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State of Florida

Public Service Commission

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DATE: April 6, 2011

TO: Ann Cole, Commission Clerk, Office of Commission Clerk

FROM: Phillip O. Ellis, Engineering Specialist II, Division of Regulatory Analysis POE
Traci L. Matthews, Government Analyst I, Division of Regulatory Analysis

RE: City of Tallahassee's 2011 Ten-Year Site Plan

Attached is the City of Tallahassee's 2011 Ten-Year Site Plan, submitted on April 1, 2011, consistent with Rule 25-22.071, Florida Administrative Code (F.A.C.). Please place this item in Docket No. 110000 – Undocketed Filings for 2011, as it relates to the annual undocketed staff Ten-Year Site Plan Review project.

If you have any additional questions, please contact me.

POE

Attachment

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Ten Year Site Plan: 2011-2020

City of Tallahassee Utilities

Report prepared by: City of Tallahassee Electric Utility System Planning

ENERGY SMART PLUS™
SAVE ENERGY SAVE WATER SAVE MONEY

City of Tallahassee
Your Own Utilities℠

CITY OF TALLAHASSEE
TEN YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES
2011-2020
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III. Projected Facility Requirements

IV. Proposed Plant Sites and Transmission Lines

Appendix A

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 Utility presently serves approximately 113,700 customers located within a 221 square mile service territory (see Figure A). The Electric Utility 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.

The City's Hopkins 1 steam generating unit can be fired with natural gas, residual oil or both while the Purdom 7 steam unit can only be fired with natural gas. 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.

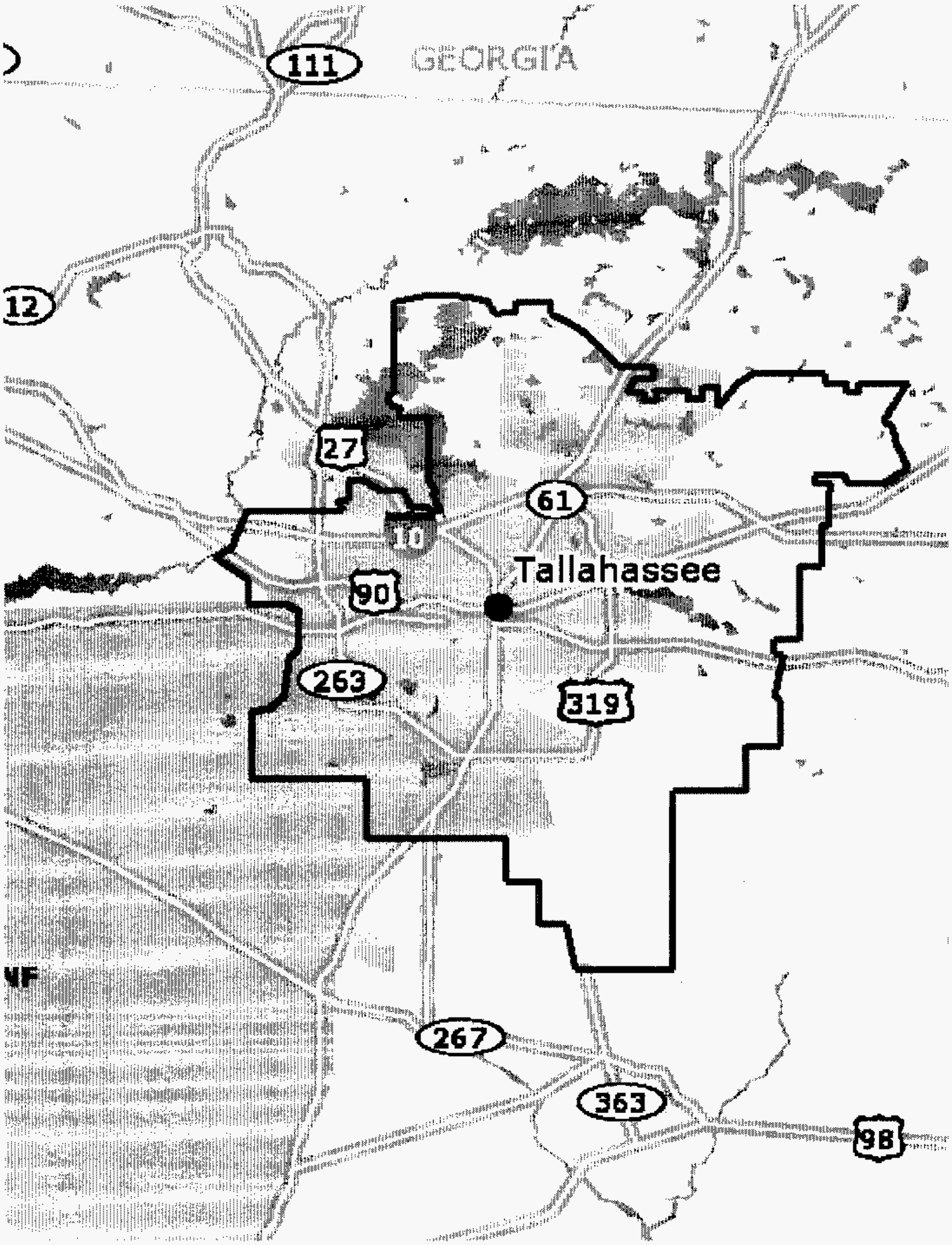
The City's total net summer installed generating capability is 794 MW. The corresponding winter net peak installed generating capability is 870 MW. Table 1.1 contains the details of the individual generating units.

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, 2010

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant	Unit No.	Location	Unit Type	Fuel Pri	Fuel Alt	Fuel Transport Primary	Fuel Transport Alternate	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate (kW)	Net Capability Summer (MW)	Net Capability Winter (MW)
Sam O. Purdom	7	Wakulla	ST	NG	NG	PL	PL	[1, 2]	6/66	3/12	50,000	48	48
	8		CC	NG	FO2	PL	TK	[2, 3]	7/00	12/40	247,743	222	258 [7]
	GT-1		GT	NG	FO2	PL	TK	[2, 3]	12/63	3/12	15,000	10	10
	GT-2		GT	NG	FO2	PL	TK	[2, 3]	5/64	3/12	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 [7]
	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, 201(			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 l 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 origin 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
- [7] Summer and winter ratings are based on 95°F and 29 °F ambient temperature, respectively.

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 not 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 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 2011 and the horizon year of 2020. 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 2010 - 2012 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 14% of the City's 2010 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 2011 base forecasts for these characteristics that are generally lower than the corresponding 2010 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 was 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 assessment is discussed in Chapter 3, Section 3.2.6, "Future Power Supply Resources".

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
Energy Efficiency Loan Program	Customized Loan Program
Gas New Construction Rebates	Energy Efficiency 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
Low Income Weatherization Assistance	Solar Net Metering Program
Energy Star Appliance Rebates	
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 City's last Integrated Resource Planning (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.

Implementation of portions of the City's DSM program was delayed by efforts to contract with an energy services provider to assist staff in deploying some measures. This contract is now in place and work is proceeding. Implementation of the City's demand response/direct load control (DR/DLC) measures has also been postponed as some of the technology is still evolving. 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 City's last 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 2010 TYSP. The revised projections reflect the City getting back on pace with the demand and energy savings contemplated in the City's last IRP Study by 2020. 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 2011-2020. Figure B4 displays the percentage of energy by fuel type in 2011 and 2020.

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
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	18,312	88,630
2006	272,648	-	1,097	92,017	11,927	1,604	18,533	86,548
2007	273,684	-	1,099	93,569	11,744	1,657	18,583	89,169
2008	274,926	-	1,054	94,640	11,132	1,626	18,597	87,433
2009	274,822	-	1,050	94,827	11,071	1,611	18,478	87,180
2010	275,593	-	1,136	95,268	11,928	1,618	18,426	87,812
2011	277,575	-	1,017	95,527	10,641	1,627	18,720	86,890
2012	279,569	-	1,016	96,356	10,544	1,636	18,815	86,966
2013	281,576	-	1,015	97,190	10,444	1,625	18,911	85,918
2014	283,600	-	1,015	98,031	10,356	1,611	19,008	84,762
2015	285,806	-	1,015	98,947	10,261	1,599	19,114	83,657
2016	288,313	-	1,013	99,987	10,136	1,588	19,234	82,586
2017	290,845	-	1,012	101,037	10,015	1,577	19,355	81,482
2018	293,402	-	1,011	102,097	9,898	1,567	19,477	80,447
2019	295,979	-	1,012	103,166	9,810	1,557	19,600	79,424
2020	298,501	-	1,013	104,212	9,724	1,545	19,721	78,361

[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

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)
2001	-	-	-		13		2,431
2002	-	-	-		13		2,588
2003	-	-	-		12		2,602
2004	-	-	-		14		2,682
2005	-	-	-		14		2,726
2006	-	-	-		15		2,716
2007	-	-	-		0		2,756
2008	-	-	-		0		2,679
2009	-	-	-		0		2,661
2010	-	-	-		0		2,754
2011	-	-	-		0		2,643
2012	-	-	-		0		2,652
2013	-	-	-		0		2,640
2014	-	-	-		0		2,626
2015	-	-	-		0		2,614
2016	-	-	-		0		2,602
2017	-	-	-		0		2,589
2018	-	-	-		0		2,577
2019	-	-	-		0		2,569
2020	-	-	-		0		2,559

[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]
2001	0	125	2,556	0	97,336
2002	0	165	2,753	0	97,986
2003	0	153	2,755	0	99,508
2004	0	159	2,841	0	102,764
2005	0	164	2,890	0	107,780
2006	0	154	2,870	0	110,550
2007	0	158	2,914	0	112,151
2008	0	154	2,834	0	113,237
2009	0	144	2,805	0	113,305
2010	0	177	2,931	0	113,693
2011	0	157	2,800	0	114,247
2012	0	158	2,810	0	115,171
2013	0	157	2,797	0	116,101
2014	0	156	2,782	0	117,039
2015	0	155	2,770	0	118,061
2016	0	155	2,757	0	119,221
2017	0	154	2,743	0	120,391
2018	0	153	2,731	0	121,574
2019	0	153	2,721	0	122,766
2020	0	152	2,711	0	123,933

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

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

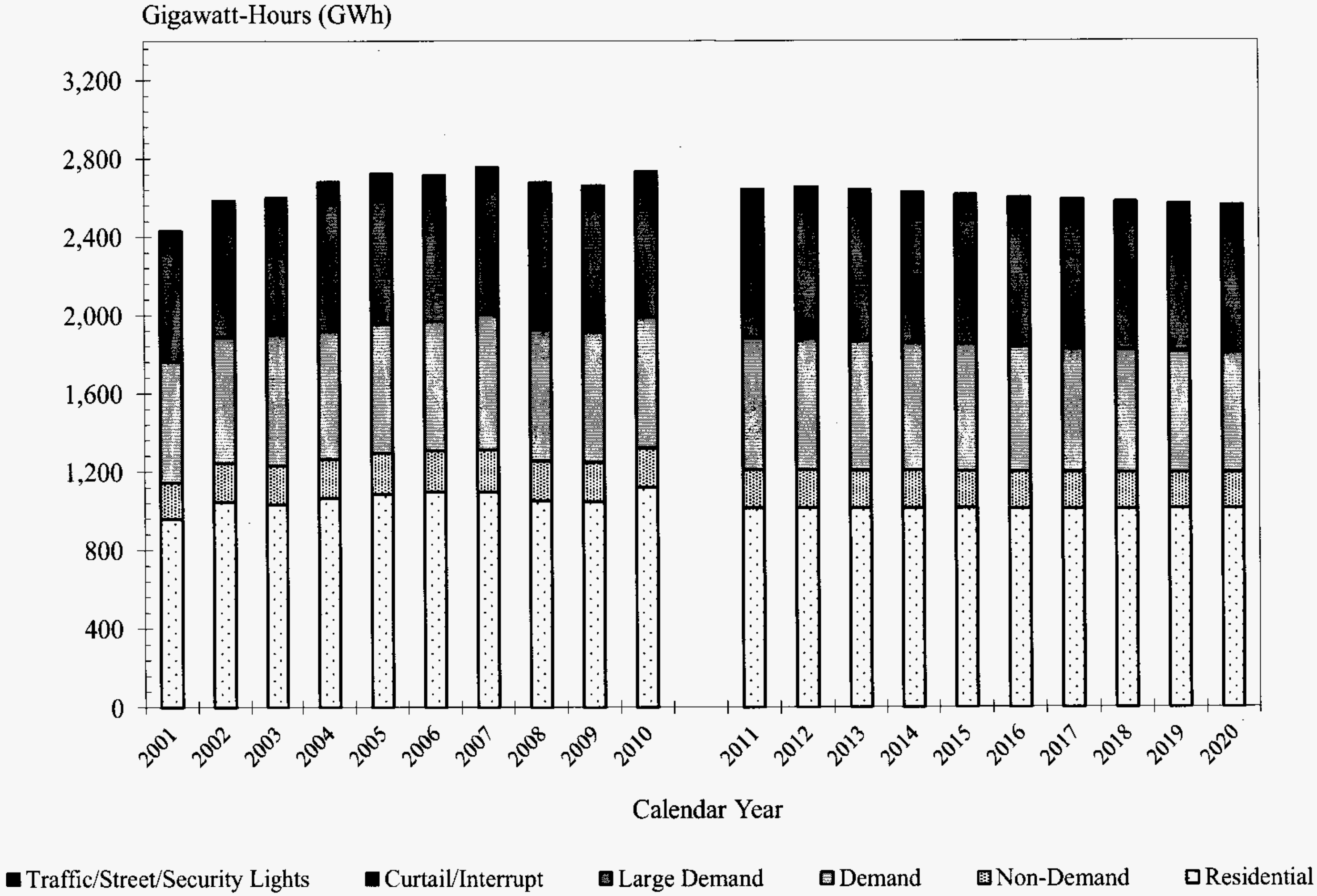
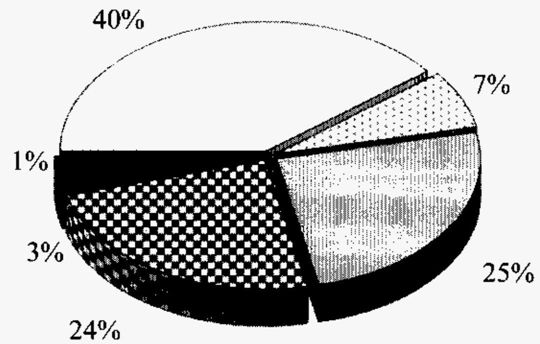


Figure B1

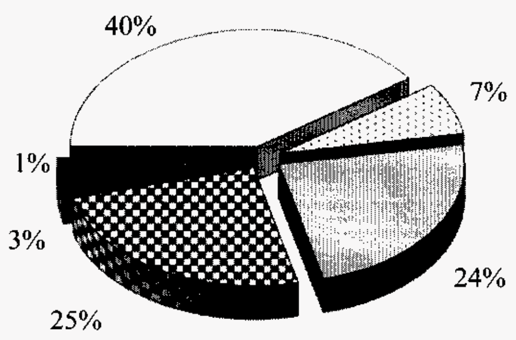
Energy Consumption By Customer Class
(Excluding DSM Impacts)

Calendar Year 2011



Total 2011 Sales = 2,694 GWh

Calendar Year 2020



Total 2020 Sales = 2,945 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]
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	605		605						605
2010	602		602		0	1	0	0	601
2011	608		608		5	6	7	2	587
2012	615		615		19	8	18	4	566
2013	621		621		21	11	18	10	562
2014	626		626		23	13	18	16	556
2015	632		632		26	15	18	22	550
2016	638		638		26	17	19	30	547
2017	645		645		26	20	19	38	541
2018	651		651		26	23	19	47	536
2019	658		658		26	26	19	54	532
2020	665		665		27	30	20	60	529

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2010 DSM is actual at peak.
[3] 2010 values reflect incremental increase from 2009.

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]
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	605		605						605
2010	602		602		0	1	0	0	601
2011	621		621		5	6	7	2	600
2012	633		633		19	8	18	4	584
2013	642		642		21	11	18	10	583
2014	652		652		23	13	18	16	582
2015	661		661		26	15	18	23	579
2016	672		672		26	17	19	29	581
2017	683		683		26	20	19	38	579
2018	694		694		26	23	19	46	579
2019	705		705		26	26	19	53	579
2020	716		716		27	30	20	60	580

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2010 DSM is actual at peak.
[3] 2010 values reflect incremental increase from 2009.

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]
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	605		605						605
2010	602		602		0	1	0	0	601
2011	595		595		5	6	7	1	574
2012	598		598		19	8	18	4	549
2013	600		600		21	11	18	10	541
2014	601		601		23	13	18	16	531
2015	603		603		26	15	18	22	521
2016	605		605		26	17	19	29	514
2017	607		607		26	20	19	39	503
2018	610		610		26	23	19	46	495
2019	612		612		26	26	19	54	486
2020	614		614		27	30	20	60	478

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2010 DSM is actual at peak.
[3] 2010 values reflect incremental increase from 2009.

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], [3]	(7) Residential Conservation [2], [4]	(8) Comm./Ind Load Management [2], [3]	(9) Comm./Ind Conservation [2], [4]	(10) Net Firm Demand [1]
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	633		633						633
2010 -2011	586		586		0	2	0	0	584
2011 -2012	555		555		0	8	0	4	542
2012 -2013	560		560		0	11	0	10	540
2013 -2014	565		565		0	13	0	16	536
2014 -2015	570		570		0	15	0	22	533
2015 -2016	575		575		0	16	0	30	530
2016 -2017	581		581		0	18	0	38	525
2017 -2018	587		587		0	20	0	43	524
2018 -2019	593		593		0	23	0	48	522
2019 -2020	599		599		0	26	0	52	521
2020 -2021	605		605		0	30	0	52	523

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2010 DSM is actual at peak.
[3] Reflects no expected utilization of demand response (DR) resources in winter. Winter DR capability presented in Table 2.17.
[4] 2010 values reflect incremental increase from 2009.

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], [3]	(7) Residential Conservation [2], [4]	(8) Comm./Ind Load Management [2], [3]	(9) Comm./Ind Conservation [2], [4]	(10) Net Firm Demand [1]
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	633		633						633
2010 -2011	586		586		0	2	0	0	584
2011 -2012	570		570		0	8	0	5	557
2012 -2013	579		579		0	11	0	10	559
2013 -2014	587		587		0	13	0	17	558
2014 -2015	596		596		0	15	0	22	559
2015 -2016	606		606		0	16	0	29	561
2016 -2017	616		616		0	18	0	37	560
2017 -2018	625		625		0	20	0	43	562
2018 -2019	635		635		0	23	0	48	564
2019 -2020	645		645		0	26	0	52	567
2020 -2021	655		655		0	30	0	52	573

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2010 DSM is actual.
[3] Reflects no expected utilization of demand response (DR) resources in winter. Winter DR capability presented in Table 2.17.
[4] 2010 values reflect incremental increase from 2009.

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], [3]	(7) Residential Conservation [2], [4]	(8) Comm./Ind Load Management [2], [3]	(9) Comm./Ind Conservation [2], [4]	(10) Net Firm Demand [1]
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	633		633						633
2010 -2011	586		586		0	2	0	0	584
2011 -2012	539		539		0	8	0	5	525
2012 -2013	541		541		0	11	0	9	522
2013 -2014	542		542		0	13	0	17	512
2014 -2015	543		543		0	15	0	22	506
2015 -2016	545		545		0	16	0	30	500
2016 -2017	547		547		0	18	0	38	491
2017 -2018	549		549		0	20	0	43	486
2018 -2019	551		551		0	23	0	49	479
2019 -2020	553		553		0	26	0	52	475
2020 -2021	555		555		0	30	0	52	473

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2010 DSM is actual.
[3] Reflects no expected utilization of demand response (DR) resources in winter. Winter DR capability presented in Table 2.17.
[4] 2010 values reflect incremental increase from 2009.

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]
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	53
2004	2,682			2,682		159	2,841	57
2005	2,726			2,726		164	2,890	62
2006	2,716			2,716		154	2,870	57
2007	2,756			2,756		158	2,914	54
2008	2,679			2,679		154	2,834	55
2009	2,661			2,661		144	2,805	53
2010	2,767	12	1	2,754		177	2,931	56
2011	2,694	44	7	2,643		157	2,800	54
2012	2,727	56	19	2,652		158	2,810	57
2013	2,752	69	43	2,640		157	2,797	57
2014	2,775	80	69	2,626		156	2,782	57
2015	2,800	93	93	2,614		155	2,770	57
2016	2,829	109	118	2,602		155	2,757	58
2017	2,857	125	144	2,589		154	2,743	58
2018	2,886	141	168	2,577		153	2,731	58
2019	2,916	154	193	2,569		153	2,721	58
2020	2,945	167	219	2,559		152	2,711	59

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2010 DSM is actual.
[3] 2010 values reflect incremental increase from 2009.

Table 2.10

City Of Tallahassee

Schedule 3.3.2
History and Forecast of Annual Net Energy for Load
High 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]
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	53
2004	2,682			2,682		159	2,841	57
2005	2,726			2,726		164	2,890	62
2006	2,716			2,716		154	2,870	57
2007	2,756			2,756		158	2,914	54
2008	2,679			2,679		154	2,834	55
2009	2,661			2,661		144	2,805	53
2010	2,767	12	1	2,754		177	2,931	56
2011	2,754	44	7	2,703		161	2,864	54
2012	2,805	56	19	2,730		163	2,892	57
2013	2,846	69	43	2,734		162	2,897	57
2014	2,887	80	69	2,738		163	2,901	57
2015	2,931	93	93	2,745		163	2,908	57
2016	2,978	109	118	2,751		164	2,915	57
2017	3,026	125	144	2,758		164	2,922	58
2018	3,073	141	168	2,765		164	2,929	58
2019	3,123	154	193	2,776		165	2,941	58
2020	3,172	167	219	2,786		166	2,952	58

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2010 DSM is actual.
[3] 2010 values reflect incremental increase from 2009.

Table 2.11

City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total Sales	Residential Conservation [2], [3]	Comm./Ind Conservation [2], [3]	Retail Sales [1]	Wholesale	Utility Use & Losses	Net Energy for Load [1]	Load Factor % [1]
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	53
2004	2,682			2,682		159	2,841	57
2005	2,726			2,726		164	2,890	62
2006	2,716			2,716		154	2,870	57
2007	2,756			2,756		158	2,914	54
2008	2,679			2,679		154	2,834	55
2009	2,661			2,661		144	2,805	53
2010	2,767	12	1	2,754		177	2,931	56
2011	2,634	44	7	2,584		154	2,737	54
2012	2,650	56	19	2,575		153	2,728	57
2013	2,658	69	43	2,546		151	2,698	57
2014	2,664	80	69	2,515		149	2,665	57
2015	2,671	93	93	2,485		148	2,632	58
2016	2,681	109	118	2,454		146	2,600	58
2017	2,690	125	144	2,422		144	2,566	58
2018	2,701	141	168	2,392		142	2,534	58
2019	2,711	154	193	2,364		141	2,505	59
2020	2,719	167	219	2,333		139	2,472	59

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2010 DSM is actual.
[3] 2010 values reflect incremental increase from 2009.

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)
	2010 Forecast [1]		2011 Forecast [1][2]		2012 Forecast [1]	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	633	258	539	236	542	237
February	542	226	508	208	511	209
March	476	207	420	202	422	202
April	399	200	423	200	425	201
May	526	246	520	235	523	235
June	581	277	587	271	566	272
July	601	290	587	277	566	278
August	580	296	579	275	566	276
September	557	271	553	259	556	260
October	483	214	524	220	526	220
November	376	194	373	194	375	195
December	539	253	458	223	460	224
TOTAL		2,931		2,800		2,810

[1] Peak Demand and NEL include DSM Impacts.
[2] Represents forecast values for 2011.

City of Tallahassee, Florida

2011 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	0.925
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 Consumption	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.

Table 2.14

City of Tallahassee

2011 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

Ten Year Site Plan
April 2011
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Banded Summer Peak Load Forecast Vs. Supply Resources
(Load Includes 17% Reserve Margin)

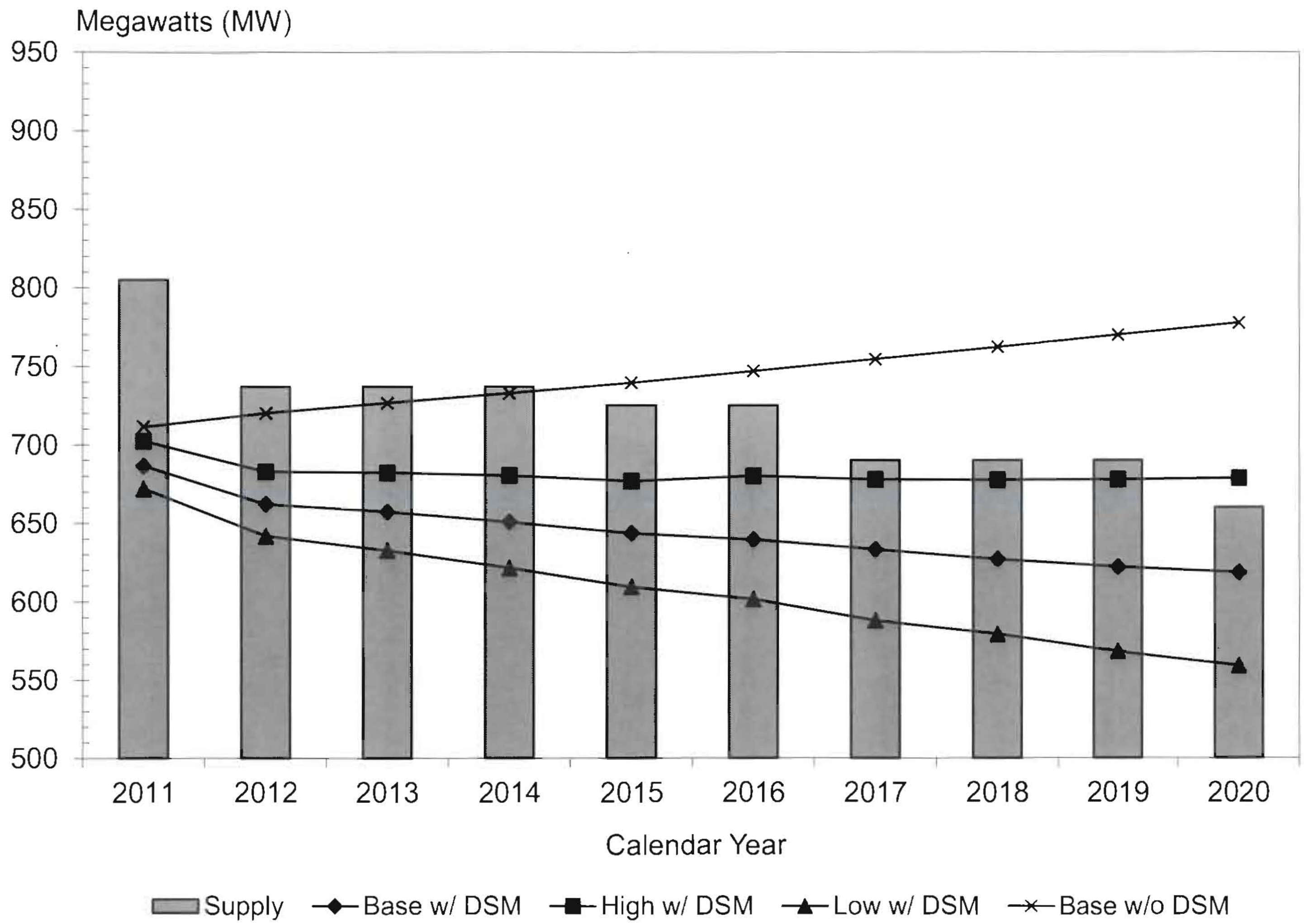


Figure B3

City Of Tallahassee

2011 Electric System Load Forecast

Projected Demand Side Management Energy Reductions [1]

Calendar Year Basis

Year	Residential Impact (MWh)	Commercial Impact (MWh)	Total Impact (MWh)
2011	46,647	7,270	53,917
2012	59,366	19,643	79,009
2013	72,687	45,731	118,418
2014	84,948	72,879	157,827
2015	98,269	98,968	197,237
2016	115,135	125,113	240,248
2017	132,001	152,318	284,320
2018	148,868	178,464	327,331
2019	162,923	204,666	367,589
2020	176,978	231,927	408,905

[1] Reductions estimated at busbar.

City Of Tallahassee

2011 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 [2] (MW)	Summer (MW)	Winter [2] (MW)	Summer (MW)	Winter (MW)
2011	2011-2012	6	8	2	4	5	19	7	18	21	49
2012	2012-2013	8	11	4	10	19	21	18	18	49	59
2013	2013-2014	11	13	10	16	21	23	18	18	59	70
2014	2014-2015	13	15	16	22	23	26	18	18	70	82
2015	2015-2016	15	16	22	30	26	26	18	19	82	91
2016	2016-2017	17	18	30	38	26	26	19	19	92	101
2017	2017-2018	20	20	38	43	26	26	19	19	104	109
2018	2018-2019	23	23	47	48	26	26	19	19	115	117
2019	2019-2020	26	26	54	52	26	26	19	20	126	124
2020	2020-2021	30	30	60	52	27	26	20	20	136	128

[1] Reductions estimated at busbar.

[2] Represents projected winter peak reduction capability associated with demand response (DR) resource. However, as reflected on Schedules 3.1.1-3.2.3 (Tables 2.4-2.9), DR utilization expected to be predominantly in the summer months.

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 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(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	0	12	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	12	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	9	8	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	9	2	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	0	6	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	20,677	21,282	20,231	20,231	20,754	20,711	20,428	20,424	20,835	20,796	20,639	20,526
(14)		Steam	1000 MCF	1,583	2,497	765	765	1,126	1,223	775	918	1,041	766	1,029	314
(15)		CC	1000 MCF	17,668	18,265	18,832	18,832	18,850	18,468	19,173	18,910	19,044	19,340	18,991	18,563
(16)		CT	1000 MCF	1,426	519	634	634	778	1,020	480	596	750	690	619	1,649
(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 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Annual Firm Interchange		GWh	99	100	118	119	119	120	120	113	25	25	25	30
(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	0	6	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWh	0	6	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	4	3	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	4	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	0	3	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	2,612	2,614	2,698	2,716	2,694	2,678	2,673	2,667	2,723	2,721	2,701	2,687
(15)		Steam	GWh	122	191	64	59	99	109	68	81	92	68	90	28
(16)		CC	GWh	2454	2378	2568	2569	2521	2469	2555	2524	2553	2581	2547	2486
(17)		CT	GWh	37	45	66	88	74	100	50	62	78	72	64	173
(18)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Hydro		GWh	21	20	18	18	18	18	18	16	18	18	18	18
(20)	Economy Interchange[1]		GWh	64	188	-34	-43	-34	-34	-41	-39	-23	-33	-23	-24
(21)	Renewables		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(22)	Net Energy for Load		GWh	2,801	2,931	2,800	2,810	2,797	2,782	2,770	2,757	2,743	2,731	2,721	2,711

[1] Negative values reflect expected need to sell off-peak power to satisfy generator minimum load requirements, primarily in shoulder mont

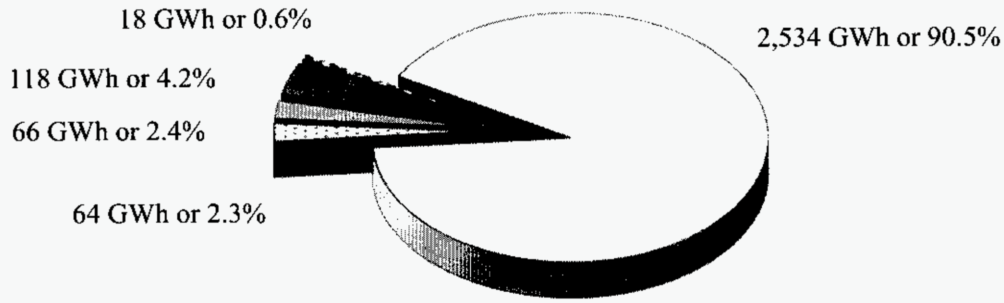
City Of Tallahassee

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 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Annual Firm Interchange		%	3.5	3.4	4.2	4.2	4.3	4.3	4.3	4.1	0.9	0.9	0.9	1.1
(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	%	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		Steam	%	0.0	0.2	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	%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CC	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		CT	%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	Total	%	93.3	89.2	96.4	96.7	96.3	96.3	96.5	96.7	99.3	99.6	99.3	99.1
(15)		Steam	%	4.4	6.5	2.3	2.1	3.5	3.9	2.5	2.9	3.4	2.5	3.3	1.0
(16)		CC	%	87.6	81.1	91.7	91.4	90.1	88.7	92.2	91.5	93.1	94.5	93.6	91.7
(17)		CT	%	1.3	1.5	2.4	3.1	2.6	3.6	1.8	2.2	2.8	2.6	2.4	6.4
(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		%	0.8	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
(20)	Economy Interchange		%	2.3	6.4	-1.2	-1.5	-1.2	-1.2	-1.5	-1.4	-0.8	-1.2	-0.8	-0.9
(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

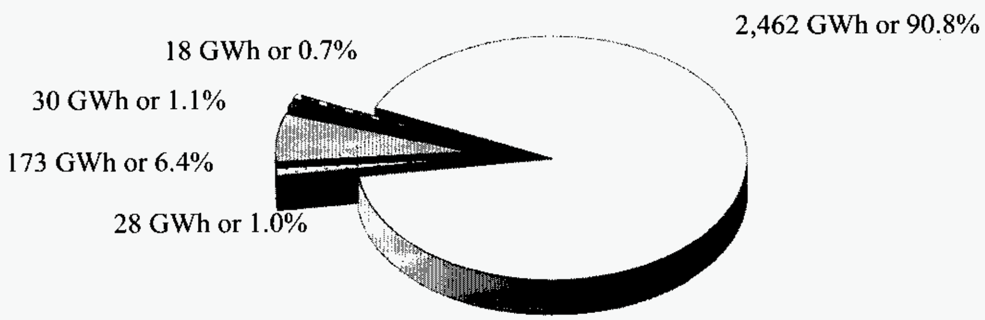
Generation By Resource/Fuel Type

Calendar Year 2011



Total 2011 NEL = 2,800 GWh

Calendar Year 2020



Total 2020 NEL = 2,711 GWh

CC - Gas | Steam - Gas | CT/Diesel - Gas | Firm Purchase | Hydro

Chapter III

Projected Facility Requirements

3.1 PLANNING PROCESS

In December 2006 the City completed its last comprehensive 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 IRP Study was a detailed analysis of how the DSM and power supply alternatives perform under base and alternative assumptions.

As reported in the 2010 TYSP, the resource plan identified in the 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 its resource plan. These revisions will be discussed in this chapter.

3.2 PROJECTED RESOURCE REQUIREMENTS

3.2.1 TRANSMISSION LIMITATIONS

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. To satisfy load, planning reserve and operational requirements in the reporting period, the City may need to advance the in-service date of 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 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 Recent and 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.

No new resource additions are expected to be needed in the near term (2011-2015). Resource additions expected in the longer term (2016-2020) are discussed in Section 3.2.6, "Future Power Supply Resources".

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. 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.

Another important consideration in the City's planning process is the number and diversity of power supply resources in terms of their sizes and expected duty cycles. To satisfy electric system requirements the City must not only assess the adequacy of its total capability of power supply resources but also must evaluate the appropriate mix of those resources. Currently, about two-thirds of the City's power supply comes from two generating units, Purdom 8 and Hopkins 2. The outage of either of these units can present operational challenges especially when coupled with transmission limitations (as discussed in Section 3.2.1). For this reason the City intends to evaluate alternative or supplemental metrics to its current load reserve margin criterion that may better balance resource adequacy and operational needs with utility and customer costs. An update of the City's efforts in this regard will be provided in a future TYSP report(s).

Purchase contracts can provide some of the diversity desired in the City's power supply resource portfolio. The City's last IRP Study evaluated both short and long-term purchased power options based on conventional sources as well as power offers based on renewable resources. A consultant-assisted study completed in 2008 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 that, 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.

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 2010 the City has a portfolio of 81 kW of solar PV operated and maintained by the Electric Utility and a cumulative total of 859 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.

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 a local site may well face public opposition. The original target in service date for the RFT facility was to be October 1, 2010. The condition of the financial market in recent years has slowed the project as RFT has continued to seek the remaining financing requirements. While the contract remains in effect the RFT developers have assigned the contract to Ecosphere LLC for financing and development and the expected in-service date has been amended to December 31, 2013. Because of the 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.

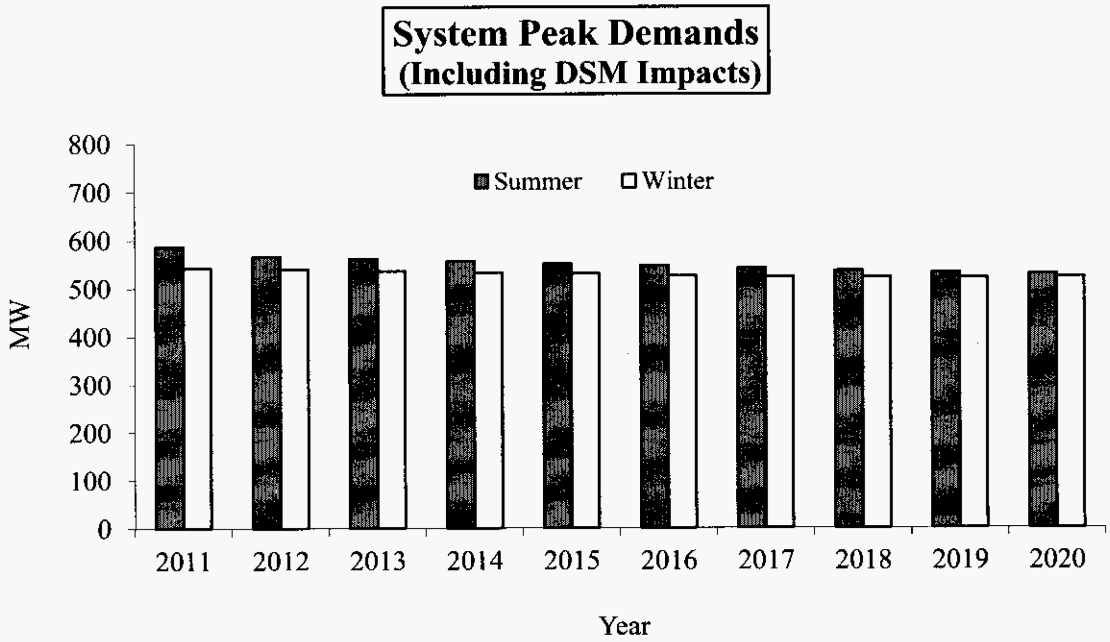
3.2.6 FUTURE POWER SUPPLY RESOURCES

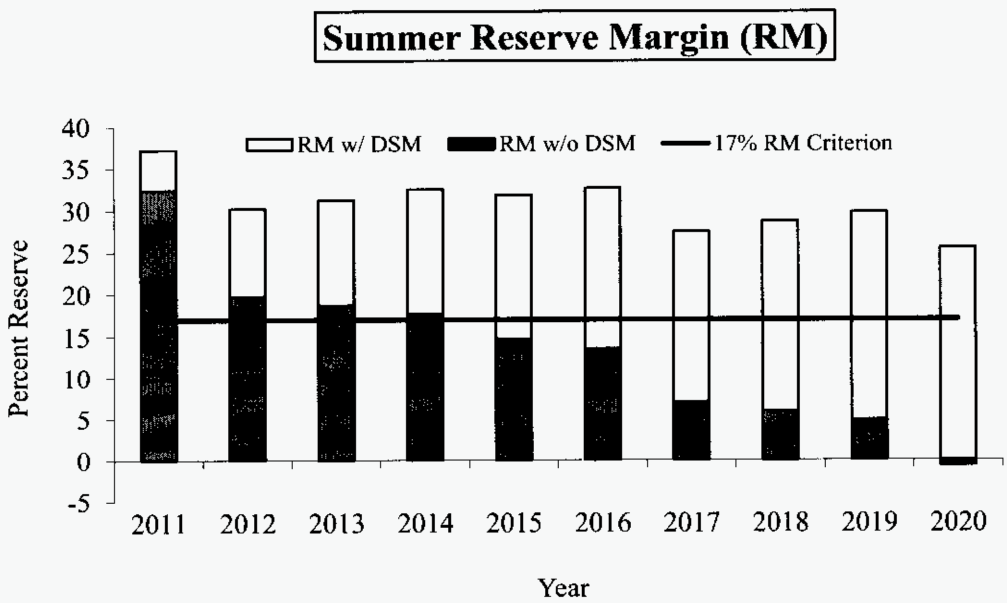
The City currently projects that, following the retirement of Hopkins 1, additional power supply resources will be needed by the summer of 2020 to maintain electric system adequacy and reliability. For the purposes of this report, the City has identified the addition of a GE LM 6000 combustion turbine generator (similar to the City's existing Hopkins CT3 and CT4) at its existing Hopkins Plant site. The timing, site, type and size of this new power supply resource may vary as the nature of the need becomes better defined. Alternatively, this proposed addition could be a generator(s) of a different type/size at the same or different location or a peak season purchase. The suitability of 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 capacity associated with the C.H. Corn Hydroelectric Station or RFT renewable energy purchase agreement toward meeting the City's planning reserve requirement. 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).

Following the extended periods of extremely low temperatures observed during 2009/10 winter season the City initiated an effort to produce an extreme winter peak demand sensitivity forecast. The purpose of this sensitivity forecast was 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. The City had sufficient capacity to serve the 633 MW peak demand experienced on January 11, 2010 (a 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. A comparison of the winter capabilities of the City's power supply resources with the winter peak demand sensitivity forecast has indicated no change in the timing of the City's next capacity need. 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, absent any other considerations the City would need no additional resources to meet planning reserve requirements until the summer of 2030. 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)
Summer
Winter
800
700
600
500
400
300
200
100
0
MW
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Year


Summer Reserve Margin (RM)
RM w/ DSM
RM w/o DSM
17% RM Criterion
40
35
30
25
20
15
10
5
0
-5
Percent Reserve
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
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
2011	794	11	0	0	805	587	218	37	0	218	37
2012	726	11	0	0	737	566	171	30	0	171	30
2013	726	11	0	0	737	562	175	31	0	175	31
2014	726	11	0	0	737	556	181	32	0	181	32
2015	714	11	0	0	725	550	175	32	0	175	32
2016	714	11	0	0	725	547	178	33	0	178	33
2017	690	0	0	0	690	541	149	27	0	149	27
2018	690	0	0	0	690	536	154	29	0	154	29
2019	690	0	0	0	690	532	158	30	0	158	30
2020	660	0	0	0	660	529	131	25	0	131	25

[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
2011/12	870	11	0	0	881	542	339	63	0	339	63
2012/13	802	11	0	0	813	540	273	51	0	273	51
2013/14	802	11	0	0	813	536	277	52	0	277	52
2014/15	802	11	0	0	813	533	280	53	0	280	53
2015/16	788	11	0	0	799	530	269	51	0	269	51
2016/17	788	0	0	0	788	525	263	50	0	263	50
2017/18	762	0	0	0	762	524	238	46	0	238	46
2018/19	762	0	0	0	762	522	240	46	0	240	46
2019/20	762	0	0	0	762	521	241	46	0	241	46
2020/21	732	0	0	0	732	523	209	40	0	209	40

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

City Of Tallahassee

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Net Capability		
	Unit		Unit	Fuel		Fuel Transportation		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Mo/Yr	Mo/Yr	Mo/Yr	(kW)	(MW)	(MW)	Status
Purdom	CT-1	Wakulla	GT	NG	DFO	PL	TK	NA	12/63	3/12	15,000	-10	-10	RT
Purdom	CT-2	Wakulla	GT	NG	DFO	PL	TK	NA	5/64	3/12	15,000	-10	-10	RT
Purdom	7	Wakulla	ST	NG	RFO	PL	WA	NA	6/66	3/12	50,000	-48	-48	RT
Hopkins	CT-1	Leon	GT	NG	DFO	PL	TK	NA	2/70	3/15	16,320	-12	-14	RT
Hopkins	CT-2	Leon	GT	NG	DFO	PL	TK	NA	9/72	3/17	27,000	-24	-26	RT
Hopkins	1	Leon	ST	NG	RFO	PL	TK	NA	5/71	3/20	75,000	-76	-78	RT
Hopkins	CT-5 [1]	Leon	GT	NG	DFO	PL	TK	NA	5/20	Unknown	60,500	46	48	P

[1] For the purposes of this report, the City has identified the addition of a GE LM 6000 combustion turbine generator (similar to the City's existing Hopkins CT3 and CT4) at its existing Hopkins Plant site. The timing, site, type and size of this new power supply resource may vary as the nature of the need becomes better defined. Alternatively, this proposed addition could be a generator(s) of a different type/size at the same or different location or a peak season purchase.

Acronyms

GT	Gas Turbine	Pri	Primary Fuel	kW	Kilowatts
ST	Steam Turbine	Alt	Alternate Fuel	MW	Megawatts
		NG	Natural Gas	RT	Existing generator scheduled for retirement.
		DFO	Diesel Fuel Oil	P	Planned for installation but not utility authorized. Not under construction.
		RFO	Residual Fuel Oil		
		PL	Pipeline		
		TK	Truck		

City Of Tallahassee

Generation Expansion Plan

Year	Load Forecast & Adjustments: 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
2011	608	21	587	794		11			805	37	
2012	615	49	566	726	[3]	11			737	30	
2013	621	59	562	726		11			737	31	
2014	626	70	556	726		11			737	32	
2015	632	82	550	714		11			725	32	
2016	638	92	547	714	[4]	11			725	33	
2017	645	104	541	690					690	27	
2018	651	115	536	690	[5]				690	29	
2019	658	126	532	690					690	30	
2020	665	136	529	614	[6]			46	660	25	[7]

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 ST 7 and Purdom CTs 1 and 2 official retirement currently scheduled for March 2012.

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

[5] Hopkins CT 2 official retirement currently scheduled for March 2017.

[6] Hopkins ST 1 official retirement currently scheduled for March 2020.

[7] For the purposes of this report, the City has identified the addition of a GE LM 6000 combustion turbine generator (similar to the City's existing Hopkins CT3 and CT4) at its existing Hopkins Plant site. The timing, site, type and size of this new power supply resource may vary as the nature of the need becomes better defined. Alternatively, this proposed addition could be a generator(s) of a different type/size at the same or different location or a peak season purchase.

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 for the City's 115 kV 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 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 230 kV 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 winter 2012/2013 (if DSM performance warrants), and then upgrade existing 115 kV 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 loop 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 2012 is currently ongoing, and any revisions to project budgets in the electric utility will not be finalized until the summer of 2011. 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:	Hopkins CT 5	[1]
(2)	Capacity		
	a.) Summer:	46	
	b.) Winter:	48	
(3)	Technology Type:	CT	
(4)	Anticipated Construction Timing		
	a.) Field Construction start - date:	Dec-18	
	b.) Commercial in-service date:	May-20	
(5)	Fuel		
	a.) Primary fuel:	NG	
	b.) Alternate fuel:	DFO	
(6)	Air Pollution Control Strategy:	BACT compliant	
(7)	Cooling Status:	Unknown	
(8)	Total Site Area:	Unknown	
(9)	Construction Status:	Not started	
(10)	Certification Status:	Not started	
(11)	Status with Federal Agencies:	Not started	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF):		
	Forced Outage Factor:		
	Equivalent Availability Factor (EAF):		
	Resulting Capacity Factor (%):	4.30%	[2]
	Average Net Operating Heat Rate (ANOHR):	9,815 Btu/kWh	[3]
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost (In-Service Year $/kW)	1216	[4]
	Direct Construction Cost ($/kW):	974	[5]
	AFUDC Amount ($/kW):	NA	
	Escalation ($/kW):	242	
	Fixed O & M ($kW-Yr):	6.98	[5]
	Variable O & M ($/MWH):	14.70	[5]
	K Factor:	NA	

Notes

[1] For the purposes of this report, the City has identified the addition of a GE LM 6000 combustion turbine generator (similar to the City's existing Hopkins CT3 and CT4) at its existing Hopkins Plant site. The timing, site, type and size of this new power supply resource may vary as the nature of the need becomes better defined. Alternatively, this proposed addition could be a generator(s) of a different type/size at the same or different location or a peak season purchase.

[2] Expected first year capacity factor.

[3] Expected full load average heat rate at 68°F.

[4] Estimated 2020 dollars.

[5] Estimated 2011 dollars.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Hopkins CT 5	[1]
(2)	Capacity		
	a.) Summer:	46	
	b.) Winter:	48	
(3)	Technology Type:	CT	
(4)	Anticipated Construction Timing		
	a.) Field Construction start - date:	Dec-18	
	b.) Commercial in-service date:	May-20	
(5)	Fuel		
	a.) Primary fuel:	NG	
	b.) Alternate fuel:	DFO	
(6)	Air Pollution Control Strategy:	BACT compliant	
(7)	Cooling Status:	Unknown	
(8)	Total Site Area:	Unknown	
(9)	Construction Status:	Not started	
(10)	Certification Status:	Not started	
(11)	Status with Federal Agencies:	Not started	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF):		
	Forced Outage Factor:		
	Equivalent Availability Factor (EAF):		
	Resulting Capacity Factor (%):	4.30%	[2]
	Average Net Operating Heat Rate (ANOHR):	9,815 Btu/kWh	[3]
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost (In-Service Year $/kW)	1216	[4]
	Direct Construction Cost ($/kW):	974	[5]
	AFUDC Amount ($/kW):	NA	
	Escalation ($/kW):	242	
	Fixed O & M ($kW-Yr):	6.98	[5]
	Variable O & M ($/MWH):	14.70	[5]
	K Factor:	NA	

Notes

[1] For the purposes of this report, the City has identified the addition of a GE LM 6000 combustion turbine generator (similar to the City's existing Hopkins CT3 and CT4) at its existing Hopkins Plant site. The timing, site, type and size of this new power supply resource may vary as the nature of the need becomes better defined. Alternatively, this proposed addition could be a generator(s) of a different type/size at the same or different location or a peak season purchase.

[2] Expected first year capacity factor.

[3] Expected full load average heat rate at 68°F.

[4] Estimated 2020 dollars.

[5] Estimated 2011 dollars.

Figure D-1 – Hopkins Plant Site

Figure D-2 – Purdom Plant Site

City Of Tallahassee

Planned Transmission Projects, 2011-2020

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 24	Sub 9	7509	Sub 21	7521	4/30/11	115	3.0
	Line 27	Sub 14	7514	Sub 7	7507	6/30/12	115	6.0
	Line 26	Sub 17	7517	Sub 14	7514	12/31/12	115	4.0
	Line 25	Sub 21	7521	Sub 17	7517	12/31/12	115	6.0
	230 Loop Phase I	Hopkins S	7610	Sub 5	7605	12/31/12	230	8.0
	230 Loop Phase II	Sub 5	7605	Sub 7	7607	6/1/16	230	12.8
	Line 28	Sub 15	7515	Sub 18	7518	12/31/17	115	Unknown
	Line 29	Sub 18	7518	Sub 9	7509	12/31/17	115	Unknown
Line Rebuild/ Reconductor	Line 2C	Switch St	7553	Sub 5	7505	12/31/11	115	1.6
	Line 7A	Hopkins	7550	Sub 10	7510	6/1/12	115	5.0
	Line 15A	Sub 5	7505	Sub 4	7504	6/30/13	115	9.0
	Line 15B	Sub 5	7505	Sub 9	7509	6/30/13	115	6.0
	Line 15C	Sub 9	7509	Sub 4	7504	6/30/13	115	4.0
Transformers	Sub 7 230/115 Auto	Sub 7 230	7607	Sub 7 115	7507	10/30/11	NA	NA
	Sub 5 230/115 Auto	Sub 5 230	7605	Sub 5 115	7505	12/31/12	NA	NA
	Sub 4 230/115 Auto	Sub 4 230	7604	Sub 4 115	7504	6/1/16	NA	NA
Substations	Sub 21 (Bus 7521)	NA	NA	NA	NA	5/1/11	115	NA
	Sub 14 (Bus 7514)	NA	NA	NA	NA	6/30/12	115	NA
	Sub 17 (Bus 7517)	NA	NA	NA	NA	12/31/12	115	NA
	Sub 22 (Bus 7522)	NA	NA	NA	NA	6/30/13	115	NA
	Sub 23 (Bus 7523)	NA	NA	NA	NA	12/31/13	115	NA
	Sub 18 (Bus 7518)	NA	NA	NA	NA	12/31/17	115	NA

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:	Start - 2009 End - 2012
(7)	Anticipated Capital Investment [1]:	$11.0 million
(8)	Substations:	Hopkins South (tap Hopkins-Crawfordville 230 kV) [2]
(9)	Participation with Other Utilities:	None

Notes

[1] Cumulative capital requirement identified in FY 2011 budget.

[2] New substation to serve as west terminus for new 230 kV line. Existing Substation 5 will be east terminus.

City Of Tallahassee

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

(1)	Point of Origin and Termination:	Substation 5 - Substation 4 - 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:	See note [1]
(8)	Substations:	See note [2]
(9)	Participation with Other Utilities:	None

Notes

[1] Anticipated capital investment associated with rebuilding/reconductoring associated transmission and substation facilities has not been segregated from that related to other improvements being made to these facilities for purposes other than that of establishing this 230 kV transmission line.

[2] North terminus will be existing Substation 7; south terminus will be existing Substation 5; intermediate terminus will be existing Substation 4.

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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	9.65%	NA	5.48%	NA	84.54%	NA	NA
Corn	2	[1]	NA	9.65%	NA	5.48%	NA	84.54%	NA	NA
Corn	3	[1]	NA	9.65%	NA	5.48%	NA	84.54%	NA	NA
Hopkins	1		1.94%	4.78%	0.07%	3.92%	97.99%	90.61%	12,175	11,846
Hopkins	CC 2	[2]	17.07%	7.27%	5.76%	3.19%	77.16%	86.90%	8,066	7,678
Hopkins	GT-1	[3]	0.06%	4.96%	0.00%	5.23%	99.94%	87.58%	29,582	22,190
Hopkins	GT-2	[3]	0.29%	3.41%	0.05%	4.27%	99.66%	89.22%	32,047	18,953
Hopkins	GT-3		0.45%	5.08%	0.46%	3.47%	99.09%	90.08%	10,710	9,969
Hopkins	GT-4		0.24%	5.08%	0.10%	3.47%	99.66%	90.08%	10,552	9,953
Purdom	7	[3]	0.71%	4.78%	7.52%	3.92%	91.78%	90.61%	12,791	14,911
Purdom	8		3.02%	7.27%	9.47%	3.19%	87.51%	86.90%	7,691	7,835
Purdom	GT-1	[3]	4.03%	4.96%	0.06%	5.23%	95.91%	87.58%	27,991	NA
Purdom	GT-2	[3]	4.06%	4.96%	1.46%	5.23%	94.49%	87.58%	24,221	NA
Future Units										
Hopkins	GT-5	[4]	NA	5.08%	NA	3.47%	NA	90.08%	NA	9,877

NOTES: Historical - average of past three calendar years

Projected - average of next ten calendar years (Peer unit data in 2005-9 NERC Generating Availability Report (GAR) used for POF, FOF and EAF)

[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) since it began operation in June 2008.

[3] Historical data reflects average gross operating heat rate (Btu/kWh).

[4] For the purposes of this report, the City has identified the addition of a GE LM 6000 combustion turbine generator (similar to the City's existing Hopkins CT3 and CT4) at its existing Hopkins Plant site. The timing, site, type and size of this new power supply resource may vary as the nature of the need becomes better defined. Alternatively, this proposed addition could be a generator(s) of a different type/size at the same or different location or a peak season purchase.

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]	2008	NA	NA	NA	57.91	919	-	NA	NA	NA
	2009	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
	2010	NA	NA	NA	57.23	908	-2.5%	NA	NA	NA
Forecast	2011	NA	NA	NA	77.33	1227	35.1%	NA	NA	NA
	2012	NA	NA	NA	78.72	1249	1.8%	NA	NA	NA
	2013	NA	NA	NA	80.29	1274	2.0%	NA	NA	NA
	2014	NA	NA	NA	81.90	1300	2.0%	NA	NA	NA
	2015	NA	NA	NA	83.54	1326	2.0%	NA	NA	NA
	2016	NA	NA	NA	85.21	1352	2.0%	NA	NA	NA
	2017	NA	NA	NA	86.91	1380	2.0%	NA	NA	NA
	2018	NA	NA	NA	88.65	1407	2.0%	NA	NA	NA
	2019	NA	NA	NA	90.42	1435	2.0%	NA	NA	NA
	2020	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]	2008	NA	NA	NA	57.91	919	-	NA	NA	NA
	2009	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
	2010	NA	NA	NA	57.23	908	-2.5%	NA	NA	NA
Forecast [2]	2011	NA	NA	NA	77.33	1227	35.1%	NA	NA	NA
	2012	NA	NA	NA	80.65	1280	4.3%	NA	NA	NA
	2013	NA	NA	NA	84.28	1338	4.5%	NA	NA	NA
	2014	NA	NA	NA	88.07	1398	4.5%	NA	NA	NA
	2015	NA	NA	NA	92.04	1461	4.5%	NA	NA	NA
	2016	NA	NA	NA	96.18	1527	4.5%	NA	NA	NA
	2017	NA	NA	NA	100.51	1595	4.5%	NA	NA	NA
	2018	NA	NA	NA	105.03	1667	4.5%	NA	NA	NA
	2019	NA	NA	NA	109.76	1742	4.5%	NA	NA	NA
	2020	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]	2008	NA	NA	NA	57.91	919	-	NA	NA	NA
	2009	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
	2010	NA	NA	NA	57.23	908	-2.5%	NA	NA	NA
Forecast [2]	2011	NA	NA	NA	77.33	1227	35.1%	NA	NA	NA
	2012	NA	NA	NA	76.78	1219	-0.7%	NA	NA	NA
	2013	NA	NA	NA	76.40	1213	-0.5%	NA	NA	NA
	2014	NA	NA	NA	76.02	1207	-0.5%	NA	NA	NA
	2015	NA	NA	NA	75.64	1201	-0.5%	NA	NA	NA
	2016	NA	NA	NA	75.26	1195	-0.5%	NA	NA	NA
	2017	NA	NA	NA	74.88	1189	-0.5%	NA	NA	NA
	2018	NA	NA	NA	74.51	1183	-0.5%	NA	NA	NA
	2019	NA	NA	NA	74.14	1177	-0.5%	NA	NA	NA
	2020	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]	2008	70.44	1209	-	1,064	10.98	-
	2009	108.67	1866	54.3%	857	8.74	-20.4%
	2010	128.49	2215	18.7%	769	7.83	-10.4%
Forecast	2011	125.22	2159	-2.5%	498	5.08	-35.2%
	2012	129.87	2239	3.7%	558	5.68	12.0%
	2013	132.72	2288	2.2%	598	6.10	7.2%
	2014	135.38	2334	2.0%	631	6.43	5.5%
	2015	138.08	2381	2.0%	662	6.75	5.0%
	2016	140.85	2428	2.0%	689	7.03	4.1%
	2017	143.66	2477	2.0%	705	7.18	2.2%
	2018	146.54	2526	2.0%	724	7.37	2.6%
	2019	149.47	2577	2.0%	740	7.54	2.2%
	2020	152.46	2629	2.0%	756	7.71	2.2%

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

[1] Actual average cost of distillate oil and gas burned.
[2] 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]	2008	70.44	1214	-	1,064	11.07	-
	2009	108.67	1874	54.3%	857	8.91	-19.5%
	2010	128.49	2215	18.2%	769	8.00	-10.3%
Forecast [4]	2011	125.22	2159	-2.5%	498	5.18	-35.2%
	2012	133.00	2293	6.2%	570	5.93	14.5%
	2013	139.25	2401	4.7%	626	6.51	9.7%
	2014	145.51	2509	4.5%	676	7.03	8.0%
	2015	152.06	2622	4.5%	726	7.55	7.5%
	2016	158.90	2740	4.5%	774	8.05	6.6%
	2017	166.05	2863	4.5%	811	8.43	4.7%
	2018	173.53	2992	4.5%	853	8.87	5.1%
	2019	181.33	3126	4.5%	893	9.29	4.7%
	2020	189.49	3267	4.5%	935	9.73	4.7%

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

[1] Actual average cost of distillate oil and gas burned.
[2] 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]	2008	70.44	1214	-	1,064	11.07	-
	2009	108.67	1874	54.3%	857	8.91	-19.5%
	2010	128.49	2215	18.2%	769	8.00	-10.3%
Forecast [4]	2011	125.22	2159	-2.5%	498	5.18	-35.2%
	2012	126.74	2185	1.2%	545	5.67	9.5%
	2013	126.35	2179	-0.3%	571	5.94	4.7%
	2014	125.72	2168	-0.5%	588	6.12	3.0%
	2015	125.09	2157	-0.5%	603	6.27	2.5%
	2016	124.47	2146	-0.5%	612	6.37	1.6%
	2017	123.85	2135	-0.5%	611	6.35	-0.3%
	2018	123.23	2125	-0.5%	612	6.36	0.1%
	2019	122.61	2114	-0.5%	610	6.34	-0.3%
	2020	122.00	2103	-0.5%	609	6.33	-0.3%

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

[1] Actual average cost of distillate oil and gas burned.
[2] 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	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
	2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2011	53.82	224	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	54.34	226	1.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	54.86	229	1.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	55.39	231	1.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	55.92	233	1.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	57.21	238	2.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	58.52	244	2.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2018	59.87	249	2.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2019	61.24	255	2.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2020	62.64	261	2.3%	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] Nominal "Electric Power, Steam Coal" price per U.S. Energy Information Administration's 2011 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	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
	2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2011	53.82	224	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	55.69	232	3.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	57.61	240	3.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	59.61	248	3.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	61.67	257	3.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	64.63	269	4.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	67.73	282	4.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2018	70.98	296	4.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2019	74.39	310	4.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2020	77.94	325	4.8%	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	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
	2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2011	53.82	224	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	52.99	221	-1.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	52.18	217	-1.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	51.37	214	-1.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	50.58	211	-1.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	50.48	210	-0.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	50.38	210	-0.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2018	50.28	210	-0.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2019	50.18	209	-0.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2020	50.07	209	-0.2%	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	2008	NA	NA	64.96	-
	2009	NA	NA	57.40	-11.6%
	2010	NA	NA	58.35	1.7%
Forecast	2011	NA	NA	60.12	3.0%
	2012	NA	NA	61.83	2.8%
	2013	NA	NA	63.60	2.9%
	2014	NA	NA	65.42	2.9%
	2015	NA	NA	67.29	2.9%
	2016	NA	NA	70.33	4.5%
	2017	NA	NA	144.43	105.4%
	2018	NA	NA	148.04	2.5%
	2019	NA	NA	151.74	2.5%
	2020	NA	NA	155.53	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	127.87%	[1]
	PREFERRED	N/A	[2]
	ASSETS	69.07%	[3]
	EQUITY	166.86%	[3]
RATE OF RETURN (6)			
	DEBT	4.70%	[4]
	PREFERRED	N/A	[2]
	ASSETS	2.54%	[5]
	EQUITY	6.14%	[5]
INCOME TAX RATE:			
	STATE	N/A	[6]
	FEDERAL	N/A	[6]
	EFFECTIVE	N/A	[6]
OTHER TAX RATE:			
Sales Tax (< $5,000)		7.50%	[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 (7.5% 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 %
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
2020	2.5	2.5	2.5	2.5

Monthly Peak Demands and Date of Occurrence for 2008 - 2010

			Calendar Year 2008		
		Hour	Daily Temp. (^oF)		Peak Demand
Month	Date	Ending	Min.	Max.	(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	6:00 P.M.	70	96	548
July	21-Jul	5:00 P.M.	75	97	587
August	6-Aug	5:00 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		
		Hour	Daily Temp. (^oF)		Peak Demand
Month	Date	Ending	Min.	Max.	(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

			Calendar Year 2010		
		Hour	Daily Temp. (^oF)		Peak Demand
Month	Date	Ending	Min.	Max.	(MW)
January	11-Jan	8:00 A.M.	14	50	633
February	17-Feb	8:00 A.M.	23	56	542
March	4-Mar	8:00 A.M.	28	56	476
April	6-Apr	5:00 P.M.	52	85	399
May	24-May	6:00 P.M.	66	96	526
June	16-Jun	5:00 P.M.	75	98	581
July	30-Jul	5:00 P.M.	78	103	601
August	4-Aug	4:00 P.M.	74	96	580
September	10-Sep	5:00 P.M.	68	97	557
October	27-Oct	4:00 P.M.	72	88	483
November	8-Nov	8:00 A.M.	31	72	376
December	14-Dec	8:00 A.M.	24	46	539

Historical and Projected Heating and Cooling Degree Days

	Year	Heating Degree Days (HDD)	Cooling Degree Days (CDD)
History	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	1,573	2,797
	2010	1924	3047
Forecast	2011	1,578	2,787
	2012	1,578	2,787
	2013	1,578	2,787
	2014	1,578	2,787
	2015	1,578	2,787
	2016	1,578	2,787
	2017	1,578	2,787
	2018	1,578	2,787
	2019	1,578	2,787
	2020	1,578	2,787

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	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	67.30	64.70	65.74	2.145
	2010	60.32	51.04	54.76	2.181
	2011	60.32	51.04	54.76	
Forecast [2]	2012	60.32	51.04	54.76	
	2013	60.32	51.04	54.76	
	2014	60.32	51.04	54.76	
	2015	60.32	51.04	54.76	
	2016	60.32	51.04	54.76	
	2017	60.32	51.04	54.76	
	2018	60.32	51.04	54.76	
	2019	60.32	51.04	54.76	
	2020	60.32	51.04	54.76	

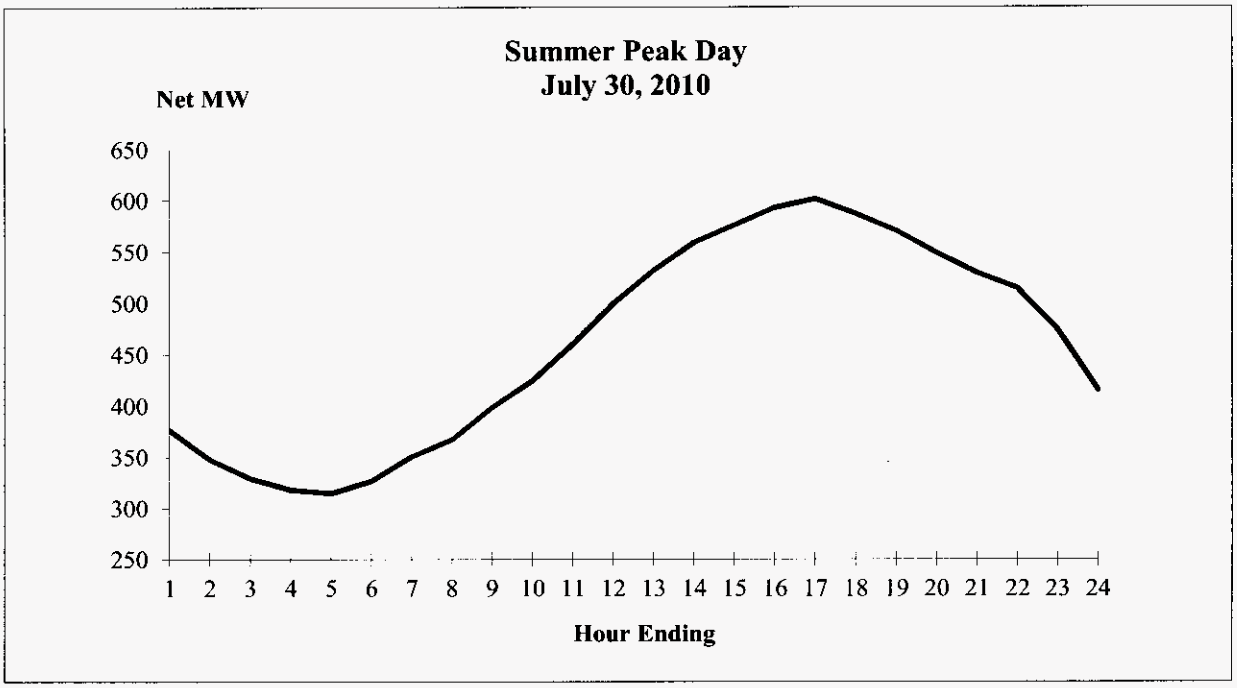
[1] Deflator is CPI Index per U. S. Dept. of Labor Bureau of Labor Stats. ('82 Dollars).

[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.

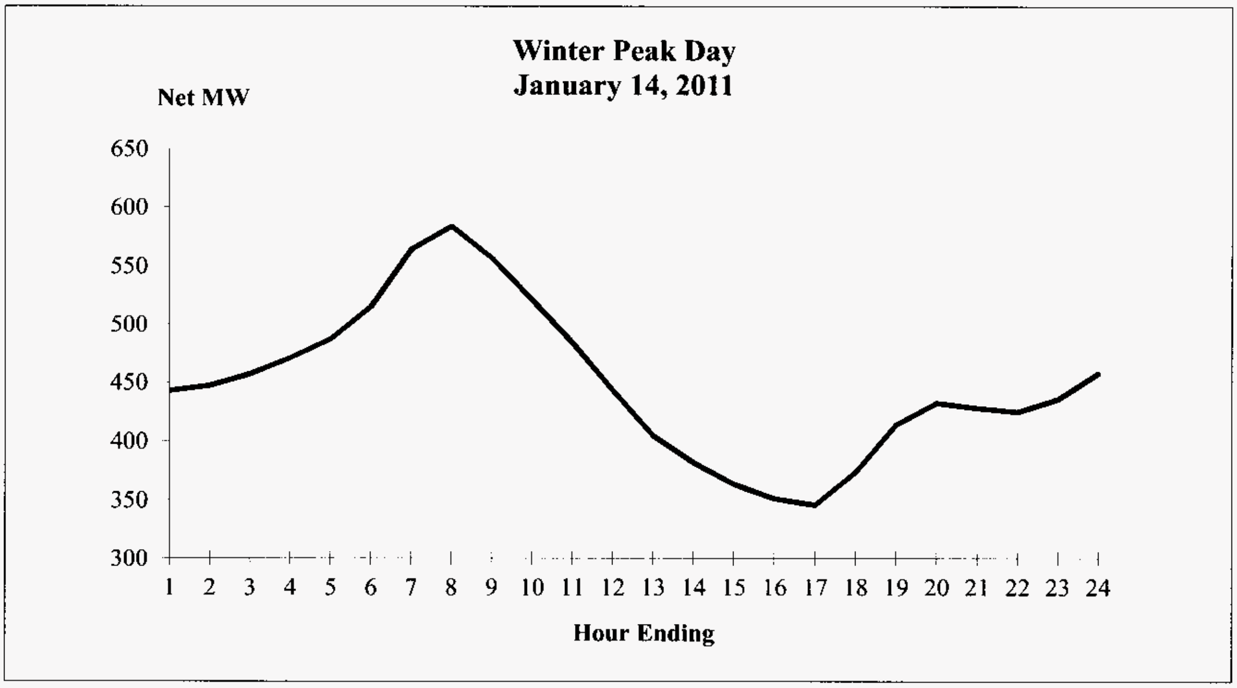
Loss of Load Probability, Reserve Margin, and Expected Unserved Energy Base Case Load Forecast

(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)
2011						
2012						
2013						
2014				See note [1] below		
2015						
2016						
2017						
2018						
2019						
2020						

[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	376	13	532
2	348	14	559
3	329	15	576
4	318	16	593
5	315	17	**601**
6	327	18	586
7	351	19	570
8	367	20	549
9	399	21	529
10	425	22	514
11	460	23	474
12	500	24	415



Hour Ending	Net Load (MW)	Hour Ending	Net Load (MW)
1	443	13	405
2	447	14	382
3	457	15	363
4	471	16	351
5	487	17	345
6	515	18	374
7	564	19	414
8	**584**	20	432
9	557	21	428
10	521	22	425
11	484	23	435
12	443	24	458

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