW)	2.18
	FIXED O&M (2001 $/kW-YR)	3.81
	VARIABLE O&M (2001 $/MWh)	2.95
	K-FACTOR [1]	1.597

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

SCHEDULE 9

TABLE IV-4
(Page 2 of 6)

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	JAN 2001
	B. COMMERCIAL IN-SERVICE DATE	JAN 2003
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(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)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	15.5
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,131 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	302.79
	DIRECT CONSTRUCTION COST ($/kW)	284.47
	AFUDC AMOUNT ($/kW)	11.09
	ESCALATION ($/kW)	7.23
	FIXED O&M (2003 $/kW-YR)	3.62
	VARIABLE O&M (2003 $/MWh)	2.80
	K-FACTOR [1]	1.609

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

SCHEDULE 9

TABLE IV-4
(Page 3 of 6)

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 2002
	B. COMMERCIAL IN-SERVICE DATE	JAN 2004
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(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)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	17.2
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,119 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	322.08
	DIRECT CONSTRUCTION COST ($/kW)	284.47
	AFUDC AMOUNT ($/kW)	10.56
	ESCALATION ($/kW)	27.05
	FIXED O&M (2004 $/kW-YR)	3.72
	VARIABLE O&M (2004 $/MWh)	2.88
	K-FACTOR [1]	1.616

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

SCHEDULE 9

TABLE IV-4
(Page 4 of 6)

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 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	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(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)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	17.5
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,087 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	327.89
	DIRECT CONSTRUCTION COST ($/kW)	284.47
	AFUDC AMOUNT ($/kW)	8.89
	ESCALATION ($/kW)	34.53
	FIXED O&M (2005 $/kW-YR)	3.82
	VARIABLE O&M (2005 $/MWh)	2.96
	K-FACTOR [1]	1.622

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

SCHEDULE 9

TABLE IV-4
(Page 5 of 6)

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 2005
	B. COMMERCIAL IN-SERVICE DATE	JAN 2007
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(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)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	20.8
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,018 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	343.94
	DIRECT CONSTRUCTION COST ($/kW)	284.47
	AFUDC AMOUNT ($/kW)	9.94
	ESCALATION ($/kW)	50.03
	FIXED O&M (2007 $/kW-YR)	3.92
	VARIABLE O&M (2007 $/MWh)	3.04
	K-FACTOR [1]	1.635

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

SCHEDULE 9

TABLE IV-4
(Page 6 of 6)

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

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 7
(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	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(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)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	19.5
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,067 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	353.08
	DIRECT CONSTRUCTION COST ($/kW)	284.47
	AFUDC AMOUNT ($/kW)	10.56
	ESCALATION ($/kW)	58.05
	FIXED O&M (2008 $/kW-YR)	4.02
	VARIABLE O&M (2008 $/MWh)	3.12
	K-FACTOR [1]	1.642

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK 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
Barcola - Pebbledale	1	No new right of way is required	TEC 2.7 miles FPC 1.2 miles	230 kV	Fall 2003	TEC $3 million	No new substations	Joint Project with FPC
Lithia - Wheeler	1	No new right of way is required	11.0 miles	230 kV	Summer 2003	$10 million	Lithia Switching Station	None
Polk - Mines - Lithia	1	28 miles long and 100 feet wide	28.0 miles	230 kV	Fall 2003	$19 million	No new substations	None
Gapway	1	No new right of way is required	0.2 miles	230 kV	Summer 2004	$3 million	No new substations	None
Polk - Lithia	1	No new right of way is required	28.0 miles	230 kV	Fall 2004	$2.5 million	No new substations	None
Davis - Dale Mabry	1	No new right of way is required	14.0 miles	230 kV	Fall 2004	$11.5 million	Davis Switching Station	None
Wheeler - Davis	1	No new right of way is required	12.0 miles	230 kV	Summer 2005	$6 million	No new substations	None
Lithia - Davis	1	No new right of way is required	23.0 miles	230 kV	Summer 2008	$2 million	No new substations	None
Chapman - Sheldon	1	No new right of way is required	9.0 miles	230 kV	Summer 2009	$4 million	No new substations	None

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CHAPTER V

OTHER PLANNING ASSUMPTIONS AND INFORMATION

Transmission Constraints and Impacts

Assessments of Tampa Electric transmission system performance are based upon planning studies completed in 1999 in support of Tampa Electric'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 our system which violate the submitted performance criteria contained in the Generation and Transmission Reliability Criteria section of this document.

Expansion Plan Economics and Load Sensitivity

The overall economics and cost-effectiveness of the plan were analyzed as stated in Tampa Electric's Integrated Resource Planning process. This process is discussed in detail later in this chapter. Sensitivity analyses using high and low bands of the base case load forecast yielded generation expansion plans that were significantly different from the base case plan of one combustion turbine in each of the years 2001, 2003, 2004, 2005, 2007 and 2008. Optimization based on the low load forecast deferred the 2004 combustion turbine one year, the 2005 combustion turbine two years, and moved the 2007 and 2008 combustion turbines out of the ten-year planning window. The expansion plan based on the high load forecast adds two additional combustion turbines.

Fuel Forecast and Sensitivity

Product price for actual and forecast data for the purpose of deriving base, high, and low forecast pricing is done by careful analysis of actual price and current and previous 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 the base case and escalating at a slightly higher escalation rate on a monthly basis to 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.

Expansion Plan Sensitivity Constant Fuel Differential

Even though Tampa Electric does not recognize, as a viable forecasting method, the arbitrary development of a fuel forecast by fixing the price differential between non-linked fuels, an expansion plan fuel sensitivity was performed by holding the differential between oil/gas and coal constant. The base case expansion plan did not change as a result of this change in the fuel price forecast. This result was expected because Tampa Electric Company's base case expansion plan consists of combustion turbines. These dual-fuel combustion turbines will be fired by natural gas and distillate oil. Because this sensitivity lowers Tampa Electric Company's natural gas and oil price forecasts and Tampa Electric Company's future resources are fired by natural gas and oil, it results in the same base case plan.

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 over its useful life the total original investment in a plant item 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.

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 January of 2001, 2003, 2004, 2005, 2007 and 2008. These 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, and Tampa Electric's long-term purchase power contract with Hardee Power Partners Limited remains at 297 MW summer net capability and 360 MW winter net capability for the entire study period.

TAMPA ELECTRIC COMPANY
INTEGRATED RESOURCE PLAN METHODOLOGY

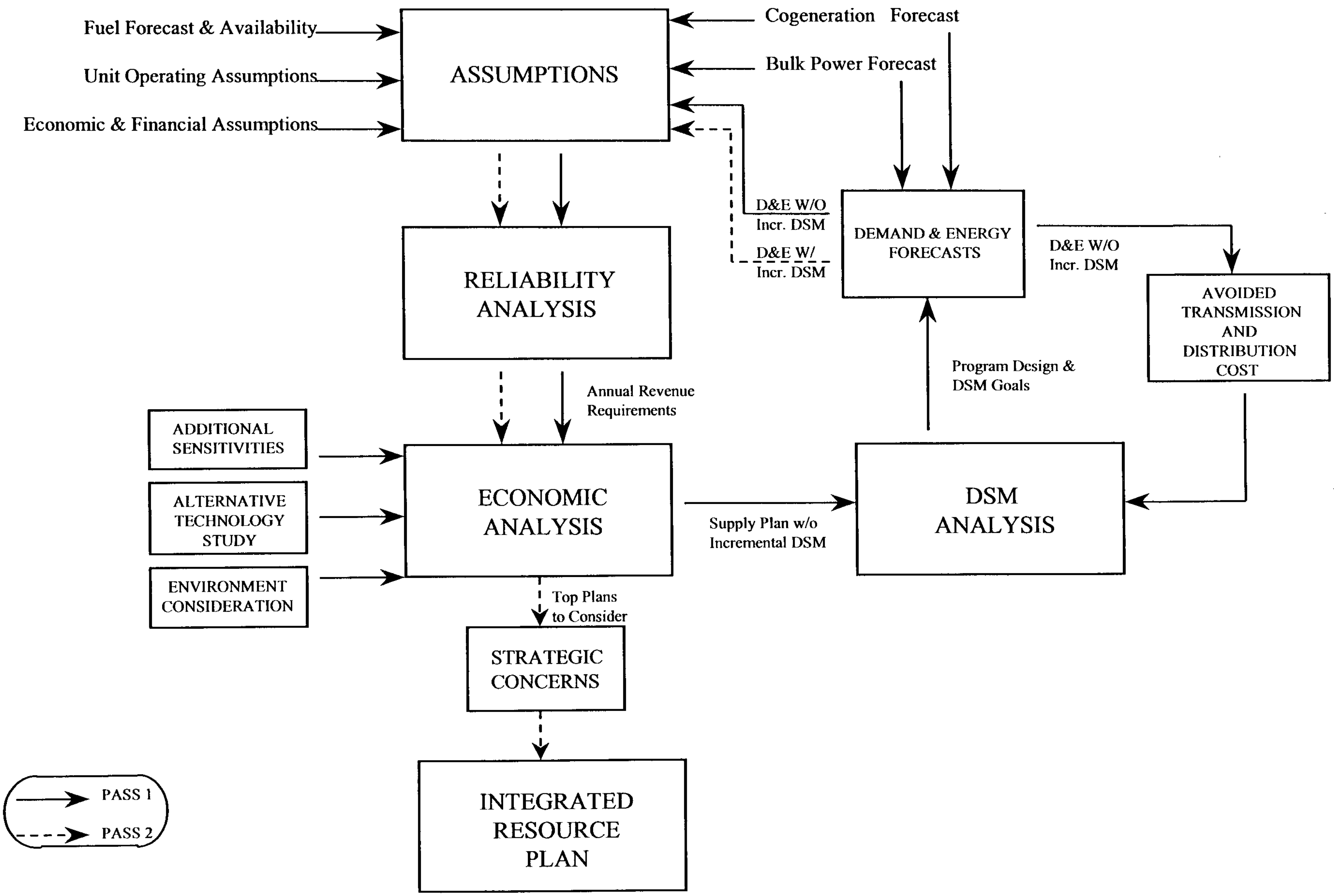

FIGURE VI

Generation and Transmission Reliability Criteria

Generation

Tampa Electric Company uses the dual reliability criteria of 1% Expected Unserved Energy (%EUE) and a 15% minimum firm winter reserve margin for planning purposes.

Tampa Electric Company's approach to calculating percent reserves is consistent with the 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 percent Expected Unserved Energy (%EUE) criteria is a weighted measure of both the frequency and magnitude of firm system energy requirements that are not expected to be met with firm supply-side resources. Similar to calculating percent reserves, all firm unit and station power sales, including retail and firm wholesale commitments are accounted for in determining Tampa Electric's available capacity resources. The 1% EUE target was developed as an equivalent to the loss of Tampa Electric's largest unit (Big Bend Unit 4, 447 MW) for an entire year and maintaining firm reserves of approximately 15%. In calculating the EUE, the Hardee Power Station is considered to be available as a Tampa Electric capacity resource only after its availability is reduced for planned outages, forced outages, and projected Seminole Electric Cooperative (SEC) usage. SEC provides Tampa Electric with its projected usage of the Hardee Power Station capacity. Percent EUE is calculated by dividing Tampa Electric's projected annual emergency energy purchases by its Net Energy for Load (includes retail and firm wholesale) and multiplying by 100%.

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:

Transmission System Loading Limits	
Transmission System Conditions	Acceptable Loading Limit for Transformers and Transmission Lines
All facilities in service	100% or less

Transmission System Voltage Limits			
	Industrial Substation Buses at point-of-service	69 kV Buses	138 kV and 230 kV Buses
All facilities in service	0.950 - 1.050 pu	0.900 - 1.050 pu	0.950 - 1.060 pu

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. In the course of single contingency analysis, single contingency fault events which result in the removal of multiple transmission system elements from service due to protection system response are modeled in the manner that the system would respond to the fault. 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	FCTTC
Lake Tarpon-Sheldon 230 kV	1100 MVA
Big Bend-Florida Power & Light 230 kV	1500 MVA

DSM Energy Savings Durability

Tampa Electric Company identifies and verifies the durability of energy savings from our conservation and DSM programs by several methods. First, Tampa Electric Company has established a monitoring and evaluation (M&E) 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, our 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 planned generating units at the Polk Power Station change the prevailing direction of power flow throughout the bulk 230 kV system. Loads in the Eastern and Plant City Service Areas, which have traditionally been served by generation at Big Bend and Gannon Stations, 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, major transmission and substation construction projects are directed at improving the reliability and efficiency of the 230 kV bulk system, which transmits power north from Big Bend and Gannon Stations. As load growth continues and more generation is installed at Polk Power Station, additional transmission lines and substations must be built to deliver this new generation into the load centers in Eastern, Central and Western Service Areas.

For details on construction projects, see Table IV-5.

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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. There are no new potential sites being considered for the 10-year horizon.

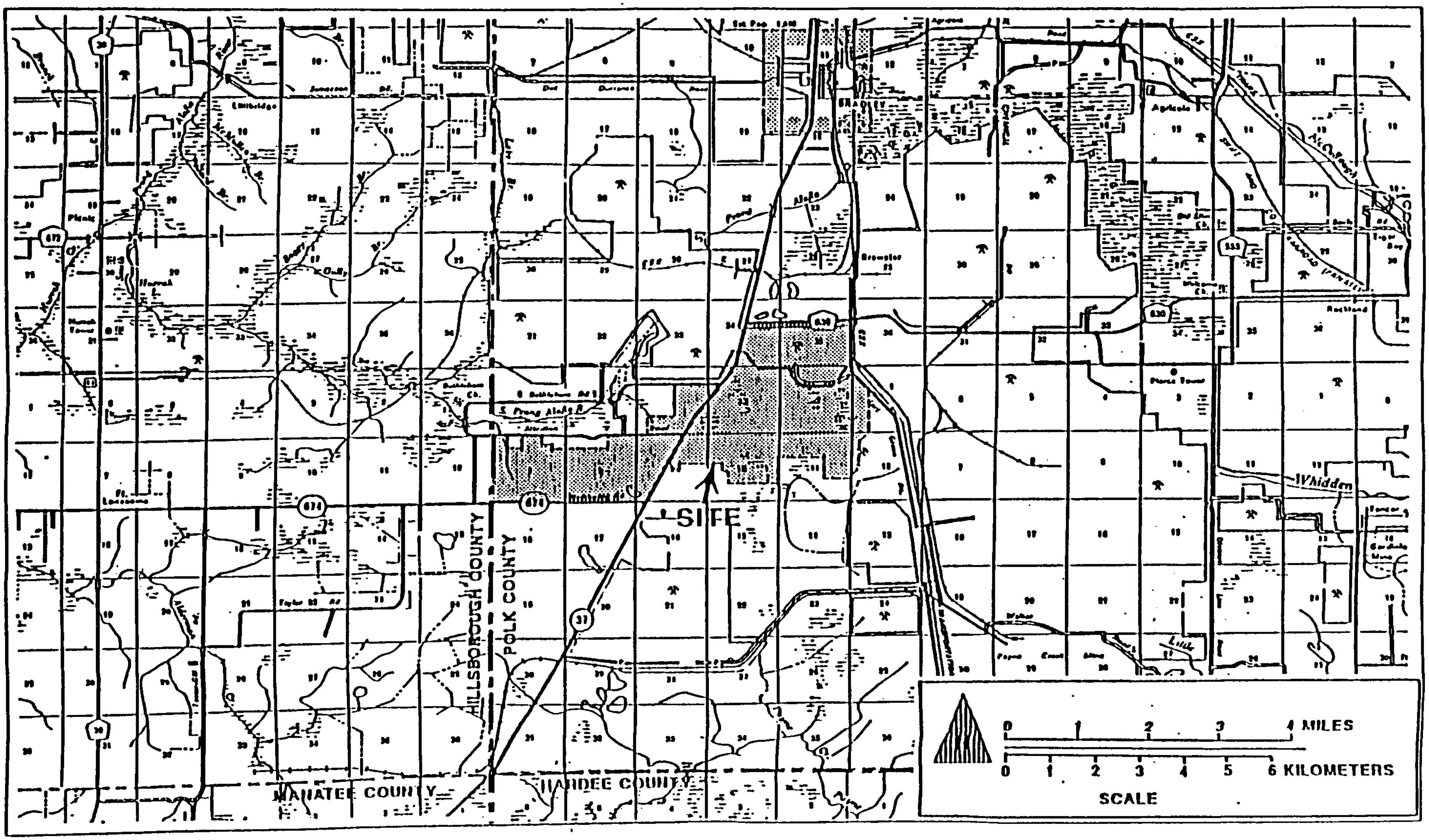

FIGURE VI-1

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