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City of Tallahassee
Your Own Utilities

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April 2, 2007

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk
And Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

070000

Dear Ms. Bayó:

Attached are twenty-five (25) copies of the City of Tallahassee's 2007 Ten Year Site Plan. If you have any questions, please e-mail me at childsv@talgov.com or call me at 891-3122.

Sincerely,

Venus Childs

Venus Childs
Planning Engineer

Attachments
cc: KGW
GSB

CMP ____
COM ____
CTR ____
ECR 3+1
GCL ____
OPC ____
RCA ____
SCR ____
SGA ____
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OTH 2 - K. Pena

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Recycled Paper

Ten Year Site Plan
2007-2016

City of Tallahassee
Electric Utility

Report Prepared By:
City of Tallahassee Electric Utility
System Planning

City of Tallahassee
Your Own Utilities℠

CITY OF TALLAHASSEE
TEN YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES
2007-2016
TABLE OF CONTENTS

Chapter I

Description of Existing Facilities

1.0 INTRODUCTION

The City of Tallahassee (City) owns, operates, and maintains an electric generation, transmission, and distribution system that supplies electric power in and around the corporate limits of the City. The City was incorporated in 1825 and has operated since 1919 under the same charter. The City began generating its power requirements in 1902 and the City's Electric Department presently serves approximately 110,550 customers located within a 221 square mile service territory. The Electric Department operates three generating stations with a total summer season net generating capacity of 744 megawatts (MW).

The City has two fossil-fueled generating stations, which contain combined cycle (CC), steam and combustion turbine (CT) electric generating facilities. The Sam O. Purdom Generating Station, located in the town of St. Marks, Florida has been in operation since 1952; and the Arvah B. Hopkins Generating Station, located on Geddie Road west of the City, has been in commercial operation since 1970. The City has also been generating electricity at the C.H. Corn Hydroelectric Station, located on Lake Talquin west of Tallahassee, since August of 1985.

1.1 SYSTEM CAPABILITY

The City maintains six points of interconnection with Progress Energy Florida ("Progress", formerly Florida Power Corporation); three at 69 kV, two at 115 kV, and one at 230 kV; and a 230 kV interconnection with Georgia Power Company (a subsidiary of the Southern Company ("Southern")).

As shown in Table 1.1 (Schedule 1), 233 MW (net summer rating) of CC generation, 48 MW (net summer rating) of steam generation and 20 MW (net summer rating) of CT generation facilities are located at the City's Sam O. Purdom Generating Station. The Arvah B. Hopkins Generating Station includes 304 MW (net summer rating) of steam generation and 128 MW (net summer rating) of CT generation facilities.

All of the City's available steam generating units at these sites can be fired with natural gas, residual oil or both. The CC and CT units can be fired on either natural gas or diesel oil but cannot burn these fuels concurrently. The total capacity of the three units at the C.H. Corn Hydroelectric Station is 11 MW.

The City's total net summer installed generating capability is 744 MW. The corresponding winter net peak installed generating capability is 795 MW. Table 1.1 contains the details of the individual generating units.

1.2 PURCHASED POWER AGREEMENTS

The City has a long-term firm capacity and energy purchase agreement with Progress for 11.4 MW.

City Of Tallahassee

Schedule 1
Existing Generating Facilities
As of December 31, 2006

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.				Net Capability	
								Fuel	Commercial	Expected	Gen. Max.		
	Unit		Unit	Fuel		Fuel Transport		Days	In-Service	Retirement	Nameplate	Summer	Winter
Plant	No.	Location	Type	Pri	Alt	Primary	Alternate	Use	Month/Year	Month/Year	(kW)	(MW)	(MW)
Sam O. Purdom	7	Wakulla	ST	NG	FO6	PL	WA	[1, 2]	6/66	3/11	50,000	48	50
	8		CC	NG	FO2	PL	TK	[2, 3]	7/00	12/40	247,743	233	262
	GT-1		GT	NG	FO2	PL	TK	[2, 3]	12/63	3/11	15,000	10	10
	GT-2		GT	NG	FO2	PL	TK	[2, 3]	5/64	3/11	15,000	10	10
											Plant Total	301	332
A. B. Hopkins	1	Leon	ST	NG	FO6	PL	TK	[1]	5/71	3/16	75,000	76	78
	2		ST	NG	FO6	PL	TK	[1]	10/77	3/22	259,250	228	238
	GT-1		GT	NG	FO2	PL	TK	8	2/70	3/15	16,320	12	14
	GT-2		GT	NG	FO2	PL	TK	8	9/72	3/17	27,000	24	26
	GT-3		GT	NG	FO3	PL	TK	8	9/05	Unknown	60,500	46	48
	GT-4		GT	NG	FO4	PL	TK	8	11/05	Unknown	60,500	46	48
											Plant Total	432	452
C. H. Corn	1	Leon/	HY	WAT	WAT	WAT	WAT	NA	9/85	Unknown	4,440	4	4
Hydro Station	2	Gadsden	HY	WAT	WAT	WAT	WAT	NA	8/85	Unknown	4,440	4	4
	3		HY	WAT	WAT	WAT	WAT	NA	1/86	Unknown	3,430	3	3
											Plant Total	11	11
									Total System Capacity as of December 31, 2006			744	795

Notes
[1] The City maintains a minimum inventory of approximately 19 peak load days between the Purdom and Hopkins sites.
[2] Due to the Purdom facility-wide emissions caps, utilization of liquid fuel at this facility is limited.
[3] Purdom has sufficient diesel storage on site for approximately 30 full load hours of operation for all three combustion turbines units.

CHAPTER II

Forecast of Energy/Demand Requirements and Fuel Utilization

2.0 INTRODUCTION

Chapter II includes the City of Tallahassee's forecasts of (i) demand and energy requirements, (ii) energy sources and (iii) fuel requirements. This chapter also explains the impacts attributable to the Demand Side Management (DSM) plan submitted as a part of the City of Tallahassee's Integrated Resource Planning (IRP) Study. The City is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA) and, therefore, the FPSC does not set numeric conservation goals for the City. However, the City expects to continue its commitment to conservation and the DSM programs that prove beneficial to the City's ratepayers.

2.1 SYSTEM DEMAND AND ENERGY REQUIREMENTS

Historical and forecast energy consumption and customer information are presented in Tables 2.1, 2.2 and 2.3 (Schedules 2.1, 2.2, and 2.3). Figure B1 shows the historical and forecast trends of energy sales by customer class. Figure B2 shows the percentage of energy sales by customer class for the base year of 2007 and the horizon year of 2016. Tables 2.4 through 2.12 (Schedules 3.1.1 - 3.3.3) contain historical and forecast seasonal peak demands and net energy for load for base, high, and low values. Table 2.13 (Schedule 4) compares actual and two-year forecast peak demand and energy values by month for the 2006 - 2008 period.

2.1.1 SYSTEM LOAD AND ENERGY FORECASTS

The peak demand and energy forecasts contained in this plan are the results of the load and energy forecasting study performed by the City. The forecast is developed utilizing a methodology that the City first employed in 1980, and has updated and revised every one or two years. The methodology consists of ten multi-variable linear regression models based on detailed examination of the system's historical growth, usage patterns and population statistics. Several key regression formulas utilize econometric variables.

Table 2.14 lists the econometric-based linear regression forecasting models that are used as predictors. Note that the City uses regression models with the capability of separately predicting commercial customers and consumption by rate sub-class: general service non-demand (GS), general service demand (GSD), and general service large demand (GSLD). These, along with the residential class, represent the major classes of the City's electric customers. In addition to these customer class models, the City's forecasting methodology also incorporates into the demand and energy projections estimated reductions from interruptible and curtailable customers. The key explanatory variables used in each of the models are indicated by an "X" on the table.

Table 2.15 documents the City's internal and external sources for historical and forecast economic, weather and demographic data. These tables summarize the details of the models used to generate the system customer, consumption and seasonal peak load forecasts. In addition to those explanatory variables listed, a component is also included in the models that reflect the acquisition of certain Talquin Electric Cooperative (Talquin) customers over the study period consistent with the territorial agreement negotiated between the City and Talquin and approved by the FPSC.

The customer models are used to predict number of customers by customer class, which in turn serve as input into the customer class consumption models. The customer class consumption models are aggregated to form a total base system sales forecast. The effects of DSM programs and system losses are incorporated in this base forecast to produce the system net energy for load (NEL) requirements.

Since 1992, the City has used two econometric models to separately predict summer and winter peak demand. Table 2.14 also shows the key explanatory variables used in the demand models. The winter peak is dependent upon the minimum temperature on the peak day, the day of the week on which it occurs, and the duration of the cold period. Based upon the actual 2005 and 2006 winter peaks and model refinements, the 2007 winter peak demand forecast is lower than the projections made in the 2006 demand forecast.

The most significant input assumptions for the 2007 forecast were the incremental load modifications at Florida State University (FSU), Florida A&M University (FAMU), Tallahassee Memorial Hospital (TMH) and the State Capitol Center. These four customers represent approximately 14% of the City's energy sales. Their incremental additions are highly dependent upon annual economic and budget constraints, which would cause fluctuations in their demand projections if they were projected using a model. Therefore, each entity submits their proposed incremental additions/reductions to the City and these modifications are included as submitted in the load and energy forecast.

The City believes that the inclusion of these incremental additions/reductions, utilizing the five-year average of the actual temperature at the time of seasonal peak demand, the routine update of forecast model coefficients and other minor model refinements have improved the accuracy of its forecast so that they are more consistent with the historical trend of growth in seasonal peak demand and energy consumption.

2.1.2 Load Forecast Sensitivities

Uncertainty associated with the forecast input variables and the final forecast are addressed by adjusting selected input variables in the load forecast models, to establish "high load growth" and "low load growth" sensitivity cases. For the sensitivities to the base 2007 load forecast the key explanatory variables that were changed were Leon County population, heating degree-days and cooling degree-days for the energy forecast. For the peak demand forecasts, the Leon County population and maximum & minimum temperature on the peak days for the summer and winter, respectively, were changed.

Sensitivities on the peak demand forecasts are useful in planning for future power supply resource needs. The graph shown in Figure B3 compares summer peak demand (multiplied by 117% for reserve margin requirements) for the three forecast sensitivity cases with reductions from proposed DSM portfolio and the base forecast without proposed DSM reductions against the City's existing and planned power supply resources. This graph allows for the review of the effect of load growth variations on the timing of new resource additions. The highest probability weighting, of course, is placed on the base case assumptions, and the low and high cases are given a smaller likelihood of occurrence.

2.1.3 ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT PROGRAMS

The City currently offers a variety of conservation and DSM programs to its residential and commercial customers, which are listed below:

Residential Programs	Commercial Programs
HVAC Loan	Customized HVAC Loan
Homebuilder Rebates	Secured Loan
Gas Water Heater Conversion Loan	Demonstrations
Information and Audits	Information and Audits
Ceiling Insulation Loan	Commercial Gas Conversion Rebates
Low Income Ceiling Insulation Rebate	

The City has a goal to improve the efficiency of customers' end-use of energy resources when such improvements provide a measurable economic and/or environmental benefit to the customers and the City utilities. During the IRP Study the City tested potential DSM measures (conservation, energy efficiency, load management, and demand response) for cost-effectiveness utilizing an integrated approach that is based on projections of total achievable capacity and energy reductions and their associated annual costs developed specifically for the City. The measures were combined into bundles affecting similar end uses and /or having similar costs per kWh saved. Projected capacity and energy savings, and implementation costs, were developed for each bundle. The individual program measures that were identified as cost-effective were combined to form a proposed DSM portfolio. The City intends to extend the existing DSM program and will identify and implement specific groups of measures that achieve the capacity benefit and energy savings identified in the proposed DSM portfolio that was part of the Integrated Resource Plan.

Energy and demand reductions attributable to the proposed DSM portfolio have been incorporated into the future load and energy forecasts. Table 2.16 displays the estimated energy savings associated with the menu of DSM measures. Table 2.17 shows similar data for demand savings. The figures on these tables reflect the cumulative annual impacts of the proposed DSM portfolio on system energy and demand requirements.

2.2 ENERGY SOURCES AND FUEL REQUIREMENTS

Tables 2.18 (Schedule 5), 2.19 (Schedule 6.1), and 2.20 (Schedule 6.2) present the projections of fuel requirements, energy sources by resource/fuel type in gigawatt-hours, and energy sources by resource/fuel type in percent, respectively, for the period 2006-2015. Figure B4 displays the percentage of energy by fuel type in 2007 and 2016.

The City's generation portfolio includes combustion turbine/combined cycle, combustion turbine/simple cycle, conventional steam and hydroelectric units. The City's combustion turbine/combined cycle and combustion turbine/simple cycle units are capable of generating energy using natural gas or distillate fuel oil. Natural gas and residual fuel oil may be burned concurrently in the City's steam units. This mix of generation types coupled with opportunities for firm and economy purchases from neighboring systems provides allows the City to satisfy its total energy requirements consistent with our energy policies that seek to balance the cost of power with the environmental quality of our community.

The projections of fuel requirements and energy sources are taken from the results of computer simulations using Global Energy Decisions, Inc.'s PROSYM production simulation model and are based on the resource plan described in Chapter III.

City Of Tallahassee

Schedule 2.1
History and Forecast of Energy Consumption and Number of Customers by Customer Class

Base Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial [4]		
Year	Population [1]	Members Per Household	(GWh) [2]	Average No. of Customers [3]	Average kWh Consumption Per Customer	(GWh) [2]	Average No. of Customers [3]	Average kWh Consumption Per Customer
1997	177,347	-	850	74,259	11,446	1,324	15,490	85,474
1998	180,725	-	940	75,729	12,413	1,396	15,779	88,472
1999	184,239	-	926	77,357	11,970	1,419	16,183	87,685
2000	186,839	-	971	79,108	12,274	1,458	16,663	87,499
2001	190,575	-	959	80,347	11,936	1,459	16,988	85,884
2002	193,941	-	1048	81,208	12,905	1,527	16,778	91,012
2003	200,304	-	1,035	82,219	12,588	1,555	17,289	89,942
2004	203,106	-	1,064	84,496	12,592	1,604	17,553	91,380
2005	205,908	-	1,088	89,468	12,161	1,621	18,310	88,531
2006	208,789	-	1,097	92,017	11,922	1,602	18,533	86,440
2007	211,669	-	1,138	93,729	12,141	1,678	18,888	88,839
2008	214,550	-	1,155	95,433	12,103	1,717	19,142	89,698
2009	217,430	-	1,170	97,137	12,045	1,748	19,396	90,122
2010	220,311	-	1,182	98,824	11,961	1,773	19,648	90,238
2011	223,056	-	1,191	100,482	11,853	1,797	19,897	90,315
2012	225,801	-	1,201	102,140	11,758	1,823	20,145	90,494
2013	228,546	-	1,208	103,798	11,638	1,844	20,394	90,419
2014	231,290	-	1,217	105,456	11,540	1,860	20,642	90,108
2015	234,035	-	1,226	107,022	11,456	1,873	20,879	89,707
2016	236,509	-	1,236	108,432	11,399	1,887	21,096	89,448

[1] Population data represents Leon County population served by City of Tallahassee Electric Utility not the general population of Leon County.
[2] Values include DSM Impacts.
[3] Average end-of-month customers for the calendar year. Marked increase in residential customers between 2004 and 2005 due to change in internal customer accounting practices.
[4] Includes Traffic Control and Security Lighting use.

Table 2.1

City Of Tallahassee

Schedule 2.2
History and Forecast of Energy Consumption and Number of Customers by Customer Class

Base Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	(GWh)	Average No. of Customers [1]	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)
1997	-	-	-	-	12	-	2,186
1998	-	-	-	-	13	-	2,349
1999	-	-	-	-	13	-	2,358
2000	-	-	-	-	12	-	2,441
2001	-	-	-	-	13	-	2,431
2002	-	-	-	-	13	-	2,588
2003	-	-	-	-	12	-	2,602
2004	-	-	-	-	14	-	2,682
2005	-	-	-	-	14	-	2,723
2006	-	-	-	-	15	-	2,714
2007	-	-	-	-	15	-	2,831
2008	-	-	-	-	15	-	2,887
2009	-	-	-	-	15	-	2,933
2010	-	-	-	-	15	-	2,970
2011	-	-	-	-	15	-	3,003
2012	-	-	-	-	15	-	3,039
2013	-	-	-	-	16	-	3,068
2014	-	-	-	-	16	-	3,093
2015	-	-	-	-	16	-	3,115
2016	-	-	-	-	16	-	3,139

[1] Average end-of-month customers for the calendar year.

City Of Tallahassee

Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

Base Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale (GWh)	Utility Use & Losses (GWh) [1]	Net Energy for Load (GWh)	Other Customers (Average No.)	Total No. of Customers [1]
1997	0	133	2,319	0	89,749
1998	0	128	2,477	0	91,508
1999	0	139	2,497	0	93,540
2000	0	155	2,596	0	95,771
2001	0	125	2,556	0	97,335
2002	0	165	2,753	0	97,986
2003	0	153	2,755	0	99,508
2004	0	159	2,841	0	102,049
2005	0	164	2,887	0	107,778
2006	0	154	2,868	0	110,550
2007	0	168	2,999	0	112,617
2008	0	172	3,059	0	114,575
2009	0	174	3,107	0	116,533
2010	0	177	3,147	0	118,472
2011	0	179	3,182	0	120,379
2012	0	180	3,219	0	122,285
2013	0	182	3,250	0	124,192
2014	0	183	3,276	0	126,098
2015	0	185	3,300	0	127,901
2016	0	187	3,326	0	129,528

[1] Average number of customers for the calendar year.

History and Forecast Energy Consumption By Customer Class

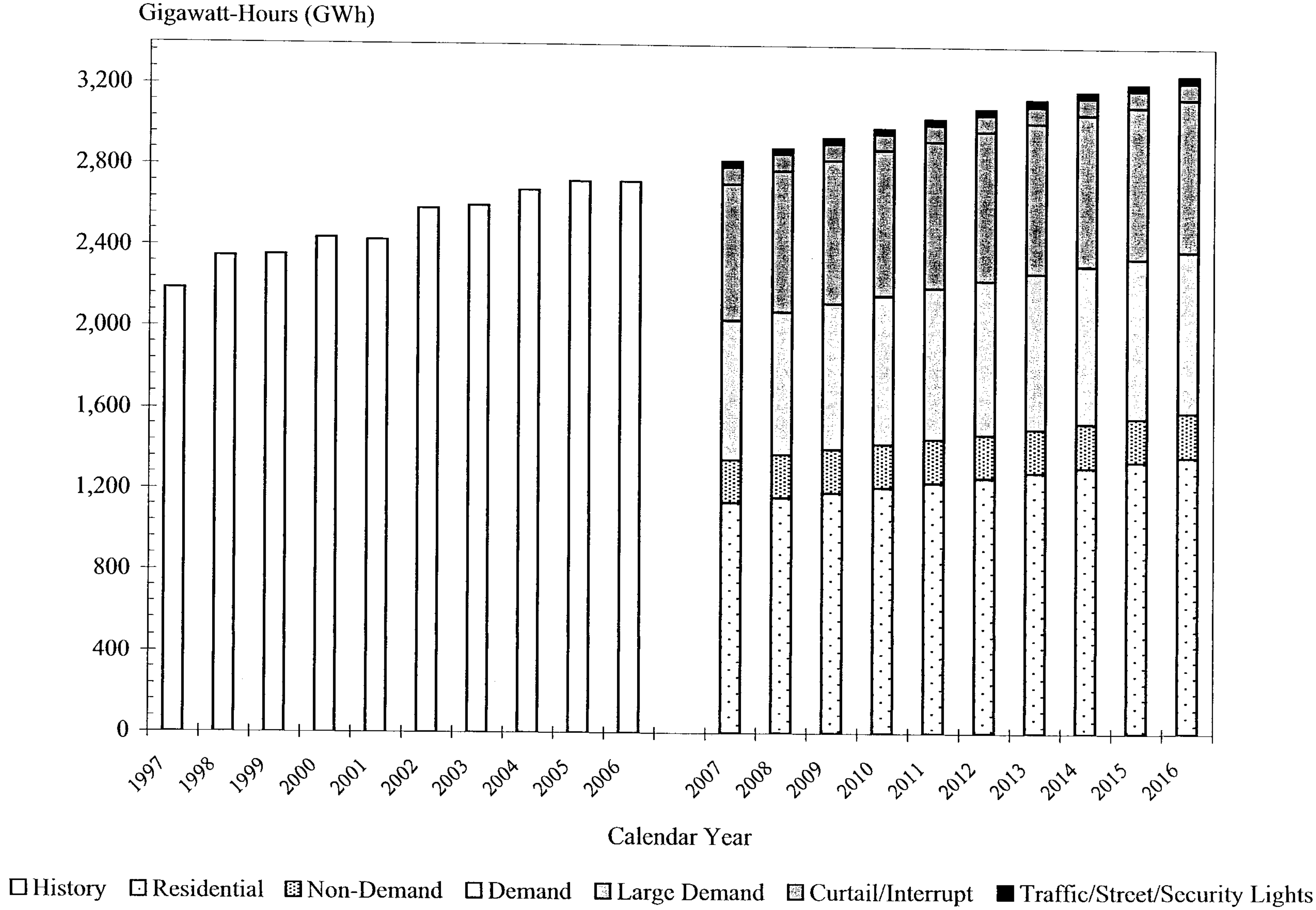
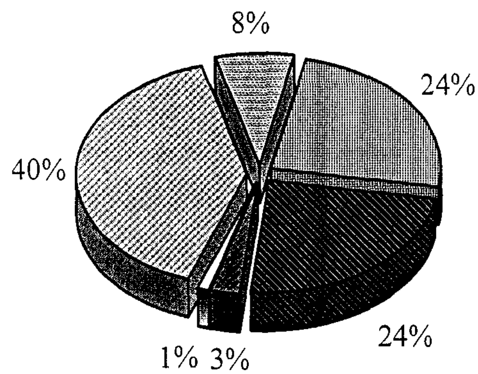


Figure B1

Figure B2

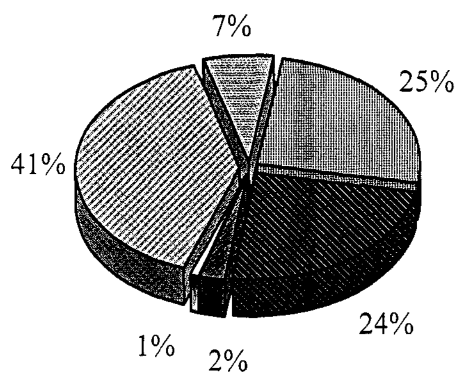
Energy Consumption By Customer Class

Calendar Year 2007



Total 2007 Sales = 2,842 GWh
Values exclude DSM impacts

Calendar Year 2016



Total 2016 Sales = 3,436 GWh
Values exclude DSM impacts

Residential
Non Demand
Demand
Large Demand
Curtail/Interrupt
Traffic/Street/Security Lights

City Of Tallahassee

Schedule 3.1.1
History and Forecast of Summer Peak Demand
Base Forecast
(MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
1997	486		486						486
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	580		580						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	578		578			1			577
2007	610		610		1	1	3	2	603
2008	622		622		3	3	7	3	606
2009	634		634		4	5	10	8	607
2010	646		646		6	8	14	11	607
2011	659		659		7	12	17	16	607
2012	672		672		9	16	18	20	609
2013	683		683		10	20	18	26	609
2014	694		694		12	24	18	32	608
2015	704		704		13	28	18	38	607
2016	713		713		15	32	19	42	605

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar.
[3] 2006 DSM Jan - July accumulation.

City Of Tallahassee

Schedule 3.1.2
History and Forecast of Summer Peak Demand
High Forecast
(MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
1997	486		486						486
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	580		580						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	578		578			1			577
2007	637		637		1	1	3	2	630
2008	650		650		3	3	7	3	634
2009	663		663		4	5	10	8	636
2010	675		675		6	8	14	11	636
2011	688		688		7	12	17	16	636
2012	701		701		9	16	18	20	638
2013	712		712		10	20	18	26	638
2014	724		724		12	24	18	32	638
2015	734		734		13	28	18	38	637
2016	744		744		15	32	19	42	636

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar.

City Of Tallahassee

Schedule 3.1.3
History and Forecast of Summer Peak Demand
Low Forecast
(MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
1997	486		486						486
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	580		580						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	578		578			1			577
2007	588		588		1	1	3	2	581
2008	600		600		3	3	7	3	584
2009	613		613		4	5	10	8	586
2010	624		624		6	8	14	11	585
2011	637		637		7	12	17	16	585
2012	649		649		9	16	18	20	586
2013	660		660		10	20	18	26	586
2014	671		671		12	24	18	32	585
2015	681		681		13	28	18	38	584
2016	690		690		15	32	19	42	582

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.
[3] 2006 DSM Jan - July accumulation.

City Of Tallahassee

Schedule 3.2.1
History and Forecast of Winter Peak Demand
Base Forecast
(MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2]	(10) Net Firm Demand [1]
1997 -1998	421		421						421
1998 -1999	513		513						513
1999 -2000	497		497						497
2000 -2001	521		521						521
2001 -2002	510		510						510
2002 -2003	590		590						590
2003 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	534		534			6			528
2007 -2008	570		570		3	3	7	3	554
2008 -2009	586		586		4	5	10	6	561
2009 -2010	602		602		6	8	14	9	565
2010 -2011	618		618		7	11	17	14	569
2011 -2012	635		635		9	15	18	17	576
2012 -2013	649		649		10	19	18	22	580
2013 -2014	663		663		12	23	18	27	583
2014 -2015	677		677		13	26	18	34	586
2015 -2016	689		689		15	30	19	36	589
2016 -2017	700		700		15	33	19	41	592

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.

City Of Tallahassee

Schedule 3.2.2
History and Forecast of Winter Peak Demand
High Forecast
(MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2]	(10) Net Firm Demand [1]
1997 -1998	421		421						421
1998 -1999	513		513						513
1999 -2,000	497		497						497
2000 -2001	521		521						521
2001 -2,002	510		510						510
2002 -2,003	590		590						590
2003 -2,004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	534		534			6			528
2007 -2008	624		624		3	3	7	3	608
2008 -2009	640		640		4	5	10	6	615
2009 -2010	657		657		6	8	14	9	620
2010 -2011	673		673		7	11	17	14	624
2011 -2012	691		691		9	15	18	17	632
2012 -2013	705		705		10	19	18	22	636
2013 -2014	719		719		12	23	18	27	639
2014 -2015	734		734		13	26	18	34	643
2015 -2016	746		746		15	30	19	36	646
2016 -2017	758		758		15	33	19	41	650

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.

City Of Tallahassee

Schedule 3.2.3
History and Forecast of Winter Peak Demand
Low Forecast
(MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2]	(10) Net Firm Demand [1]
1997 -1998	421		421						421
1998 -1999	513		513						513
1999 -2,000	497		497						497
2000 -2001	521		521						521
2001 -2,002	510		510						510
2002 -2003	590		590						590
2003 -2,004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	534		534			6			528
2007 -2008	516		516		3	3	7	3	500
2008 -2009	531		531		4	5	10	6	506
2009 -2010	547		547		6	8	14	9	510
2010 -2011	563		563		7	11	17	14	514
2011 -2012	580		580		9	15	18	17	521
2012 -2013	593		593		10	19	18	22	524
2013 -2014	607		607		12	23	18	27	527
2014 -2015	621		621		13	26	18	34	530
2015 -2016	632		632		15	30	19	36	532
2016 -2017	644		644		15	33	19	41	536

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.

City Of Tallahassee

Schedule 3.3.1
History and Forecast of Annual Net Energy for Load
Base Forecast
(GWh)

(1) Year	(2) Total Sales	(3) Residential Conservation [2]	(4) Comm./Ind Conservation [2]	(5) Retail Sales [1]	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load [1]	(9) Load Factor % [1]
1997	2,186			2,186		133	2,319	54
1998	2,349			2,349		128	2,477	53
1999	2,358			2,358		139	2,497	54
2000	2,441			2,441		155	2,596	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	57
2004	2,682			2,682		159	2,841	57
2005	2,724			2,724		164	2,888	55
2006	2,725	11		2,714		154	2,868	57
2007	2,842	5	6	2,831		168	2,999	57
2008	2,915	13	15	2,887		172	3,059	58
2009	2,983	24	26	2,933		174	3,107	58
2010	3,049	37	42	2,970		177	3,147	59
2011	3,115	53	59	3,003		179	3,182	60
2012	3,184	69	76	3,039		180	3,219	60
2013	3,252	88	96	3,068		182	3,250	61
2014	3,316	106	117	3,093		183	3,276	62
2015	3,378	125	138	3,115		185	3,300	62
2016	3,436	141	156	3,139		187	3,326	63

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. Previous year DSM is actual at peak.

City Of Tallahassee

Schedule 3.3.2
History and Forecast of Annual Net Energy for Load
High Forecast
(GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total Sales	Residential Conservation [2]	Comm./Ind Conservation [2]	Retail Sales [1]	Wholesale	Utility Use & Losses	Net Energy for Load [1]	Load Factor % [1]
1997	2,186			2,186		133	2,319	54
1998	2,349			2,349		128	2,477	53
1999	2,358			2,358		139	2,497	54
2000	2,441			2,441		155	2,596	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	57
2004	2,682			2,682		159	2,841	57
2005	2,724			2,724		164	2,888	55
2006	2,725	11		2,714		154	2,868	57
2007	3,041	5	6	3,030		180	3,210	58
2008	3,117	13	15	3,089		184	3,273	59
2009	3,189	24	26	3,139		186	3,325	60
2010	3,257	37	42	3,178		190	3,368	60
2011	3,327	53	59	3,215		191	3,406	61
2012	3,399	69	76	3,254		193	3,447	62
2013	3,470	88	96	3,286		194	3,480	62
2014	3,537	106	117	3,314		196	3,510	63
2015	3,602	125	138	3,339		198	3,537	63
2016	3,662	141	156	3,365		201	3,566	64

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. Previous year DSM is actual at peak.

City Of Tallahassee

Schedule 3.3.3
History and Forecast of Annual Net Energy for Load
Low Forecast
(GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total Sales	Residential Conservation [2]*	Comm./Ind Conservation [2]	Retail Sales [1]	Wholesale	Utility Use & Losses	Net Energy for Load [1]	Load Factor % [1]
1997	2,186			2,186		133	2,319	54
1998	2,349			2,349		128	2,477	53
1999	2,358			2,358		139	2,497	54
2000	2,441			2,441		155	2,596	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	57
2004	2,682			2,682		159	2,841	57
2005	2,724			2,724		164	2,888	55
2006	2,725	11		2,714		154	2,868	57
2007	2,675	5	6	2,664		158	2,822	55
2008	2,745	13	15	2,717		162	2,879	56
2009	2,811	24	26	2,761		164	2,925	57
2010	2,874	37	42	2,795		167	2,962	58
2011	2,938	53	59	2,826		168	2,994	58
2012	3,005	69	76	2,860		169	3,029	59
2013	3,070	88	96	2,886		171	3,057	60
2014	3,132	106	117	2,909		172	3,081	60
2015	3,192	125	138	2,929		173	3,102	61
2016	3,247	141	156	2,950		176	3,126	61

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. Previous year DSM is actual at peak.

Table 2.12

City Of Tallahassee

Schedule 4
Previous Year and 2-Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2006 Actual		2007 Forecast [1]		2008 Forecast [1]	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	465	217	493	236	554	241
February	537	209	504	217	519	222
March	406	208	447	216	452	220
April	502	224	462	216	468	221
May	524	246	548	254	551	259
June	572	272	578	281	581	287
July	577	292	595	304	598	310
August	576	306	603	310	606	316
September	539	254	572	275	575	280
October	473	223	505	242	508	247
November	406	204	463	212	469	216
December	528	213	539	236	546	240
TOTAL		2,868		2,999		3,059

[1] Peak Demand and NEL include DSM Impacts.

City Of Tallahassee

2007 Electric System Load Forecast

Key Explanatory Variables

Model Name	Leon County Population	Residential Customers	Total Customers	Cooling Degree Days	Heating Degree Days	Tallahassee Per Capita Taxable Sales	Price of Electricity	State of Florida Population	Minimum Winter Peak day Temp.	Maximum Summer Peak day Temp.	Appliance Saturation	R Squared [1]
Residential Customers	X											0.989
Residential Consumption		X		X	X	X	X				X	0.921
Florida State University Consumption				X			X	X				0.930
State Capitol Consumption				X			X	X				0.892
Florida A & M University Consumption				X				X				0.926
Street Lighting Consumption	X											0.961
General Service Non-Demand Customers		X										0.958
General Service Demand Customers		X										0.927
General Service Non-Demand Consumption	X			X	X	X	X					0.961
General Service Demand Consumption	X			X	X							0.990
General Service Large Demand Consumption	X			X	X							0.974
Summer Peak Demand			X							X	X	0.982
Winter Peak demand									X		X	0.965

[1] R Squared, sometimes called the coefficient of determination, is a commonly used measure of goodness od fit of a linear model. If the observations fall on the model regression line, R Squared is 1. If there is no linear relationship between the dependent and independent variable, R Squared is 0. A reasonably good R Squared value could be anywhere from 0.6 to 1.

City of Tallahassee

2007 Electric System Load Forecast

Sources of Forecast Model Input Information

Energy Model Input Data	Source
1. Leon County Population	City Planning Office
2. Talquin Customers Transferred	City Power Engineering
3. Cooling Degree Days	NOAA reports
4. Heating Degree Days	NOAA reports
5. AC Saturation Rate	December 2005 Appliance Saturation Study
6. Heating Saturation Rate	December 2005 Appliance Saturation Study
7. Real Tallahassee Taxable Sales	Department of Revenue
8. Florida Population	Governor's Office of Budget & Planning
9. State Capitol Incremental	Department of Management Services
10. FSU Incremental Additions	FSU Planning Department
11. FAMU Incremental Additions	FAMU Planning Department
12. GSLD Incremental Additions	City Utility Services
13. Other Commercial Customers	Utility Services
14. Tall. Memorial Curtailable	System Planning/ Utilities Accounting.
15. System Peak Historical Data	City System Planning
16. Historical Customer Projections by Class	System Planning & Customer Accounting
17. Historical Customer Class Energy	System Planning & Customer Accounting
18. GDP Forecast	Governor's Planning & Budgeting Office
19. CPI Forecast	Governor's Planning & Budgeting Office
20. Florida Taxable Sales	Governor's Planning & Budgeting Office
21. Interruptible, Traffic Light Sales, & Security Light Additions	System Planning & Customer Accounting
22. Historical Residential Real Price of Electricity	Calculated from Revenues, kWh sold, CPI
23. Historical Commercial Real Price Of Electricity	Calculated from Revenues, kWh sold, CPI

Banded Summer Peak Load Forecast Vs. Supply Resources
(Load Includes 17% Reserve Margin)

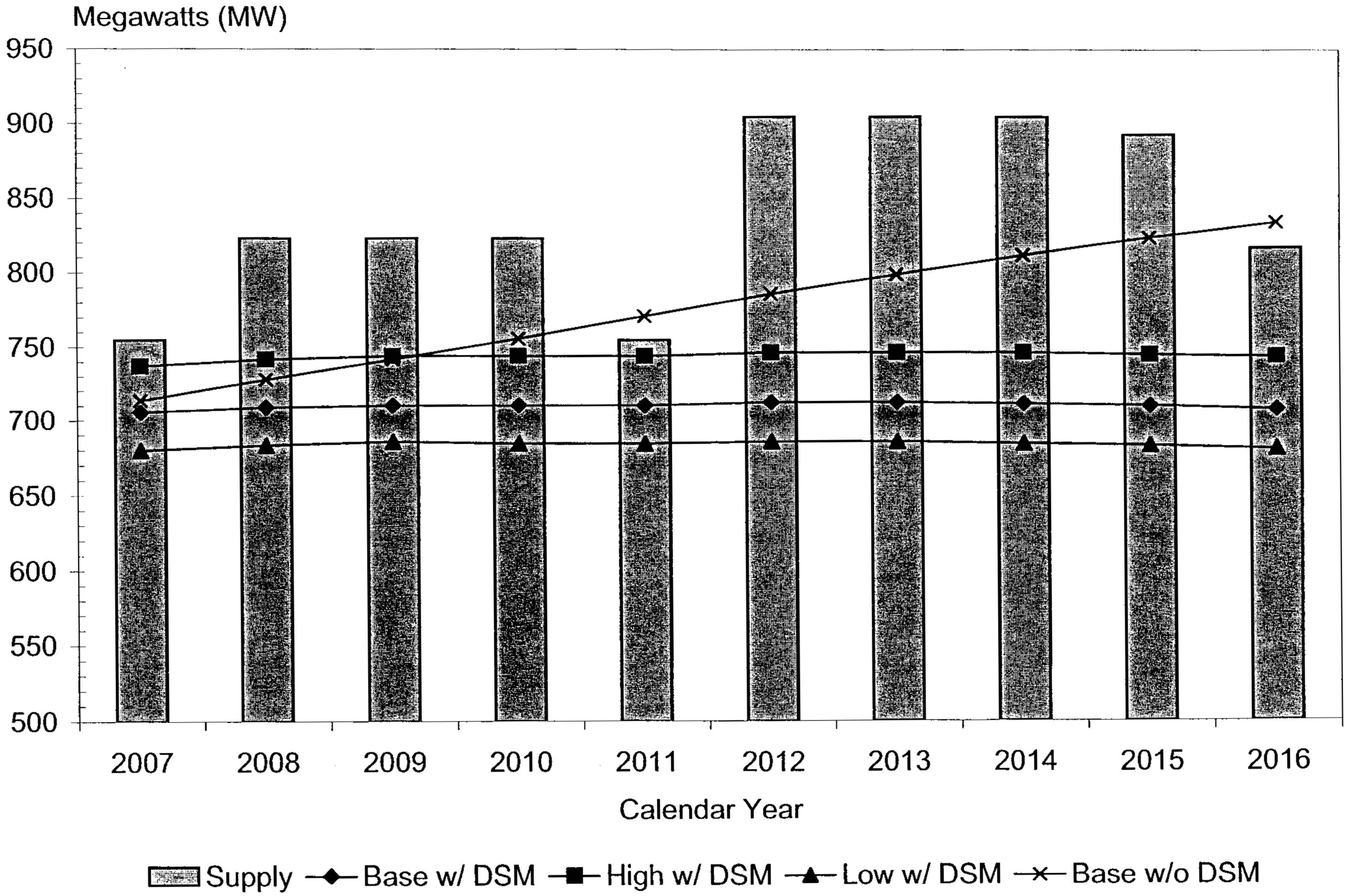


Figure B3

City Of Tallahassee

2007 Electric System Load Forecast

Projected Demand Side Management Energy Reductions [1]

Calendar Year Basis

Year	Residential Impact (MWh)	Commercial Impact (MWh)	Total Impact (MWh)
2007	5,622	6,243	11,865
2008	14,055	15,608	29,663
2009	25,299	28,094	53,393
2010	39,355	43,701	83,056
2011	56,221	62,431	118,652
2012	73,087	81,161	154,248
2013	92,764	103,012	195,776
2014	112,442	124,862	237,304
2015	132,119	146,713	278,832
2016	148,985	165,443	314,428

[1] Reductions estimated at busbar.

City Of Tallahassee

2007 Electric System Load Forecast

Projected Demand Side Management
Seasonal Demand Reductions [1]

Year		Residential Energy Efficiency Impact		Commercial Energy Efficiency Impact		Residential Demand Response Impact		Commercial Demand Response Impact		Demand Side Management Total	
Summer	Winter	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
2007	2007-2008	1	3	2	3	1	3	3	7	7	16
2008	2008-2009	3	5	4	6	3	4	6	10	16	25
2009	2009-2010	5	8	7	10	4	6	11	13	27	37
2010	2010-2011	8	11	11	14	6	7	14	17	39	49
2011	2011-2012	12	15	16	18	7	9	17	17	52	59
2012	2012-2013	16	19	21	23	9	10	17	17	63	69
2013	2013-2014	20	23	26	28	10	12	18	17	74	80
2014	2014-2015	24	26	32	32	12	13	18	20	86	91
2015	2015-2016	28	30	38	37	13	15	18	18	97	100
2016	2016-2017	32	33	42	41	15	15	19	19	108	108

[1] Reductions estimated at busbar.

City Of Tallahassee

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2005	Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	**Nuclear**		Billion Btu	0	0	0	0	0	0	0	0	0	0	0	0
(2)	**Coal**		1000 Ton	0	0	0	0	0	0	0	227	325	343	336	295
(3)	**Residual**	**Total**	1000 BBL	555	194	202	98	43	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	555	194	202	98	43	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(8)	**Distillate (Diesel)**	**Total**	1000 BBL	7	7	0	0	0	0	0	0	0	0	0	0
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	7	7	0	0	0	0	0	0	0	0	0	0
(12)		Diesel	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(13)	**Natural Gas**	**Total**	1000 MCF	16,730	19,818	22,023	22,129	22,403	22,124	21,750	18,128	17,148	16,576	17,015	18,672
(14)		Steam	1000 MCF	5,244	6,484	6,055	2,214	437	852	743	899	809	998	794	203
(15)		CC	1000 MCF	11,157	12,416	11,304	18,297	21,356	20,798	20,431	16,347	15,817	14,858	15,656	18,006
(16)		CT	1000 MCF	329	918	4,664	1,618	610	474	576	882	522	720	565	463
(17)		Diesel	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(18)	**Other (Specify)**		Trillion Btu	0	0	0	0	0	0	0	0	0	0	0	0

City Of Tallahassee

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2005	Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	**Annual Firm Interchange**		GWh	102	100	121	116	116	116	117	117	117	117	118	111
(2)	**Coal**		GWh	0	0	0	0	0	0	0	561	801	851	830	718
(3)	**Nuclear**		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(4)	**Residual**	**Total**	GWh	327	110	108	51	22	0	0	0	0	0	0	0
(5)		Steam	GWh	327	110	108	51	22	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(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 (Diesel)**	**Total**	GWh	4	4	0	0	0	0	0	0	0	0	0	0
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	4	4	0	0	0	0	0	0	0	0	0	0
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	**Natural Gas**	**Total**	GWh	2,040	2,409	2,624	2,816	2,905	2,803	2,713	2,209	2,034	1,990	2,041	2,204
(15)		Steam	GWh	460	584	550	196	36	71	62	76	68	84	67	17
(16)		CC	GWh	1,556	1,734	1604	2455	2808	2685	2596	2041	1911	1830	1915	2138
(17)		CT	GWh	24	91	470	165	61	47	55	92	55	76	59	49
(18)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(19)	**Hydro**		GWh	27	9	18	18	18	18	18	18	18	18	18	18
(20)	**Economy Interchange**		GWH	387	236	128	58	46	210	334	314	280	300	293	275
(21)	**Net Energy for Load**		GWh	2,887	2,868	2,999	3,059	3,107	3,147	3,182	3,219	3,250	3,276	3,300	3,326

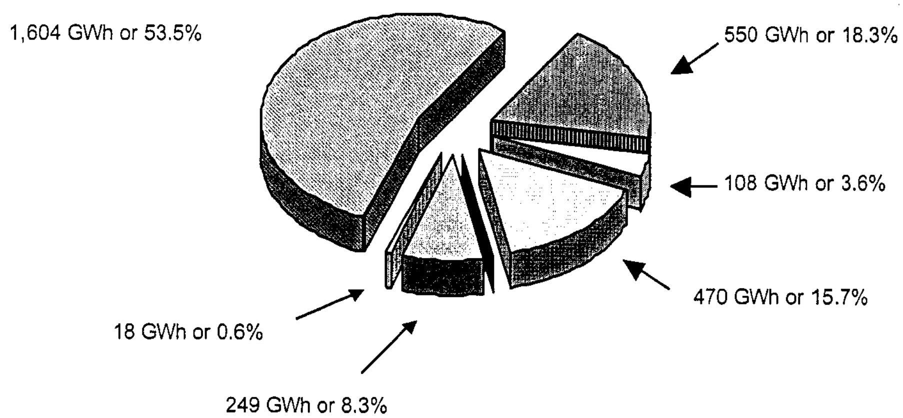
City Of Tallahassee

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2005	Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	**Annual Firm Interchange**		%	3.5	3.5	4.0	3.8	3.7	3.7	3.7	3.6	3.6	3.6	3.6	3.3
(2)	**Coal**		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.4	24.7	26.0	25.1	21.6
(3)	**Nuclear**		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(4)	**Residual**	**Total**	%	11.3	3.8	3.6	1.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		Steam	%	11.3	3.8	3.6	1.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		CT	%	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0
(9)	**Distillate (Diesel)**	**Total**	%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		CT	%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	**Natural Gas**	**Total**	%	70.7	84.0	87.5	92.1	93.5	89.1	85.3	68.7	62.6	60.8	61.9	66.3
(15)		Steam	%	15.9	20.5	18.3	6.4	1.2	2.3	2.0	2.3	2.1	2.6	2.0	0.5
(16)		CC	%	53.9	60.5	53.5	80.3	90.4	85.3	81.6	63.5	58.8	55.9	58.1	64.3
(17)		CT	%	0.8	3.2	15.7	5.4	2.0	1.5	1.7	2.9	1.7	2.3	1.8	1.5
(18)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(19)	**Hydro**		%	0.9	0.3	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5
(20)	**Economy Interchange**		%	13.4	8.2	4.3	1.9	1.5	6.7	10.5	9.7	8.6	9.1	8.9	8.3
(21)	**Net Energy for Load**		%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

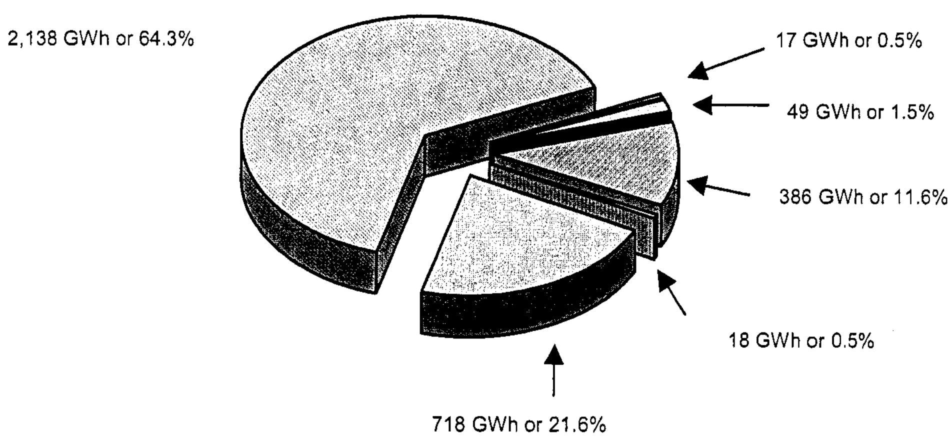
Generation By Resource/Fuel Type

Calendar Year 2007



Total 2007 NEL = 2,999 GWh

Calendar Year 2016



Total 2016 NEL = 3,326 GWh

□ CC - Gas	▨ Steam - Gas	□ Steam - Oil	□ CT/Diesel - Gas
■ CT/Deisel - Oil	□ Purch	□ Hydro	□ Coal

Chapter III

Projected Facility Requirements

3.1 PLANNING PROCESS

In August 2004 the City issued a task order to Black & Veatch Consultants to conduct a comprehensive integrated resource planning (IRP) study. The purpose of this study was to review future demand-side management (DSM) and power supply options that are consistent with the City's policy objectives. The City and Black & Veatch completed Phase I of the IRP study in March 2005 which included data collection, assumption and methodology development and a screening analysis that identified those DSM and power supply alternatives that were carried forward into the final Phase II. The second and final phase (Phase II) of the IRP study was completed in December 2006 and included a detailed analysis of how the DSM and power supply alternatives perform under base and alternative assumptions. The City's proposed generation expansion plan described in Section 3.2 is that identified in the IRP study as presenting the best overall balance of the evaluation criteria – reliability, diversity, cost and environmental impact.

Electric utility planning staff continuously reviewed the progress and results of the IRP Study as directed by the City Commission. This review process included updating information with regard to expected conditions (existing system performance, load and energy requirements, fuel price forecasts, economic variables), DSM alternatives, power supply alternatives (electric generating equipment and new power purchase opportunities), transmission issues and other information to enhance the IRP study assumptions or methodology. Staff researched options available to the City to achieve some supply resource portfolio diversity. In addition, staff reviewed and developed means to mitigate the potential impacts of significant events in the electric utility industry.

3.2 PROJECTED RESOURCE REQUIREMENTS

3.2.1 TRANSMISSION LIMITATIONS

The City has projected that additional resources will be required during the 2007-2016 Ten Year Site Plan time frame to maintain a reliable electric system. The City's projected transmission import capability is a major determinant of the type and timing of future power resource additions. The City has worked with its neighboring utilities, Progress and Southern, to plan and maintain sufficient transmission import capability to allow the City to make emergency power purchases in the event of the most severe single contingency, the loss of the system's largest generating unit. As has been seen in other parts of the country since the passage of the Energy Policy Act of 1992, there has been little investment in the regional transmission system around Tallahassee. Consequently, the City's internal transmission studies have reflected a gradual deterioration of the system's transmission import (and export) capability into the future, due in part to this lack of investment in facilities as well as the impact of unscheduled power flow-through on the City's transmission system. The prospects for significant expansion of the regional transmission system around Tallahassee hinges on (i) the City's ongoing discussions with Progress and Southern, (ii) the Florida Reliability Coordinating Council's (FRCC) regional transmission planning process, (iii) alternatives to the formerly proposed GridFlorida RTO, and (iv) the alternative mechanisms envisioned by recently enacted and possible future federal legislation on electric industry restructuring. Unfortunately, none of these efforts is expected to produce substantive improvements to the City's transmission import/export capability in the time frame of the system's short-term resource needs. The City continues to discuss the limitations of the existing transmission grid in the panhandle region with Progress. In consideration of the City's projected transmission import capability reductions and the associated grid limitations, the results of the IRP Study and other internal analysis of options tend to favor local generation alternatives as the means to satisfy future power supply requirements.

3.2.2 RESERVE REQUIREMENTS

Historically, the City has planned to maintain a load reserve margin of 17%. However, in previous Ten Year Site Plan reports, the City has discussed the possibility of increasing its reserve margin criterion. The perceived need to evaluate alternative reliability criteria/levels arose primarily from three considerations: (i) the projected deterioration of the City's transmission import capability discussed in the previous section, (ii) the stipulation made by the state's three investor-owned utilities (Florida Power & Light, Progress Energy Florida and Tampa Electric Company) to increase their respective reserve margins to 20% by 2004 in response to the FPSC's reserve margin docket of 1998, and (iii) the size of the City's individual generating units as a percent of its total supply resource capability. However, as mentioned in the previous year's Ten Year Site Plan reports, the City evaluated various reliability measures and determined that the 17% reserve margin continues to be appropriate for planning purposes.

For the purposes of the IRP study and this TYSP report the City has reviewed and decided to postpone the scheduled retirement dates for the 20 MW of gas turbines at the Purdom Plant (now scheduled for retirement in 2011 as shown in Schedule 1). Assuming the base case load forecast, recognizing the projected impacts of the City's new DSM Plan, repowering of the City's existing Hopkins Unit 2 to combined cycle operation by the summer of 2008 and postponing the retirement of the Purdom CTs until 2011, additional power supply need to maintain a 17% planning reserve margin first occurs in the summer of 2016; assuming the high load forecast additional power supply would be needed in the summer of 2011.

3.2.3 NEAR TERM RESOURCE ADDITIONS

At their October 17, 2005 meeting the City Commission gave the Electric Utility approval to proceed with the repowering of Hopkins Unit 2 to combined cycle operation. The repowering will be accomplished by retiring the existing Hopkins Unit 2 boiler and replacing it with a combustion turbine generator (CTG) and a heat recovery steam generator (HRSG). The existing Hopkins 2 steam turbine and generator will be powered by the steam generated in the HRSG. Duct burners will be installed in the HRSG to provide additional peak generating capability. The repowering project will provide additional capacity as well as increased efficiency versus the Hopkins Unit 2 current capabilities. The repowered unit is projected to achieve seasonal net capacities of 296 MW in the summer and 333 MW in the winter. The major equipment has been procured and construction activities commenced in December of 2006. Current plans are for the unit to ready for commercial operation in late May of 2008. The CTG is a General Electric 7FA similar to Purdom Unit 8.

3.2.4 POWER SUPPLY DIVERSITY

Resource diversity, particularly with regard to fuels, has long been sought after by the City because of the system's heavy reliance on natural gas as its primary fuel source and has received even greater emphasis in light of the volatility in natural gas prices seen over recent years. The City has also attempted to address this concern by implementing an Energy Risk Management (ERM) program in an effort to limit the City's exposure to energy price fluctuations. The ERM program established a organizational structure of interdepartmental committees and working groups and included the adoption of an Energy Risk Management Policy that, among other things, identifies acceptable risk mitigation products to prevent asset value losses, ensure price stability and provide protection against market volatility for fuels and energy to the City's electric and gas utilities and their customers.

Purchase contracts can provide some of the diversity desired in the City's power supply resource portfolio. The IRP Study evaluated both short and long-term purchased power options based on conventional sources as well as power offers based on renewable resources.

As an additional strategy to address the City's lack of power supply diversity, planning staff has investigated options for joint ownership of a solid-fuel unit. Natural gas supply prices and cost and performance parameters for coal units indicate that the economics for adding some amount of coal capacity to the City's resource portfolio may be favorable under certain conditions. The City continues to assess the potential benefits and risks associated with including a solid-fuel resource in the City's long-range power supply plan. This assessment must focus on participation in a remotely sited resource in recognition of the constraints placed on the City as a result of a 1991 charter amendment relating to pursuit of any locally sited coal plant.

3.2.5 Renewable Resources

As part of its continuing commitment to explore clean energy alternatives, the City has continued to invest in opportunities to develop viable solar photovoltaic (PV) projects as part of our efforts to offer "green power" to our customers. The City believes that offering green power alternatives to its customers is a sound business strategy: it will provide for a measure of supply diversification, reduce dependence on fossil fuels, promote cleaner energy sources, and enhance the City's already strong commitment to protecting the environment and the quality of life in Tallahassee. Currently the City has a portfolio of 40 kW of solar PV dedicated to supporting our *Green For You* program, a retail offering which uses tradable renewable certificates (green tags) to promote development of green power projects.

The City has also investigated other renewable resource alternatives, including solar thermal and biomass. Concurrently with these investigations, the City solicited responses from potential developers of biomass facilities. The City also evaluated other unsolicited biomass opportunities including joint ventures and purchased power arrangements.

The results of this evaluation led to the inclusion of a biomass energy and gas purchase contract with Biomass, Gas and Electric (BG&E) in the City's long-range resource plan. The City will purchase up to 40 MW of energy and 60 million British thermal units (Btu) per hour of synthetic gas produced by BG&E's biomass-fueled synthetic gas production and electric generating facility to be constructed locally. The target in service date for the facility is June 1, 2010.

The BG&E facility will produce the synthetic gas using the Klepper gasification technology introduced in 1995 and currently in the development process. There are no operating electric plants of the size contemplated in the purchase agreement in commercial service using this technology. The City will mitigate the risk associated with this emerging technology by (i) having no contractual cost obligations other than to pay for the electric energy and the synthetic gas actually delivered, and (ii) not counting the facility as dependable capacity until actual performance for a sufficient period warrants.

3.2.6 FUTURE POWER SUPPLY RESOURCES

The City's currently proposed resource additions to meet system needs is represented in this report and includes participation in the Taylor Energy Center Project, discussed further in the following paragraphs, to be in service by the summer of 2012, in addition to the contributions expected from the City's enhanced DSM portfolio.

The Taylor Energy Center (TEC) Project

In July 2005 the City joined a group of municipal electric utilities (JEA, Reedy Creek Improvement District, and the Florida Municipal Power Agency) to evaluate the possibility of locating an 800 MW-class supercritical pulverized coal unit on a greenfield site near Perry, Florida. The TEC project participants filed a petition for determination of need for the unit at the FPSC in September 2006, and a need hearing on this project was held at the FPSC in January 2007. The project participants are targeting commercial operation of the unit by the summer of 2012.

Under the current participation arrangement, the City would be entitled to approximately 20% of the unit (about 150 MW net summer). The City's participation in the TEC Project was supported by the outcome of evaluations performed in the IRP Study. Despite the uncertainty regarding whether the TEC Project will ultimately be included in the City's long-range resource plan, the schedule of resource additions included in this report reflects the City's share of that unit. Should the resource plan ultimately approved by the City Commission not include the TEC Project, the City will submit revised Tables and Schedules reflecting that alternative resource plan. The table below is a comparison of the resource addition schedules for the plan reported in this Ten Year Site Plan filing including the City's share of the TEC Project and an alternative plan that does not include the TEC Project:

Comparison of Resource Addition Schedules	
2007 TYSP with TEC	Without TEC
2012 – Taylor Energy Center	2016 – LM 6000 CT

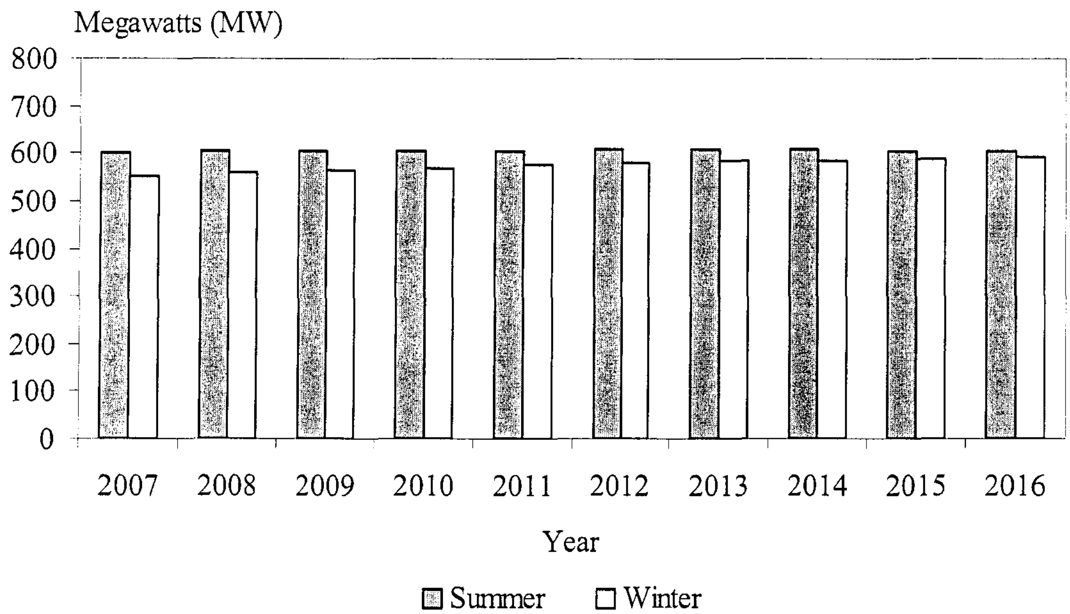
As currently envisioned the City's share of the project output would be delivered over the transmission system of Progress Energy Florida under a standard transmission service agreement. Progress Energy is currently completing a facilities study that will identify the specific transmission interconnections required for TEC. That study should be completed and shared with the project participants in mid April 2007.

The City will continue its evaluation of the different power supply alternatives identified in the IRP study, as well as options that may subsequently become available, and update the FPSC in future TYSP reports.

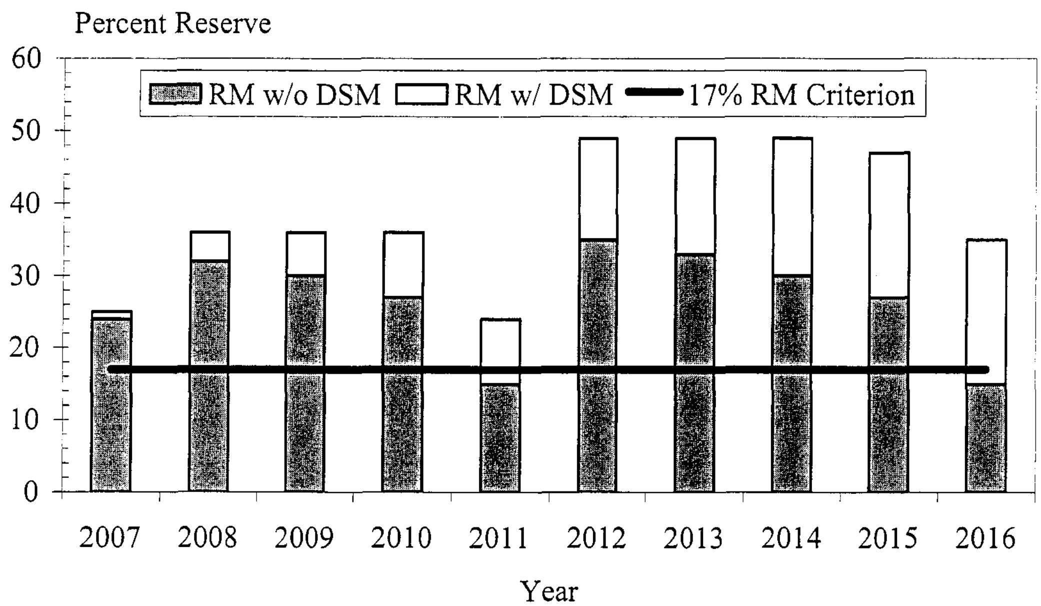
Tables 3.1 and 3.2 (Schedules 7.1 and 7.2) provide information on the resources and reserve margins during the next ten years for the City's system. The City has specified its planned capacity additions, retirements and changes on Table 3.3 (Schedule 8). These capacity resources have been incorporated into the City's dispatch simulation model in order to provide information related to fuel consumption and energy mix (see Tables 2.18, 2.19 and 2.20). Figure C compares seasonal net peak load and the system reserve margin based on summer peak load requirements. Table 3.4 provides the City's generation expansion plan. The additional supply capacity required to maintain the City's 17% reserve margin criterion is included in the "Resource Additions" column.

Figure C

System Peak Demands Net of Conservation



Summer Reserve Margin (RM)



City Of Tallahassee

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak [1]

(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
2007	744	11			755	603	152	25		152	25
2008	812	11			823	606	217	36		217	36
2009	812	11			823	607	216	36		216	36
2010	812	11			823	607	216	36		216	36
2011	744	11			755	607	148	24		148	24
2012	894	11			905	609	296	49		296	49
2013	894	11			905	609	296	49		296	49
2014	894	11			905	608	297	49		297	49
2015	882	11			893	607	286	47		286	47
2016	806	11			817	605	212	35		212	35

[1] All installed and firm import capacity changes are identified in the proposed generation expansion plan (Table 3.4).

City Of Tallahassee

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak [1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity (MW)	Firm Capacity Import (MW)	Firm Capacity Export (MW)	QF (MW)	Total Capacity Available (MW)	System Firm Winter Peak Demand (MW)	Reserve Margin Before Maintenance (MW)	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance (MW)	Reserve Margin After Maintenance (MW)	Reserve Margin After Maintenance % of Peak
2006/07 [2]	795	11			806	528	278	53		278	53
2007/08	795	11			806	554	252	45		252	45
2008/09	890	11			901	561	340	61		340	61
2009/10	890	11			901	565	336	59		336	59
2010/11	890	11			901	569	332	58		332	58
2011/12	820	11			831	576	255	44		255	44
2012/13	976	11			987	580	407	70		407	70
2013/14	976	11			987	583	404	69		404	69
2014/15	976	11			987	586	401	68		401	68
2015/16	962	11			973	589	384	65		384	65
2016/17	884				884	592	292	49		292	49

Notes

[1] All installed and firm import capacity changes are identified in the proposed generation expansion plan (Table 3.4).

[2] Actual 2006/07 winter peak occurred on December 9, 2006.

City Of Tallahassee

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Net Capability		
	Unit		Unit	Fuel		Fuel Transportation		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Mo/Yr	Mo/Yr	Mo/Yr	(kW)	(MW)	(MW)	Status
Hopkins [1]	2	Leon	ST	NG	DFO	PL	TK	1/07	5/08	Unknown	259250	-88	-88	U
Hopkins [1]	5	Leon	CT	NG	DFO	PL	TK	1/07	5/08	Unknown	Unknown	156	183	U
Purdom	CT-1	Wakulla	GT	NG	DFO	PL	TK	NA	12/63	3/11	15000	-10	-10	RT
Purdom	CT-2	Wakulla	GT	NG	DFO	PL	TK	NA	5/64	3/11	15000	-10	-10	RT
Purdom	7	Wakulla	ST	NG	RFO	PL	WA	NA	6/66	3/11	50000	-48	-50	RT
Taylor Energy Center [2]	1	Taylor	ST	BIT	PC	RR	RR	4/08	5/12	Unknown	Unknown	150	156	P
Hopkins	CT-1	Leon	GT	NG	DFO	PL	TK	NA	2/70	3/15	16320	-12	-14	RT
Hopkins	1	Leon	ST	NG	RFO	PL	TK	NA	5/71	3/16	75000	-76	-78	RT

Notes

[1] The City has committed to a combined cycle repowering project converting the existing Hopkins 2 steam unit to a 1-on-1 combined cycle unit (296 MW summer, 333 MW winter) with the addition of a new Hopkins 5 combustion turbine to be in service by May of 2008. The "Net Capability" values in the table above reflect the decrease in the existing Hopkins 2 net capacity and the additional net capacity of the Hopkins 5 combustion turbine associated with the repowering project.

[2] Identified as a preferred capacity addition in the City's recently completed integrated resource planning study. Pending utility and regulatory authorization.

Acronym	Definition
CC	Combined cycle
GT	Gas Turbine
PC	Pulverized Coal
PRI	Primary Fuel
ALT	Alternate Fuel
NG	Natural Gas
DFO	Diesel Fuel Oil
BIT	Bituminous Coal
PC	Petroleum Coke
PL	Pipeline
TK	Truck
RR	Railroad
U	Under construction, less than or equal to 50% complete.
P	Planned for installation but not utility authorized. Not under construction.
RT	Existing generator scheduled for retirement.
kW	Kilowatts
MW	Megawatts

City Of Tallahassee

Generation Expansion Plan

Year	Load Forecast & Adjustments: Fcst Peak Demand (MW)	DSM [1] (MW)	Net Peak Demand (MW)	Existing Capacity Net (MW)		Firm Imports [2] (MW)	Firm Exports (MW)	Resource Additions (Cumulative) (MW)	Total Capacity (MW)	Res %	New Resources
2007	610	7	603	744		11			755	25	
2008	622	16	606	744		11		68	823	36	[3]
2009	634	27	607	744		11		68	823	36	
2010	646	39	607	744		11		68	823	36	
2011	659	52	607	676	[4]	11		68	755	24	
2012	672	63	609	676		11		218	905	49	[5]
2013	683	74	609	676		11		218	905	49	
2014	694	86	608	676		11		218	905	49	
2015	704	97	607	664	[6]	11		218	893	47	
2016	713	108	605	588	[7]	11		218	817	35	

Notes

[1] Demand Side Management includes energy efficiency and demand response/control measures. Identified as maximum achieveable reductions in the City's recently completed integrated resource planning study.

[2] Firm imports include 11 MW purchase from Progress Energy Florida (formerly Florida Power Corporation).

[3] Hopkins 2 combined cycle repowering.

[4] Purdom 7 and Purdom CTs 1 & 2 official retirement currently scheduled for March 2011.

[5] City's prospective 150 MW (after losses) ownership share of 754 MW (summer net) Taylor Energy Center supercritical pulverized coal unit. Identified as a preferred capacity addition in the City's recently completed integrated resource planning study. Pending utility and regulatory authorization.

[6] Hopkins CT 1 official retirement currently scheduled for March 2015.

[7] Hopkins 1 official retirement currently scheduled for March 2016.

Table 3.4

Chapter IV

Proposed Plant Sites and Transmission Lines

4.1 Proposed Plant Site

As discussed in Chapter 3 the City's proposed plan to meet future system needs includes postponing the retirement of Purdom CTs 1 and 2 (previously scheduled for March 2008 and 2009, respectively) until the spring of 2011, repowering the City's existing Hopkins Unit 2 to combined cycle operation by the summer of 2008 and partial ownership of the Taylor Energy Center projected to be in service by summer 2012 (see Tables 4.1 – 4.2).

4.2 Transmission Line Additions/Upgrades

Internal studies of the transmission system have identified a number of system improvements and additions that will be required to reliably serve future load. The attached transmission system map (Figure D1) shows the planned transmission additions covered by this Ten Year Site Plan.

Over the last decade, the City has experienced significant growth and development, and a corresponding increase in the demand for electricity. This has been especially true in the fast growing eastern portion of the City and adjacent Leon County where development has outpaced the construction of electric transmission lines and substations. The only acceptable and permanent way of providing a reliable source of electricity and providing for continuing growth to the eastern part of Tallahassee is to reinforce this area with the proper substation and transmission infrastructure.

The Electric Utility determined which areas would be the most beneficial to locate substation facilities to support this load growth. With due concern about environmental issues and public acceptance, an independent route study was performed, Electric Utility staff conducted numerous public workshops, and the final transmission route recommendation for the Eastern Transmission Line (ETL) Project was approved by the City Commission.

Following that approval, the City acquired a portion of Welaunee property for the line and additional property for the two proposed substations. A consulting engineer has been hired and specifications for the underground portion of the ETL Project have been prepared. The substation and overhead transmission line designs are proceeding and construction is expected to start in mid 2007 and be completed by late 2008.

As discussed in Section 3.2, the City has been working with its neighboring utilities, Progress and Southern, to identify improvements to assure the continued reliability and commercial viability of the transmission systems in and around Tallahassee. At a minimum, the City attempts to plan for and maintain sufficient transmission import capability to allow for emergency power purchases in the event of the most severe single contingency, the loss of the system's largest generating unit. The City's internal transmission studies have reflected a gradual deterioration of the system's transmission import (and export) capability into the future. This reduction in capability is driven by lack of investment in facilities in the panhandle region as well as the impact of unscheduled power flow-through on the City's transmission system. The City is committed to continue to work with Progress and Southern as well as existing and prospective regulatory bodies in an effort to pursue improvements to the regional transmission systems that will allow the City to continue to provide reliable and affordable electric service to the citizens of Tallahassee in the future. The City will provide the FPSC with information regarding any such improvements as it becomes available.

As mentioned earlier in this report, the Taylor Energy Center (TEC) project will be connected to the transmission system of Progress Energy in the area around Perry, FL. Under current FERC large generator interconnection rules, Progress Energy is responsible for the design and construction of the transmission facilities associated with this proposed generating unit. Progress Energy is currently finalizing a facilities study that will identify the specific transmission lines and associated improvements necessary to reliably interconnect the TEC to the regional grid. A draft of that study should be presented to the TEC participants in mid April and the transmission infrastructure associated with the project should be finalized by late summer 2007.

In addition to the transmission improvements described above and shown in Figure D1, the City conducted additional studies of its transmission system to identify further improvements and expansions to provide increased reliability and respond more effectively to certain critical contingencies both on the system and in the surrounding grid in the panhandle. While these evaluations are not yet complete, initial results indicate that additional infrastructure projects may be included in subsequent Ten Year Site Plan filings; these projects generally address either (i) improvements in capability to deliver power from the Hopkins Plant (on the west side of the City's service territory) to the load center, or (ii) the strengthening of the system on the east side of the City's service territory to improve the voltage profile in that area and enhance response to contingencies.

For this Ten Year Site Plan, the City's most recent system transmission expansion planning studies indicate that with current load projections, a 230kV loop around the eastern side of the City is necessary by summer 2016 to ensure reliable service consistent with current and anticipated FERC and NERC requirements. For this proposed transmission project, the City intends to tap its existing Hopkins-PEF Crawfordville 230kV transmission line and extend a 230kV transmission line to the east terminating at Substation BP-5 as the first phase of the project to be in service by summer 2011, and then upgrade an existing 115kV line to 230 kV from Substation BP-5 to Substation BP-7 for the second phase of the project completing the loop by summer 2016. This new 230kV line would address a number of potential line overloads for the single contingency loss of other key transmission lines in the City's system. Possible locations for a second 230:115kV autotransformer include Substations BP-5 or BP-4 as alternatives to the currently planned connection at Substation BP-7. Table 4.3 summarizes the proposed new facilities or improvements from the transmission planning study that are within this Ten Year Site Plan reporting period.

With the exception of the second 230:115kV autotransformer currently planned for addition at Substation BP-7 the 230 kV additions discussed in the preceding paragraph represent planned but not yet budgeted projects. The City's budget planning cycle for FY2008 is currently ongoing, and project budgets in the electric utility will not be finalized until the summer of 2007. Some of the preliminary engineering and design work is planned for later this year in anticipation of these projects being budgeted in the FY2008 cycle. If these improvements do not make the budgeted project list, the City has prepared operating solutions to mitigate any system constraints that might occur as a results of the delay in the in-service date of these improvements.

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Hopkins 2 Combined Cycle Repowering	
(2)	Capacity		
	a.) Summer:	296	[1]
	b.) Winter:	333	[1]
(3)	Technology Type:	CC	
(4)	Anticipated Construction Timing		
	a.) Field Construction start - date:	Jan-07	
	b.) Commercial in-service date:	May-08	
(5)	Fuel		
	a.) Primary fuel:	NG	
	b.) Alternate fuel:	DFO	
(6)	Air Pollution Control Strategy:	DLN on natural gas, Water Injection for LFO, SCR	
(7)	Cooling Status:	Closed loop cooling (existing)	
(8)	Total Site Area:	5 acres	
(9)	Construction Status:	Under construction, less than or equal to 50% complete.	
(10)	Certification Status:	Regulatory approval received.	
(11)	Status with Federal Agencies:	Regulatory approval received.	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF):	8.61%	[2]
	Forced Outage Factor:	2.39%	[2]
	Equivalent Availability Factor (EAF):	84.65%	[2]
	Resulting Capacity Factor (%):	48.90%	[3]
	Average Net Operating Heat Rate (ANOHR):	7,198	[4]
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost (In-Service Year $/kW)	392	[5]
	Direct Construction Cost ($/kW):	373	[6]
	AFUDC Amount ($/kW):	NA	
	Escalation ($/kW):	19	
	Fixed O & M ($kW-Yr):	13.29	[7]
	Variable O & M ($/MWH):	2.78	[7]
	K Factor:	NA	

Notes

[1] The City has committed to a combined cycle repowering project converting the existing Hopkins 2 steam unit to a 1-on-1 combined cycle unit to be in service by May of 2008. The "Capacity" values provided in the table above reflect the total net capacity of the repowered unit. These represent incremental seasonal capacity additions of 68 MW summer net and 95 MW winter net.

[2] Per North American Electric Reliability Council's (NERC) Generating Availability Data System (GADS) report of 1999-2003 averages for "Combined Cycle, All MW Sizes".

[3] Projected capacity factor for first full calendar year of operation (2009).

[4] Expected full load average net heat rate at 68°F without supplemental duct firing.

[5] 2008 cost per total unit summer net MW capability.

[6] 2006 cost per total unit summer net MW capability.

[7] 2008 costs per current IRP assumptions for generic 1-on-1 GE 7FA combined cycle unit.

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Taylor Energy Center	
(2)	Capacity		
	a.) Summer:	754.1	[3]
	b.) Winter:	785.3	[3]
(3)	Technology Type:	PC	
(4)	Anticipated Construction Timing		
	a.) Field Construction start - date:	Apr-08	
	b.) Commercial in-service date:	May-12	
(5)	Fuel		
	a.) Primary fuel:	BIT/PC	
	b.) Alternate fuel:	NA	
(6)	Air Pollution Control Strategy:	BACT compliant	
(7)	Cooling Status:	Mechanical draft	
(8)	Total Site Area:	Approximately 3,000 acres	
(9)	Construction Status:	Not started	
(10)	Certification Status:	Underway	
(11)	Status with Federal Agencies:	Underway	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF):	4.38%	
	Forced Outage Factor:	5.20%	
	Equivalent Availability Factor (EAF):	90%	
	Resulting Capacity Factor (%):	90%	
	Average Net Operating Heat Rate (ANOHR):	9,238 Btu/kWh	[1]
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost (In-Service Year $/kW)	2664	[1]
	Direct Construction Cost ($/kW):	2152	[1]
	AFUDC Amount ($/kW):	208	[1]
	Escalation ($/kW):	304	[1]
	Fixed O & M ($kW-Yr):	24.31	[1] [2]
	Variable O & M ($/MWH):	1.43	[1] [2]
	K Factor:	NA	

Notes
[1] Based on operation at average ambient conditions.
[2] In 2007 dollars.
[3] The City's prospective ownership share is 20.3% (153 summer net and 159 winter net).

Planned Transmission Projects, 2007-2016

Project Type	Project Name	From Bus Name	From Bus Number	To Bus Name	To Bus Number	Expected In-Service Date	Voltage (kV)	Line Length (miles)
New Line	Line 9B	Sub 17	7517	Sub 14	7514	6/1/08	115	4.0
	Line 9A	Sub 9	7509	Sub 17	7517	6/1/08	115	9.0
	Line 9C	Sub 14	7514	Sub 7	7507	12/1/08	115	6.0
	Hopkins - PEF Tallahassee	Hopkins	7550	Tallahas	3136	5/1/09	115	4.0
	Line 18C	Sub 18	7518	Sub 9	7509	12/1/10	115	9.0
	Line 18B	Sub 15	7515	Sub 18	7518	12/1/10	115	6.0
	230 loop Phase I	Hop-Craw Tap	NA	Sub 5	7605	6/1/11	230	8.0
	231 loop Phase II	Sub 5	7605	Sub 7	7607	6/1/16	230	12.8
Rebuild/ Reconductor	3A reconductor &	Purdom	7551	TECWoodvl	7554	6/1/07	115	11.5
	Talquin Woodville Sub	TECWoodvl	7554	Sub 11	7511	11/1/07	115	6.7
	Line 12B	Sub 2	7502	Sub 31	7531	12/1/07	115	4.3
	Line 10	Sub 6	7506	Sub 31	7531	12/1/07	115	2.0
	Line 3C	Sub 3	7503	Sub 31	7503	6/1/08	115	0.4
	Line 21	Sub 31	7531	Tallahas	3136	5/1/09	115	4.0
	Line 2C	Switch St	7553	Sub 5	7505	10/1/09	115	1.6
	Line 15C	Sub 9	7509	Sub 4	7504	6/1/10	115	4.0
	Line 15B	Sub 5	7505	Sub 9	7509	6/1/10	115	6.0
	Line 15A	Sub 5	7505	Sub 4	7504	6/1/10	115	9.0
	Line 7A	Hopkins	7550	Sub 10	7510	6/1/10	115	5.0

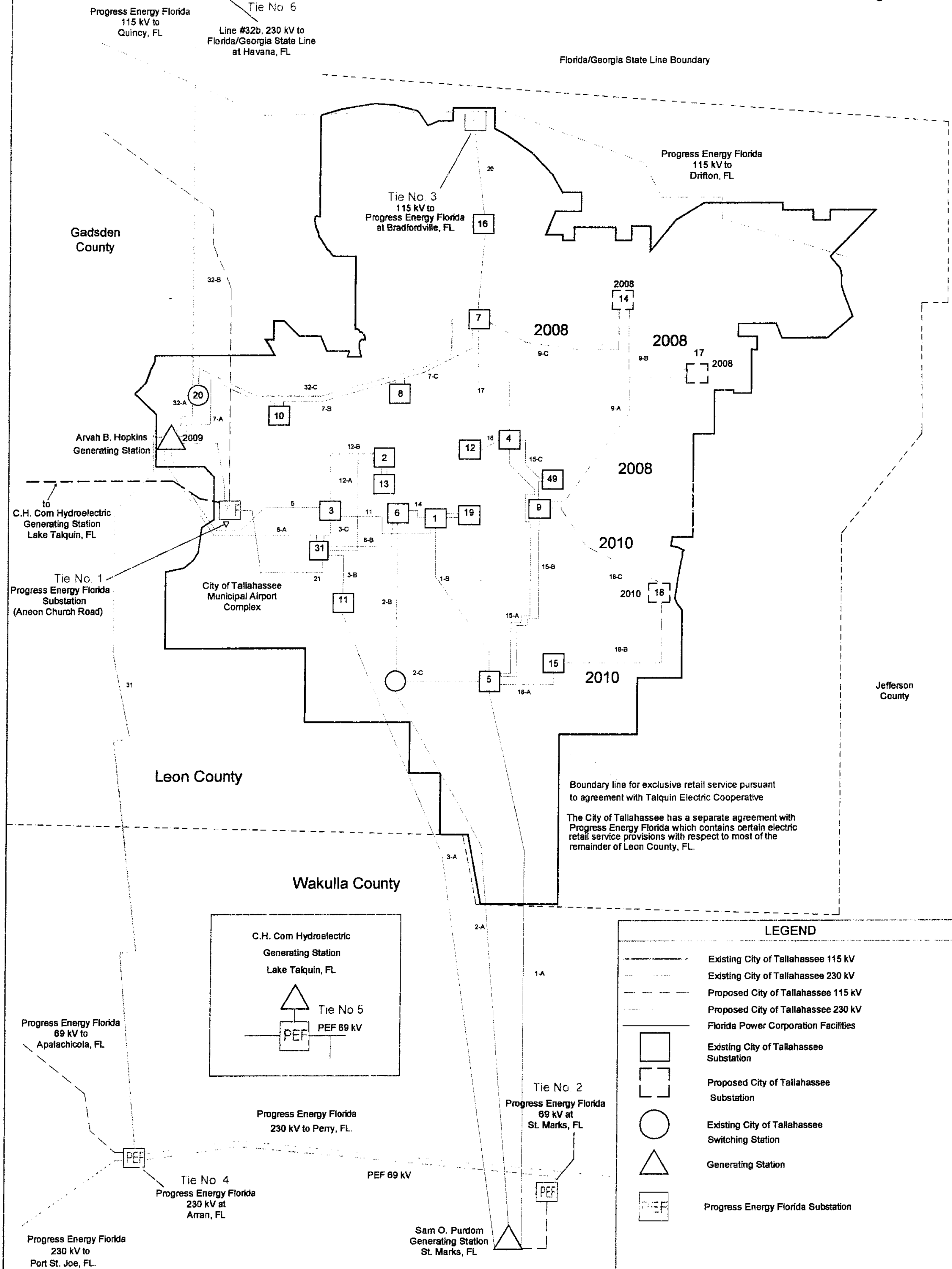
Table 4.3

City Of Tallahassee

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1)	Point of Origin and Termination:	No facility additions or improvements to report at this time.
(2)	Number of Lines:	
(3)	Right-of -Way:	
(4)	Line Length:	
(5)	Voltage:	
(6)	Anticipated Capital Timing:	
(7)	Anticipated Capital Investment:	
(8)	Substations:	
(9)	Participation with Other Utilities:	

Figure D1



PROPOSED TRANSMISSION SYSTEM

City of Tallahassee

Electric Transmission System
2007 - 2017

APPENDIX A
Supplemental Data

The following Appendix represents supplemental data typically requested by the Florida Public Service Commission.

Existing Generating Unit Operating Performance

(1)	(2)		(3)		(4)		(5)		(6)	
			Planned Outage Factor (POF)		Forced Outage Factor (FOF)		Equivalent Availability Factor (EAF)		Average Net Operating Heat Rate (ANOHR)	
Plant Name	Unit No.		Historical	Projected	Historical	Projected	Historical	Projected	Historical	Projected
Existing Units										
Corn	1	[1]	NA	8.12%	NA	2.94%	NA	88.53%	NA	NA
Corn	2	[1]	NA	8.12%	NA	2.94%	NA	88.53%	NA	NA
Corn	3	[1]	NA	8.12%	NA	2.94%	NA	88.53%	NA	NA
Hopkins	1		10.29%	4.89%	0.02%	1.89%	89.69%	92.41%	12,635	12,257
Hopkins	2	[2]	5.51%	11.35%	0.17%	2.90%	84.19%	85.75%	10,963	11,127
Hopkins	GT-1		0.33%	4.37%	0.06%	3.37%	99.61%	89.23%	27,801	22,220
Hopkins	GT-2		15.75%	3.29%	3.07%	1.76%	81.18%	89.90%	30,533	18,944
Hopkins	GT-3	[3]	0.70%	4.34%	0.50%	2.17%	98.80%	89.55%	18,935	9,867
Hopkins	GT-4	[3]	0.35%	4.34%	0.04%	2.17%	99.62%	89.55%	10,763	9,868
Purdom	7		0.39%	4.89%	0.42%	1.89%	99.19%	92.41%	12,873	14,482
Purdom	8		4.57%	8.61%	16.01%	2.39%	79.42%	89.00%	7,381	7,761
Purdom	GT-1		0.69%	4.37%	0.33%	3.37%	98.98%	89.23%	36,828	28,936
Purdom	GT-2		0.57%	4.37%	1.89%	3.37%	97.53%	89.23%	25,647	28,936
Future Units										
Hopkins	CC	[2]	NA	8.61%	NA	2.39%	NA	89.00%	NA	8,651
Taylor Energy Center	1		NA	4.38%	NA	5.20%	NA	90.00%	NA	9,735

NOTES: Historical - average of past three fiscal years
Projected - average of next ten fiscal years

[1] The City does not track the planned outage, forced outage or equivalent availability factors for the Corn Hydro units.
[2] Unit to be repowered to combined cycle operation in 2008.
[3] Units placed in service in the fall of 2005. Available historical data provided.

Nominal, Delivered Residual Oil Prices
Base Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Residual Oil (By Sulfur Content)								
		Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
	Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History [1]	2004	NA	NA	NA	31.76	504	-	NA	NA	NA
	2005	NA	NA	NA	40.86	649	28.7%	NA	NA	NA
	2006	NA	NA	NA	54.80	870	34.1%	NA	NA	NA
Forecast	2007	NA	NA	NA	53.99	857	-1.5%	NA	NA	NA
	2008	NA	NA	NA	54.49	865	0.9%	NA	NA	NA
	2009	NA	NA	NA	54.99	873	0.9%	NA	NA	NA
	2010	NA	NA	NA	55.48	881	0.9%	NA	NA	NA
	2011	NA	NA	NA	56.16	891	1.2%	NA	NA	NA
	2012	NA	NA	NA	56.82	902	1.2%	NA	NA	NA
	2013	NA	NA	NA	56.40	895	-0.7%	NA	NA	NA
	2014	NA	NA	NA	55.91	888	-0.9%	NA	NA	NA
	2015	NA	NA	NA	55.35	879	-1.0%	NA	NA	NA
	2016	NA	NA	NA	57.61	914	4.1%	NA	NA	NA

ASSUMPTIONS: heat content - 6.3 MMBtu/BBL, ash content - Not Available

[1] Actual average cost of oil burned.

Nominal, Delivered Residual Oil Prices
High Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Residual Oil (By Sulfur Content)								
		Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
	Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History [1]	2004	NA	NA	NA	31.76	504	-	NA	NA	NA
	2005	NA	NA	NA	40.86	649	28.7%	NA	NA	NA
	2006	NA	NA	NA	54.80	870	34.1%	NA	NA	NA
Forecast [2]	2007	NA	NA	NA	53.99	857	-1.5%	NA	NA	NA
	2008	NA	NA	NA	55.84	886	3.4%	NA	NA	NA
	2009	NA	NA	NA	57.75	917	3.4%	NA	NA	NA
	2010	NA	NA	NA	59.70	948	3.4%	NA	NA	NA
	2011	NA	NA	NA	61.93	983	3.7%	NA	NA	NA
	2012	NA	NA	NA	64.21	1019	3.7%	NA	NA	NA
	2013	NA	NA	NA	65.34	1037	1.8%	NA	NA	NA
	2014	NA	NA	NA	66.41	1054	1.6%	NA	NA	NA
	2015	NA	NA	NA	67.40	1070	1.5%	NA	NA	NA
	2016	NA	NA	NA	71.83	1140	6.6%	NA	NA	NA

ASSUMPTIONS: heat content - 6.3 MMBtu/BBL, ash content - Not Available

[1] Actual fiscal year average cost of oil burned.
[2] For the high case, compound annual escalation rates (CAER) are assumed to be 2.5% higher than the base case CAERs.

Nominal, Delivered Residual Oil Prices
Low Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Residual Oil (By Sulfur Content)								
		Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
	Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History [1]	2004	NA	NA	NA	31.76	504	-	NA	NA	NA
	2005	NA	NA	NA	40.86	649	28.7%	NA	NA	NA
	2006	NA	NA	NA	54.80	870	34.1%	NA	NA	NA
Forecast [2]	2007	NA	NA	NA	53.99	857	-1.5%	NA	NA	NA
	2008	NA	NA	NA	53.14	844	-1.6%	NA	NA	NA
	2009	NA	NA	NA	52.30	830	-1.6%	NA	NA	NA
	2010	NA	NA	NA	51.45	817	-1.6%	NA	NA	NA
	2011	NA	NA	NA	50.80	806	-1.3%	NA	NA	NA
	2012	NA	NA	NA	50.13	796	-1.3%	NA	NA	NA
	2013	NA	NA	NA	48.51	770	-3.2%	NA	NA	NA
	2014	NA	NA	NA	46.87	744	-3.4%	NA	NA	NA
	2015	NA	NA	NA	45.23	718	-3.5%	NA	NA	NA
	2016	NA	NA	NA	45.95	729	1.6%	NA	NA	NA

ASSUMPTIONS: heat content - 6.3 MMBtu/BBL, ash content - Not Available

[1] Actual fiscal year average cost of oil burned.
[2] For the low case, compound annual escalation rates (CAER) are assumed to be 2.5% lower than the base case CAERs.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Base Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil			Natural Gas [2]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2004	39.15	675	-	643	6.67	-
	2005	69.26	1194	76.9%	765	7.95	19.2%
	2006	77.72	1340	12.2%	916	9.47	19.2%
Forecast	2007	80.69	1391	3.8%	800	8.32	-12.1%
	2008	80.98	1396	0.4%	859	8.94	7.4%
	2009	81.17	1400	0.2%	820	8.53	-4.6%
	2010	82.42	1421	1.5%	790	8.22	-3.6%
	2011	82.41	1421	0.0%	772	8.02	-2.4%
	2012	81.86	1411	-0.7%	757	7.87	-1.9%
	2013	80.97	1396	-1.1%	781	8.12	3.1%
	2014	78.73	1357	-2.8%	797	8.28	2.0%
	2015	77.69	1340	-1.3%	818	8.51	2.7%
	2016	80.06	1380	3.0%	833	8.66	1.8%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.8 MMBtu/BBL; ash content, sulfur content - Not Available

[1] Actual average cost of distillate oil and gas burned.
[2] Delivered gas price reflects cost at Henry Hub increased by 3% for compression losses.

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil			Natural Gas [3]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2004	39.15	675	-	643	6.69	-
	2005	69.26	1194	76.9%	765	7.96	19.0%
	2006	77.72	1340	12.2%	916	9.53	19.7%
Forecast [2]	2007	80.69	1391	3.8%	800	8.32	-12.6%
	2008	83.00	1431	2.9%	879	9.14	9.9%
	2009	85.27	1470	2.7%	861	8.95	-2.1%
	2010	88.71	1530	4.0%	851	8.85	-1.1%
	2011	90.92	1568	2.5%	853	8.87	0.1%
	2012	92.59	1596	1.8%	858	8.92	0.6%
	2013	93.89	1619	1.4%	906	9.42	5.6%
	2014	93.65	1615	-0.3%	947	9.85	4.5%
	2015	94.75	1634	1.2%	996	10.36	5.2%
	2016	100.00	1724	5.5%	1,039	10.81	4.3%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.8 MMBtu/BBL;
ash content, sulfur content - Not Available

[1] Actual average cost of distillate oil and gas burned.
[2] For the high case, compound annual escalation rates (CAER) are assumed to be 2.5% higher than the base case CAERs.
[3] Delivered gas price reflects cost at Henry Hub increased by 3% for compression losses.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil			Natural Gas [3]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2004	39.15	675	-	643	6.69	-
	2005	69.26	1194	76.9%	765	7.96	19.0%
	2006	77.72	1340	12.2%	916	9.53	19.7%
Forecast [2]	2007	80.69	1391	3.8%	800	8.32	-12.6%
	2008	78.96	1361	-2.1%	839	8.73	4.9%
	2009	77.18	1331	-2.3%	780	8.11	-7.1%
	2010	76.43	1318	-1.0%	732	7.61	-6.1%
	2011	74.52	1285	-2.5%	697	7.24	-4.9%
	2012	72.16	1244	-3.2%	666	6.93	-4.4%
	2013	69.56	1199	-3.6%	670	6.97	0.6%
	2014	65.90	1136	-5.3%	667	6.94	-0.5%
	2015	63.38	1093	-3.8%	668	6.95	0.2%
	2016	63.73	1099	0.5%	664	6.90	-0.7%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.8 MMBtu/BBL;
ash content, sulfur content - Not Available

[1] Actual average cost of distillate oil and gas burned.
[2] For the low case, compound annual escalation rates (CAER) are assumed to be 2.5% lower than the base case CAERs.
[3] Delivered gas price reflects cost at Henry Hub increased by 3% for compression losses.

Nominal, Delivered Coal Prices [1]
Base Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
		Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
	Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
History	2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2007	60.92	254	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2008	65.73	274	7.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	69.18	288	5.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	71.53	298	3.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	72.32	301	1.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	71.92	300	-0.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	72.50	302	0.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	77.04	321	6.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	80.44	335	4.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	82.91	345	3.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA

[1] Coal is not currently a part of the City's generation fuel mix. However, it's forecast price is required for the City's resource planning efforts as it will allow for the evaluation of coal-based resource options.

[2] Hill & Associates forecast for a 72% Latin American coal/28% petroleum coke blend as prepared for the Taylor Energy Center project partners.

Nominal, Delivered Coal Prices [1]
High Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
		Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
	Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
History	2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2007	45.74	254	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2008	46.09	280	10.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	46.48	302	7.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	46.68	320	5.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	47.66	331	3.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	48.68	338	1.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	49.72	349	3.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	50.80	379	8.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	51.92	406	6.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	52.92	428	5.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA

[1] Coal is not currently a part of the City's generation fuel mix. However, it's forecast price is required for the City's resource planning efforts as it will allow for the evaluation of coal-based resource options.

[2] For the high case, compound annual escalation rates (CAER) are assumed to be 2.5% higher than the base case CAERs.

Nominal, Delivered Coal Prices [1]
Low Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
		Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
	Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
History	2004	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2007	45.74	254	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2008	46.09	268	5.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	46.48	275	2.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	46.68	277	0.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	47.66	273	-1.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	48.68	265	-3.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	49.72	261	-1.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	50.80	270	3.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	51.92	276	1.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	52.92	277	0.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA

[1] Coal is not currently a part of the City's generation fuel mix. However, it's forecast price is required for the City's resource planning efforts as it will allow for the evaluation of coal-based resource options.
[2] For the low case, compound annual escalation rates (CAER) are assumed to be 2.5% lower than the base case CAERs.

Nominal, Delivered Nuclear Fuel and Firm Purchases

	(1)	(2)	(3)	(4)	(5)
		Nuclear		Firm Purchases [1]	
	Year	c/MBTU	Escalation %	$/MWh	Escalation %
History	2004	NA	NA	45.74	-
	2005	NA	NA	67.58	47.7%
	2006	NA	NA	42.18	-37.6%
Forecast	2007	NA	NA	42.00	-0.4%
	2008	NA	NA	43.05	2.5%
	2009	NA	NA	44.13	2.5%
	2010	NA	NA	45.23	2.5%
	2011	NA	NA	46.36	2.5%
	2012	NA	NA	47.52	2.5%
	2013	NA	NA	48.71	2.5%
	2014	NA	NA	49.92	2.5%
	2015	NA	NA	51.17	2.5%
	2016	NA	NA	52.45	2.5%

[1] Historical data is for all purchases, firm and non-firm

Financial Assumptions
Base Case

AFUDC RATE	5.25%	
CAPITALIZATION RATIOS:		
DEBT	143.55%	[1]
PREFERRED	N/A	[2]
ASSETS	65.76%	[3]
EQUITY	139.12%	[3]
RATE OF RETURN (6)		
DEBT	3.49%	[4]
PREFERRED	N/A	[2]
ASSETS	1.60%	[5]
EQUITY	3.38%	[5]
INCOME TAX RATE:		
STATE	N/A	[6]
FEDERAL	N/A	[6]
EFFECTIVE	N/A	[6]
OTHER TAX RATE:		
Sales Tax (< $5,000)	7.00%	[7]
Sales Tax (> $5,000)	6.00%	[7]
DISCOUNT RATE:	2.75% - 5.25%	
TAX DEPRECIATION RATE:	N/A	[6]

[1] Plant-in-service compared to total debt
[2] No preferred "stock" in municipal utilities
[3] Net plant-in-service compared to total assets / net plant-in-service compared to total fund equity
[4] Net income compared to total debt
[5] Net income compared to total assets / net income compared to total fund equity
[6] Municipal utilities are exempt from income tax
[7] Municipal utilities are exempt from other taxes except Florida sales tax on expansion of electric transmission and distribution (T&D) tangible personal property used in the T&D system (7% on first $5,000 and 6% thereafter). Sales tax is no longer charged for T&D system maintenance.

Financial Escalation Assumptions

(1) Year	(2) General Inflation %	(3) Plant Construction Cost %	(4) Fixed O&M Cost %	(5) Variable O&M Cost %
2007	2.5	2.5	2.5	2.5
2008	2.5	2.5	2.5	2.5
2009	2.5	2.5	2.5	2.5
2010	2.5	2.5	2.5	2.5
2011	2.5	2.5	2.5	2.5
2012	2.5	2.5	2.5	2.5
2013	2.5	2.5	2.5	2.5
2014	2.5	2.5	2.5	2.5
2015	2.5	2.5	2.5	2.5
2016	2.5	2.5	2.5	2.5

Monthly Peak Demands and Date of Occurrence for 2004 - 2006

Calendar Year 2004

Month	Date	Hour Ending	Daily Temp. (°F) Min.	Daily Temp. (°F) Max.	Peak Demand (MW)
January	29-Jan	8:00 A.M.	23	58	509
February	19-Feb	8:00 A.M.	28	66	445
March	11-Mar	8:00 A.M.	30	69	362
April	29-Apr	9:00 P.M.	57	84	378
May	26-May	5:00 P.M.	63	94	508
June	18-Jun	4:00 P.M.	74	95	518
July	12-Jul	4:00 P.M.	74	97	557
August	3-Aug	4:00 P.M.	76	97	565
September	9-Sep	5:00 P.M.	69	93	534
October	1-Oct	3:00 P.M.	65	88	491
November	3-Nov	4:00 P.M.	63	85	443
December	15-Dec	8:00 A.M.	29	51	480

Calendar Year 2005

Month	Date	Hour Ending	Daily Temp. (°F) Min.	Daily Temp. (°F) Max.	Peak Demand (MW)
January	24-Jan	8:00 A.M.	19	54	532
February	11-Feb	8:00 A.M.	32	59	428
March	2-Mar	10:00 A.M.	27	59	462
April	22-Apr	3:00 P.M.	52	83	391
May	24-May	5:00 P.M.	75	96	550
June	15-Jun	4:00 P.M.	73	97	579
July	27-Jul	4:00 P.M.	76	96	583
August	22-Aug	5:00 P.M.	75	96	598
September	19-Sep	5:00 P.M.	74	99	578
October	3-Oct	3:00 P.M.	76	90	494
November	30-Nov	8:00 P.M.	37	63	425
December	23-Dec	9:00 A.M.	23	62	476

Calendar Year 2006

Month	Date	Hour Ending	Daily Temp. (°F) Min.	Daily Temp. (°F) Max.	Peak Demand (MW)
January	19-Jan	8:00 A.M.	28	78	465
February	14-Feb	8:00 A.M.	22	82	537
March	21-Mar	4:00 P.M.	29	91	406
April	20-Apr	4:00 P.M.	38	93	502
May	30-May	5:00 P.M.	48	96	524
June	22-Jun	4:00 P.M.	54	98	572
July	19-Jul	6:00 P.M.	61	99	577
August	8-Aug	4:00 P.M.	68	97	576
September	1-Sep	5:00 P.M.	47	95	539
October	2-Oct	5:00 P.M.	35	92	473
November	20-Nov	7:00 A.M.	33	82	406
December	8-Dec	9:00 P.M.	21	79	528

Historical and Projected Heating and Cooling Degree Days

	Year	Heating Degree Days (HDD)	Cooling Degree Days (CDD)
History	1997	1,427	2,515
	1998	1,272	3,148
	1999	1,461	2,768
	2000	1,640	2,757
	2001	1,429	2,451
	2002	1,504	2,910
	2003	1,645	2,578
	2004	1,646	2,705
	2005	1,509	2,743
	2006	1,464	2,595
Forecast	2007	1,464	2,595
	2008	1,464	2,595
	2009	1,464	2,595
	2010	1,464	2,595
	2011	1,464	2,595
	2012	1,464	2,595
	2013	1,464	2,595
	2014	1,464	2,595
	2015	1,464	2,595
	2016	1,464	2,595

Average Real Retail Price of Electricity

Residential Real Price of Electricity (\$/MWh)	Commercial Real Price of Electricity (\$/MWh)	System-Wide Real Price of Electricity (\$/MWh)	Deflator [1]
55.14	46.75	47.80	1.605
52.98	45.96	45.06	1.630
51.32	42.87	43.67	1.666
52.47	45.63	43.62	1.722
52.48	44.04	43.17	1.771
45.22	37.08	42.50	1.799
53.00	44.28	43.29	1.840
55.29	46.84	48.01	1.889
55.08	46.81	47.92	1.953
63.34	55.15	58.43	2.016
63.34	55.15	58.44	
63.34	55.15	58.44	
63.34	55.15	58.44	
63.34	55.15	58.44	
63.34	55.15	58.44	
63.34	55.15	58.44	
63.34	55.15	58.44	
63.34	55.15	58.44	
63.34	55.15	58.44	
63.34	55.15	58.44	

Deflator is CPI Index per U. S. Dept. of Labor Bureau of Labor Stats. ('82 Dollars).

For the City's 2007 Load Forecast, it was assumed that the future real price of electricity for commercial customers would remain constant at the 2006 level. While fuel prices are projected to increase in real terms, as in past load forecasts, it was assumed that these price increases would be offset by more efficient generation, reduced operation and maintenance costs, and the effects of competition.

Loss of Load Probability, Reserve Margin,
and Expected Unserved Energy
Base Case Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Annual Isolated			Annual Assisted		
Year	Loss of Load Probability (Days/Yr)	Reserve Margin % (Including Firm Purch.)	Expected Unserved Energy (MWh)	Loss of Load Probability (Days/Yr)	Reserve Margin % (Including Firm Purch.)	Expected Unserved Energy (MWh)
2003						
2004						
2005						
2006			See note [1] below			
2007						
2008						
2009						
2010						
2011						
2012						

[1] The City provides its projection of reserve margin with and without supply resource additions in Tables 3.1 and 3.2 (Schedules 7.1 and 7.2, respectively) on pages 40 and 41 and in Table 3.4 (Generation Expansion Plan) on page 43 of the City's 2004 Ten Year Site Plan. The City does not currently evaluate isolated and assisted LOLP and EUE reliability indices.