City of Tallahassee
Your Own Utilities℠

2602 Jackson Bluff Road, Tallahassee, Florida 32304, (850) 891-4YOU (4968), talgov.com

April 3, 2006

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

Dear Ms. Bayó:

Attached are twenty-five (25) copies of the City of Tallahassee's 2006 Ten Year Site Plan. If you have any questions, please e-mail me at childsv@talgov.com or call me at 891-3122.

Sincerely,

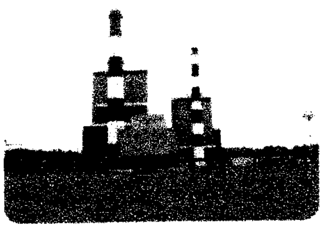
Venus Childs

Venus Childs
Planning Engineer

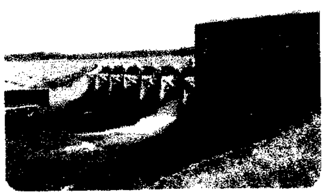
Attachments
cc: KGW
GSB

Ten Year Site Plan 2006-2015

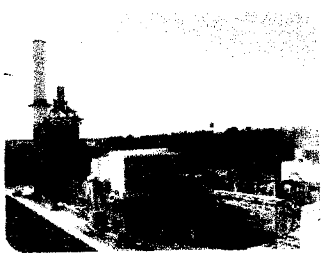
City of Tallahassee Electric Utility



Arvah B. Hopkins
Generating Station



C. H. Corn
Hydroelectric Station



Sam O. Purdom
Generating Station

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
2006-2015
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 107,780 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 five points of interconnection with Progress Energy Florida ("Progress", formerly Florida Power Corporation); two 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, 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.					
								Fuel	Commercial	Expected	Gen. Max.	Net Capability	
	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]	Jun-66	3/11	50,000	48	50
	8		CC	NG	FO2	PL	TK	[2, 3]	Jul-00	12/40	247,743	233	262
	GT-1		GT	NG	FO2	PL	TK	[2, 3]	Dec-63	3/11	15,000	10	10
	GT-2		GT	NG	FO2	PL	TK	[2, 3]	May-64	3/11	15,000	10	10
											Plant Total	301	332
A. B. Hopkins	1	Leon	ST	NG	FO6	PL	TK	[1]	May-71	3/16	75,000	76	78
	2		ST	NG	FO6	PL	TK	[1]	Oct-77	3/22	259,250	228	238
	GT-1		GT	NG	FO2	PL	TK	8	Feb-70	3/15	16,320	12	14
	GT-2		GT	NG	FO2	PL	TK	8	Sep-72	3/17	27,000	24	26
	GT3		GT	NG	FO2	PL	TK	8	Sep-05	UNKNOWN	60,500	46	48
	GT4		GT	NG	FO2	PL	TK	8	Nov-05	UNKNOWN	60,500	46	48
											Plant Total	432	452
C. H. Corn	1	Leon/	HY	WAT	WAT	WAT	WAT	NA	Sep-85	UNKNOWN	4,440	4	4
Hydro Station	2	Gadsden	HY	WAT	WAT	WAT	WAT	NA	Aug-85	UNKNOWN	4,440	4	4
	3		HY	WAT	WAT	WAT	WAT	NA	Jan-86	UNKNOWN	3,430	3	3
											Plant Total	11	11
								TOTAL SYSTEM CAPACITY AS OF DECEMBER 31, 2005				744	795

Table 1.1

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 City's 2006 Load Forecast and the Demand Side Management plan filed with the Florida Public Service Commission (FPSC) on March 1, 1996.

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 2006 and the horizon year of 2015. Tables 2.4 through 2.12 (Schedules 3.1.1 - 3.3.3) contain historical and forecast 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 2005 - 2007 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 R.W. Beck, Inc. Consulting. 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 approximately 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 (TEC) customers over the study period consistent with the territorial agreement negotiated between the City and TEC 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 demand-side management 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. Utilizing the five-year average of the actual temperature at the time of seasonal peak demand, routinely updating the forecast model coefficients and making other minor model refinements have improved the accuracy of the forecast so that it is more consistent with the historical trend of growth in seasonal peak demand and energy consumption.

Based upon the actual 2004 and 2005 winter peaks and model refinements, the 2006 winter peak demand forecast is lower than the projections made in the 2005 demand forecast. 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. The minimum temperature on the peak day in 2005 was 19 degrees, which was lower than the 5-year average of 20 degrees. However, the peak demand value was low, contributing to the lowering of the 2006 winter peak demand forecast.

The most significant input assumptions for the 2006 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 15% 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. 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. Presently there are two projects pending that may impact load forecast projections in the future. The State of Florida Department of Management Services has proposed to transition state office buildings to interruptible service and install onsite generation totaling 20 MW to serve as back up power. This may impact demand estimates beginning in 2007. Tallahassee Memorial Hospital is also projecting 6 MW of demand reduction, with a proposed in service date of summer 2008.

The City believes that the inclusion of these incremental additions/reductions, 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 2006 load forecast the key explanatory variables that were changed were Leon County population, Florida 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 cases 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 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. On March 1, 1996 the City filed its Demand Side Management (DSM) Plan with the FPSC. This plan indicated the demand and energy reductions due to conservation efforts that are expected over the period 1997-2006. The individual program measures that were selected for inclusion in the plan were identified as cost effective in Integrated Resource Planning (IRP) studies conducted by the City. During 2006 the City is planning to prepare a new DSM Plan concurrently with an updated IRP Study.

The following menu of programs is included in the current DSM plan, which was implemented in fiscal year 1997:

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	

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

As a part of the current IRP Study, the City is evaluating an expanded set of DSM measures that, if determined to be cost-effective, will be included in the preferred resource plan. This set of measures represents additional conservation and energy efficiency programs above the amount that is included in the City's load forecast. In determining the cost-effectiveness of this set of measures, the City is utilizing several criteria including the Total Resource Cost (TRC) Test and levelized system avoided cost comparisons. Following the completion of the IRP Study, the City intends to undertake a detailed DSM program design study to identify and implement specific groups of measures that achieve the capacity benefit and energy savings included in the preferred resource plan.

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 2006 and 2015.

The City's generation portfolio includes combustion turbine/combined cycle, combustion turbine/simple cycle, conventional steam and hydroelectric units. This mix of generation types coupled with opportunities for firm and economy purchases from neighboring systems provides the City with a reasonable amount of resource diversity 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 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.

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 [2]		
Year	Population [3]	Members Per Household	(GWh)	Average No. of Customers [1]	Average kWh Consumption Per Customer	(GWh)	Average No. of Customers [1]	Average kWh Consumption Per Customer
1996	175,373	-	893	72,998	12,233	1,316	15,142	86,911
1997	177,347	-	850	74,259	11,446	1,324	15,495	85,447
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	1,457	15,891	91,687
2001	190,575	-	959	80,348	11,936	1,459	16,988	85,884
2002	193,941	-	1,048	81,208	12,905	1,527	16,831	90,661
2003	200,304	-	1,035	82,219	13,030	1,555	17,289	107,870
2004	203,106	-	1,063	84,496	12,580	1,604	17,553	91,380
2005	205,908	-	1,088	89,468	12,161	1,621	18,310	88,531
2006	208,789	-	1,072	90,506	11,845	1,647	18,496	89,046
2007	211,669	-	1,093	91,882	11,896	1,702	18,709	90,972
2008	214,550	-	1,114	93,259	11,945	1,756	18,922	92,802
2009	217,430	-	1,136	94,636	12,004	1,790	19,136	93,541
2010	220,311	-	1,158	95,998	12,063	1,820	19,347	94,071
2011	223,056	-	1,179	97,334	12,113	1,850	19,555	94,605
2012	225,801	-	1,201	98,671	12,172	1,880	19,763	95,127
2013	228,546	-	1,224	100,007	12,239	1,910	19,971	95,639
2014	231,290	-	1,248	101,344	12,314	1,941	20,179	96,189
2015	234,035	-	1,272	102,628	12,394	1,971	20,380	96,712

[1] 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.
[2] Includes Traffic Control and Security Lighting use.
[3] Population data represents Leon County population served by City of Tallahassee Electric Utility not the general population of Leon County.

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)
1996	-	-	-	-	12		2,221
1997	-	-	-	-	12		2186
1998	-	-	-	-	12		2348
1999	-	-	-	-	13		2358
2000	-	-	-	-	13		2,441
2001					13		2,431
2002					13		2,588
2003					13		2,603
2004					14		2,681
2005					14		2,723
2006	-	-	-		14		2,733
2007	-	-	-		14		2,809
2008	-	-	-		15		2,885
2009	-	-	-		15		2,941
2010	-	-	-		15		2,993
2011	-	-	-		15		3,044
2012	-	-	-		15		3,096
2013	-	-	-		15		3,149
2014	-	-	-		15		3,204
2015					15		3,258

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

City Of Tallahassee

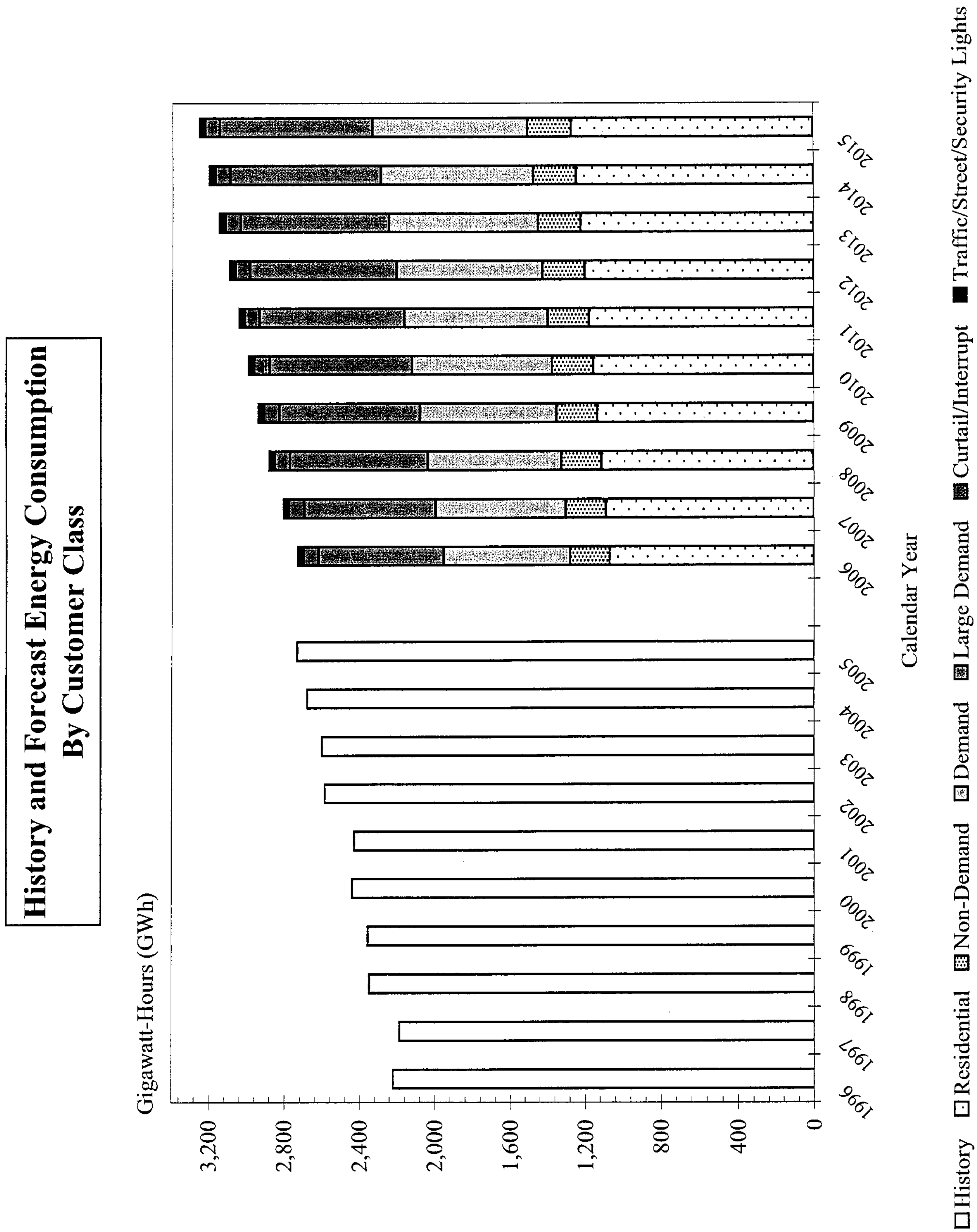
Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

Base Load Forecast

(1) Year	(2) Sales for Resale (GWh)	(3) Utility Use & Losses (GWh) [1]	(4) Net Energy for Load (GWh)	(5) Other Customers (Average No.)	(6) Total No. of Customers [1]
1996	0	111	2,332		88,140
1997	0	132	2,318		89,754
1998	0	129	2,477		91,508
1999	0	139	2,497		93,540
2000	0	155	2,596		94,999
2001	0	125	2,556		97,336
2002	0	165	2,753		98,039
2003	0	152	2,755		99,508
2004	0	160	2,841		102,049
2005	0	164	2,887		107,778
2006	0	162	2,895		109,002
2007	0	167	2,976		110,591
2008	0	171	3,056		112,181
2009	0	175	3,116		113,772
2010	0	178	3,171		115,345
2011	0	181	3,225		116,889
2012	0	184	3,280		118,434
2013	0	187	3,336		119,978
2014	0	190	3,394		121,523
2015	0	194	3,452		123,008

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

Figure B1

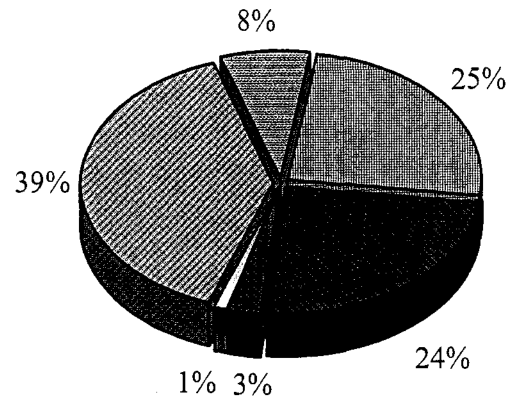


History and Forecast Energy Consumption
By Customer Class
Gigawatt-Hours (GWh)
3,200
2,800
2,400
2,000
1,600
1,200
800
400
0
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
Calendar Year
History
Residential
Non-Demand
Demand
Large Demand
Curtail/Interrupt
Traffic/Street/Security Lights

Figure B2

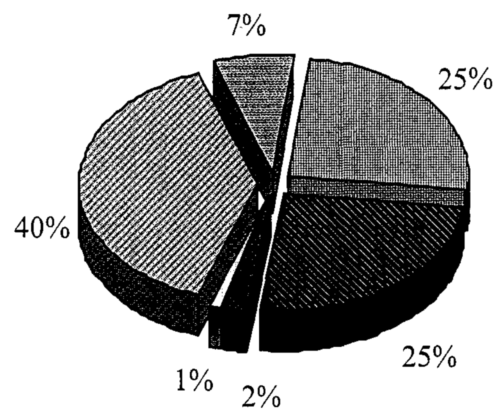
Energy Consumption By Customer Class

Calendar Year 2006



Total 2006 Sales = 2,740 GWh
Values exclude DSM impacts

Calendar Year 2015



Total 2015 Sales = 3,265 GWh
Values exclude DSM impacts

Residential | Non Demand | Demand
Large Demand | Curtail/Interrupt | Traffic/Street/Secur

City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation [2]	Comm./Ind Load Management	Comm./Ind Conservation [2]	Net Firm Demand [1]
1996	500		500						500
1997	486		486						486
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	581		581						581
2003	549		549						549
2004	565		565						565
2005	599		599			1	[3]	0	598
2006	611		611			1		1	609
2007	628		628			1		1	626
2008	639		639			1		1	637
2009	648		648			1		1	646
2010	658		658			1		1	656
2011	668		668			1		1	666
2012	678		678			1		1	676
2013	688		688			1		1	686
2014	698		698			1		1	696
2015	707		707			1		1	705

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar.
[3] 2005 DSM Jan - July accumulation.

Table 2.4

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	(7) Residential Conservation [2]	(8) Comm./Ind Load Management	(9) Comm./Ind Conservation [2]	(10) Net Firm Demand [1]
1996	500		500						500
1997	486		486						486
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	581		581						581
2003	549		549						549
2004	565		565						565
2005	599		599			1	[3]		598
2006	638		638			1		1	636
2007	656		656			1		1	654
2008	667		667			1		1	665
2009	676		676			1		1	674
2010	686		686			1		1	684
2011	697		697			1		1	695
2012	707		707			1		1	705
2013	717		717			1		1	715
2014	727		727			1		1	725
2015	737		737			1		1	735

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar.
[3] 2005 DSM Jan - July accumulation.

City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation [2]	Comm./Ind Load Management	Comm./Ind Conservation [2]	Net Firm Demand [1]
1996	500		500						500
1997	486		486						486
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	581		581						581
2003	549		549						549
2004	565		565						565
2005	599		599			1	[3]		598
2006	590		590			1		1	588
2007	607		607			1		1	605
2008	618		618			1		1	616
2009	627		627			1		1	625
2010	637		637			1		1	635
2011	646		646			1		1	644
2012	656		656			1		1	654
2013	666		666			1		1	664
2014	675		675			1		1	673
2015	685		685			1		1	683

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.
[3] 2005 DSM Jan - July accumulation.

Table 2.6

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	(7) Residential Conservation [2]	(8) Comm./Ind Load Management	(9) Comm./Ind Conservation [2]	(10) Net Firm Demand [1]
1996 -1997	431		431						431
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	543		543			6		0	537
2006 -2007	576		576			5		1	570
2007 -2008	590		590			5		1	584
2008 -2009	602		602			5		1	596
2009 -2010	614		614			5		1	608
2010 -2011	627		627			5		1	621
2011 -2012	639		639			5		1	633
2012 -2013	651		651			5		1	645
2013 -2014	664		664			5		1	658
2014 -2015	676		676			5		1	670
2015 -2016	687		687			5		1	681

[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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation [2]	Comm./Ind Load Management	Comm./Ind Conservation [2]	Net Firm Demand [1]
1996 -1997	431		431						431
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 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	543		543			6			537
2006 -2007	626		626			5		1	620
2007 -2008	641		641			5		1	635
2008 -2009	653		653			5		1	647
2009 -2010	666		666			5		1	660
2010 -2011	678		678			5		1	672
2011 -2012	691		691			5		1	685
2012 -2013	703		703			5		1	697
2013 -2014	716		716			5		1	710
2014 -2015	729		729			5		1	723
2015 -2016	740		740			5		1	734

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

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	(7) Residential Conservation [2]	(8) Comm./Ind Load Management	(9) Comm./Ind Conservation [2]	(10) Net Firm Demand [1]
1996 -1997	431		431						431
1997 -1998	421		421						421
1998 -1999	513		513						513
1999 -2,000	497		497						497
2000 -2001	521		521						521
2001 -2002	510		510						510
2002 -2,003	590		590						590
2003 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	543		543			6			537
2006 -2007	525		525			5		1	519
2007 -2008	539		539			5		1	533
2008 -2009	551		551			5		1	545
2009 -2010	563		563			5		1	557
2010 -2011	575		575			5		1	569
2011 -2012	587		587			5		1	581
2012 -2013	599		599			5		1	593
2013 -2014	612		612			5		1	606
2014 -2015	624		624			5		1	618
2015 -2016	635		635			5		1	629

[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]
1996	2,221			2,221		111	2,332	53
1997	2,186			2,186		132	2,318	54
1998	2,349			2,349		129	2,478	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	2,603			2,603		152	2,755	57
2004	2,681			2,681		160	2,841	57
2005	2,734	11	0	2,723		164	2,887	55
2006	2,740	6	1	2,733		162	2,895	54
2007	2,816	6	1	2,809		167	2,976	54
2008	2,892	6	1	2,885		171	3,056	55
2009	2,948	6	1	2,941		175	3,116	55
2010	3,000	6	1	2,993		178	3,171	55
2011	3,051	6	1	3,044		181	3,225	55
2012	3,103	6	1	3,096		184	3,280	55
2013	3,156	6	1	3,149		187	3,336	56
2014	3,211	6	1	3,204		190	3,394	56
2015	3,265	6	1	3,258		194	3,452	56

[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]
1996	2,221	0	0	2,221	0	111	2,332	53
1997	2,186	0	0	2,186	0	132	2,318	54
1998	2,349	0	0	2,349	0	129	2,478	53
1999	2,358	0	0	2,358	0	139	2,497	54
2000	2,441	0	0	2,441	0	155	2,596	54
2001	2,431	0	0	2,431	0	125	2,556	56
2002	2,588	0	0	2,588	0	165	2,753	54
2003	2,603	0	0	2,603	0	152	2,755	57
2004	2,681	0	0	2,681	0	160	2,841	57
2005	2,734	11	0	2,723	0	164	2,887	55
2006	2,935	6	1	2,928		174	3,102	56
2007	3,013	6	1	3,006		179	3,185	56
2008	3,092	6	1	3,085		183	3,268	56
2009	3,151	6	1	3,144		187	3,331	56
2010	3,205	6	1	3,198		190	3,388	57
2011	3,260	6	1	3,253		193	3,446	57
2012	3,314	6	1	3,307		197	3,504	57
2013	3,369	6	1	3,362		200	3,562	57
2014	3,426	6	1	3,419		203	3,622	57
2015	3,483	6	1	3,476		207	3,683	57

[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]
1996	2,221	0	0	2,221	0	111	2,332	53
1997	2,186	0	0	2,186	0	132	2,318	54
1998	2,349	0	0	2,349	0	129	2,478	53
1999	2,358	0	0	2,358	0	139	2,497	54
2000	2,441	0	0	2,441	0	155	2,596	54
2001	2,431	0	0	2,431	0	125	2,556	56
2002	2,588	0	0	2,588	0	165	2,753	54
2003	2,603	0	0	2,603	0	152	2,755	57
2004	2,681	0	0	2,681	0	160	2,841	57
2005	2,734	11	0	2,723	0	164	2,887	55
2006	2,576	6	1	2,569		153	2,722	53
2007	2,649	6	1	2,642		157	2,799	53
2008	2,724	6	1	2,717		161	2,878	53
2009	2,777	6	1	2,770		165	2,935	54
2010	2,827	6	1	2,820		168	2,988	54
2011	2,877	6	1	2,870		171	3,041	54
2012	2,927	6	1	2,920		174	3,094	54
2013	2,977	6	1	2,970		177	3,147	54
2014	3,030	6	1	3,023		180	3,203	54
2015	3,082	6	1	3,075		183	3,258	54

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

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)
	2005 Actual		**2006 Forecast [1]**		**2007 Forecast [1]**	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	532	227	465	234	494	240
February	428	200	537	212	570	218
March	462	213	396	205	420	211
April	391	199	399	200	424	206
May	550	236	549	245	565	252
June	579	268	573	271	589	278
July	583	299	597	290	614	299
August	598	298	609	292	626	300
September	578	278	579	266	595	274
October	494	239	502	238	516	245
November	425	202	430	205	456	211
December	476	228	469	237	498	242
TOTAL		2,887		2,895		2,976

[1] Peak Demand and NEL include DSM impacts

City Of Tallahassee

2006 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

2006 Electric 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	Residential Utility Customer Trends
6. Heating Saturation Rate	City Utility Research
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	Utility Services
23. Historical Commercial Real Price Of Electricity	Utility Services

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

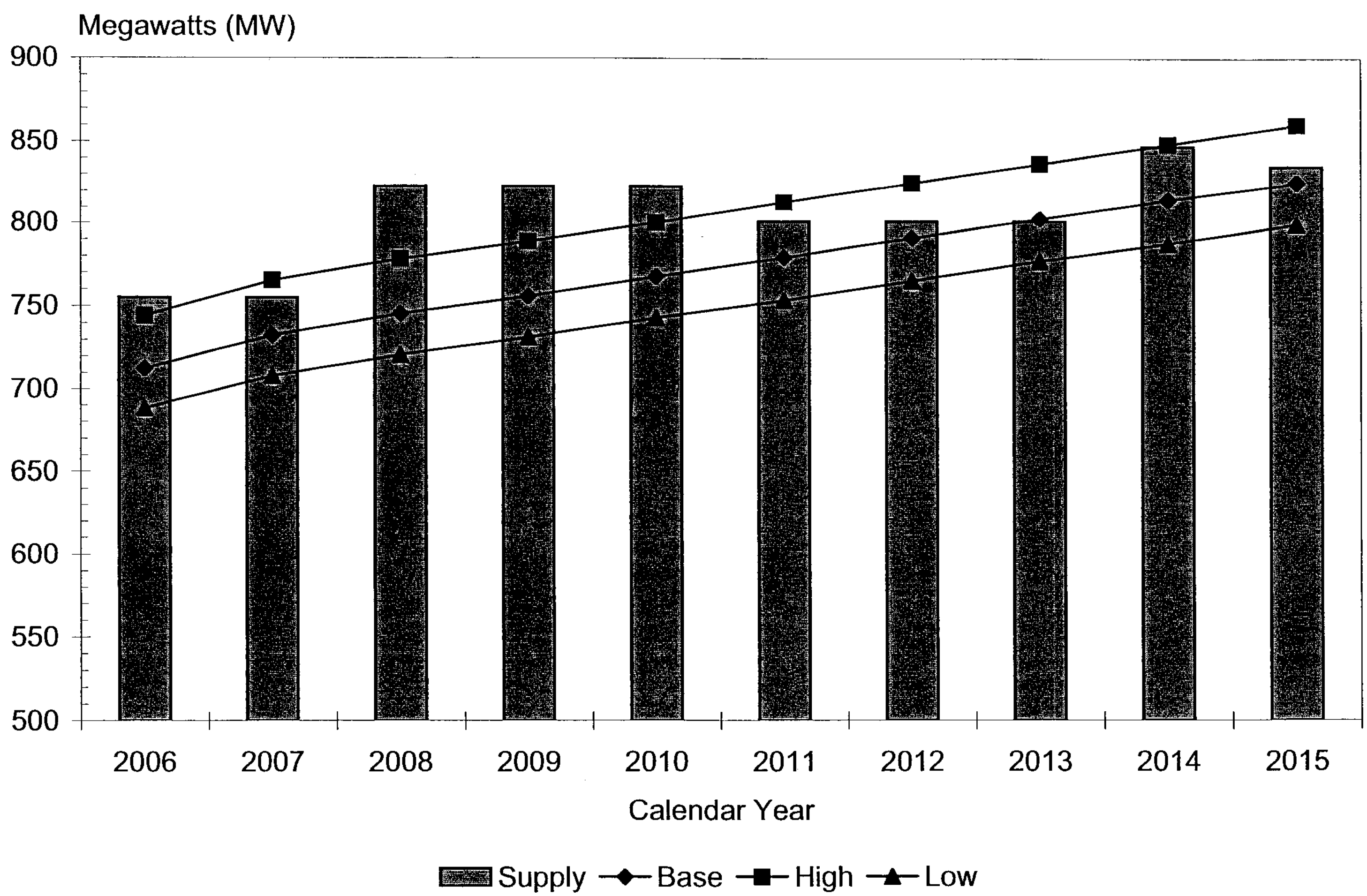


Figure B3

City Of Tallahassee

2006 Electric System Load Forecast

Projected Demand Side Management
Energy Reductions [1]

Calendar Year Basis

Year	Residential Impact (MWh)	Commercial Impact (MWh)	Total Impact (MWh)
2006	6,343	1,521	7,864
2007	6,343	1,521	7,864
2008	6,343	1,521	7,864
2009	6,343	1,521	7,864
2010	6,343	1,521	7,864
2011	6,343	1,521	7,864
2012	6,343	1,521	7,864
2013	6,343	1,521	7,864
2014	6,343	1,521	7,864
2015	6,343	1,521	7,864

[1] Reductions estimated at busbar.

City Of Tallahassee

2006 Electric System Load Forecast

Projected Demand Side Management
Seasonal Demand Reductions [1]

Year		Residential Energy Efficiency Impact		Commercial Energy Efficiency Impact		Demand Side Management Total	
Summer	Winter	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
2006	2005-2006	1	5	1	1	2	6
2007	2006-2007	1	5	1	1	2	6
2008	2007-2008	1	5	1	1	2	6
2009	2008-2009	1	5	1	1	2	6
2010	2009-2010	1	5	1	1	2	6
2011	2010-2011	1	5	1	1	2	6
2012	2011-2012	1	5	1	1	2	6
2013	2012-2013	1	5	1	1	2	6
2014	2013-2014	1	5	1	1	2	6
2015	2014-2015	1	5	1	1	2	6

[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 2004	Actual 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
						0	0	0	0	0	0	0	0	0	0
(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	0	0	0	0	0
(3)	**Residual**	**Total**	1000 BBL	599	555	485	958	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	599	555	485	958	0	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
(7)		Diesel	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(8)	**Distillate (Diesel)**	**Total**	1000 BBL	12	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	12	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	14,609	16,729	18,727	15,995	21,602	22,194	22,516	22,777	22,760	23,492	24,282	24,364
(14)		Steam	1000 MCF	6,965	5,244	5,007	2,561	2,306	393	677	478	609	236	649	503
(15)		CC	1000 MCF	7,499	11,156	12,426	11,547	18,345	21,313	21,260	21,605	20,847	22,663	22,857	23,152
(16)		CT	1000 MCF	145	329	1,294	1,887	951	488	579	694	1,304	593	776	709
(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 2004	Actual 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	**Annual Firm Interchange**		GWh	205	102	111	112	112	112	112	113	121	113	113	114
						0	0	0	0	0	0	0	0	0	0
(2)	**Coal**		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	**Nuclear**		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(4)	**Residual**	**Total**	GWh	355	327	265	552	0	0	0	0	0	0	0	0
(5)		Steam	GWh	355	327	265	552	0	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	3	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	3	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	1,671	2,041	2,393	2,077	2,843	2,986	3,029	3,079	3,065	3,199	3,263	3,315
(15)		Steam	GWh	620	460	471	227	204	33	57	40	52	20	55	43
(16)		CC	GWh	1,045	1,557	1,793	1,667	2,545	2,905	2,913	2,968	2,881	3,119	3,130	3,200
(17)		CT	GWh	6	24	129	183	94	48	59	71	132	60	78	72
(18)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(19)	**Hydro**		GWh	24	27	14	18	18	18	18	18	18	18	18	18
						0	0	0	0	0	0	0	0	0	0
(20)	**Economy Interchange**		GWH	583	386	112	217	83	0	12	15	76	6	0	5
(21)	**Net Energy for Load**		GWh	2,841	2,887	2,895	2,976	3,056	3,116	3,171	3,225	3,280	3,336	3,394	3,452

City Of Tallahassee

Schedule 6.2
Energy Sources

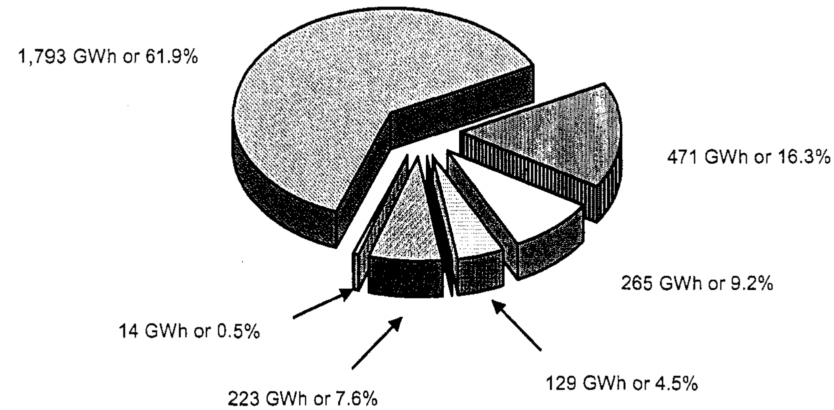
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2004	Actual 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	**Annual Firm Interchange**		%	7.22	3.53	3.80	3.80	3.70	3.60	3.50	3.50	3.70	3.40	3.30	3.30
(2)	**Coal**		%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(3)	**Nuclear**		%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(4)	**Residual**	**Total**	%	12.50	11.33	9.20	18.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(5)		Steam	%	12.50	11.33	9.20	18.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(6)		CC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(7)		CT	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(8)		Diesel	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(9)	**Distillate (Diesel)**	**Total**	%	0.11	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(10)		Steam	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(11)		CC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(12)		CT	%	0.11	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(13)		Diesel	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(14)	**Natural Gas**	**Total**	%	58.82	70.70	82.70	69.80	93.00	95.80	95.50	95.50	93.40	95.90	96.10	96.00
(15)		Steam	%	21.82	15.93	16.30	7.60	6.70	1.10	1.80	1.20	1.60	0.60	1.60	1.20
(16)		CC	%	36.78	53.93	61.90	56.00	83.30	93.20	91.90	92.00	87.80	93.50	92.20	92.70
(17)		CT	%	0.21	0.83	4.50	6.10	3.10	1.50	1.90	2.20	4.00	1.80	2.30	2.10
(18)		Diesel	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(19)	**Hydro**		%	0.84	0.94	0.50	0.60	0.60	0.60	0.60	0.60	0.50	0.50	0.50	0.50
(20)	**Economy Interchange**		%	20.52	13.37	3.80	7.30	2.70	0.00	0.40	0.50	2.30	0.20	0.00	0.10
(21)	**Net Energy for Load**		%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.1	99.9	100.0	99.9	99.9

Table 2.20

Figure B4

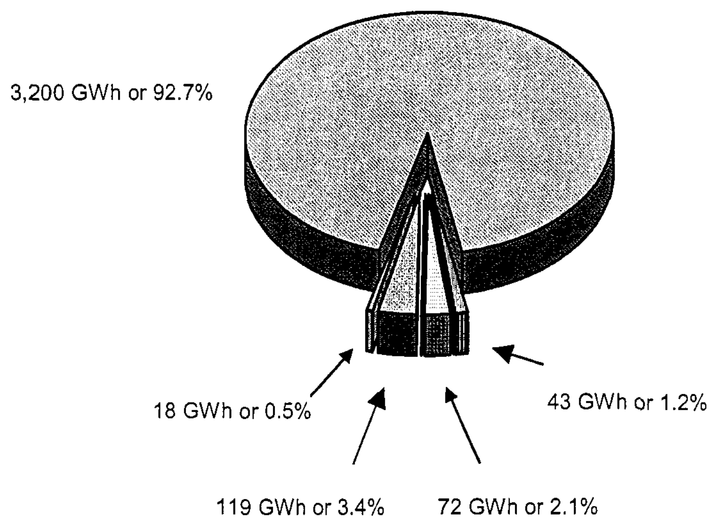
Generation By Resource/Fuel Type

Calendar Year 2006



Total 2006 NEL = 2,895 GWh

Calendar Year 2015



Total 2015 NEL = 3,452

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

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 is 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 have completed Phase I of the IRP study 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. As of the time of this TYSP filing, Phase II of the IRP study is underway. Phase II includes a detailed analysis of how the DSM and power supply alternatives perform under base and alternative assumptions. The IRP study could not be completed in time for this TYSP filing. Therefore, the City's proposed generation expansion plan described in Section 3.2 is based in part on the results of the 2002 IRP study, the preliminary results of the ongoing IRP study and the results of other internal studies.

Electric utility planning staff continuously reviews the progress and results of the current IRP Study as directed by the City Commission. This review process has 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 has researched options available to the City to achieve some supply resource portfolio diversity. In addition, staff continues to review and develop means to mitigate the potential impacts of significant events in the electric utility industry including but not necessarily limited to the collapse of Enron, other former energy trading companies and merchant generators and the subsequent impact on energy sector investment and financial markets, the ongoing initiatives for the formation of regional transmission organizations (RTO) and federal legislation related to energy policy and electric utility industry restructuring.

3.2 Projected Resource Requirements

3.2.1 Transmission Limitations

The City has projected that additional resources will be required during the 2006-2015 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 an increasing level 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 proposed 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 interim results of the ongoing 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 ongoing 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 2005 peaking capacity additions 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 2011; assuming the high load forecast, less than 10 MW of additional power supply would be needed in the summer of 2007. The repowering of the City's existing Hopkins Unit 2 to combined cycle operation by the summer of 2008 (discussed in the next section) is otherwise expected to cover the City's peak demand and planning reserve requirements until the summer of 2011 under both the base and high peak demand forecast scenarios.

3.2.3 NEAR TERM RESOURCE ADDITIONS

In order to meet the year 2005 capacity shortfalls identified in the 2002 IRP, the City has completed the addition of 92 MW (summer net) of new peaking capacity. This new capacity utilizes two (2) dual fuel simple cycle combustion turbines. The combustion turbines are General Electric LM-6000 Sprint combustion turbines with a summer rating of 46 MW (fully degraded net capability at 94° F, firing natural gas with chiller in service) each. The combustion turbines are equipped with inlet chilling, and selective catalytic reduction and oxidation catalyst to reduce the emissions of oxides of nitrogen and carbon monoxide respectively. These new generation units possess the ability to utilize natural gas or clean low sulfur diesel as their primary fuel and are designed to be on line and at full load withing ten (10) minutes of initiation of the start sequence. The two combustion turbines have been installed at the A. B. Hopkins Generation Station.

The first of the LM-6000's began commercial operation in September 2005 and the second in November 2005.

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). 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. As of the time of this TYSP report preliminary engineering and equipment procurement for this project are in progress.

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 could provide some of the diversity desired in the City's power supply resource portfolio. In the current IRP Study the City is evaluating both short and long-term purchased power options based on conventional sources as well as power offers based on renewable resources. The results of this analysis may lead to the inclusion of one of more of these purchased power options in the City's long-range resource plan.

As an additional strategy to address the City's lack of power supply diversity, planning staff continues to investigate options for joint ownership of a solid-fuel unit. Recent changes in the natural gas market and in cost and performance parameters for coal units indicate favorable economics for adding some amount of coal capacity to the City's resource portfolio. An assessment of the potential benefits and risks associated with including a coal-fueled unit in the City's long-range power supply plan is being conducted in the ongoing IRP study. The analysis focuses primarily 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 a green power alternative 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 we have a portfolio of 40kW 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 is also investigating other renewable resource alternatives, including solar thermal and biomass. These options are being evaluated in the current IRP Study and may become part of the City's preferred long-range resource plan. Concurrently with these evaluations, the City has solicited responses from potential developers of biomass facilities in an attempt to gauge the type of proposals that might be submitted if the City were to issue an RFP for a biomass project at the conclusion of the IRP Study. In addition to preparing for a possible bid process, the City is also evaluating other unsolicited biomass opportunities including joint ventures and purchased power arrangements.

3.2.6 FUTURE POWER SUPPLY RESOURCES

The City's currently proposed resource additions to meet system needs in the summer of 2011 and beyond is represented in this report as one 46 MW (summer net) combustion turbine to be in service by the summer of 2011 and another 46 MW (summer net) combustion turbine to be in service by the summer of 2014.

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 800MW-class supercritical pulverized coal unit on a greenfield site near Perry, Florida. The TEC Project is currently in the site assessment and preliminary design phase, and the project participants anticipate that a petition for determination of need for the unit may be filed at the FPSC this summer with a site certification application submitted shortly thereafter. 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 will be determined in part on the outcome of evaluations currently underway in the ongoing IRP Study. Those evaluations are not scheduled for completion until June of this year. Because of the uncertainty regarding the inclusion of the TEC Project in the City's preferred long-range resource plan, the schedule of resource additions included in this report does not include the City's share of that unit. Should the preferred resource plan approved by the City Commission at the conclusion of the IRP Study include the TEC Project, the City will submit a revised Table 3.3 (Schedule 8) reflecting that resource. The table below is a comparison of the resource addition schedules for the plan reported in this Ten Year Site Plan filing and a likely plan including the City's share of the TEC Project:

Comparison of Resource Addition Schedules

2006 TYSP	With TEC Project
2008 - Hopkins 2 CC Repowering	2008 - Hopkins 2 CC Repowering
2011 - LM 6000 CT	2011 - LM 6000 CT
2014 - LM 6000 CT	2012 - Taylor Energy Center

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. However, the City continues to assess the possibility of constructing transmission facilities to directly connect the TEC Project to the City's electric transmission system. If that option is chosen by the City as the most cost-effective method of taking delivery of the output of the project, a subsequent TYSP filing will include identification of the associated transmission facilities.

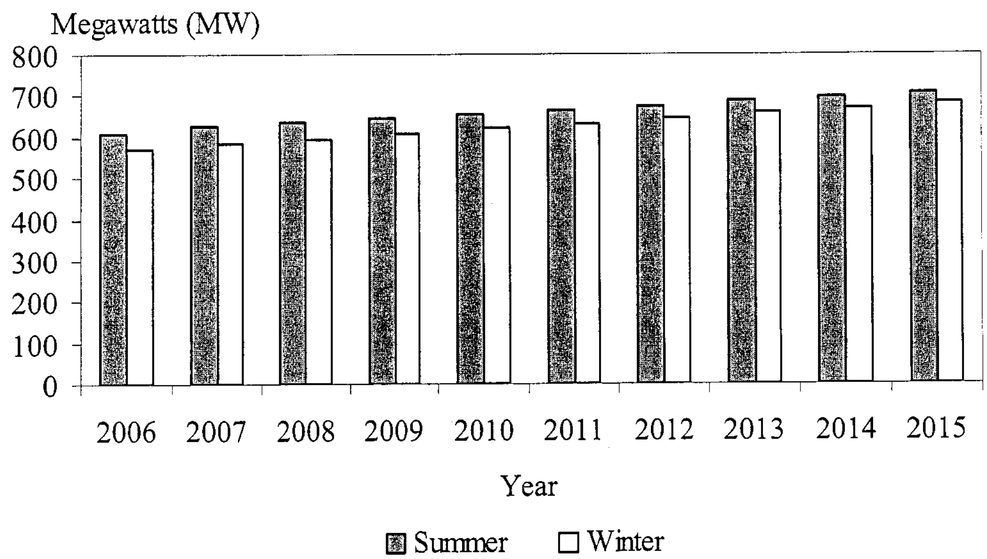
The City will continue its evaluation of the different power supply alternatives in its ongoing IRP study and update the FPSC in future TYSP reports.

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.

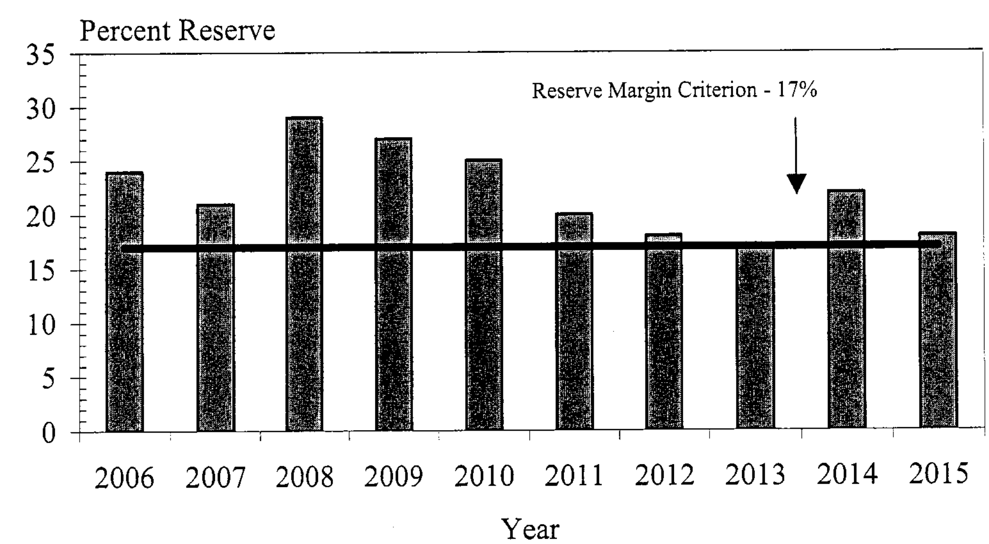
In addition power supply resources identified in the previous sections and aforementioned tables of this TYSP, as a part of the ongoing IRP study the City is evaluating some other alternatives that would increase the effective capacity of our existing power supply resources and thereby defer the need for new resource additions,. These alternatives could provide a very cost-effective increase in system capacity with relatively short lead times, and would give the City more flexibility in meeting its future power supply requirements.

Figure C

System Peak Demands Net of Conservation



Summer Reserve Margin



City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity (MW)	Firm Capacity Import (MW)	Firm Capacity Export (MW)	QF (MW)	Total Capacity Available (MW)	System Firm Summer Peak Demand (MW)	(MW)	% of Peak	Scheduled Maintenance (MW)	(MW)	% of Peak
2006	744	11			755	609	146	24		146	24
2007	744	11			755	626	129	21		129	21
2008	812	11			823	637	186	29		186	29
2009	812	11			823	646	177	27		177	27
2010	812	11			823	656	167	25		167	25
2011	790	11			801	666	135	20		135	20
2012	790	11			801	676	125	18		125	18
2013	790	11			801	686	115	17		115	17
2014	836	11			847	696	151	22		151	22
2015	824	11			835	705	130	18		130	18

[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)	(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)	(MW)	% of Peak	Scheduled Maintenance (MW)	(MW)	% of Peak
2005/06	795	11			806	537	260	48		260	48
2006/07	795	11			806	570	236	41		236	41
2007/08	795	11			806	584	222	38		222	38
2008/09	890	11			901	596	305	51		305	51
2009/10	890	11			901	608	293	48		293	48
2010/11	890	11			901	621	280	45		280	45
2011/12	868	11			879	633	246	39		246	39
2012/13	868	11			879	645	234	36		234	36
2013/14	868	11			879	658	221	34		221	34
2014/15	916	11			927	670	257	38		257	38
2015/16	904	11			915	681	234	34		234	34

Notes

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

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 2 CC Repowering [1]	2	Leon	CC	NG	DFO	0	PL	TK	1/07	5/08	Unknown	Unknown	68	95	L
Purdom	CT-1	Wakulla	GT	NG	DFO	0	PL	TK	NA	12/63	3/11	15,000	-10	-10	RT
Purdom	CT-2	Wakulla	GT	NG	DFO	0	PL	TK	NA	5/64	3/11	15,000	-10	-10	RT
Purdom	7	Wakulla	ST	NG	RFO	0	PL	WA	NA	6/66	3/11	50,000	-48	-50	RT
Combustion Turbine [2]	A	Undetermined	GT	NG	DFO	0	PL	TK	Unknown	5/11	Unknown	60,500	46	48	P
Combustion Turbine [2]	B	Undetermined	GT	NG	DFO	0	PL	TK	Unknown	5/14	Unknown	60,500	46	48	P

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) to be in service by May of 2008. The "Net Capability" values provided in the table above reflect the incremental capacity additions associated with the repowering project.

[2] Prospective locations for these CTs include the Purdom plant and a greenfield site yet to be determined. The City is currently conducting an integrated resource planning study whereby the type and timing of generating unit additions following the Hopkins 2 combined cycle repowering project wil be determined.

Acronym	Definition
IC	Internal Combustion
GT	Gas Turbine
PRI	Primary Fuel
ALT	Alternate Fuel
NG	Natural Gas
DFO	Diesel Fuel Oil
PL	Pipeline
TK	Truck
L	Regulatory approval pending. Not under construction.
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
2006	611	2	609	744		11			755	24	
2007	628	2	626	744		11			755	21	
2008	639	2	637	744		11		68	823	29	[3]
2009	648	2	646	744		11		68	823	27	
2010	658	2	656	744		11		68	823	25	
2011	668	2	666	676	[4]	11		114	801	20	[5]
2012	678	2	676	676		11		114	801	18	
2013	688	2	686	676		11		114	801	17	
2014	698	2	696	676		11		160	847	22	[5]
2015	707	2	705	664	[6]	11		160	835	18	

Notes

[1] Demand Side Management
[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] One 46 MW (summer net) CT in 2011 and another in 2014.
[6] Hopkin GT 1 retired in March 2015

Chapter IV

Proposed Plant Sites and Transmission Lines

4.1 Proposed Plant Site

As discussed in Chapter 3, pending the outcome of the ongoing IRP study 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 adding one 46 MW (summer net) combustion turbine by the summer of 2011 and another 46 MW (summer net) combustion turbine by the summer of 2014 (see Tables 4.1 – 4.3).

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 City is currently planning and is in some cases in the process of constructing several new substations on the east side of its system. These are intended to serve future load in this rapidly growing area. The new substations (14, 17, and 18) will be connected to the City's 115 kV transmission system, which is the standard voltage throughout the City's service territory. When complete, the area will be served by two reliable "loops" between substations 7 and 9 and between substations 9 and 5. The anticipated in-service dates for these new substations and lines are shown on Figure D1.

In the mid 1990's, the Electric Utility determined which areas would be the most beneficial to locate substation facilities to support this load growth and, after several years of negotiation with the landowner, the City obtained property for two proposed substations and selected a tentative transmission line route. Concern about environmental issues and public acceptance prompted further investigation and an effort to obtain more community input to the process.

To provide information and involve the residents of the area in the transmission line route selection process Electric Utility staff conducted numerous public workshops. In addition, an independent route study was conducted from June 2002 to June 2003. The Final Report from the route consultant was submitted to the City in late September 2003. On December 10, 2003 the City Commission considered the issue and requested staff to conduct another public workshop, which was held on January 6, 2004. On February 11, 2004 the City Commission held a public hearing on the route selection and requested staff to consider a further route option and return with a recommendation.

During 2004 staff participated in meetings with citizens and with Powerhouse to develop routes and design alternatives on the Welaunee property. This culminated in a final route recommendation, including the acquisition of a portion of Welaunee property by the City, which was approved by the City Commission on February 9, 2005.

Since that time, the property acquisition has been completed, a consulting engineer has been hired to assist with the underground portions of the transmission line and the line and substation design is proceeding. Construction will start in the fall of 2006 and is expected to be completed by late 2007.

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 an increasing level 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.

In addition to the transmission improvements described above and shown in Figure D1, the City is currently conducting 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, preliminary 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.

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:	68	[1]
	b.) Winter:	95	[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:	Regulatory approval pending. Not under construction.	
(10)	Certification Status:	Regulatory approval pending. Not under construction.	
(11)	Status with Federal Agencies:	Regulatory approval pending. Not under construction.	
(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 (296 MW summer, 333 MW winter) to be in service by May of 2008. The "Capacity" values provided in the table above r

[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:	Combustion Turbine A
(2)	Capacity	
	a.) Summer:	46
	b.) Winter:	48
(3)	Technology Type:	CT
(4)	Anticipated Construction Timing	
	a.) Field Construction start - date:	Unknown
	b.) Commercial in-service date:	May-11
(5)	Fuel	
	a.) Primary fuel:	NG
	b.) Alternate fuel:	DFO
(6)	Air Pollution Control Strategy:	Unknown
(7)	Cooling Status:	Unknown
(8)	Total Site Area:	Unknown
(9)	Construction Status:	Planned for installation but not utility authorized. Not under construction.
(10)	Certification Status:	NA
(11)	Status with Federal Agencies:	NA
(12)	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor: Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	Data dependent on selected unit manufacturer, nature of contracts, etc. To be determined.
(13)	Projected Unit Financial Data Book Life (Years) Total Installed Cost (In-Service Year $/kW) Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O & M ($kW-Yr): Variable O & M ($/MWH): K Factor:	

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Combustion Turbine B
(2)	Capacity	
	a.) Summer:	46
	b.) Winter:	48
(3)	Technology Type:	CT
(4)	Anticipated Construction Timing	
	a.) Field Construction start - date:	Unknown
	b.) Commercial in-service date:	May-14
(5)	Fuel	
	a.) Primary fuel:	NG
	b.) Alternate fuel:	DFO
(6)	Air Pollution Control Strategy:	Unknown
(7)	Cooling Status:	Unknown
(8)	Total Site Area:	Unknown
(9)	Construction Status:	Planned for installation but not utility authorized. Not under construction.
(10)	Certification Status:	NA
(11)	Status with Federal Agencies:	NA
(12)	Projected Unit Performance Data	Data dependent on selected unit manufacturer, nature of contracts, etc. To be determined.
	Planned Outage Factor (POF):	
	Forced Outage Factor:	
	Equivalent Availability Factor (EAF):	
	Resulting Capacity Factor (%):	
	Average Net Operating Heat Rate (ANOHR):	
(13)	Projected Unit Financial Data	
	Book Life (Years)	
	Total Installed Cost (In-Service Year $/kW)	
	Direct Construction Cost ($/kW):	
	AFUDC Amount ($/kW):	
	Escalation ($/kW):	
	Fixed O & M ($kW-Yr):	
	Variable O & M ($/MWH):	
	K Factor:	

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:	

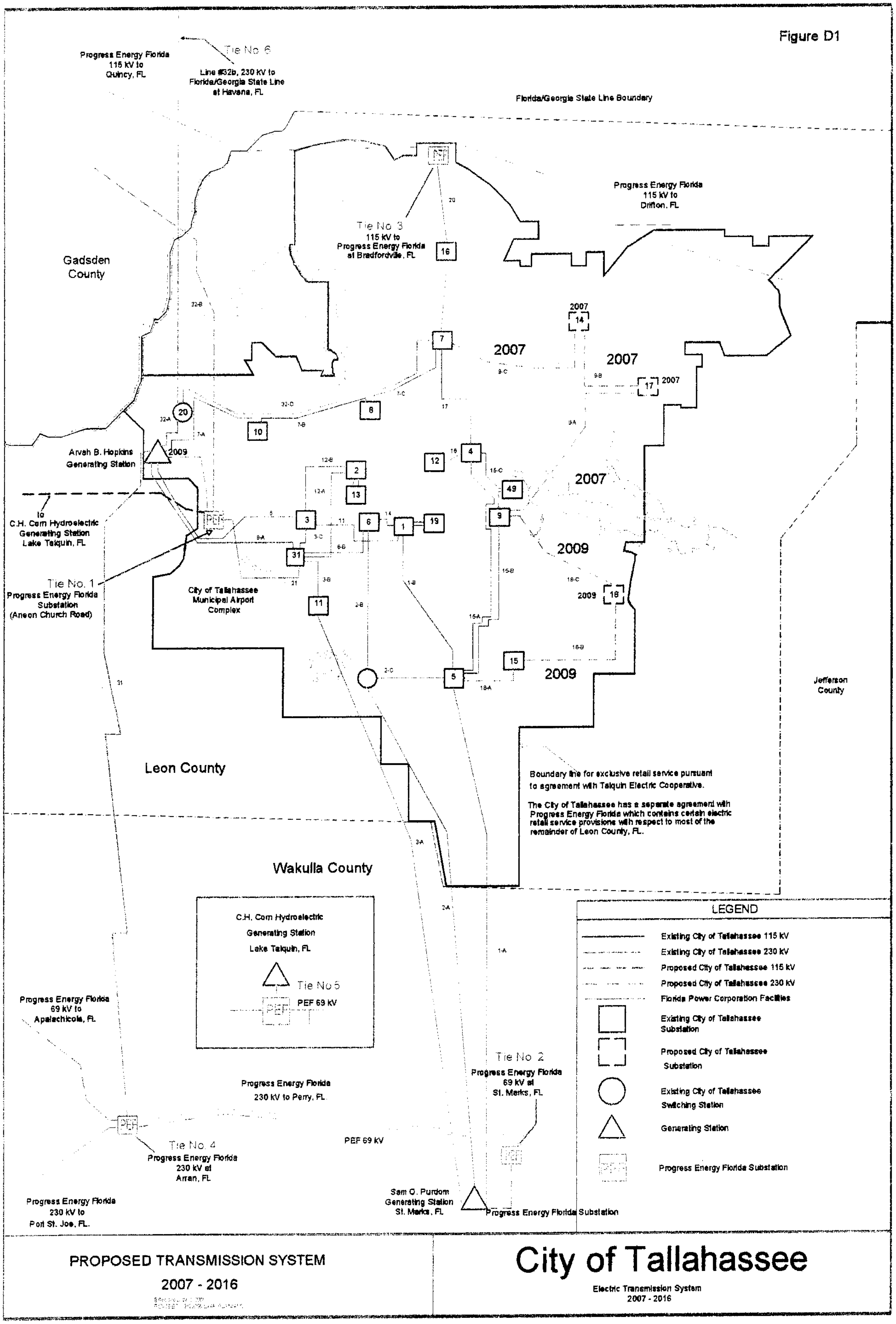


Figure D1
Progress Energy Florida 115 kV to Quincy, FL
Tie No. 6
Line #32b, 230 KV to Florida/Georgia State Line at Havana, FL
Florida/Georgia State Line Boundary
Progress Energy Florida 115 kV to Drifton, FL
Tie No. 3 115 kV to Progress Energy Florida at Bradfordville, FL
Gadsden County
2007
2009
Arvah B. Hopkins Generating Station
to C.H. Corn Hydroelectric Generating Station Lake Talquin, FL
Tie No. 1 Progress Energy Florida Substation (Aneon Church Road)
City of Tallahassee Municipal Airport Complex
Jefferson County
Leon County
Boundary line for exclusive retail service pursuant to agreement with Talquin Electric Cooperative.
The City of Tallahassee has a separate agreement with Progress Energy Florida which contains certain electric retail service provisions with respect to most of the remainder of Leon County, FL.
Wakulla County
C.H. Corn Hydroelectric Generating Station Lake Talquin, FL
Tie No 5
PEF 69 kV
Progress Energy Florida 69 kV to Apalachicola, FL
Progress Energy Florida 230 kV to Perry, FL
Tie No. 2 Progress Energy Florida 69 kV at St. Marks, FL
Tie No. 4 Progress Energy Florida 230 kV at Arran, FL
PEF 69 kV
Progress Energy Florida 230 kV to Port St. Joe, FL
Sam O. Purdom Generating Station St. Marks, FL
Progress Energy Florida Substation
LEGEND
Existing City of Tallahassee 115 kV
Existing City of Tallahassee 230 kV
Proposed City of Tallahassee 115 kV
Proposed City of Tallahassee 230 kV
Florida Power Corporation Facilities
Existing City of Tallahassee Substation
Proposed City of Tallahassee Substation
Existing City of Tallahassee Switching Station
Generating Station
Progress Energy Florida Substation
PROPOSED TRANSMISSION SYSTEM
2007 - 2016
City of Tallahassee
Electric Transmission System
2007 - 2016

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	0.076	NA	0.036	NA	0.882	NA	NA
Corn	2	[1]	NA	0.076	NA	0.036	NA	0.882	NA	NA
Corn	3	[1]	NA	0.076	NA	0.036	NA	0.882	NA	NA
Hopkins	1		0.056	0.066	0.002	0.023	0.929	0.901	12,679	12,238
Hopkins	2	[2]	0.054	0.119	0.002	0.031	0.940	0.830	10,907	11,020
Hopkins	GT-1		0.028	0.052	0.002	0.028	0.966	0.890	37,333	22,243
Hopkins	GT-2		0.146	0.046	0.030	0.022	0.811	0.881	20,752	18,968
Hopkins	GT-3	[3]	NA	0.058	NA	0.022	NA	0.882	NA	9,957
Hopkins	GT-4	[3]	NA	0.058	NA	0.022	NA	0.882	NA	9,950
Purdom	7		0.000	0.066	0.018	0.023	0.978	0.901	12,929	14,809
Purdom	8		0.019	0.086	0.163	0.024	0.799	0.847	7,401	7,322
Purdom	GT-1		0.007	0.052	0.091	0.028	0.903	0.890	34,875	28,936
Purdom	GT-2		0.004	0.052	0.019	0.028	0.975	0.890	25,930	28,936
Future Units										
Hopkins	2	[2]	NA	0.086	NA	0.024	NA	0.847	NA	7,828
Combustion Turbine	A		NA	0.058	NA	0.022	NA	0.882	NA	9,921
Combustion Turbine	B		NA	0.058	NA	0.022	NA	0.882	NA	9,921

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. Insufficient operating experience to establish meaningful history.

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]	2003	NA	NA	NA	32.39	514	-	NA	NA	NA
	2004	NA	NA	NA	31.76	504	-1.9%	NA	NA	NA
	2005	NA	NA	NA	40.86	649	28.7%	NA	NA	NA
Forecast [2]	2006	NA	NA	NA	55.77	885	36.5%	NA	NA	NA
	2007	NA	NA	NA	53.99	857	-3.2%	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	58.92	935	3.7%	NA	NA	NA
	2014	NA	NA	NA	61.07	969	3.7%	NA	NA	NA
	2015	NA	NA	NA	63.16	1003	3.4%	NA	NA	NA

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

[1] Actual fiscal year average cost of oil burned.
[2] Current IRP forecast.

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]	2003	NA	NA	NA	32.39	514	-	NA	NA	NA
	2004	NA	NA	NA	31.76	504	-1.9%	NA	NA	NA
	2005	NA	NA	NA	40.86	649	28.7%	NA	NA	NA
Forecast [2]	2006	NA	NA	NA	55.77	885	36.5%	NA	NA	NA
	2007	NA	NA	NA	55.38	879	-0.7%	NA	NA	NA
	2008	NA	NA	NA	57.29	909	3.4%	NA	NA	NA
	2009	NA	NA	NA	59.24	940	3.4%	NA	NA	NA
	2010	NA	NA	NA	61.24	972	3.4%	NA	NA	NA
	2011	NA	NA	NA	63.53	1008	3.7%	NA	NA	NA
	2012	NA	NA	NA	65.87	1046	3.7%	NA	NA	NA
	2013	NA	NA	NA	69.95	1110	6.2%	NA	NA	NA
	2014	NA	NA	NA	74.25	1179	6.2%	NA	NA	NA
	2015	NA	NA	NA	78.65	1248	5.9%	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]	2003	NA	NA	NA	32.39	514	-	NA	NA	NA
	2004	NA	NA	NA	31.76	504	-1.9%	NA	NA	NA
	2005	NA	NA	NA	40.86	649	28.7%	NA	NA	NA
Forecast [2]	2006	NA	NA	NA	55.77	885	36.5%	NA	NA	NA
	2007	NA	NA	NA	52.59	835	-5.7%	NA	NA	NA
	2008	NA	NA	NA	51.77	822	-1.6%	NA	NA	NA
	2009	NA	NA	NA	50.95	809	-1.6%	NA	NA	NA
	2010	NA	NA	NA	50.13	796	-1.6%	NA	NA	NA
	2011	NA	NA	NA	49.49	785	-1.3%	NA	NA	NA
	2012	NA	NA	NA	48.84	775	-1.3%	NA	NA	NA
	2013	NA	NA	NA	49.42	784	1.2%	NA	NA	NA
	2014	NA	NA	NA	49.99	793	1.2%	NA	NA	NA
	2015	NA	NA	NA	50.45	801	0.9%	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 [3]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2003	36.44	628	-	555	5.77	-
	2004	39.08	674	7.2%	644	6.70	16.0%
	2005	69.64	1201	78.2%	758	7.88	17.7%
Forecast [2]	2006	79.82	1376	14.6%	883	9.18	16.5%
	2007	75.74	1306	-5.1%	871	9.06	-1.4%
	2008	76.03	1311	0.4%	686	7.13	-21.3%
	2009	76.22	1314	0.3%	601	6.25	-12.3%
	2010	77.47	1336	1.6%	536	5.57	-10.9%
	2011	77.46	1336	0.0%	590	6.14	10.2%
	2012	76.83	1325	-0.8%	610	6.35	3.4%
	2013	78.47	1353	2.1%	653	6.79	7.0%
	2014	80.16	1382	2.2%	611	6.36	-6.4%
	2015	81.79	1410	2.0%	665	6.92	8.8%

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] Current IRP forecast.
[3] Delivered gas price reflects cost at Henry Hub increased by 2.87% 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]	2003	36.44	628	-	555	5.77	-
	2004	39.08	674	7.2%	644	6.70	16.0%
	2005	69.64	1201	78.2%	758	7.88	17.7%
Forecast [2]	2006	79.82	1376	14.6%	883	9.18	16.5%
	2007	77.74	1340	-2.6%	893	9.29	1.1%
	2008	79.98	1379	2.9%	725	7.54	-18.8%
	2009	82.18	1417	2.8%	654	6.80	-9.8%
	2010	85.58	1476	4.1%	599	6.23	-8.4%
	2011	87.71	1512	2.5%	675	7.02	12.7%
	2012	89.19	1538	1.7%	715	7.44	5.9%
	2013	93.32	1609	4.6%	783	8.14	9.5%
	2014	97.67	1684	4.7%	753	7.83	-3.9%
	2015	102.09	1760	4.5%	838	8.72	11.3%

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 2.87% 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]	2003	36.44	628	-	555	5.77	-
	2004	39.08	674	7.2%	644	6.70	16.0%
	2005	69.64	1201	78.2%	758	7.88	17.7%
Forecast [2]	2006	79.82	1376	14.6%	883	9.18	16.5%
	2007	73.74	1271	-7.6%	849	8.83	-3.9%
	2008	72.18	1245	-2.1%	647	6.73	-23.8%
	2009	70.56	1217	-2.2%	551	5.73	-14.8%
	2010	69.95	1206	-0.9%	477	4.96	-13.4%
	2011	68.20	1176	-2.5%	514	5.35	7.7%
	2012	65.94	1137	-3.3%	519	5.39	0.9%
	2013	65.69	1133	-0.4%	542	5.64	4.5%
	2014	65.47	1129	-0.3%	494	5.14	-8.9%
	2015	65.16	1123	-0.5%	525	5.46	6.3%

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 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 2.87% 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	2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	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
Forecast [2]	2006	73.43	306	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	65.54	273	-10.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2008	58.71	245	-10.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	51.55	215	-12.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	52.21	218	1.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	52.90	220	1.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	53.59	223	1.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	54.78	228	2.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	55.98	233	2.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	57.19	238	2.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS:
Low Sulfur Coal - Central Appalachian 0.7% sulfur coal delivered by rail to Ga. Power Co. Scherer Plant, heat content - 24 MMBtu/ton, ash content unknown

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

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	2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	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
Forecast [2]	2006	45.74	306	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	46.09	281	-8.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2008	46.48	258	-7.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	46.68	233	-9.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	47.66	242	3.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	48.68	252	3.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	49.72	261	3.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	50.80	273	4.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	51.92	286	4.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	52.92	300	4.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS:
Low Sulfur Coal - Central Appalachian 0.7% sulfur coal delivered by rail to Ga. Power Co. Scherer Plant, heat content - 24 MMBtu/ton, ash content unknown

[1] Coal is not currently a part of the City's generation fuel mix. However, it's forecast price is important to the City's resource planning efforts as it will allow for the evaluation of coal-based purchase 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	2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	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
Forecast [2]	2006	45.74	306	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	46.09	265	-13.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2008	46.48	231	-12.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	46.68	197	-14.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	47.66	195	-1.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	48.68	192	-1.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	49.72	190	-1.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	50.80	190	-0.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	51.92	189	-0.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	52.92	188	-0.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS:
Low Sulfur Coal - Central Appalachian 0.7% sulfur coal delivered by rail to Ga. Power Co. Scherer Plant, heat content - 24 MMBtu/ton, ash content unknown

[1] Coal is not currently a part of the City's generation fuel mix. However, it's forecast price is important to the City's resource planning efforts as it will allow for the evaluation of coal-based purchase 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	2003	NA	NA	42.22	-
	2004	NA	NA	45.74	8.3%
	2005	NA	NA	67.58	47.7%
Forecast	2006	NA	NA	42.00	-37.9%
	2007	NA	NA	42.00	0.0%
	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%

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

Financial Assumptions
Base Case

AFUDC RATE	5.25%	
CAPITALIZATION RATIOS:		
DEBT	203.96%	[1]
PREFERRED	N/A	[2]
ASSETS	75.50%	[3]
EQUITY	133.00%	
RATE OF RETURN (6)		
DEBT	-0.05%	[4]
PREFERRED	N/A	[2]
ASSETS	-0.02%	[5]
EQUITY	-0.03%	[5]
INCOME TAX RATE:		
STATE	N/A	[7]
FEDERAL	N/A	[7]
EFFECTIVE	N/A	[7]
OTHER TAX RATE:		
Sales Tax (< $5,000)	7.00%	[8]
Sales Tax (> $5,000)	6.00%	[8]
DISCOUNT RATE:	2.75% - 5.25%	
TAX DEPRECIATION RATE:	N/A	[7]

[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] The Electric Utility had a net loss for fiscal 2004 which generated negative Rates of Return.
[7] Municipal utilities are exempt from income tax
[8] 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 %
2006	2.5	2.5	2.5	2.5
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

Monthly Peak Demands and Date of Occurrence for 2003 - 2005

Calendar Year 2003

Month	Date	Hour Ending	Daily Temp. (°F) Min.	Daily Temp. (°F) Max.	Peak Demand (MW)
January	24-Jan	8:00 A.M.	18	43	590
February	12-Feb	8:00 A.M.	31	70	408
March	20-Mar	8:00 P.M.	66	83	365
April	30-Apr	6:00 P.M.	64	86	429
May	7-May	4:00 P.M.	70	90	487
June	16-Jun	4:00 P.M.	70	93	515
July	10-Jul	4:00 P.M.	71	93	539
August	26-Aug	4:00 P.M.	74	93	549
September	2-Sep	4:00 P.M.	72	90	517
October	6-Oct	5:00 P.M.	62	86	428
November	6-Nov	4:00 P.M.	70	86	421
December	18-Dec	8:00 A.M.	26	66	452

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

Historical and Projected Heating and Cooling Degree Days

	Year	Heating Degree Days (HDD)	Cooling Degree Days (CDD)
History	1996	1,807	2,470
	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	1,418	2,813
	2003	1,642	2,551
	2004	1,613	2,722
	2005	1,494	2,733
Forecast	2006	1,597	2,644
	2007	1,597	2,644
	2008	1,597	2,644
	2009	1,597	2,644
	2010	1,597	2,644
	2011	1,597	2,644
	2012	1,597	2,644
	2013	1,597	2,644
	2014	1,597	2,644
	2015	1,597	2,644

Average Real Retail Price of Electricity

	Year	Residential Real Price of Electricity ($/MWh)	Commercial Real Price of Electricity ($/MWh)	System-Wide Real Price of Electricity ($/MWh)	Deflator [1]
History	1996	55.24	46.92	47.66	1.569
	1997	55.14	46.75	47.80	1.605
	1998	52.98	45.96	45.06	1.630
	1999	51.32	42.87	43.67	1.666
	2000	52.47	45.63	43.62	1.722
	2001	52.48	44.04	43.17	1.771
	2002	45.22	37.08	42.50	1.799
	2003	50.55	41.94	43.29	1.840
	2004	56.25	47.70	48.01	1.889
	2005	55.70	45.12	47.92	1.953
Forecast [2]	2006	62.52	45.12	52.00	
	2007	62.52	45.12	52.00	
	2008	62.52	45.12	52.00	
	2009	62.52	45.12	52.00	
	2010	62.52	45.12	52.00	
	2011	62.52	45.12	52.00	
	2012	62.52	45.12	52.00	
	2013	62.52	45.12	52.00	
	2014	62.52	45.12	52.00	
	2015	62.52	45.12	52.00	

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

[2] For the City's 2006 Load Forecast, it was assumed that the future real price of electricity for commercial customers would remain constant at the FY 2005 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)
2006						
2007						
2008						
2009			See note [1] below			
2010						
2011						
2012						
2013						
2014						
2015						

[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 41 and 42 and in Table 3.4 (Generation Expansion Plan) on page 44 of the City's 2006 Ten Year Site Plan. The City does not currently evaluate isolated and assisted LOLP and EUE reliability indices.