Ten Year Site Plan

2010-2019

City of Tallahassee
Electric Utility

Report Prepared By:
City of Tallahassee Electric Utility
System Planning

City of Tallahassee
Your Own Utilities℠

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DIVISION OF
REGULATORY COMPLIANCE

CITY OF TALLAHASSEE
TEN YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES
2010-2019
TABLE OF CONTENTS

I. Description of Existing Facilities

1.0	Introduction	1
1.1	System Capability	1
1.2	Purchased Power Agreements	2
Figure A	Service Territory Map	3
Table 1.1	FPSC Schedule 1 Existing Generating Facilities	4

II. Forecast of Energy/Demand Requirements and Fuel Utilization

2.0	Introduction	5
2.1	System Demand and Energy Requirements	5
2.1.1	System Load and Energy Forecasts	5
2.1.2	Load Forecast Uncertainty & Sensitivities	7
2.1.3	Energy Efficiency and Demand Side Management Programs	9
2.2	Energy Sources and Fuel Requirements	10
Table 2.1	FPSC Schedule 2.1 History/Forecast of Energy Consumption (Residential and Commercial Classes)	11
Table 2.2	FPSC Schedule 2.2 History/Forecast of Energy Consumption (Industrial and Street Light Classes)	12
Table 2.3	FPSC Schedule 2.3 History/Forecast of Energy Consumption (Utility Use and Net Energy for Load)	13
Figure B1	Energy Consumption by Customer Class (2000-2019)	14
Figure B2	Energy Consumption: Comparison by Customer Class (2010 and 2019)	15
Table 2.4	FPSC Schedule 3.1.1 History/Forecast of Summer Peak Demand – Base Forecast	16
Table 2.5	FPSC Schedule 3.1.2 History/Forecast of Summer Peak Demand – High Forecast	17
Table 2.6	FPSC Schedule 3.1.3 History/Forecast of Summer Peak Demand – Low Forecast	18
Table 2.7	FPSC Schedule 3.2.1 History/Forecast of Winter Peak Demand – Base Forecast	19
Table 2.8	FPSC Schedule 3.2.2 History/Forecast of Winter Peak Demand – High Forecast	20
Table 2.9	FPSC Schedule 3.2.3 History/Forecast of Winter Peak Demand – Low Forecast	21
Table 2.10	FPSC Schedule 3.3.1 History/Forecast of Annual Net Energy for Load – Base Forecast	22
Table 2.11	FPSC Schedule 3.3.2 History/Forecast of Annual Net Energy for Load – High Forecast	23
Table 2.12	FPSC Schedule 3.3.3 History/Forecast of Annual Net Energy for Load – Low Forecast	24
Table 2.13	FPSC Schedule 4 Previous Year Actual and Two Year Forecast Demand/Energy by Month	25
Table 2.14	Load Forecast: Key Explanatory Variables	26
Table 2.15	Load Forecast: Sources of Forecast Model Input Information	27
Figure B3	Banded Summer Peak Load Forecast vs. Supply Resources	28
Table 2.16	Projected DSM Energy Reductions	29
Table 2.17	Projected DSM Seasonal Demand Reductions	30
Table 2.18	FPSC Schedule 5.0 Fuel Requirements	31
Table 2.19	FPSC Schedule 6.1 Energy Sources (GWh)	32
Table 2.20	FPSC Schedule 6.2 Energy Sources (%)	33
Figure B4	Generation by Fuel Type (2010 and 2019)	34

DOCUMENT NUMBER-DATE
02963 APR 16 ≌
FPSC-COMMISSION CLERK

III. Projected Facility Requirements

3.1	Planning Process	35
3.2	Projected Resource Requirements	35
3.2.1	Transmission Limitations	35
3.2.2	Reserve Requirements	36
3.2.3	Near Term Resource Additions	36
3.2.4	Power Supply Diversity	37
3.2.5	Renewable Resources	38
3.2.6	Future Power Supply Resources	40
Figure C	System Peak Demands and Summer Reserve Margins	41
Table 3.1	FPSC Schedule 7.1 Forecast of Capacity, Demand and Scheduled Maintenance at Time of Summer Peak	42
Table 3.2	FPSC Schedule 7.2 Forecast of Capacity, Demand and Scheduled Maintenance at Time of Winter Peak	43
Table 3.3	FPSC Schedule 8 Planned and Prospective Generating Facility Additions and Changes	44
Table 3.4	Generation Expansion Plan	45

IV. Proposed Plant Sites and Transmission Lines

4.1	Proposed Plant Site	47
4.2	Transmission Line Additions/Upgrades	47
Table 4.1	FPSC Schedule 9 Status Report and Specifications of Proposed Generating Facilities	49
Figure D1	Hopkins Plant Site	50
Figure D2	Purdom Plant Site	50
Table 4.2	Planned Transmission Projects 2010-2019	51
Table 4.3	FPSC Schedule 10 Status Report and Spec. of Proposed Directly Associated Transmission Lines	52
Table 4.4	FPSC Schedule 10 Status Report and Spec. of Proposed Directly Associated Transmission Lines	53

Appendix A

Existing Generating Unit Operating Performance	A-1
Nominal, Delivered Residual Oil Prices Base Case	A-2
Nominal, Delivered Residual Oil Prices High Case	A-3
Nominal, Delivered Residual Oil Prices Low Case	A-4
Nominal, Delivered Distillate Oil and Natural Gas Prices Base Case	A-5
Nominal, Delivered Distillate Oil and Natural Gas Prices High Case	A-6
Nominal, Delivered Distillate Oil and Natural Gas Prices Low Case	A-7
Nominal, Delivered Coal Prices Base Case	A-8
Nominal, Delivered Coal Prices High Case	A-9
Nominal, Delivered Coal Prices Low Case	A-10
Nominal, Delivered Nuclear Fuel and Firm Purchases	A-11
Financial Assumptions Base Case	A-12
Financial Escalation Assumptions	A-13
Monthly Peak Demands and Date of Occurrence for 2007 – 2009	A-14
Historical and Projected Heating and Cooling Degree Days	A-15
Average Real Retail Price of Electricity	A-16
Loss of Load Probability, Reserve Margin, and Expected Unserved Energy Base Case Load Forecast	A-17
2009 Summer Peak Day Net Load Curve and Data Table	A-18
2009/10 Winter Peak Day Net Load Curve and Data Table	A-19

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 113,300 customers located within a 221 square mile service territory (see Figure A). The Electric Department operates three generating stations with a total summer season net generating capacity of 794 megawatts (MW).

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

1.1 SYSTEM CAPABILITY

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

As shown in Table 1.1 (Schedule 1), 222 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 300 MW (net summer rating) of CC generation, 76 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. However, because the hydroelectric generating units are effectively run-of-river (dependent upon rainfall, reservoir and downstream conditions), the City considers these units as “energy only” and not as dependable capacity for planning purposes.

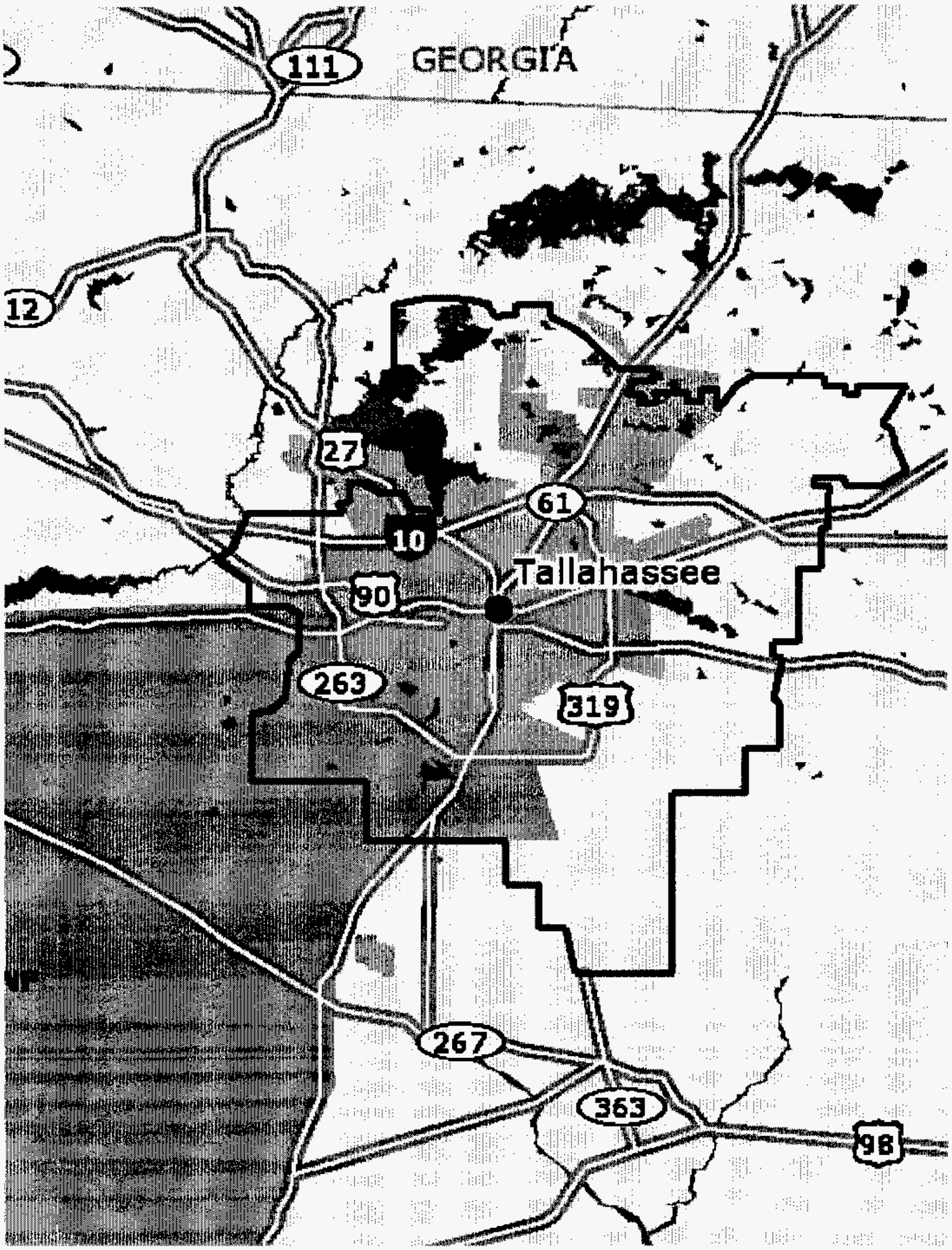
The City’s total net summer installed generating capability is 794 MW. The corresponding winter net peak installed generating capability is 870 MW. Table 1.1 contains the details of the individual generating units.

1.2 Purchased Power Agreements

The City has a long-term firm capacity and energy purchase agreement with Progress for 11.4 MW. This purchase is scheduled to expire on December 3, 2016.

City of Tallahassee, Electric Utility

Service Territory Map



City Of Tallahassee

Schedule 1
Existing Generating Facilities
As of December 31, 2009

(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]	6/66	3/11	50,000	48	48
	8		CC	NG	FO2	PL	TK	[2, 3]	7/00	12/40	247,743	222	258
	GT-1		GT	NG	FO2	PL	TK	[2, 3]	12/63	3/11	15,000	10	10
	GT-2		GT	NG	FO2	PL	TK	[2, 3]	5/64	3/11	15,000	10	10
											Plant Total	290	326
A. B. Hopkins	1	Leon	ST	NG	FO6	PL	TK	[1]	5/71	3/20	75,000	76	78
	2		CC	NG	FO2	PL	TK	[3]	6/08 [4]	Unknown	358,200 [5]	300	330
	GT-1		GT	NG	FO2	PL	TK	[3]	2/70	3/15	16,320	12	14
	GT-2		GT	NG	FO2	PL	TK	[3]	9/72	3/17	27,000	24	26
	GT-3		GT	NG	FO2	PL	TK	[3]	9/05	Unknown	60,500	46	48
	GT-4		GT	NG	FO2	PL	TK	[3]	11/05	Unknown	60,500	46	48
											Plant Total	504	544
C. H. Corn	1	Leon/	HY	WAT	WAT	WAT	WAT	NA	9/85	Unknown	4,440	0	0
Hydro Station	2	Gadsden	HY	WAT	WAT	WAT	WAT	NA	8/85	Unknown	4,440	0	0
[6]	3		HY	WAT	WAT	WAT	WAT	NA	1/86	Unknown	3,430	0	0
											Plant Total	0	0
									Total System Capacity as of December 31, 2009			794	870

Notes

[1] The City maintains a minimum residual fuel oil inventory of approximately 19 peak load days between the Purdom and Hopkins sites.

[2] Due to the Purdom facility-wide emissions caps, utilization of liquid fuel at this facility is limite

[3] Historically, sufficient diesel storage has been maintained at Purdom for approximately 30 full load hours of operation for all three CT units and at Hopkins for approximatel 8 peak load days of operation for all four CT units. Following the Hopkins 2 CC repowering the City's system-wide target for minimum diesel fuel oil inventory will b approximately 18.5 peak load days. This target will not be attained until storage tank upgrades at the Hopkins and Purdom sites are completed in summer/fall of 200

[4] Reflects the commercial operations date of Hopkins 2 repowered to a combined cycle generating unit with a new General Electric Frame 7A combustion turbine. The origina commercial operations date of the existing steam turbine generator was October 1977

[5] Hopkins 2 nameplate rating is based on combustion turbine generator (CTG) nameplate and modeled steam turbine generator (STG) output in a 1x1 combined cycle (CC configuration with supplemental duct firing

[6] Because the C. H. Corn hydroelectric generating units are effectively run-of-river (dependent upon rainfall, reservoir and downstream conditions), the City considers thes units as "energy only" and not as dependable capacity for planning purposes.

CHAPTER II

Forecast of Energy/Demand Requirements and Fuel Utilization

2.0 INTRODUCTION

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

2.1 SYSTEM DEMAND AND ENERGY REQUIREMENTS

Historical and forecast energy consumption and customer information are presented in Tables 2.1, 2.2 and 2.3 (Schedules 2.1, 2.2, and 2.3). Figure B1 shows the historical total energy sales and forecast energy sales by customer class. Figure B2 shows the percentage of energy sales by customer class (excluding the impacts of DSM) for the base year of 2010 and the horizon year of 2019. Tables 2.4 through 2.12 (Schedules 3.1.1 - 3.3.3) contain historical and base, high, and low forecasts of seasonal peak demands and net energy for load. Table 2.13 (Schedule 4) compares actual and two-year forecast peak demand and energy values by month for the 2009 - 2011 period.

2.1.1 SYSTEM LOAD AND ENERGY FORECASTS

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

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

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

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

Since 1992, the City has used two econometric models to separately predict summer and winter peak demand. Table 2.14 also shows the key explanatory variables used in the demand models. The seasonal peak demand forecasts are developed first by forecasting expected system load factor. Based on the historical relationship of seasonal peaks to annual NEL, system load factors are projected separately relative to both summer and winter peak demand. The predictive variables for projected load factors versus summer peak demand include maximum summer temperature, maximum temperature on the day prior to the peak, annual degree-days cooling and real residential price of electricity. For projected load factors versus winter peak demand minimum winter temperature, degree-days heating the day prior to the winter peak day, deviation from a base minimum temperature of 22 degrees and annual degree-days cooling are used as input. The projected load factors are then applied to the forecast of NEL to obtain the summer and winter peak demand forecasts.

Some of the most significant input assumptions for the forecast are 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 represented approximately 15% of the City's 2009 energy sales. Their incremental additions are highly dependent upon annual economic and budget constraints, which would cause fluctuations in their demand projections if they were projected using a model. Therefore, each entity submits their proposed incremental additions/reductions to the City and these modifications are included as submitted in the load and energy forecast.

The City believes that the routine update of forecast model inputs, 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. The changes made to the forecast models for seasonal peak demands and annual sales/net energy for load requirements has resulted in 2010 base forecasts for these characteristics that are generally lower than the corresponding 2009 base forecasts.

2.1.2 Load Forecast Uncertainty & Sensitivities

To provide a sound basis for planning, forecasts are derived from projections of the driving variables obtained from reputable sources. However, there is significant uncertainty in the future level of such variables. To the extent that economic, demographic, weather, or other conditions occur that are different from those assumed or provided, the actual load can be expected to vary from the forecast. For various purposes, it is important to understand the amount by which the forecast can be in error and the sources of error.

To capture this uncertainty, the City produces high and low range results that address potential variance in driving population and economic variables from the values assumed in the base case. The base case forecast relies on a set of assumptions about future population and economic activity in Leon County. However, such projections are unlikely to exactly match actual experience.

Population and economic uncertainty tends to result in a deviation from the trend over the long term. Accordingly, separate high and low forecast results were developed to address population and economic uncertainty. These ranges are intended to capture approximately 80% of occurrences (i.e., 1.3 standard deviations). The high and low forecasts shown in this year's report use statistics provided by Woods & Poole Economics, Inc. (Woods & Poole) to develop a range of potential outcomes. Woods & Poole publishes several statistics that define the average amount by which various projections they have provided in the past are different from actual results. The City's load forecasting consultant, R.W. Beck, interpreted these statistics to develop ranges of the trends of economic activity and population representing approximately 80% of potential outcomes. These statistics were then applied to the base case to develop the high and low load forecasts presented in Schedules 3.1.2, 3.1.3, 3.2.2, 3.2.3, 3.3.2 and 3.3.3.

Sensitivities on the peak demand forecasts are useful in planning for future power supply resource needs. The graph shown in Figure B3 compares summer peak demand (multiplied by 117% for reserve margin requirements) for the three forecast sensitivity cases with reductions from proposed DSM portfolio and the base forecast without proposed DSM reductions against the City's existing and planned power supply resources. This graph allows for the review of the effect of load growth and DSM performance 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.

Extended periods of extremely low temperatures were observed during 2009/10 winter season. The City had sufficient capacity to serve the 633 MW peak demand experienced on January 11, 2010 (a new winter and all-time peak demand record for the City) and enough surplus capacity to sell a modest amount of emergency power to a neighboring utility during the peak demand hours. After the end of the 2009/10 winter season the City initiated an effort to produce an extreme winter peak demand sensitivity forecast. The purpose of this sensitivity forecast will be to allow staff to assess the adequacy of the City's existing power supply resources and determine the need for additional resources in the future to serve customer demand under extraordinary winter conditions. This forecast was not completed in time for inclusion in this report but will be discussed further in future TYSP reports.

2.1.3 Energy Efficiency and Demand Side Management Programs

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

Residential Programs	Commercial Programs
Low Interest Loan Program	Customized Loan Program
Gas New Construction Rebates	Low Interest Loan Program
Gas Appliance Conversion Rebates	Demonstrations
Information and Audits	Information and Audits
Ceiling Insulation Grants	Commercial Gas Conversion Rebates
Low Income Ceiling Insulation Rebate	Ceiling Insulation Grants
Low Income HVAC/water heater repair	Solar Water Heater Rebates
Energy Star Appliance Rebates	Solar Net Metering Program
High Efficiency HVAC Rebates	
Energy Star New Home Rebates	
Solar Water Heater Rebates	
Solar Net Metering Program	
Duct Leak Repair Grants	

The City has a goal to improve the efficiency of customers' end-use of energy resources when such improvements provide a measurable economic and/or environmental benefit to the customers and the City utilities. During the 2006 IRP Study potential DSM measures (conservation, energy efficiency, load management, and demand response) were tested for cost-effectiveness utilizing an integrated approach that is based on projections of total achievable capacity and energy reductions and their associated annual costs developed specifically for the City. The measures were combined into bundles affecting similar end uses and /or having similar costs per kWh saved.

Full implementation of the City's DSM program has been delayed by efforts to contract with an energy services provider to assist staff in deploying some measures. Implementation of the City's demand response/direct load control (DR/DLC) measures has also been delayed by efforts to integrate the associated technologies. However, staff has been implementing other measures in an effort to achieve as much of the near-term demand and energy savings projected in the 2006 IRP Study as possible. The projections of expected demand and energy savings attributable to the City's DSM efforts have therefore been updated versus those reported in the City's 2009 TYSP. The revised projections reflect the City getting back on pace with the demand and energy savings contemplated in the 2006 IRP Study by 2015. The City will provide further updates regarding its progress with and any changes in future expectations of its DSM program in subsequent TYSP reports.

Energy and demand reductions attributable to the DSM portfolio have been incorporated into the future load and energy forecasts. Tables 2.16 and 2.17 display, respectively, the estimated energy and savings associated with the menu of DSM measures. The figures on these tables reflect the cumulative annual impacts of the proposed DSM portfolio on system energy and demand requirements.

2.2 ENERGY SOURCES AND FUEL REQUIREMENTS

Tables 2.18 (Schedule 5), 2.19 (Schedule 6.1), and 2.20 (Schedule 6.2) present the projections of fuel requirements, energy sources by resource/fuel type in gigawatt-hours, and energy sources by resource/fuel type in percent, respectively, for the period 2010-2019. Figure B4 displays the percentage of energy by fuel type in 2010 and 2019.

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

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

City Of Tallahassee

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

Base Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial [4]		
Year	Population [1]	Members Per Household	(GWh) [2]	Average No. of Customers [3]	Average kWh Consumption Per Customer	(GWh) [2]	Average No. of Customers [3]	Average kWh Consumption Per Customer
2000	241,228	-	971	79,108	12,274	1,471	16,662	88,285
2001	245,640	-	959	80,348	11,936	1,459	16,988	85,884
2002	250,820	-	1,048	81,208	12,905	1,527	16,779	91,007
2003	258,627	-	1,035	82,219	12,588	1,555	17,289	89,942
2004	265,393	-	1,064	85,035	12,512	1,604	17,729	90,473
2005	269,619	-	1,088	89,468	12,164	1,623	18,310	88,656
2006	272,648	-	1,097	92,017	11,927	1,604	18,532	86,560
2007	273,684	-	1,099	93,569	11,745	1,657	18,583	89,168
2008	274,926	-	1,054	94,640	11,132	1,624	18,597	87,312
2009	275,580	-	1,050	94,827	11,071	1,611	18,478	87,180
2010	277,662	-	1,028	95,571	10,758	1,605	18,729	85,687
2011	279,760	-	1,017	96,443	10,546	1,599	18,829	84,942
2012	281,874	-	1,014	97,320	10,417	1,600	18,930	84,536
2013	284,001	-	1,008	98,204	10,264	1,592	19,032	83,657
2014	286,149	-	1,002	99,096	10,115	1,584	19,135	82,789
2015	288,529	-	998	100,084	9,970	1,578	19,249	81,963
2016	291,287	-	998	101,227	9,858	1,575	19,380	81,288
2017	294,068	-	998	102,379	9,749	1,573	19,513	80,627
2018	296,879	-	999	103,544	9,645	1,571	19,648	79,977
2019	299,717	-	1,002	104,720	9,569	1,573	19,783	79,489

[1] Population data represents Leon County population.
[2] Values include DSM Impacts.
[3] Average end-of-month customers for the calendar year. Marked increase in residential customers between 2004 and 2005 due to change in internal customer accounting practices.
[4] As of 2007 "Commercial" includes General Service Non-Demand, General Service Demand, General Service Large Demand Interruptible (FSU and Goose Pond), Curtailable (TMH), Traffic Control, Security Lights and Street & Highway Lights

Table 2.1

City Of Tallahassee

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

Base Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	(GWh)	Average No. of Customers [1]	Average kWh Consumption Per Customer	Railroads and Railways (GWh)	Street & Highway Lighting (GWh) [2]	Other Sales to Public Authorities (GWh)	Total Sales to Ultimate Consumers (GWh)
2000	-	-	-		12		2,454
2001	-	-	-		13		2,431
2002	-	-	-		13		2,588
2003	-	-	-		12		2,602
2004	-	-	-		14		2,682
2005	-	-	-		14		2,726
2006	-	-	-		15		2,718
2007	-	-	-		0		2,757
2008	-	-	-		0		2,677
2009	-	-	-		0		2,661
2010	-	-	-		0		2,633
2011	-	-	-		0		2,616
2012	-	-	-		0		2,614
2013	-	-	-		0		2,600
2014	-	-	-		0		2,586
2015	-	-	-		0		2,576
2016	-	-	-		0		2,573
2017	-	-	-		0		2,571
2018	-	-	-		0		2,570
2019	-	-	-		0		2,575

[1] Average end-of-month customers for the calendar year.
[2] As of 2007 Security Lights and Street & Highway Lighting use is included with Commercial on Schedule 2.1.

City Of Tallahassee

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

Base Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale (GWh)	Utility Use & Losses (GWh)	Net Energy for Load (GWh)	Other Customers (Average No.)	Total No. of Customers [1]
2000	0	155	2,609		95,770
2001	0	125	2,556		97,336
2002	0	165	2,753		97,986
2003	0	153	2,755		99,508
2004	0	159	2,841		102,764
2005	0	164	2,890		107,778
2006	0	154	2,872		110,549
2007	0	158	2,915		112,152
2008	0	155	2,832		113,236
2009	0	144	2,805		113,305
2010	0	156	2,789		114,300
2011	0	156	2,772		115,272
2012	0	155	2,769		116,251
2013	0	155	2,755		117,236
2014	0	154	2,740		118,231
2015	0	153	2,729		119,332
2016	0	153	2,726		120,607
2017	0	153	2,724		121,893
2018	0	153	2,723		123,192
2019	0	153	2,728		124,503

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

History and Forecast Energy Consumption
By Customer Class (Including DSM Impacts)

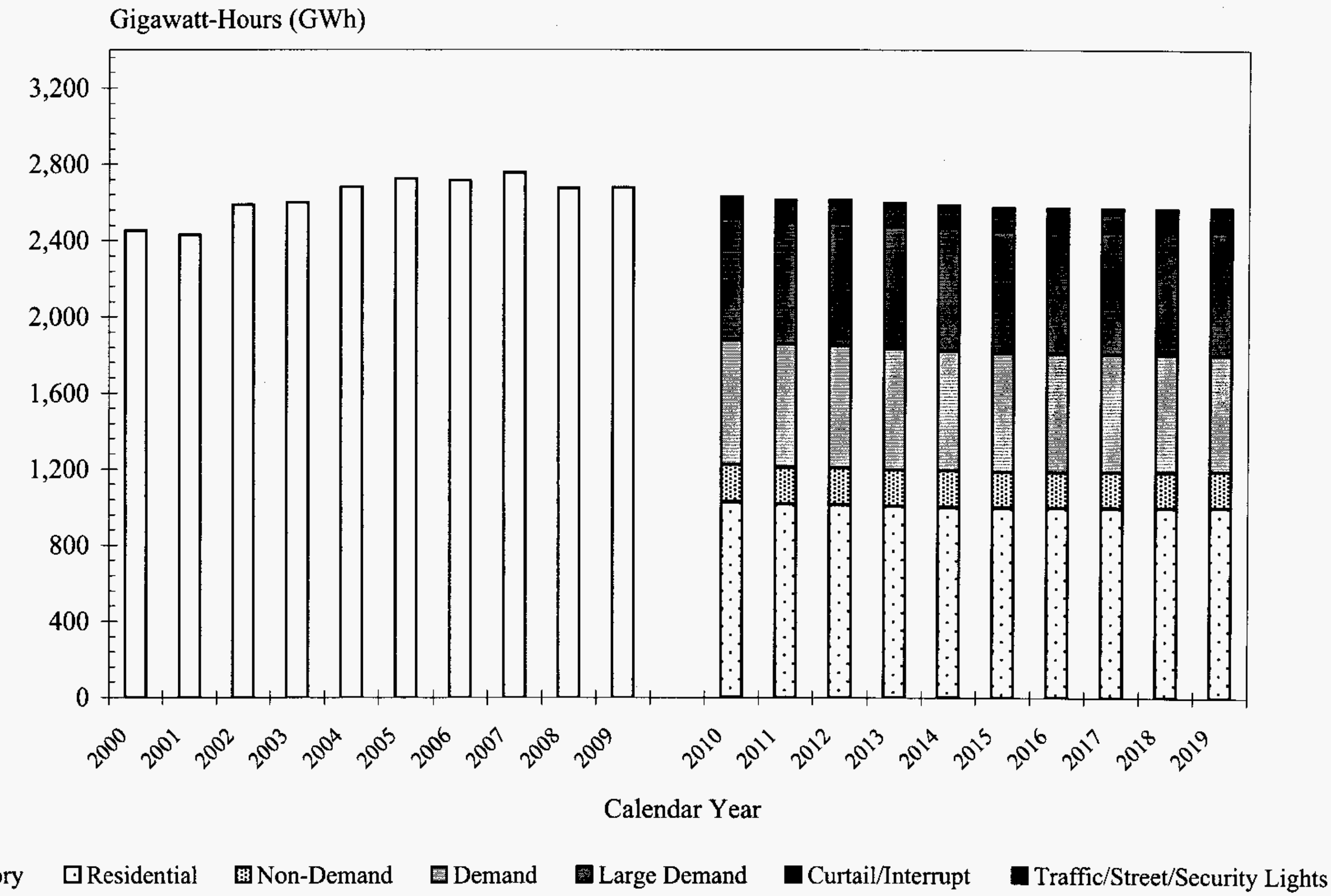
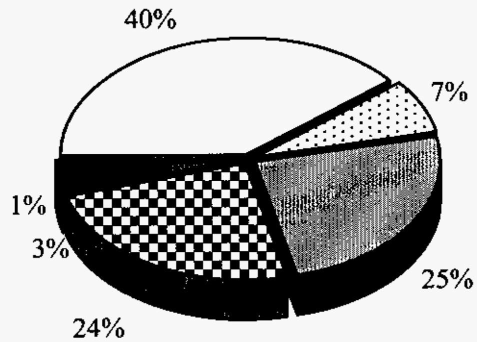


Figure B1

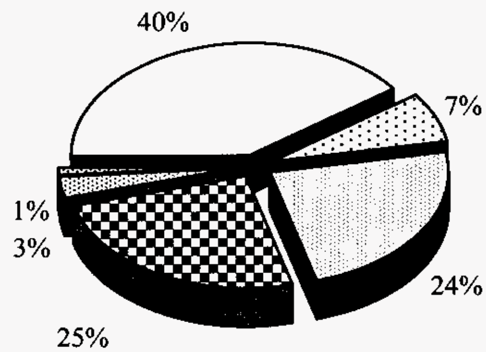
Energy Consumption By Customer Class
(Excluding DSM Impacts)

Calendar Year



Total 2010 Sales = 2,697
GWh

Calendar Year 2019



Total 2019 Sales = 2,967 GWh

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

City Of Tallahassee

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
2000	550		550						550
2001	520		520						520
2002	580		580						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	621		621						621
2008	587		587						587
2009	606		606		0	1	0	0	605
2010	620		620		6	1	6	2	605
2011	627		627		15	2	15	3	592
2012	634		634		20	4	17	9	584
2013	640		640		24	9	17	18	572
2014	646		646		28	13	18	26	561
2015	652		652		30	15	18	34	555
2016	660		660		30	18	19	41	552
2017	667		667		30	20	19	47	550
2018	674		674		30	24	19	52	549
2019	682		682		30	27	19	56	549

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2009 DSM is actual at peak.
[3] 2009 values reflect incremental increase from 2008.

City Of Tallahassee

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
2000	550		550						550
2001	520		520						520
2002	580		580						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	621		621						621
2008	587		587						587
2009	606		606		0	1	0	0	605
2010	634		634		6	1	6	2	619
2011	645		645		15	2	15	3	610
2012	656		656		20	4	17	9	606
2013	666		666		24	9	17	18	598
2014	677		677		28	13	18	26	592
2015	687		687		30	15	18	34	590
2016	699		699		30	18	19	41	591
2017	711		711		30	20	19	47	594
2018	723		723		30	24	19	52	597
2019	735		735		30	27	19	56	603

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2009 DSM is actual at peak.
[3] 2009 values reflect incremental increase from 2008.

City Of Tallahassee

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
2000	550		550						550
2001	520		520						520
2002	580		580						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	621		621						621
2008	587		587						587
2009	606		606		0	1	0	0	605
2010	606		606		6	1	6	2	591
2011	609		609		15	2	15	3	574
2012	612		612		20	4	17	9	562
2013	614		614		24	9	17	18	546
2014	615		615		28	13	18	26	530
2015	618		618		30	15	18	34	520
2016	620		620		30	18	19	41	513
2017	623		623		30	20	19	47	507
2018	626		626		30	24	19	52	501
2019	629		629		30	27	19	56	496

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2009 DSM is actual at peak.
[3] 2009 values reflect incremental increase from 2008.

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 [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
2000 -2001	521		521						521
2001 -2002	510		510						510
2002 -2003	590		590						590
2003 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	528		528						528
2007 -2008	526		526						526
2008 -2009	579		579						579
2009 -2010	634		634		0	1	0	0	633
2010 -2011	551		551		15	1	15	2	518
2011 -2012	557		557		20	4	17	5	511
2012 -2013	562		562		24	9	17	12	500
2013 -2014	567		567		28	13	18	16	492
2014 -2015	573		573		30	19	18	23	483
2015 -2016	579		579		30	22	19	29	480
2016 -2017	586		586		30	25	19	34	478
2017 -2018	592		592		30	30	19	37	476
2018 -2019	599		599		30	33	20	40	476
2019 -2020	605		605		30	36	20	43	477

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2009 DSM is actual at peak.
[3] 2009 values reflect incremental increase from 2008.

City Of Tallahassee

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
2000 -2001	521		521						521
2001 -2002	510		510						510
2002 -2003	590		590						590
2003 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	528		528						528
2007 -2008	526		526						526
2008 -2009	579		579						579
2009 -2010	634		634		0	1	0	0	633
2010 -2011	567		567		15	1	15	2	534
2011 -2012	576		576		20	4	17	5	530
2012 -2013	585		585		24	9	17	12	523
2013 -2014	594		594		28	13	18	16	519
2014 -2015	604		604		30	19	18	23	513
2015 -2016	614		614		30	22	19	29	514
2016 -2017	624		624		30	25	19	34	516
2017 -2018	635		635		30	30	19	37	519
2018 -2019	646		646		30	33	20	40	523
2019 -2020	656		656		30	36	20	43	528

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2009 DSM is actual.
[3] 2009 values reflect incremental increase from 2008.

City Of Tallahassee

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
2000 -2001	521		521						521
2001 -2002	510		510						510
2002 -2003	590		590						590
2003 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	528		528						528
2007 -2008	526		526						526
2008 -2009	579		579						579
2009 -2010	634		634		0	1	0	0	633
2010 -2011	535		535		15	1	15	2	502
2011 -2012	538		538		20	4	17	5	492
2012 -2013	539		539		24	9	17	12	477
2013 -2014	540		540		28	13	18	16	466
2014 -2015	542		542		30	19	18	23	452
2015 -2016	545		545		30	22	19	29	445
2016 -2017	548		548		30	25	19	34	440
2017 -2018	550		550		30	30	19	37	434
2018 -2019	552		552		30	33	20	40	429
2019 -2020	555		555		30	36	20	43	426

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2009 DSM is actual.
[3] 2009 values reflect incremental increase from 2008.

Table 2.9

City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total Sales	Residential Conservation [2], [3]	Comm./Ind Conservation [2], [3]	Retail Sales [1]	Wholesale	Utility Use & Losses	Net Energy for Load [1]	Load Factor % [1]
2000	2,454			2,454		155	2,609	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	62
2003	2,602			2,602		153	2,755	57
2004	2,682			2,682		159	2,841	64
2005	2,726			2,726		164	2,890	58
2006	2,718			2,718		154	2,872	55
2007	2,757			2,757		158	2,915	58
2008	2,677			2,677		155	2,832	52
2009	2,672	9	1	2,661		144	2,805	53
2010	2,697	31	34	2,633		156	2,789	53
2011	2,728	53	59	2,616		156	2,772	53
2012	2,760	69	77	2,614		155	2,769	54
2013	2,785	88	97	2,600		155	2,755	55
2014	2,810	106	118	2,586		154	2,740	56
2015	2,839	125	138	2,576		153	2,729	56
2016	2,870	141	156	2,573		153	2,726	56
2017	2,902	157	174	2,571		153	2,724	57
2018	2,934	172	192	2,570		153	2,723	57
2019	2,967	186	206	2,575		153	2,728	57

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2009 DSM is actual.
[3] 2009 values reflect incremental increase from 2008.

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], [3]	Comm./Ind Conservation [2], [3]	Retail Sales [1]	Wholesale	Utility Use & Losses	Net Energy for Load [1]	Load Factor % [1]
2000	2,454			2,454		155	2,609	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	62
2003	2,602			2,602		153	2,755	57
2004	2,682			2,682		159	2,841	64
2005	2,726			2,726		164	2,890	58
2006	2,718			2,718		154	2,872	55
2007	2,757			2,757		158	2,915	58
2008	2,677			2,677		155	2,832	52
2009	2,672	9	1	2,661		144	2,805	53
2010	2,759	31	34	2,695		160	2,855	53
2011	2,809	53	59	2,697		161	2,857	53
2012	2,856	69	77	2,711		161	2,872	54
2013	2,900	88	97	2,715		161	2,876	55
2014	2,944	106	118	2,720		162	2,882	56
2015	2,991	125	138	2,728		162	2,890	56
2016	3,042	141	156	2,746		164	2,910	56
2017	3,093	157	174	2,763		164	2,927	56
2018	3,145	172	192	2,781		165	2,947	56
2019	3,200	186	206	2,808		167	2,974	56

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2009 DSM is actual.
[3] 2009 values reflect incremental increase from 2008.

City Of Tallahassee

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

(1) Year	(2) Total Sales	(3) Residential Conservation [2], [3]	(4) Comm./Ind Conservation [2], [3]	(5) Retail Sales [1]	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load [1]	(9) Load Factor % [1]
2000	2,454			2,454		155	2,609	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	62
2003	2,602			2,602		153	2,755	57
2004	2,682			2,682		159	2,841	64
2005	2,726			2,726		164	2,890	58
2006	2,718			2,718		154	2,872	55
2007	2,757			2,757		158	2,915	58
2008	2,677			2,677		155	2,832	52
2009	2,672	9	1	2,661		144	2,805	53
2010	2,636	31	34	2,571		153	2,724	53
2011	2,649	53	59	2,537		151	2,688	53
2012	2,664	69	77	2,518		150	2,668	54
2013	2,671	88	97	2,487		148	2,634	55
2014	2,678	106	118	2,454		146	2,600	56
2015	2,688	125	138	2,425		144	2,569	56
2016	2,700	141	156	2,403		143	2,546	57
2017	2,713	157	174	2,383		142	2,524	57
2018	2,725	172	192	2,361		140	2,502	57
2019	2,737	186	206	2,345		139	2,484	57

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2009 DSM is actual.
[3] 2009 values reflect incremental increase from 2008.

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)
	2009 Forecast [1]		2010 Forecast [1][2]		2011 Forecast [1]	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	579	226	530	226	518	224
February	578	206	528	203	516	202
March	481	207	437	203	427	202
April	415	202	449	204	439	202
May	491	233	515	234	504	232
June	605	282	592	270	580	268
July	578	273	605	278	592	276
August	569	272	598	280	586	278
September	530	260	559	258	547	256
October	539	234	538	227	527	226
November	345	190	401	196	392	195
December	465	220	454	210	444	208
TOTAL		2,805		2,789		2,772

[1] Peak Demand and NEL include DSM Impacts.
[2] Represents forecast values for 2010.

City of Tallahassee, Florida

2010 Electric System Load Forecast

Key Explanatory Variables

Model Name	Leon County Population	Residential 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										0.994
Residential Consumption		X	X	X	X	X				X	0.927
Florida State University Consumption			X				X				0.930
State Capitol Consumption			X				X				0.892
Florida A&M University Consumption			X				X				0.926
Lighting Consumption	X										0.961
General Service Non-Demand Customers		X									0.996
General Service Demand Customers		X									0.987
General Service Non-Demand Consumptio	X		X	X		X					0.956
General Service Demand Consumption	X		X	X							0.979
General Service Large Demand Consumption	X		X	X							0.933
Summer Peak Demand			X			X			X		0.914
Winter Peak Demand			X	X				X			0.880

[1] R Squared, sometimes called the coefficient of determination, is a commonly used measure of goodness of 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

2010 Electric System Load Forecast

Sources of Forecast Model Input Information

Energy Model Input Data	Source
1. Leon County Population	Bureau of Economic and Business Research
2. Talquin Customers Transferred	City Power Engineering
3. Cooling Degree Days	NOAA reports
4. Heating Degree Days	NOAA reports
5. AC Saturation Rate	Appliance Saturation Study
6. Heating Saturation Rate	Appliance Saturation Study
7. Real Tallahassee Taxable Sales	Florida Department of Revenue
8. Florida Population	Bureau of Economic and Business Research
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	City 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	Blue Chip Economic Indicators
19. CPI Forecast	Blue Chip Economic Indicators
20. Florida Taxable Sales	Florida Department of Revenue
21. Interruptible, Traffic Light Sales, & Security Light Additions	System Planning & Customer Accounting
22. Historical Residential Real Price of Electricity	Calculated from Revenues, kWh sold, CPI
23. Historical Commercial Real Price Of Electricity	Calculated from Revenues, kWh sold, CPI

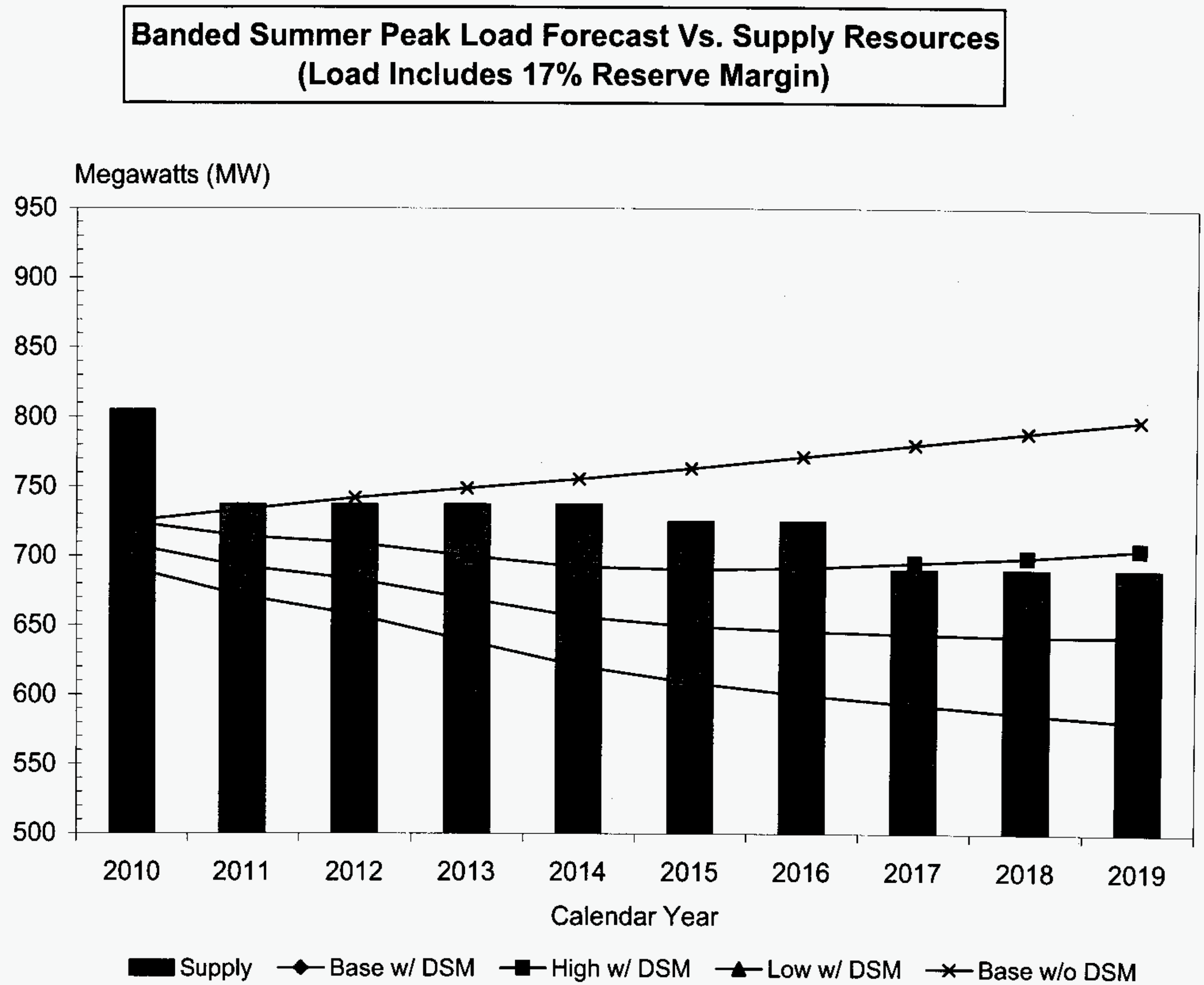

Banded Summer Peak Load Forecast Vs. Supply Resources
(Load Includes 17% Reserve Margin)
Megawatts (MW)
950
900
850
800
750
700
650
600
550
500
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
Calendar Year
Supply
Base w/ DSM
High w/ DSM
Low w/ DSM
Base w/o DSM

Figure B3

City Of Tallahassee

2010 Electric System Load Forecast

Projected Demand Side Management
Energy Reductions [1]

Calendar Year Basis

Year	Residential Impact (MWh)	Commercial Impact (MWh)	Total Impact (MWh)
2010	32,327	35,898	68,225
2011	56,221	62,431	118,652
2012	73,087	81,161	154,248
2013	92,764	103,012	195,776
2014	112,442	124,863	237,304
2015	132,119	146,714	278,832
2016	148,985	165,443	314,428
2017	165,851	184,172	350,024
2018	182,718	202,902	385,619
2019	196,773	218,510	415,282

[1] Reductions estimated at busbar.

City Of Tallahassee

2010 Electric System Load Forecast

Projected Demand Side Management
Seasonal Demand Reductions [1]

Year		Residential Energy Efficiency Impact		Commercial Energy Efficiency Impact		Residential Demand Response Impact		Commercial Demand Response Impact		Demand Side Management Total	
Summer	Winter	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
2010	2010-2011	1	1	2	2	6	15	6	15	15	33
2011	2011-2012	2	4	3	5	15	20	15	17	35	46
2012	2012-2013	4	9	9	12	20	24	17	17	50	62
2013	2013-2014	9	13	18	16	24	28	17	18	68	75
2014	2014-2015	13	19	26	23	28	30	18	18	85	90
2015	2015-2016	15	22	34	29	30	30	18	19	97	100
2016	2016-2017	18	25	41	34	30	30	19	19	108	108
2017	2017-2018	20	30	47	37	30	30	19	19	117	116
2018	2018-2019	24	33	52	40	30	30	19	20	125	123
2019	2019-2020	27	36	56	43	30	30	19	20	133	129

[1] Reductions estimated at busbar.

Table 2.17

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 2008	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(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	12	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	12	0	0	0	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	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	3	9	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	9	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	3	0	0	0	0	0	0	0	0	0	0	0
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	19,392	19,393	20,248	20,157	20,349	20,031	19,907	19,910	19,978	20,515	20,463	20,409
(14)		Steam	1000 MCF	2,645	1,583	703	510	834	786	734	761	710	691	659	544
(15)		CC	1000 MCF	16,110	17,668	18,279	18,216	18,330	18,023	17,870	18,354	18,330	19,273	19,321	19,376
(16)		CT	1000 MCF	638	1,426	1,266	1,431	1,185	1,222	1,303	795	938	551	483	489
(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

Table 2.18

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 2008	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	Annual Firm Interchange		GWh	239	100	119	120	120	121	120	120	113	24	24	25
(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	7	0	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWh	7	0	0	0	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	Total	GWh	1	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	4	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	1	0	0	0	0	0	0	0	0	0	0	0
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	2,424	2,612	2,695	2,679	2,689	2,641	2,628	2,628	2,634	2,718	2,716	2,718
(15)		Steam	GWh	228	122	59	43	71	67	62	65	60	59	56	46
(16)		CC	GWh	2139	2454	2508	2492	2499	2452	2433	2480	2476	2602	2609	2621
(17)		CT	GWh	57	37	128	144	119	122	133	83	98	57	51	51
(18)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Hydro		GWh	17	21	18	18	18	18	18	18	18	18	18	18
(20)	Economy Interchange[1]		GWh	146	67	-43	-45	-58	-25	-26	-37	-39	-36	-35	-33
(21)	Renewables		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(22)	Net Energy for Load		GWh	2,834	2,805	2,789	2,772	2,769	2,755	2,740	2,729	2,726	2,724	2,723	2,728

City Of Tallahassee

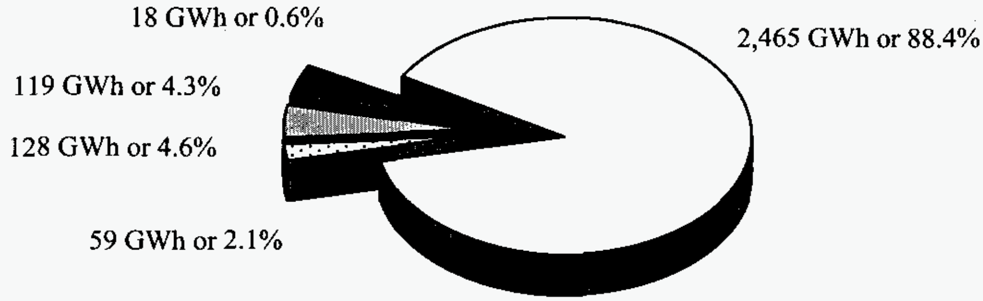
Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2008	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	Annual Firm Interchange		%	8.4	3.5	4.3	4.3	4.3	4.4	4.4	4.4	4.1	0.9	0.9	0.9
(2)	Coal		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	Nuclear		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(4)	Residual	Total	%	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		Steam	%	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Distillate	Total	%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CC	%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	Total	%	85.5	93.1	96.6	96.6	97.1	95.9	95.9	96.3	96.6	99.8	99.7	99.6
(15)		Steam	%	8.0	4.3	2.1	1.6	2.6	2.4	2.3	2.4	2.2	2.2	2.1	1.7
(16)		CC	%	75.5	87.5	89.9	89.9	90.2	89.0	88.8	90.9	90.8	95.5	95.8	96.1
(17)		CT	%	2.0	1.3	4.6	5.2	4.3	4.4	4.9	3.0	3.6	2.1	1.9	1.9
(18)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(19)	Hydro		%	0.6	0.8	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
(20)	Economy Interchange		%	5.1	2.4	-1.5	-1.6	-2.1	-0.9	-0.9	-1.4	-1.4	-1.3	-1.3	-1.2
(21)	Renewables		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(22)	Net Energy for Load		%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 2.20

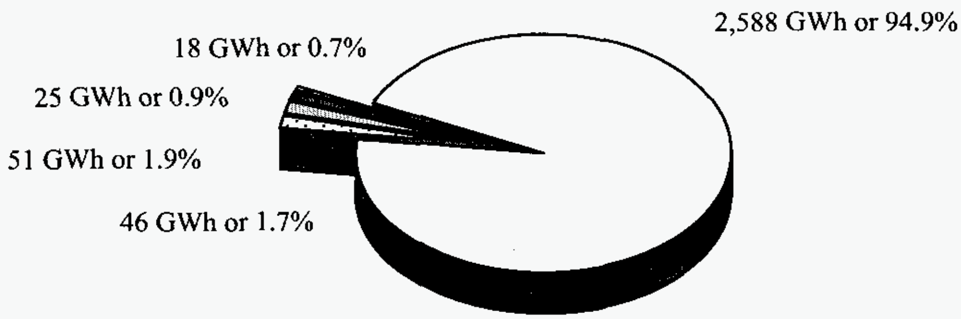
Generation By Resource/Fuel Type

Calendar Year 2010



Total 2010 NEL = 2,789 GWh

Calendar Year 2019



Total 2019 NEL = 2,728

CC - Gas | Steam - Gas | CT/Diesel - Gas | Purch | Hydro

Chapter III

Projected Facility Requirements

3.1 Planning Process

In December 2006 the City completed its last comprehensive IRP Study ("2006 IRP Study"). The purpose of this study was to review future DSM and power supply options that are consistent with the City's policy objectives. Included in the 2006 IRP Study was a detailed analysis of how the DSM and power supply alternatives perform under base and alternative assumptions.

As reported in the 2009 TYSP, the resource plan identified in the 2006 IRP Study included the the repowering of Hopkins Unit 2 to combined cycle operation, renewable energy purchases, a commitment to an aggressive DSM portfolio and the latter year addition of peaking resources to meet energy demand over the next ten years.

Based on more recent information including but not limited to the updated forecast of the City's demand and energy requirements (discussed in Chapter II) the City has made revisions to the resource plan identified in the 2006 IRP Study. These revisions will be discussed in this chapter.

3.2 Projected Resource Requirements

3.2.1 Transmission Limitations

The City has projected that no additional power supply resources will be required during the 2010-2019 TYSP reporting period to maintain a reliable electric system. However, the City's projected transmission import capability is a major determinant of the need for future power supply resource additions. As has been seen in other parts of the country, there has been little investment in the regional transmission system around Tallahassee. Consequently, the City's internal transmission studies have reflected a gradual deterioration of the system's transmission import (and export) capability into the future, due in part to this lack of investment in facilities as well as the impact of unscheduled power flow-through on the City's transmission system. The City has worked with its neighboring utilities, Progress and Southern, to plan and maintain, at minimum, 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. Though it is not currently expected that additional power supply resources will be needed to satisfy load and planning reserve requirements in the reporting period, the City may need new power supply resources to complement available transmission import capability.

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) the evolving set of mandatory reliability standards issued by the North American Electric Reliability Corporation (NERC), and (iv) alternative mechanisms envisioned by recent actions of the U.S. Department of Energy (DOE) regarding key transmission corridors. Unfortunately, none of these efforts is expected to produce substantive improvements to the City's transmission import/export capability in the short-term. The City continues to discuss the limitations of the existing transmission grid in the Florida panhandle region with Progress. In consideration of the City's projected transmission import capability reductions and the associated grid limitations, the results of the 2006 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

The City uses a load reserve margin of 17% in its resource planning studies. This margin was established based in part on loss of load probability (LOLP) analysis of the City's system performed in 2002. The City periodically conducts LOLP analyses to determine if conditions warrant a change in the reserve margin criterion. For the purposes of this year's TYSP report, the City has determined that the 17% reserve margin remains the appropriate criterion.

3.2.3 Near Term Resource Additions

At their October 17, 2005 meeting the City Commission gave the Electric Utility approval to proceed with the repowering of Hopkins Unit 2 to combined cycle operation. The repowering was completed and the unit began commercial operation in June 2008. The former Hopkins Unit 2 boiler was retired and replaced with a combustion turbine generator (CTG) and a heat recovery steam generator (HRSG). The Hopkins 2 steam turbine and generator is now powered by the steam generated in the HRSG. Duct burners have been installed in the HRSG to provide additional peak generating capability. The repowering project provides additional capacity as well as increased efficiency versus the unit's capabilities prior to the repowering project. The repowered unit has achieved official seasonal net capacities of 300 MW in the summer and 330 MW in the winter.

3.2.4 POWER SUPPLY DIVERSITY

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

Purchase contracts can provide some of the diversity desired in the City's power supply resource portfolio. The 2006 IRP Study evaluated both short and long-term purchased power options based on conventional sources as well as power offers based on renewable resources. Another consultant-assisted study conducted in recent years evaluated the potential reliability and economic benefits of prospectively increasing the City's transmission import (and export) capabilities. The results of this study indicate the potential for some electric reliability improvement resulting from addition of facilities to achieve more transmission import capability. However, the study's model of the Southern and Florida markets reflects, as with the City's generation fleet, natural gas-fired generation on the margin the majority of the time. Therefore, the cost of increasing the City's transmission import capability could not likely be offset by the potential economic benefit from increased power purchases from conventional sources.

The City has entered into a purchased power agreement with a renewable energy provider, which involves the purchase of energy when available from a project developed by a private company and located either within the City's or a neighboring utility's electric service territory (see Section 3.2.5 for details on this purchased power agreement).

As an additional strategy to address the City's lack of power supply diversity, planning staff has investigated options for a significantly enhanced DSM portfolio. Commitment to this expanded DSM effort (see Section 2.1.3), combined with a renewable energy purchase and an increase in customer-sited renewable energy projects (primarily solar panels) are contributing to an improvement in the City's overall resource diversity. However, diversity remains a significant issue for the City, in light of the City's heavy dependence upon natural gas as a fuel source for electric generation and pending federal and state legislation related to climate change and greenhouse gas (GHG) emissions control.

3.2.5 Renewable Resources

As part of its continuing commitment to explore clean energy alternatives, the City has continued to invest in opportunities to develop viable solar photovoltaic (PV) projects as part of our efforts to offer "green power" to our customers. The City believes that offering green power alternatives to its customers is a sound business strategy: it will provide for a measure of supply diversification, reduce dependence on fossil fuels, promote cleaner energy sources, and enhance the City's already strong commitment to protecting the environment and the quality of life in Tallahassee.

As of the end of calendar year 2009 the City has a portfolio of 57 kW of solar PV operated and maintained by the Electric Utility and a cumulative total of 440 kW of solar PV has been installed by customers. The City promotes and encourages environmental responsibility in our community through a variety of programs available to citizens. The commitment to renewable energy sources (and particularly to solar PV) by its customers is made possible through the Go Green Tallahassee initiative, that includes many options related to becoming a greener community such as the City's Solar PV Net Metering offer. Solar PV Net Metering promotes customer investment in renewable energy generation by allowing residential and commercial customers with small to moderate sized PV installations to return excess generated power back to the City at the full retail value.

The City has also investigated other renewable resource alternatives, including solar thermal, biomass and other alternative fuels. In 2009 the City added a 3.9 Million Btu solar thermal system at the Wade Wehunt Pool. As reported in previous submissions, the City entered into a 30-year purchase power agreement (PPA) with Biomass Gas & Electric (BG&E) for up to 3.3 GWh/year of electricity and 60 million British thermal units (Btu) per hour of synthetic gas produced by BG&E's biomass-fueled synthetic gas production from a 40 MW gasification project. The original target in-service date for the electric generating facility was to have been June 1, 2010. However, as a result of public opposition expressed during the permitting process BG&E chose to abandon its preferred site for this facility and, as of this report, the project and associated PPA have been officially terminated and no negotiations for a replacement project/PPA have been initiated.

The City's search for additional energy derived from alternative fuels also led to a 30-year PPA with Green Power Systems of Jacksonville, Florida for a 40 MW project called "Renewable Fuel Tallahassee" (RFT). The PPA contemplates that the City will purchase up to 3.1 GWh/yr of energy from the project that uses municipal solid waste (MSW) as its primary fuel source. The RFT facility will produce a synthetic gas using the Plasma Arc gasification technology that will be used as fuel for a conventional steam cycle electric generating plant. Currently there is one plant, located in Japan, that is in commercial service using this technology. Because the RFT facility is to employ an emerging technology, the City will not consider the PPA as firm capacity until its reliable performance has been demonstrated for a sufficient period. The electric generating facility is to be constructed locally though the City has considered that RFT may well face public opposition similar to that BG&E experienced in their permitting process. The original target in service date for the facility was to be October 1, 2010. On October 24, 2008, the target in service date was amended to October 31, 2011. But because of RFT's continuing difficulties with securing adequate financing of the project and the prospect of local opposition, the City has not reflected in this TYSP report any energy production associated with the PPA. The City will provide an update on the status of the RFT PPA in next year's TYSP report.

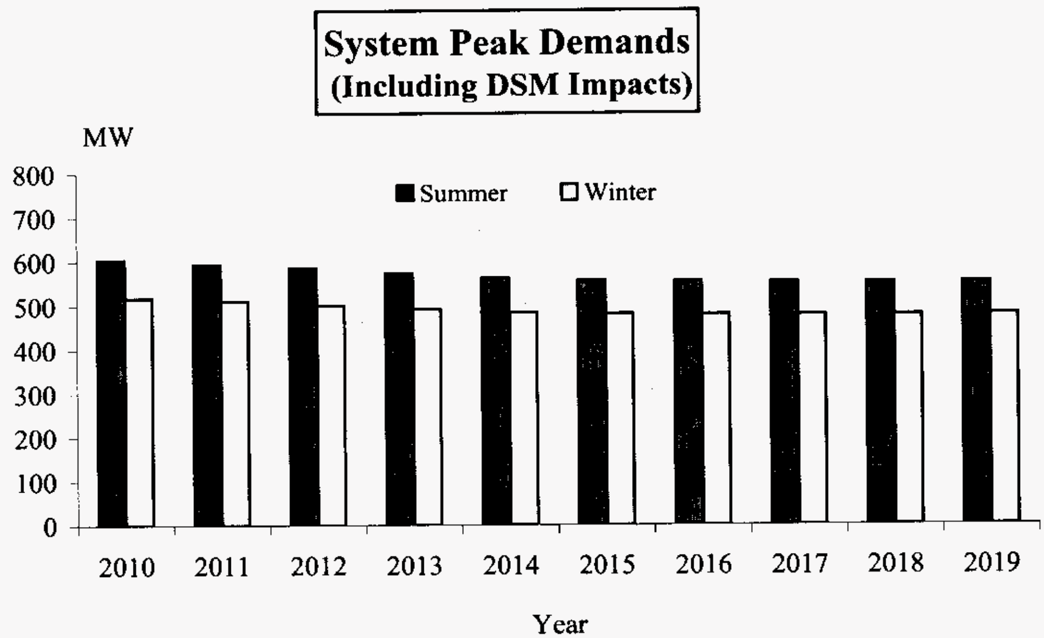
The City will mitigate the risk associated with the emerging technology employed by RFT by (i) having no contractual cost obligations other than to pay for the electric energy actually delivered, and (ii) not counting the purchase as firm capacity until the facility's reliable performance has been demonstrated for a sufficient period.

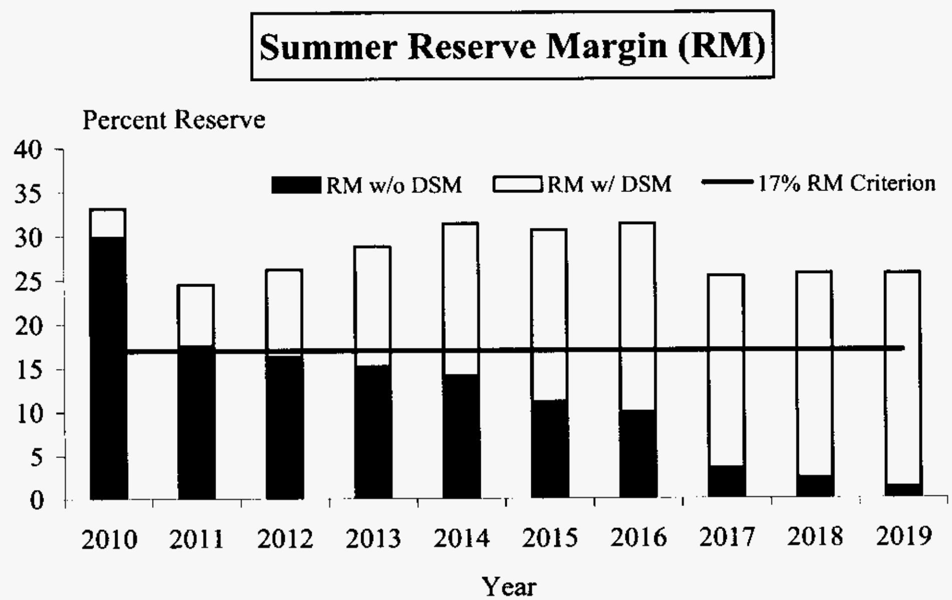
3.2.6 Future Power Supply Resources

The City currently projects that no power supply resource additions will be needed in this reporting period to maintain electric system adequacy and reliability. This resource plan is dependent on the aggressive DSM portfolio (described in Section 2.1.3 of this report) and the City's projected transmission import capability but, as previously discussed, does not count the RFT renewable energy purchase agreement toward meeting the City's planning reserve requirement. Under these base conditions, the City has sufficient reserves to meet its planning reserve requirements throughout the reporting period. If only 50% of the DSM target is achieved, the City would require no more than 25 MW to meet its planning reserve requirements in the summer of 2017 (following the expiration of the PPA with Progress Energy Florida and retirement of Hopkins CT 2). Based on this assessment, the City's resource plan is currently expected to be adequate and robust enough to withstand variations in net demand without triggering an emergency addition of capacity in the near term.

The proposed renewable energy purchase offers an additional level of flexibility to meet capacity requirements during the reporting period. If the RFT transaction achieves commercial operation and can subsequently be considered as firm capacity and 100% effectiveness of the DSM portfolio is achieved, the City would need no additional resources to meet planning reserve requirements until after 2027. The City continues to monitor closely the performance of the DSM portfolio, and will be evaluating the proposed renewable energy purchase to determine if the transaction can be included in future reserve calculations.

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 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.


System Peak Demands
(Including DSM Impacts)
MW
800
700
600
500
400
300
200
100
0
Summer
Winter
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
Year


Summer Reserve Margin (RM)
Percent Reserve
40
35
30
25
20
15
10
5
0
RM w/o DSM
RM w/ DSM
17% RM Criterion
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
Year

City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% of Peak	(MW)	(MW)	% of Peak
2010	794	11	0	0	805	605	200	33	0	200	33
2011	726	11	0	0	737	592	145	24	0	145	24
2012	726	11	0	0	737	584	153	26	0	153	26
2013	726	11	0	0	737	572	165	29	0	165	29
2014	726	11	0	0	737	561	176	31	0	176	31
2015	714	11	0	0	725	555	170	31	0	170	31
2016	714	11	0	0	725	552	173	31	0	173	31
2017	690	0	0	0	690	550	140	25	0	140	25
2018	690	0	0	0	690	549	141	26	0	141	26
2019	690	0	0	0	690	549	141	26	0	141	26

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

Table 3.1

City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% of Peak	(MW)	(MW)	% of Peak
2010/11	870	11	0	0	881	518	363	70	0	363	70
2011/12	802	11	0	0	813	511	302	59	0	302	59
2012/13	802	11	0	0	813	500	313	63	0	313	63
2013/14	802	11	0	0	813	492	321	65	0	321	65
2014/15	802	11	0	0	813	483	330	68	0	330	68
2015/16	788	11	0	0	799	480	319	67	0	319	67
2016/17	788	0	0	0	788	478	310	65	0	310	65
2017/18	762	0	0	0	762	476	286	60	0	286	60
2018/19	762	0	0	0	762	476	286	60	0	286	60
2019/20	762	0	0	0	762	477	285	60	0	285	60

[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)
				Fuel		Fuel Transportation		Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate (kW)	Summer (MW)	Winter (MW)	Status
Purdom	CT-1	Wakulla	GT	NG	DFO	PL	TK	NA	12/63	3/11	15000	-10	-10	RT
Purdom	CT-2	Wakulla	GT	NG	DFO	PL	TK	NA	5/64	3/11	15000	-10	-10	RT
Purdom	7	Wakulla	ST	NG	RFO	PL	WA	NA	6/66	3/11	50000	-48	-48	RT
Hopkins	CT-1	Leon	GT	NG	DFO	PL	TK	NA	2/70	3/15	16320	-12	-14	RT
Hopkins	CT-2	Leon	GT	NG	DFO	PL	TK	NA	9/72	3/17	27000	-24	-26	RT

Acronyms

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

Table 3.3

City Of Tallahassee

Generation Expansion Plan

	Load Forecast & Adjustments										
Year	Forecast 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
2010	620	15	605	794		11			805	33	[6]
2011	627	35	592	726	[3]	11			737	24	
2012	634	50	584	726		11			737	26	
2013	640	68	572	726		11			737	29	
2014	646	85	561	726		11			737	31	
2015	652	97	555	714	[4]	11			725	31	
2016	660	108	552	714		11			725	31	
2017	667	117	550	690	[5]				690	25	
2018	674	125	549	690					690	26	
2019	682	133	549	690					690	26	

Notes
[1] Demand Side Management includes energy efficiency and demand response/control measures. Identified as maximum achieveable reductions in the City's integrated resource planning (IRP) study completed in December 2006.
[2] *Firm imports include 11 MW purchase from Progress Energy Florida (formerly Florida Power Corporation).* Expires 12/3/2016.
[3] Purdom 7 and Purdom CTs 1 & 2 official retirement currently scheduled for March 2011.
[4] Hopkins CT 1 official retirement currently scheduled for March 2015.
[5] Hopkins CT 2 official retirement currently scheduled for March 2017.
[6] No City generation additions are projected in the 2010-2019 TYSP reporting period.

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Chapter IV

Proposed Plant Sites and Transmission Lines

4.1 PROPOSED PLANT SITE

As discussed in Chapter 3 the Citycurrently expects that no additional power supply resources will be required in the reporting period to meet future system needs (see Table 4.1).

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 majority of these improvements are planned to the City's 115kV transmission network.

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 in part by the lack of investment in facilities in the panhandle region as well as the impact of unscheduled power flow-through on the City's transmission system. The City is committed to continue to work with Progress and Southern as well as existing and prospective regulatory bodies in an effort to pursue improvements to the regional transmission systems that will allow the City to continue to provide reliable and affordable electric service to the citizens of Tallahassee in the future. The City will provide the FPSC with information regarding any such improvements as it becomes available.

Beyond assessing import and export capability, the City also conducts annual 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. These evaluations indicate that additional infrastructure projects are needed to address either (i) improvements in capability to deliver power from the Hopkins Plant (on the west side of the City's service territory) to the load center, or (ii) the strengthening of the system on the east side of the City's service territory to improve the voltage profile in that area and enhance response to contingencies.

For this TYSP, the City's most recent transmission system expansion planning studies indicate that, if the City's aggressive DSM portfolio does not perform as expected throughout the planning window, a 230 kV loop around the City would be necessary by summer 2016 to ensure reliable service consistent with current and anticipated FERC and NERC requirements. For this proposed transmission project, the City intends to tap its existing Hopkins-PEF Crawfordville 230kV transmission line and extend a 230 kV transmission line to the east terminating at the existing Substation BP-5 as the first phase of the project to be in service as early as summer 2012 (if DSM performance warrants), and then upgrade existing 115kV lines to 230 kV from Substation BP-5 to Substation BP-4 to Substation BP-7 as the second phase of the project completing the loop by summer 2016. This new 230 kV line would address a number of potential line overloads for the single contingency loss of other key transmission lines in the City's system. Possible locations for 230/115 kV transformation along the new 230 kV line include Substations BP-5 and/or BP-4. This transformation may be accomplished through the addition of a new autotransformer or the relocation of the second autotransformer currently planned for connection at Substation BP-7. Table 4.2 summarizes the proposed new facilities or improvements from the transmission planning study that are within this Ten Year Site Plan reporting period.

The City's budget planning cycle for FY 2011 is currently ongoing, and any revisions to project budgets in the electric utility will not be finalized until the summer of 2010. Some of the preliminary engineering and design work for the aforementioned 230 kV transmission projects has been authorized and is currently underway. If these improvements do not remain on the approved project list, or if other budget priorities result in the postponement of budgeted but not initiated projects, the City has prepared operating solutions to mitigate adverse system conditions that might occur as a result of the delay in the in-service date of these improvements.

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	No City generation additions are projected in the 2010-2019 TYSP reporting period.
(2)	Capacity a.) Summer: b.) Winter:	
(3)	Technology Type:	
(4)	Anticipated Construction Timing a.) Field Construction start - date: b.) Commercial in-service date:	
(5)	Fuel a.) Primary fuel: b.) Alternate fuel:	
(6)	Air Pollution Control Strategy:	
(7)	Cooling Status:	
(8)	Total Site Area:	
(9)	Construction Status:	
(10)	Certification Status:	
(11)	Status with Federal Agencies:	
(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):	
(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:	

Figure D-1 – Hopkins Plant Site

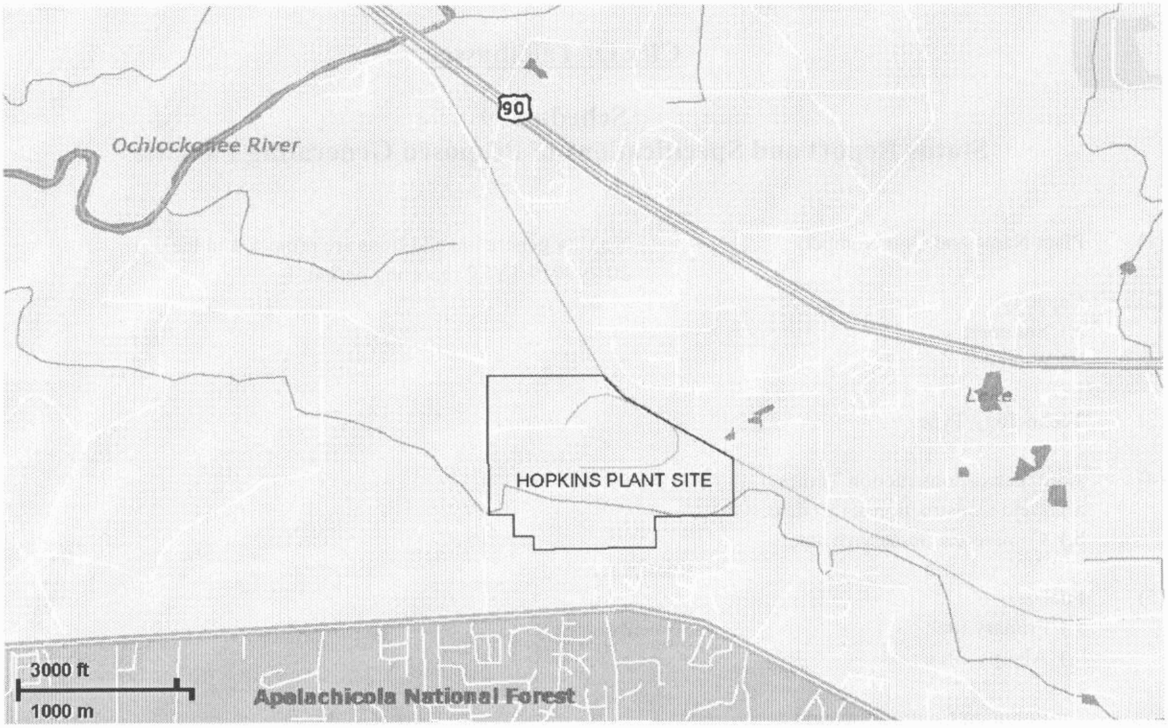
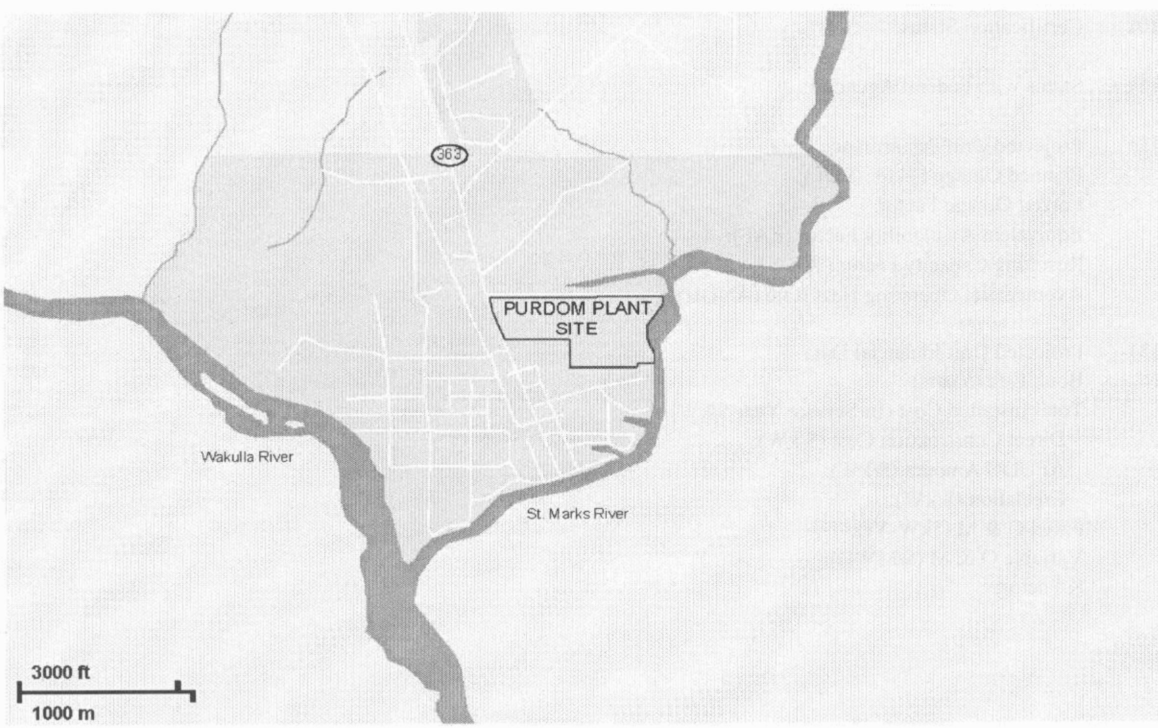


Figure D-2 – Purdom Plant Site



City Of Tallahassee

Planned Transmission Projects, 2010-2019

Project Type	Project Name	From Bus Name	From Bus Number	To Bus Name	To Bus Number	Expected In-Service Date	Voltage (kV)	Line Length (miles)
New Lines	Line 26	Sub 17	7517	Sub 14	7514	2/28/10	115	4.0
	Line 24	Sub 9	7509	Sub 21	7521	10/1/10	115	3.0
	Line 25	Sub 21	7521	Sub 17	7517	10/31/11	115	6.0
	Line 27	Sub 14	7514	Sub 7	7507	12/1/11	115	6.0
	230 Loop Phase I	Hopkins S	7610	Sub 5	7605	12/31/11	230	8.0
	230 Loop Phase II	Sub 5	7605	Sub 7	7607	6/1/16	230	12.8
Line Rebuild/ Reconductor	Line 7A	Hopkins	7550	Sub 10	7510	12/1/10	115	5.0
	Line 2C	Switch St	7553	Sub 5	7505	12/31/10	115	1.6
	Line 15C	Sub 9	7509	Sub 4	7504	9/30/12	115	4.0
	Line 15B	Sub 5	7505	Sub 9	7509	9/30/12	115	6.0
	Line 15A	Sub 5	7505	Sub 4	7504	9/30/12	115	9.0
Transformers	Sub 7 230/115 Auto	Sub 7 230	7607	Sub 7 115	7507	9/1/10	NA	NA
Interconnections	Talquin Woodville	SECI Woodville	7554	Woodville	7020	10/31/10	115	< 1.0
Substations	Sub 21 (Bus 7521)	NA	NA	NA	NA	12/1/10	115	NA
	Sub 14 (Bus 7514)	NA	NA	NA	NA	7/31/11	115	NA
	Sub 17 (Bus 7517)	NA	NA	NA	NA	1/31/12	115	NA
	Sub 22 (Bus 7522)	NA	NA	NA	NA	6/1/13	115	NA
	Sub 23 (Bus 7523)	NA	NA	NA	NA	9/30/13	115	NA

Table 4.2

City Of Tallahassee

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

(1)	Point of Origin and Termination:	Hopkins South - Substation 5
(2)	Number of Lines:	1
(3)	Right-of -Way:	TAL Owned and New Acquisitions
(4)	Line Length:	~ 10 miles
(5)	Voltage:	230 kV
(6)	Anticipated Capital Timing [1]:	Start - 2009 End - 2012
(7)	Anticipated Capital Investment:	$9.86 million
(8)	Substations:	Hopkins South (tap Hopkins-Crawfordville 230 kV) [2]
(9)	Participation with Other Utilities:	None

Notes

[1] Capital timing contemplated in FY 2009 budget for former target in service summer 2012.

[2] New substation to serve as origin for new 230 kV line to existing Substation 5.

City Of Tallahassee

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

(1)	Point of Origin and Termination:	Substation 5 - Substation 7
(2)	Number of Lines:	1
(3)	Right-of -Way:	TAL Owned and New Acquisitions
(4)	Line Length:	~ 13 miles
(5)	Voltage:	230 kV
(6)	Anticipated Capital Timing:	Not yet determined; target in service summer 2016
(7)	Anticipated Capital Investment:	Not yet determined
(8)	Substations:	None [1]
(9)	Participation with Other Utilities:	None

Notes

[1] Origin and termination of new line will be at existing Substations 5 and 7.

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APPENDIX A

SUPPLEMENTAL DATA

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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	9.60%	NA	3.70%	NA	86.43%	NA	NA
Corn	2	[1]	NA	9.60%	NA	3.70%	NA	86.43%	NA	NA
Corn	3	[1]	NA	9.60%	NA	3.70%	NA	86.43%	NA	NA
Hopkins	1		1.95%	5.03%	0.06%	2.97%	97.99%	91.39%	12,141	12,252
Hopkins	CC 2	[2]	4.93%	6.78%	1.91%	3.20%	93.16%	87.01%	8,053	7,972
Hopkins	GT-1		0.31%	4.40%	0.00%	5.24%	99.69%	87.55%	28,864	22,004
Hopkins	GT-2		0.99%	38.80%	0.06%	34.90%	98.95%	89.32%	30,242	18,873
Hopkins	GT-3		0.68%	4.71%	0.30%	3.31%	99.02%	90.24%	10,434	9,884
Hopkins	GT-4		0.53%	4.71%	0.21%	3.31%	99.26%	90.24%	10,457	9,853
Purdom	7		0.73%	5.03%	6.92%	2.97%	92.35%	91.39%	13,029	14,146
Purdom	8		7.26%	6.78%	1.98%	3.20%	90.75%	87.01%	7,624	7,445
Purdom	GT-1		0.14%	4.40%	0.06%	5.24%	99.80%	87.55%	30,453	28,936
Purdom	GT-2		0.14%	4.40%	0.01%	5.24%	99.85%	87.55%	30,982	28,936

Future Units

No City generation additions are projected in the 2010-2019 Ten Year Site Plan reporting period.

NOTES:
Historical - average of past three fiscal years
Projected - average of next ten fiscal years (Source: Peer unit data in 2003-2007 NERC Generating Availability Report (GAR))

[1] The City does not track the planned outage, forced outage or equivalent availability factors for the Corn Hydro units.
[2] Reflects available data for Hopkins 2 combined cycle (CC) which began operation in June 2008.

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]	2007	NA	NA	NA	54.80	870	-	NA	NA	NA
	2008	NA	NA	NA	57.91	919	5.7%	NA	NA	NA
	2009	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
Forecast	2010	NA	NA	NA	77.33	1227	31.8%	NA	NA	NA
	2011	NA	NA	NA	78.72	1249	1.8%	NA	NA	NA
	2012	NA	NA	NA	80.29	1274	2.0%	NA	NA	NA
	2013	NA	NA	NA	81.90	1300	2.0%	NA	NA	NA
	2014	NA	NA	NA	83.54	1326	2.0%	NA	NA	NA
	2015	NA	NA	NA	85.21	1352	2.0%	NA	NA	NA
	2016	NA	NA	NA	86.91	1380	2.0%	NA	NA	NA
	2017	NA	NA	NA	88.65	1407	2.0%	NA	NA	NA
	2018	NA	NA	NA	90.42	1435	2.0%	NA	NA	NA
	2019	NA	NA	NA	92.23	1464	2.0%	NA	NA	NA

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

[1] Actual average cost of oil burned.

Nominal, Delivered Residual Oil Prices
High Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Residual Oil (By Sulfur Content)								
		Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
	Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History [1]	2005	NA	NA	NA	54.80	870	-	NA	NA	NA
	2006	NA	NA	NA	57.91	919	5.7%	NA	NA	NA
	2007	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
Forecast [2]	2008	NA	NA	NA	77.33	1227	31.8%	NA	NA	NA
	2009	NA	NA	NA	80.65	1280	4.3%	NA	NA	NA
	2010	NA	NA	NA	84.28	1338	4.5%	NA	NA	NA
	2011	NA	NA	NA	88.07	1398	4.5%	NA	NA	NA
	2012	NA	NA	NA	92.04	1461	4.5%	NA	NA	NA
	2013	NA	NA	NA	96.18	1527	4.5%	NA	NA	NA
	2014	NA	NA	NA	100.51	1595	4.5%	NA	NA	NA
	2015	NA	NA	NA	105.03	1667	4.5%	NA	NA	NA
	2016	NA	NA	NA	109.76	1742	4.5%	NA	NA	NA
	2017	NA	NA	NA	114.69	1821	4.5%	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]	2005	NA	NA	NA	54.80	870	-	NA	NA	NA
	2006	NA	NA	NA	57.91	919	5.7%	NA	NA	NA
	2007	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
Forecast [2]	2008	NA	NA	NA	77.33	1227	31.8%	NA	NA	NA
	2009	NA	NA	NA	76.78	1219	-0.7%	NA	NA	NA
	2010	NA	NA	NA	76.40	1213	-0.5%	NA	NA	NA
	2011	NA	NA	NA	76.02	1207	-0.5%	NA	NA	NA
	2012	NA	NA	NA	75.64	1201	-0.5%	NA	NA	NA
	2013	NA	NA	NA	75.26	1195	-0.5%	NA	NA	NA
	2014	NA	NA	NA	74.88	1189	-0.5%	NA	NA	NA
	2015	NA	NA	NA	74.51	1183	-0.5%	NA	NA	NA
	2016	NA	NA	NA	74.14	1177	-0.5%	NA	NA	NA
	2017	NA	NA	NA	73.77	1171	-0.5%	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 [2]			Natural Gas [3]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2007	75.34	1293	-	834	8.61	-
	2008	70.44	1209	-6.5%	1,064	10.85	26.1%
	2009	108.67	1866	54.3%	857	8.79	-19.0%
Forecast	2010	91.80	1583	-15.2%	782	8.03	-8.7%
	2011	98.99	1707	7.8%	765	7.85	-2.2%
	2012	100.97	1741	2.0%	739	7.58	-3.4%
	2013	102.99	1776	2.0%	751	7.70	1.7%
	2014	105.05	1811	2.0%	772	7.92	2.7%
	2015	107.15	1847	2.0%	793	8.14	2.8%
	2016	109.29	1884	2.0%	815	8.36	2.7%
	2017	111.48	1922	2.0%	833	8.55	2.2%
	2018	113.71	1960	2.0%	852	8.74	2.2%
	2019	115.98	2000	2.0%	871	8.94	2.3%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.825 MMBtu/BBL;
ash content, sulfur content - Not Available

[1] Actual average cost of distillate oil and gas burned.
[2] Forecast values reflected expected prices for Gulf Coast Ultra Low Sulfur Diesel
[3] Delivered gas price reflects cost at Henry Hub increased by compression losses, basis and firm transportation cost.

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil [2]			Natural Gas [3]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2005	75.34	1299	-	834	8.67	-
	2006	70.44	1214	-6.5%	1,064	11.07	27.6%
	2007	108.67	1874	54.3%	857	8.91	-19.5%
Forecast [4]	2008	91.80	1583	-15.5%	782	8.13	-8.7%
	2009	101.28	1746	10.3%	784	8.16	0.3%
	2010	105.84	1825	4.5%	777	8.08	-0.9%
	2011	110.60	1907	4.5%	810	8.42	4.2%
	2012	115.58	1993	4.5%	852	8.86	5.2%
	2013	120.78	2082	4.5%	897	9.33	5.3%
	2014	126.22	2176	4.5%	944	9.82	5.2%
	2015	131.90	2274	4.5%	989	10.28	4.7%
	2016	137.83	2376	4.5%	1,036	10.77	4.7%
	2017	144.03	2483	4.5%	1,085	11.28	4.8%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.825 MMBtu/BBL;
ash content, sulfur content - Not Available

[1] Actual average cost of distillate oil and gas burned.
[2] Forecast values reflected expected prices for Gulf Coast Ultra Low Sulfur Diesel
[3] Delivered gas price reflects cost at Henry Hub increased by compression losses, basis and firm transportation cost.
[4] For the high case, compound annual escalation rates (CAER) are assumed to be 2.5% higher than the base case CAERs.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil [2]			Natural Gas [3]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2005	75.34	1299	-	834	8.67	-
	2006	70.44	1214	-6.5%	1,064	11.07	27.6%
	2007	108.67	1874	54.3%	857	8.91	-19.5%
Forecast [4]	2008	91.80	1583	-15.5%	782	8.13	-8.7%
	2009	96.69	1667	5.3%	745	7.75	-4.7%
	2010	96.21	1659	-0.5%	701	7.29	-5.9%
	2011	95.73	1650	-0.5%	695	7.23	-0.8%
	2012	95.25	1642	-0.5%	697	7.25	0.2%
	2013	94.77	1634	-0.5%	699	7.27	0.3%
	2014	94.30	1626	-0.5%	701	7.29	0.2%
	2015	93.83	1618	-0.5%	699	7.27	-0.3%
	2016	93.36	1610	-0.5%	697	7.25	-0.3%
	2017	92.89	1602	-0.5%	695	7.23	-0.2%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.825 MMBtu/BBL;
ash content, sulfur content - Not Available

[1] Actual average cost of distillate oil and gas burned.
[2] Forecast values reflected expected prices for Gulf Coast Ultra Low Sulfur Diesel
[3] Delivered gas price reflects cost at Henry Hub increased by compression losses, basis and firm transportation cost.
[4] For the low case, compound annual escalation rates (CAER) are assumed to be 2.5% lower than the base case CAERs.

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	2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2010	49.26	205	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	49.61	207	0.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	50.50	210	1.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	51.56	215	2.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	52.46	219	1.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	53.72	224	2.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	54.24	226	1.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	55.38	231	2.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2018	56.24	234	1.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2019	57.12	238	1.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA

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

[2] Average nominal delivered price per U.S. Energy Information Administration's 2010 Annual Energy Outlook.

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	2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2008	49.26	205	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	50.84	212	3.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	53.02	221	4.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	55.47	231	4.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	57.82	241	4.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	60.65	253	4.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	62.76	261	3.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	65.64	274	4.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	68.30	285	4.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	71.08	296	4.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA

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

[2] 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	2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2008	49.26	205	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	48.38	202	-1.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	48.03	200	-0.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	47.85	199	-0.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	47.49	198	-0.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	47.43	198	-0.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	46.71	195	-1.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	46.52	194	-0.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	46.08	192	-1.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	45.65	190	-0.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA

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

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

Nominal, Delivered Nuclear Fuel and Firm Purchases

	(1)	(2)	(3)	(4)	(5)
		Nuclear		Firm Purchases	
	Year	c/MBTU	Escalation %	$/MWh	Escalation %
History	2007	NA	NA	66.77	-
	2008	NA	NA	47.22	-29.3%
	2009	NA	NA	56.60	19.9%
Forecast	2010	NA	NA	58.76	3.8%
	2011	NA	NA	60.42	2.8%
	2012	NA	NA	62.14	2.8%
	2013	NA	NA	63.91	2.9%
	2014	NA	NA	65.74	2.9%
	2015	NA	NA	67.62	2.9%
	2016	NA	NA	70.66	4.5%
	2017	NA	NA	144.43	104.4%
	2018	NA	NA	148.04	2.5%
	2019	NA	NA	151.74	2.5%

[1] Forecast reflects projected firm purchases from Progress Energy Florida (through December 2016) and Talquin Electric Cooperative.

Financial Assumptions
Base Case

AFUDC RATE		5.25%	
CAPITALIZATION RATIOS:			
	DEBT	123.03%	[1]
	PREFERRED	N/A	[2]
	ASSETS	65.37%	[3]
	EQUITY	174.62%	[3]
RATE OF RETURN (6)			
	DEBT	0.71%	[4]
	PREFERRED	N/A	[2]
	ASSETS	0.38%	[5]
	EQUITY	1.01%	[5]
INCOME TAX RATE:			
	STATE	N/A	[6]
	FEDERAL	N/A	[6]
	EFFECTIVE	N/A	[6]
OTHER TAX RATE:			
Sales Tax (< $5,000)		7.00%	[7]
Sales Tax (> $5,000)		6.00%	[7]
DISCOUNT RATE:		2.75% - 5.25%	
TAX DEPRECIATION RATE:		N/A	[6]

[1] Plant-in-service compared to total debt
[2] No preferred "stock" in municipal utilities
[3] Net plant-in-service compared to total assets / net plant-in-service compared to total fund equity
[4] Net income compared to total debt
[5] Net income compared to total assets / net income compared to total fund equity
[6] Municipal utilities are exempt from income tax
[7] Municipal utilities are exempt from other taxes except Florida sales tax on expansion of electric transmission and distribution (T&D) tangible personal property used in the T&D system (7.0% on first $5,000 and 6% thereafter). Sales tax is no longer charged for T&D system maintenance.

Financial Escalation Assumptions

(1)	(2)	(3)	(4)	(5)
Year	General Inflation %	Plant Construction Cost %	Fixed O&M Cost %	Variable O&M Cost %
2010	2.5	2.5	2.5	2.5
2011	2.5	2.5	2.5	2.5
2012	2.5	2.5	2.5	2.5
2013	2.5	2.5	2.5	2.5
2014	2.5	2.5	2.5	2.5
2015	2.5	2.5	2.5	2.5
2016	2.5	2.5	2.5	2.5
2017	2.5	2.5	2.5	2.5
2018	2.5	2.5	2.5	2.5
2019	2.5	2.5	2.5	2.5

Monthly Peak Demands and Date of Occurrence for 2007 - 2009

Calendar Year 2007

Month	Date	Hour Ending	Daily Temp. (°F) Min.	Daily Temp. (°F) Max.	Peak Demand (MW)
January	29-Jan	8:00 A.M.	27	50	493
February	17-Feb	9:00 A.M.	18	61	504
March	28-Mar	5:00 P.M.	53	87	441
April	27-Apr	5:00 P.M.	63	85	464
May	22-May	6:00 P.M.	61	90	497
June	11-Jun	6:00 P.M.	65	101	576
July	18-Jul	5:00 P.M.	70	99	601
August	22-Aug	5:00 P.M.	75	99	621
September	6-Sep	5:00 P.M.	74	93	559
October	10-Oct	5:00 P.M.	70	91	512
November	1-Nov	6:00 P.M.	62	83	398
December	18-Dec	8:00 A.M.	31	57	437

Calendar Year 2008

Month	Date	Hour Ending	Daily Temp. (°F) Min.	Daily Temp. (°F) Max.	Peak Demand (MW)
January	3-Jan	8:00 A.M.	25	46	526
February	14-Feb	8:00 A.M.	25	64	510
March	25-Mar	8:00 A.M.	26	66	394
April	25-Apr	8:00 P.M.	62	84	430
May	29-May	6:00 P.M.	66	94	516
June	25-Jun	4:00 P.M.	70	96	548
July	21-Jul	5:00 P.M.	75	97	587
August	6-Aug	4:00 P.M.	73	98	556
September	15-Sep	5:00 P.M.	69	93	542
October	4-Oct	8:00 P.M.	53	87	520
November	19-Nov	8:00 A.M.	25	56	465
December	3-Dec	8:00 A.M.	27	59	468

Calendar Year 2009

Month	Date	Hour Ending	Daily Temp. (°F) Min.	Daily Temp. (°F) Max.	Peak Demand (MW)
January	22-Jan	8:00 A.M.	18	59	579
February	5-Feb	8:00 A.M.	14	51	578
March	4-Mar	8:00 A.M.	26	65	481
April	22-Apr	5:00 P.M.	52	91	415
May	11-May	6:00 P.M.	69	94	491
June	22-Jun	5:00 P.M.	76	103	605
July	2-Jul	4:00 P.M.	72	98	578
August	12-Aug	5:00 P.M.	74	95	569
September	24-Sep	6:00 P.M.	74	92	530
October	7-Oct	4:00 P.M.	74	94	539
November	2-Nov	8:00 P.M.	45	61	345
December	21-Dec	8:00 A.M.	28	56	465

Historical and Projected Heating and Cooling Degree Days

	Year	Heating Degree Days (HDD)	Cooling Degree Days (CDD)
History	2000	1,640	2,757
	2001	1,429	2,451
	2002	1,504	2,910
	2003	1,645	2,578
	2004	1,646	2,705
	2005	1,509	2,743
	2006	1,410	2,493
	2007	1,364	2,905
	2008	1,587	2,610
	2009	1,563	2,762
Forecast	2010	1,563	2,762
	2011	1,563	2,762
	2012	1,563	2,762
	2013	1,563	2,762
	2014	1,563	2,762
	2015	1,563	2,762
	2016	1,563	2,762
	2017	1,563	2,762
	2018	1,563	2,762
	2019	1,563	2,762

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	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	53.00	44.28	43.29	1.840
	2004	55.29	46.84	48.01	1.889
	2005	55.08	46.81	47.92	1.953
	2006	65.57	57.21	58.43	2.016
	2007	67.14	57.94	59.63	2.073
	2008	69.35	58.10	61.05	2.153
	2009	70.91	68.19	69.28	2.145
Forecast [2]	2010	70.91	68.19	69.28	
	2011	70.91	68.19	69.28	
	2012	70.91	68.19	69.28	
	2013	70.91	68.19	69.28	
	2014	70.91	68.19	69.28	
	2015	70.91	68.19	69.28	
	2016	70.91	68.19	69.28	
	2017	70.91	68.19	69.28	
	2018	70.91	68.19	69.28	
	2019	70.91	68.19	69.28	

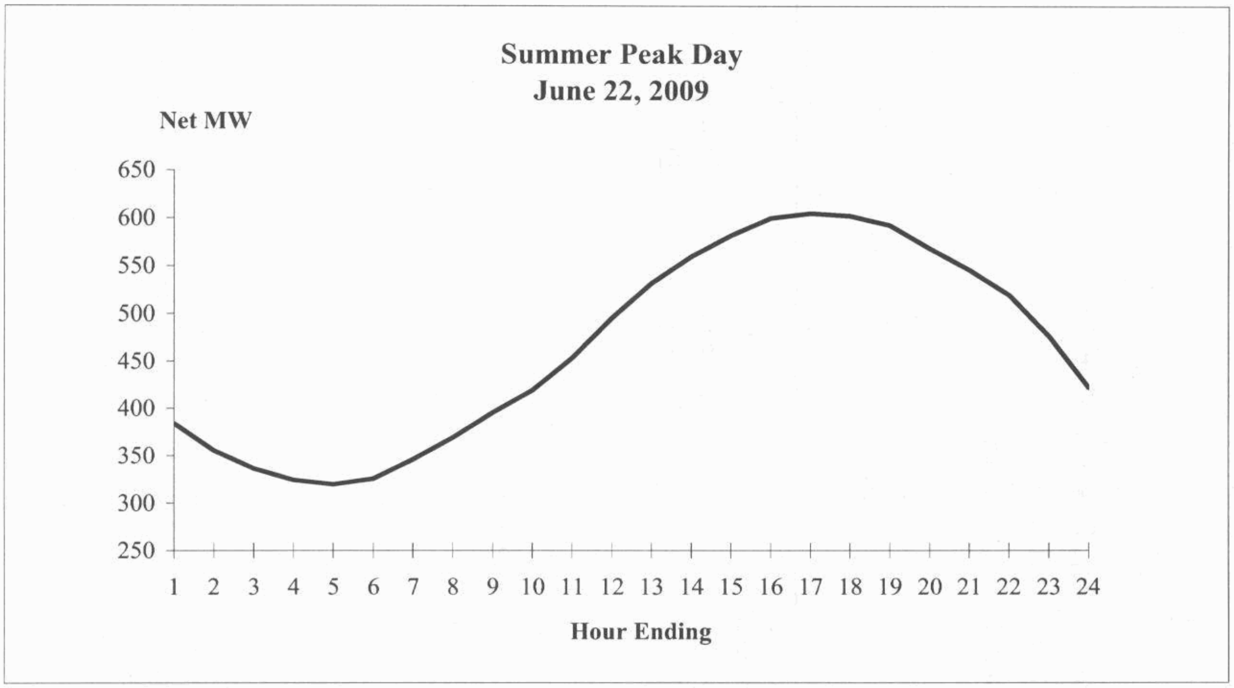
[1] Deflator is CPI Index per U. S. Dept. of Labor Bureau of Labor Stats. ('82 Dollars).

[2] For the City's 2010 Load Forecast, it was assumed that the future real price of electricity for commercial customers would remain constant at the 2009 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 operations and maintenance costs, and the effects of competition.

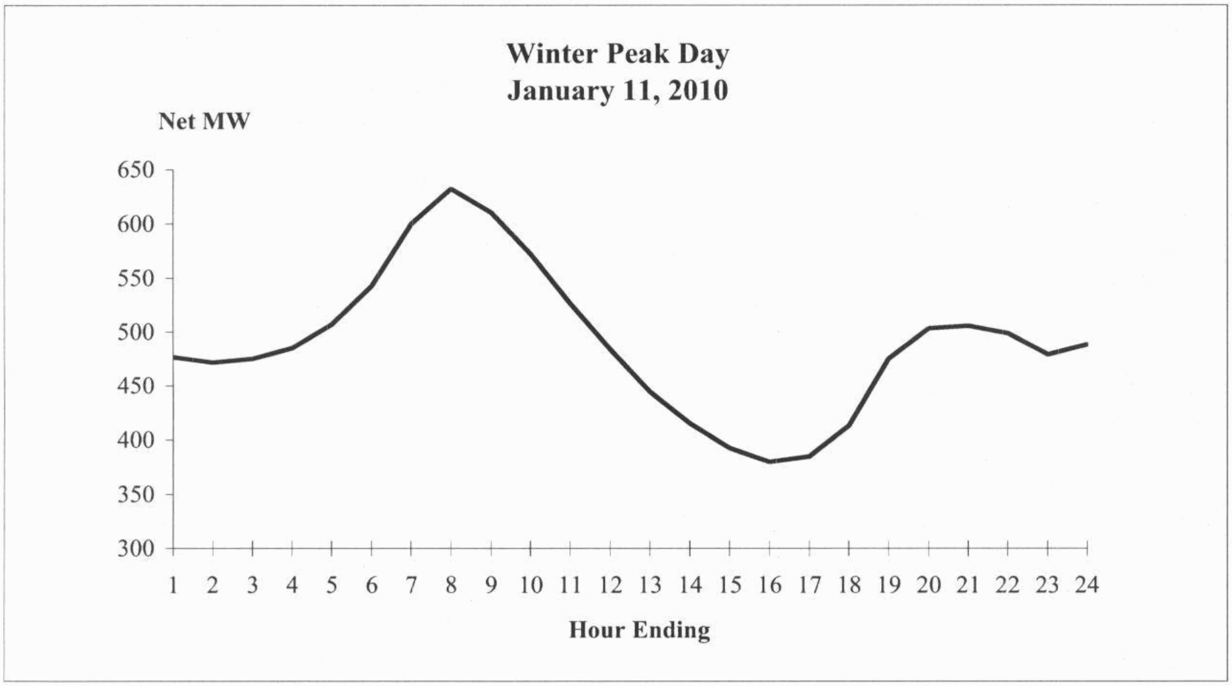
Loss of Load Probability, Reserve Margin, and Expected Unserved Energy
Base Case Load Forecast

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

[1] The City provides its projection of reserve margin with and without supply resource additions in Tables 3.1 and 3.2 (Schedules 7.1 and 7.2, respectively) on pages 43 and 44 and in Table 3.4 (Generation Expansion Plan) on page 45 of the City's 2008 Ten Year Site Plan. The City does not currently evaluate isolated and assisted LOLP and EUE reliability indices.



Hour Ending	Net Load (MW)	Hour Ending	Net Load (MW)
1	384	13	532
2	355	14	559
3	337	15	582
4	324	16	600
5	320	17	**605**
6	326	18	602
7	346	19	592
8	369	20	568
9	395	21	546
10	419	22	520
11	453	23	477
12	495	24	422



Hour Ending	Net Load (MW)	Hour Ending	Net Load (MW)
1	477	13	445
2	472	14	415
3	475	15	392
4	485	16	380
5	507	17	385
6	543	18	413
7	600	19	475
8	**633**	20	503
9	611	21	505
10	572	22	498
11	526	23	479
12	484	24	488