Ten Year Site Plan
2009-2018

City of Tallahassee
Electric Utility

Report Prepared By:
City of Tallahassee Electric Utility
System Planning

City of Tallahassee
Your Own Utilities℠

CITY OF TALLAHASSEE
TEN YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES
2009-2018
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Chapter I

Description of Existing Facilities

1.0 INTRODUCTION

The City of Tallahassee (City) owns, operates, and maintains an electric generation, transmission, and distribution system that supplies electric power in and around the corporate limits of the City. The City was incorporated in 1825 and has operated since 1919 under the same charter. The City began generating its power requirements in 1902 and the City's Electric Department presently serves approximately 113,250 customers located within a 221 square mile service territory (see Figure A). The Electric Department operates three generating stations with a total summer season net generating capacity of 805 megawatts (MW).

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

1.1 SYSTEM CAPABILITY

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

As shown in Table 1.1 (Schedule 1), 233 MW (net summer rating) of CC generation, 48 MW (net summer rating) of steam generation and 20 MW (net summer rating) of CT generation facilities are located at the City's Sam O. Purdom Generating Station. The Arvah B. Hopkins Generating Station includes 300 MW (net summer rating) of CC generation, 76 MW (net summer rating) of steam generation and 128 MW (net summer rating) of CT generation facilities.

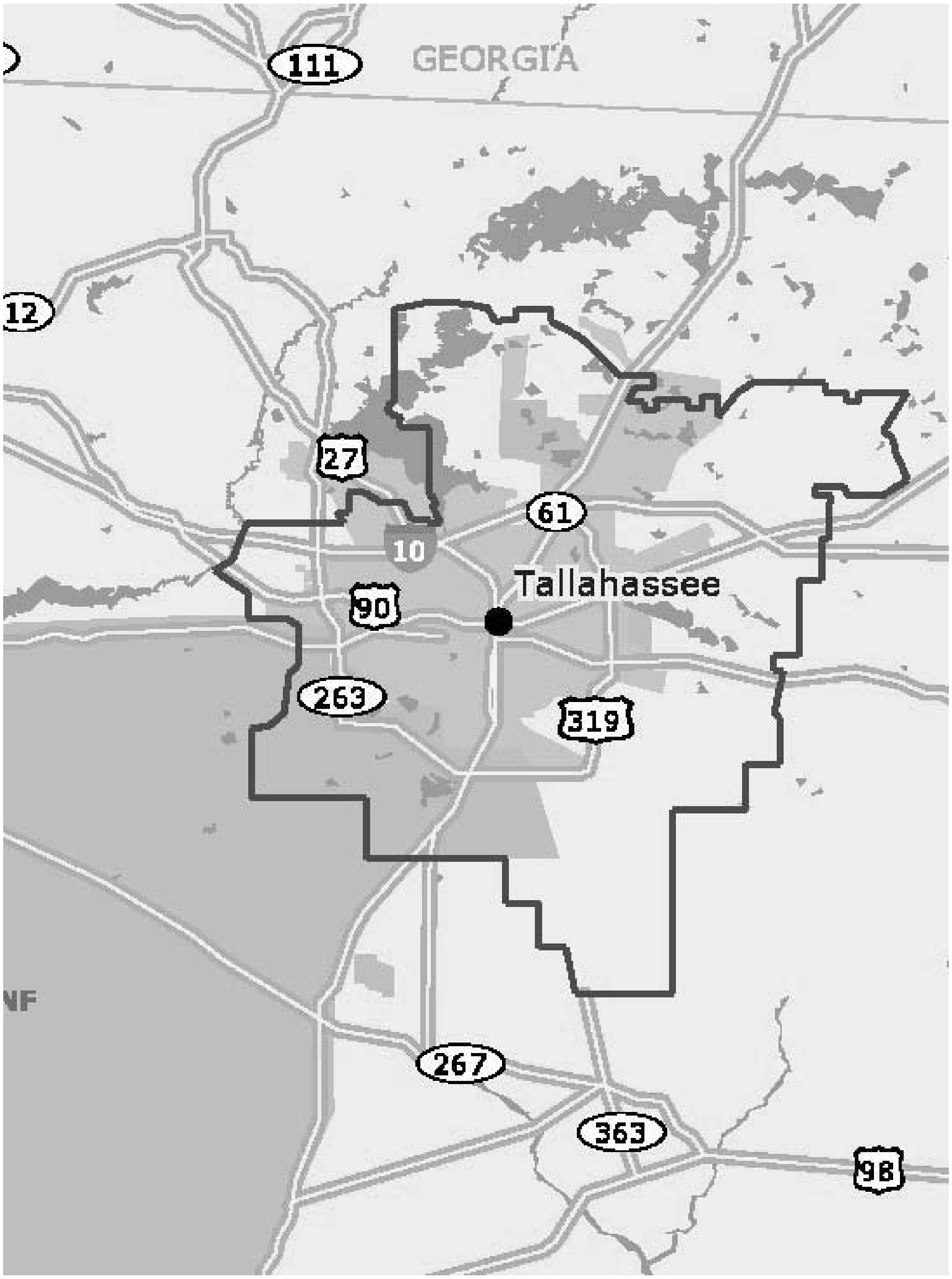
All of the City's available steam generating units at these sites can be fired with natural gas, residual oil or both. The CC and CT units can be fired on either natural gas or diesel oil but cannot burn these fuels concurrently. The total capacity of the three units at the C.H. Corn Hydroelectric Station is 11 MW. However, because the hydroelectric generating units are effectively run-of-river (dependent upon rainfall, reservoir and downstream conditions), the City considers these units as “energy only” and not as dependable capacity for planning purposes.

The City’s total net summer installed generating capability is 805 MW. The corresponding winter net peak installed generating capability is 876 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.

Figure A – Tallahassee Service Territory



City Of Tallahassee

Schedule 1
Existing Generating Facilities
As of December 31, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport		Alt. Fuel	Commercial	Expected	Gen. Max.	Net Capability	
Plant	Unit No.	Location	Unit Type	Pri	Alt	Primary	Alternate	Days Use	In-Service Month/Year	Retirement Month/Year	Nameplate (kW)	Summer (MW)	Winter (MW)
Sam O. Purdom	7	Wakulla	ST	NG	FO6	PL	WA	[1, 2]	6/66	3/11	50,000	48	50
	8		CC	NG	FO2	PL	TK	[2, 3]	7/00	12/40	247,743	233	262
	GT-1		GT	NG	FO2	PL	TK	[2, 3]	12/63	3/11	15,000	10	10
	GT-2		GT	NG	FO2	PL	TK	[2, 3]	5/64	3/11	15,000	10	10
											Plant Total	301	332
A. B. Hopkins	1	Leon	ST	NG	FO6	PL	TK	[1]	5/71	3/19	75,000	76	78
	2		CC	NG	FO2	PL	TK	[3]	6/08 [4]	Unknown	358,200 [5]	300	330
	GT-1		GT	NG	FO2	PL	TK	[3]	2/70	3/15	16,320	12	14
	GT-2		GT	NG	FO2	PL	TK	[3]	9/72	3/17	27,000	24	26
	GT-3		GT	NG	FO2	PL	TK	[3]	9/05	Unknown	60,500	46	48
	GT-4		GT	NG	FO2	PL	TK	[3]	11/05	Unknown	60,500	46	48
											Plant Total	504	544
C. H. Corn Hydro Station [6]	1	Leon/ Gadsden	HY	WAT	WAT	WAT	WAT	NA	9/85	Unknown	4,440	0	0
	2		HY	WAT	WAT	WAT	WAT	NA	8/85	Unknown	4,440	0	0
	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, 2008			805	876

Notes

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

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

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

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

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

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

CHAPTER II

Forecast of Energy/Demand Requirements and Fuel Utilization

2.0 INTRODUCTION

Chapter II includes the City's forecasts of demand and energy requirements, energy sources and fuel requirements. This chapter also explains the impacts attributable to the Demand Side Management (DSM) plan submitted as a part of the City's Integrated Resource Planning (IRP) Study completed in December 2006 ("2006 IRP Study"). The City is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA) and, therefore, the FPSC does not set numeric conservation goals for the City. However, the City expects to continue its commitment to conservation and the DSM programs that prove beneficial to the City's ratepayers.

2.1 SYSTEM DEMAND AND ENERGY REQUIREMENTS

Historical and forecast energy consumption and customer information are presented in Tables 2.1, 2.2 and 2.3 (Schedules 2.1, 2.2, and 2.3). Figure B1 shows the historical and forecast trends of energy sales by customer class. Figure B2 shows the percentage of energy sales by customer class for the base year of 2008 and the horizon year of 2017. Tables 2.4 through 2.12 (Schedules 3.1.1 - 3.3.3) contain historical and forecast seasonal peak demands and net energy for load for base, high, and low values. Table 2.13 (Schedule 4) compares actual and two-year forecast peak demand and energy values by month for the –2008 - 2010 period.

2.1.1 SYSTEM LOAD AND ENERGY FORECASTS

The peak demand and energy forecasts contained in this plan are the results of the load and energy forecasting study performed by the City. The forecast is developed utilizing a methodology that the City first employed in 1980, and has updated and revised every one or two years. The methodology consists of 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 summer peak demand model prediction is based on maximum temperature, air conditioning saturation rates, and total number of customers. The winter peak is dependent upon the minimum temperature on the peak day, electric heating saturation rates, and total number of customers.

Some of the most significant input assumptions for the 2009 forecast were the incremental load modifications at Florida State University (FSU), Florida A&M University (FAMU), Tallahassee Memorial Hospital (TMH) and the State Capitol Center. These four customers represented approximately 14% of the City's 2008 energy sales. Their incremental additions are highly dependent upon annual economic and budget constraints, which would cause fluctuations in their demand projections if they were projected using a model. Therefore, each entity submits their proposed incremental additions/reductions to the City and these modifications are included as submitted in the load and energy forecast.

The City believes that the inclusion of these incremental additions/reductions, utilizing the five-year average of the actual temperature at the time of seasonal peak demand, the routine update of forecast model coefficients and other minor model refinements have improved the accuracy of its forecast so that they are more consistent with the historical trend of growth in seasonal peak demand and energy consumption. The changes made to the forecast models for seasonal peak demands and annual sales/net energy for load requirements has resulted in 2009 base forecasts for these characteristics that are generally lower than the corresponding 2008 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 and 3.2.3.

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.

2.1.3 ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT PROGRAMS

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

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

The City has a goal to improve the efficiency of customers' end-use of energy resources when such improvements provide a measurable economic and/or environmental benefit to the customers and the City utilities. During the 2006 IRP Study the City tested potential DSM measures (conservation, energy efficiency, load management, and demand response) for cost-effectiveness utilizing an integrated approach that is based on projections of total achievable capacity and energy reductions and their associated annual costs developed specifically for the City. The measures were combined into bundles affecting similar end uses and /or having similar costs per kWh saved. The City has been delayed by efforts to contract with an energy services provider to assist staff in deploying some measures but has begun implementing specific groups of additional measures to supplement its DSM program and achieve the capacity benefit and energy savings projected in the 2006 IRP Study. An update on the City’s progress with and any changes in future expectations of its DSM program will be provided 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 2009-2018. Figure B4 displays the percentage of energy by fuel type in 2009 and 2018.

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
1999	184,239	-	926	77,357	11,970	1,419	16,183	87,685
2000	186,839	-	971	79,108	12,274	1,471	16,662	88,285
2001	190,575	-	959	80,348	11,936	1,459	16,988	85,884
2002	193,941	-	1,048	81,208	12,905	1,527	16,779	91,007
2003	200,304	-	1,035	82,219	12,588	1,555	17,289	89,942
2004	203,106	-	1,064	85,035	12,512	1,604	17,729	90,473
2005	205,908	-	1,088	89,468	12,164	1,621	18,310	88,548
2006	208,789	-	1,097	92,017	11,927	1,602	18,532	86,453
2007	211,669	-	1,099	93,569	11,745	1,657	18,583	89,168
2008	214,550	-	1,054	94,640	11,132	1,625	18,597	87,366
2009	217,430	-	1,058	95,655	11,065	1,646	18,754	87,744
2010	220,311	-	1,055	96,743	10,906	1,651	18,879	87,473
2011	223,056	-	1,051	98,207	10,701	1,657	19,048	86,994
2012	225,801	-	1,055	99,696	10,578	1,659	19,220	86,304
2013	228,546	-	1,056	101,201	10,434	1,659	19,393	85,569
2014	231,290	-	1,058	102,732	10,296	1,657	19,569	84,674
2015	234,035	-	1,059	104,156	10,172	1,655	19,734	83,867
2016	236,509	-	1,060	105,398	10,056	1,654	19,877	83,197
2017	238,982	-	1,062	106,641	9,963	1,652	20,020	82,533
2018	241,455	-	1,063	107,884	9,855	1,651	20,163	81,882

[1] Population data represents Leon County population served by City of Tallahassee Electric Utility not the general population of Leon County.
[2] Values include DSM Impacts.
[3] Average end-of-month customers for the calendar year. Marked increase in residential customers between 2004 and 2005 due to change in internal customer accounting practices.
[4] 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)
1999	-	-	-		13		2,358
2000	-	-	-		12		2,454
2001	-	-	-		13		2,431
2002	-	-	-		13		2,588
2003	-	-	-		12		2,602
2004	-	-	-		14		2,682
2005	-	-	-		14		2,725
2006	-	-	-		15		2,716
2007	-	-	-		0		2,756
2008	-	-	-		0		2,678
2009	-	-	-		0		2,704
2010	-	-	-		0		2,707
2011	-	-	-		0		2,708
2012	-	-	-		0		2,713
2013	-	-	-		0		2,715
2014	-	-	-		0		2,715
2015	-	-	-		0		2,714
2016	-	-	-		0		2,714
2017	-	-	-		0		2,715
2018	-	-	-		0		2,714

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

City Of Tallahassee

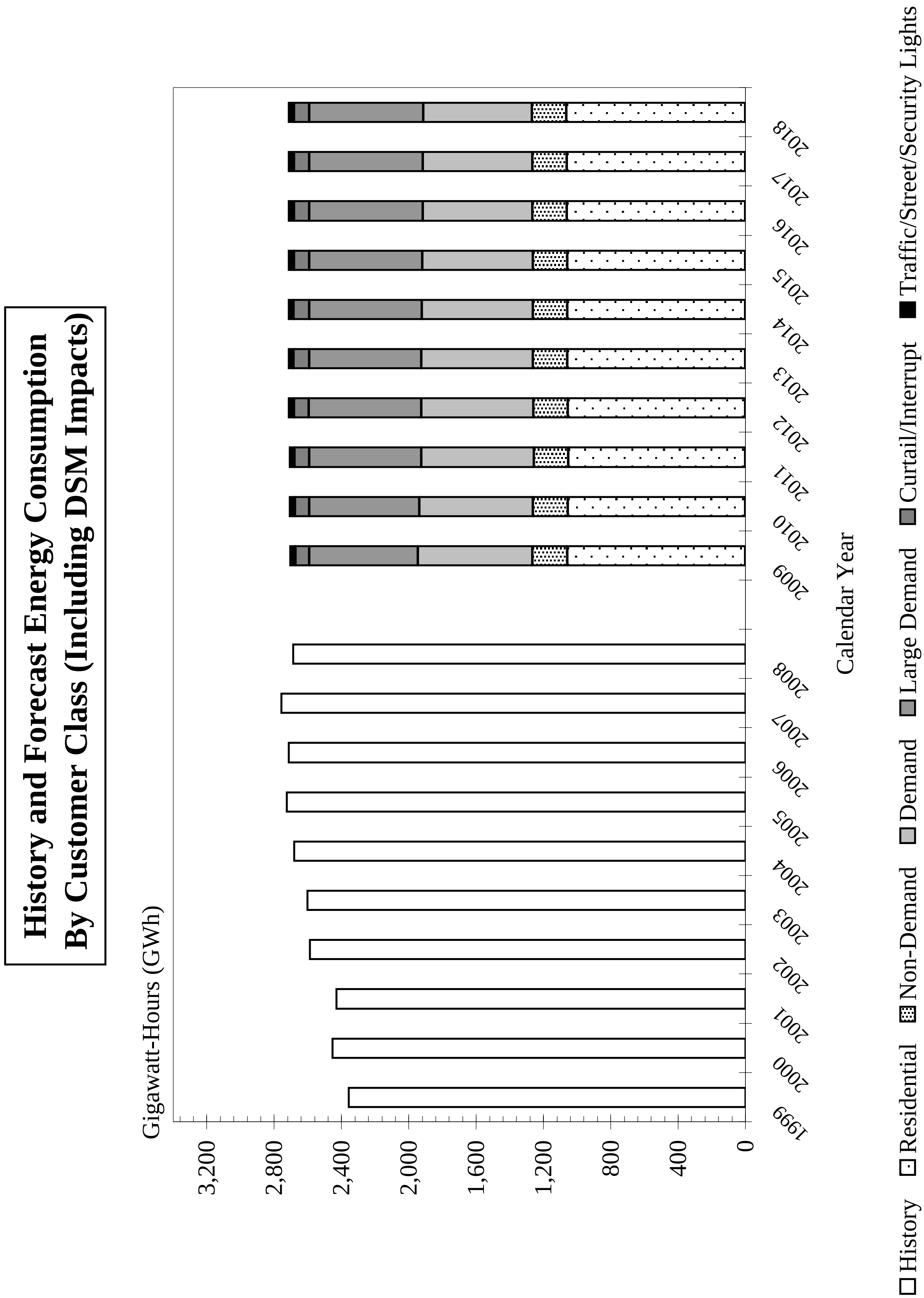
Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

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]
1999	0	139	2,497		93,540
2000	0	155	2,609		95,770
2001	0	125	2,556		97,335
2002	0	165	2,753		97,987
2003	0	153	2,755		99,508
2004	0	159	2,841		102,764
2005	0	164	2,888		107,778
2006	0	154	2,870		110,548
2007	0	158	2,914		112,151
2008	0	155	2,834		113,237
2009	0	161	2,865		114,409
2010	0	161	2,867		115,622
2011	0	161	2,869		117,255
2012	0	161	2,875		118,916
2013	0	161	2,877		120,594
2014	0	161	2,876		122,302
2015	0	161	2,876		123,889
2016	0	161	2,875		125,275
2017	0	161	2,876		126,661
2018	0	161	2,875		128,047

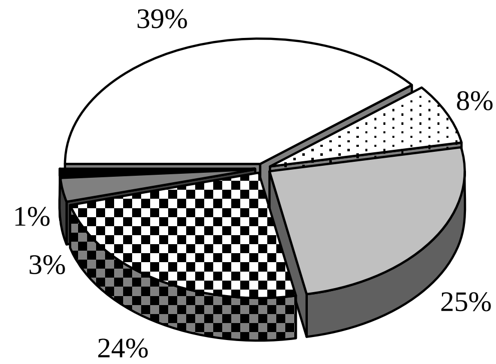
[1] Average number of customers for the calendar year.

Figure B1


History and Forecast Energy Consumption
By Customer Class (Including DSM Impacts)
Gigawatt-Hours (GWh)
3,200
2,800
2,400
2,000
1,600
1,200
800
400
0
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
Calendar Year
History
Residential
Non-Demand
Demand
Large Demand
Curtail/Interrupt
Traffic/Street/Security Lights

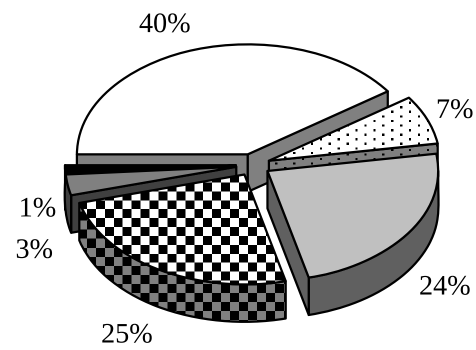
Energy Consumption By Customer Class
(Excluding DSM Impacts)

Calendar Year 2009



Total 2009 Sales = 2,732 GWh

Calendar Year 2018



Total 2018 Sales = 3,078 GWh

- Residential
- Demand
- Curtail/Interrupt
- Non-Demand
- Large Demand
- 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]
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	581		581						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	621		621						621
2008	588		588			1		0	587
2009	620		620		1	3	3	4	609
2010	629		629		4	7	10	9	599
2011	640		640		6	12	16	16	590
2012	649		649		9	16	17	21	586
2013	658		658		10	20	18	26	584
2014	667		667		12	24	18	32	581
2015	676		676		14	28	18	38	578
2016	683		683		15	32	18	42	576
2017	691		691		15	36	19	47	574
2018	699		699		16	39	19	52	573

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2008 DSM is actual at peak.
[3] 2008 values reflect incremental increase from 2007.

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]
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	581		581						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	621		621						621
2008	588		588			1		0	587
2009	634		634		1	3	3	4	623
2010	647		647		4	7	10	9	617
2011	662		662		6	12	16	16	612
2012	675		675		9	16	17	21	612
2013	689		689		10	20	18	26	615
2014	702		702		12	24	18	32	616
2015	716		716		14	28	18	38	618
2016	728		728		15	32	18	42	621
2017	740		740		15	36	19	47	623
2018	753		753		16	39	19	52	627

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2008 DSM is actual at peak.
[3] 2008 values reflect incremental increase from 2007.

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]
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	581		581						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	621		621						621
2008	588		588			1		0	587
2009	606		606		1	3	3	4	595
2010	611		611		4	7	10	9	581
2011	618		618		6	12	16	16	568
2012	623		623		9	16	17	21	560
2013	628		628		10	20	18	26	554
2014	632		632		12	24	18	32	546
2015	636		636		14	28	18	38	538
2016	639		639		15	32	18	42	532
2017	642		642		15	36	19	47	525
2018	645		645		16	39	19	52	519

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2008 DSM is actual at peak.
[3] 2008 values reflect incremental increase from 2007.

City Of Tallahassee

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
1999 -2000	497		497						497
2000 -2001	521		521						521
2001 -2002	510		510						510
2002 -2003	590		590						590
2003 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	528		528						528
2007 -2008	526		526						526
2008 -2009	580		580			1		0	579
2009 -2010	552		552		4	6	10	8	524
2010 -2011	561		561		6	11	15	14	515
2011 -2012	569		569		9	15	17	18	510
2012 -2013	577		577		10	19	17	23	508
2013 -2014	585		585		12	23	17	28	505
2014 -2015	593		593		13	27	18	33	502
2015 -2016	599		599		15	30	18	37	499
2016 -2017	606		606		15	33	19	41	498
2017 -2018	613		613		15	37	19	45	497
2018 -2019	620		620		16	40	19	48	497

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2008 DSM is actual at peak.
[3] 2008 values reflect incremental increase from 2007.

City Of Tallahassee

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
1999 -2,000	497		497						497
2000 -2001	521		521						521
2001 -2002	510		510						510
2002 -2003	590		590						590
2003 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	528		528						528
2007 -2008	526		526						526
2008 -2009	580		580			1		0	579
2009 -2010	568		568		4	6	10	8	540
2010 -2011	581		581		6	11	15	14	535
2011 -2012	592		592		9	15	17	18	533
2012 -2013	604		604		10	19	17	23	535
2013 -2014	616		616		12	23	17	28	536
2014 -2015	628		628		13	27	18	33	537
2015 -2016	638		638		15	30	18	37	538
2016 -2017	649		649		15	33	19	41	541
2017 -2018	660		660		15	37	19	45	544
2018 -2019	672		672		16	40	19	48	549

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2008 DSM is actual.
[3] 2008 values reflect incremental increase from 2007.

City Of Tallahassee

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
1999 -2,000	497		497						497
2000 -2001	521		521						521
2001 -2002	510		510						510
2002 -2003	590		590						590
2003 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	528		528						528
2007 -2008	526		526						526
2008 -2009	580		580			1		0	579
2009 -2010	536		536		4	6	10	8	508
2010 -2011	542		542		6	11	15	14	496
2011 -2012	546		546		9	15	17	18	487
2012 -2013	550		550		10	19	17	23	481
2013 -2014	554		554		12	23	17	28	474
2014 -2015	558		558		13	27	18	33	467
2015 -2016	561		561		15	30	18	37	461
2016 -2017	563		563		15	33	19	41	455
2017 -2018	566		566		15	37	19	45	450
2018 -2019	569		569		16	40	19	48	446

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2008 DSM is actual.
[3] 2008 values reflect incremental increase from 2007.

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]
1999	2,358			2,358		139	2,497	54
2000	2,454			2,454		155	2,609	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	53
2004	2,682			2,682		159	2,841	57
2005	2,725			2,725		164	2,888	55
2006	2,716			2,716		154	2,870	57
2007	2,756			2,756		158	2,914	54
2008	2,686	8	0	2,678		155	2,834	55
2009	2,732	13	15	2,704		161	2,865	54
2010	2,771	31	33	2,708		160	2,867	55
2011	2,820	53	59	2,708		161	2,869	56
2012	2,859	69	77	2,713		162	2,876	56
2013	2,899	88	97	2,714		162	2,877	56
2014	2,939	106	118	2,715		161	2,876	57
2015	2,977	125	139	2,712		162	2,875	57
2016	3,010	141	155	2,715		161	2,876	57
2017	3,044	157	173	2,715		161	2,876	57
2018	3,078	172	192	2,714		161	2,875	57

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2008 DSM is actual.
[3] 2008 values reflect incremental increase from 2007.

City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total Sales	Residential Conservation [2], [3]	Comm./Ind Conservation [2], [3]	Retail Sales [1]	Wholesale	Utility Use & Losses	Net Energy for Load [1]	Load Factor % [1]
1999	2,358			2,358		139	2,497	54
2000	2,454			2,454		155	2,609	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	53
2004	2,682			2,682		159	2,841	57
2005	2,725			2,725		164	2,888	55
2006	2,716			2,716		154	2,870	57
2007	2,756			2,756		158	2,914	54
2008	2,686	8	0	2,678		155	2,834	55
2009	2,795	13	15	2,767		164	2,931	54
2010	2,851	31	33	2,788		166	2,952	55
2011	2,917	53	59	2,805		167	2,972	55
2012	2,975	69	77	2,829		168	2,997	56
2013	3,035	88	97	2,850		170	3,021	56
2014	3,094	106	118	2,870		171	3,041	56
2015	3,153	125	139	2,889		173	3,062	57
2016	3,206	141	156	2,909		173	3,082	57
2017	3,261	157	173	2,932		174	3,106	57
2018	3,317	172	192	2,953		176	3,129	57

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2008 DSM is actual.
[3] 2008 values reflect incremental increase from 2007.

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]
1999	2,358			2,358		139	2,497	54
2000	2,454			2,454		155	2,609	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	53
2004	2,682			2,682		159	2,841	57
2005	2,725			2,725		164	2,888	55
2006	2,716			2,716		154	2,870	57
2007	2,756			2,756		158	2,914	54
2008	2,686	8	0	2,678		155	2,834	55
2009	2,671	13	15	2,643		158	2,802	54
2010	2,692	31	34	2,627		156	2,783	55
2011	2,724	53	59	2,612		155	2,767	56
2012	2,744	69	76	2,600		154	2,754	56
2013	2,765	88	97	2,580		153	2,733	56
2014	2,785	106	118	2,561		152	2,713	57
2015	2,802	125	138	2,539		151	2,690	57
2016	2,817	141	154	2,522		148	2,670	57
2017	2,830	157	173	2,501		148	2,648	58
2018	2,842	172	192	2,478		148	2,627	58

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2008 DSM is actual.
[3] 2008 values reflect incremental increase from 2007.

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)
	2008 Actual		**2009 Forecast [1]**		**2010 Forecast [1]**	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	526	240	510	227	501	227
February	510	205	533	208	524	209
March	394	204	426	208	419	208
April	430	211	482	215	474	215
May	516	239	530	243	522	243
June	548	271	585	272	576	272
July	587	284	609	290	599	290
August	556	274	605	297	595	297
September	542	261	566	261	557	261
October	520	223	519	228	511	228
November	465	209	436	205	429	205
December	468	211	492	211	484	212
TOTAL		2,836		2,865		2,867

[1] Peak Demand and NEL include DSM Impacts.

City of Tallahassee, Florida

2009 Electric System Load Forecast

Key Explanatory Variables

Model Name	Leon County Population	Residential Customers	Total Customers	Cooling Degree Days	Heating Degree Days	Tallahassee Per Capita Taxable Sales	Price of Electricity	State of Florida Population	Minimum Winter Peak day Temp.	Maximum Summer Peak day Temp.	Appliance Saturation	R Squared [1]
Residential Customers	X											0.994
Residential Consumption		X		X	X	X	X				X	0.927
Florida State University Consumption				X				X				0.930
State Capitol Consumption				X				X				0.892
Florida A&M University Consumption				X				X				0.926
Lighting Consumption	X											0.961
General Service Non-Demand Customers		X										0.996
General Service Demand Customers		X										0.987
General Service Non-Demand Consumptior	X			X	X		X					0.956
General Service Demand Consumption	X			X	X							0.979
General Service Large Demand Consumption	X			X	X							0.933
Summer Peak Demand				X			X			X		0.914
Winter Peak Demand				X	X				X			0.880

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

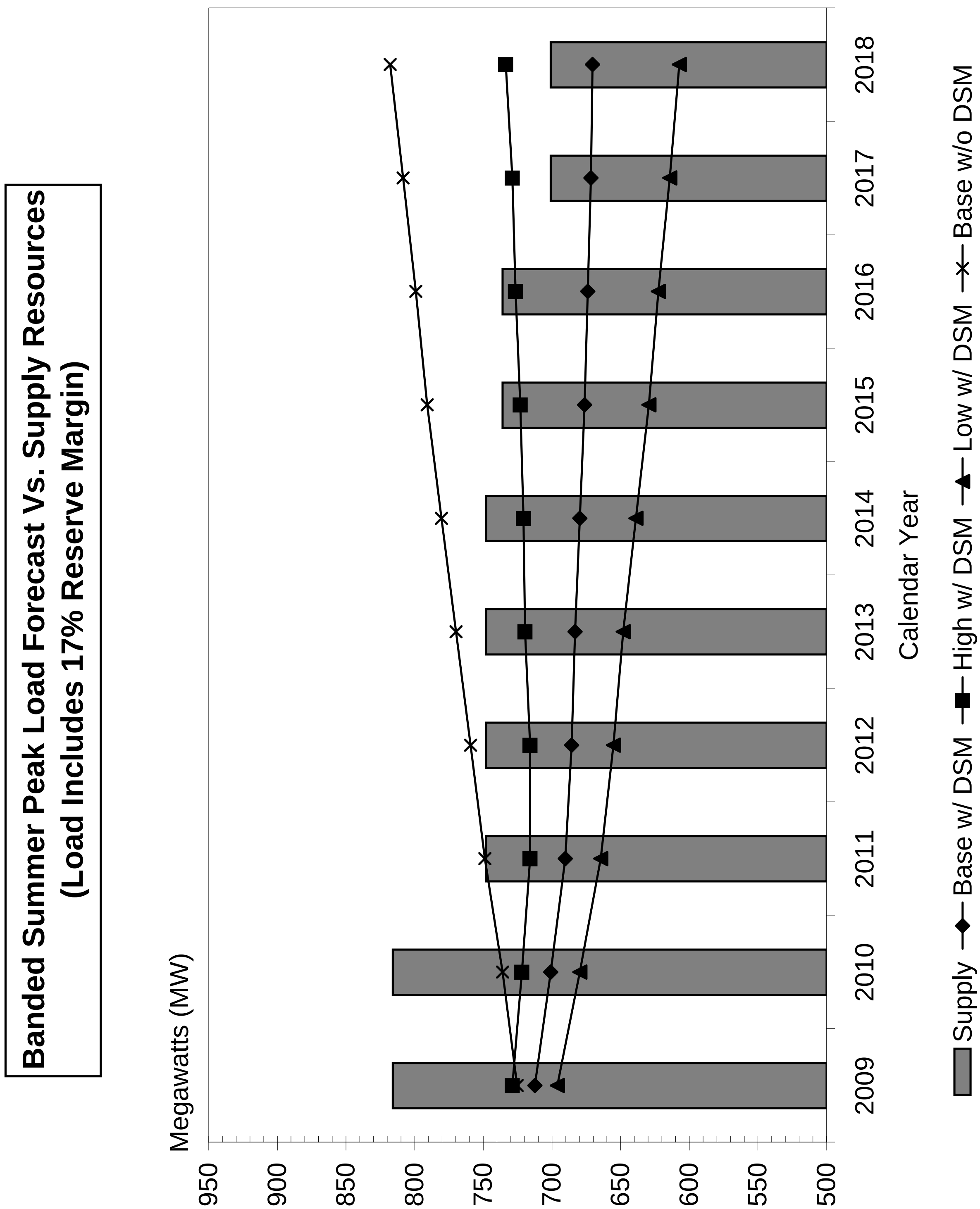
City of Tallahassee

2009 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	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	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	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

Figure B3



Banded Summer Peak Load Forecast Vs. Supply Resources
(Load Includes 17% Reserve Margin)
Megawatts (MW)
950
900
850
800
750
700
650
600
550
500
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
Calendar Year
Supply
Base w/ DSM
High w/ DSM
Low w/ DSM
Base w/o DSM

City Of Tallahassee

2009 Electric System Load Forecast

Projected Demand Side Management Energy Reductions [1]

Calendar Year Basis

Year	Residential Impact (MWh)	Commercial Impact (MWh)	Total Impact (MWh)
2009	14,055	15,608	29,663
2010	32,327	35,898	68,225
2011	56,221	62,431	118,652
2012	73,087	81,161	154,248
2013	92,764	103,012	195,776
2014	112,442	124,863	237,304
2015	132,119	146,714	278,832
2016	148,985	165,443	314,428
2017	165,851	184,172	350,024
2018	182,718	202,902	385,619

[1] Reductions estimated at busbar.

City Of Tallahassee

2009 Electric System Load Forecast

Projected Demand Side Management Seasonal Demand Reductions [1]

Year		Residential Energy Efficiency Impact		Commercial Energy Efficiency Impact		Residential Demand Response Impact		Commercial Demand Response Impact		Demand Side Management Total	
Summer	Winter	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
2009	2009-2010	3	6	4	8	1	4	3	10	11	28
2010	2010-2011	7	11	9	14	4	6	10	15	30	47
2011	2011-2012	12	15	16	18	6	9	16	17	51	58
2012	2012-2013	16	19	21	23	9	10	17	17	62	68
2013	2013-2014	20	23	26	28	10	12	18	17	74	79
2014	2014-2015	24	27	32	33	12	13	18	18	86	93
2015	2015-2016	28	30	38	37	14	15	18	18	98	99
2016	2016-2017	32	33	42	41	15	15	18	19	107	108
2017	2017-2018	36	37	47	45	15	15	19	19	118	116
2018	2018-2019	39	40	52	48	16	16	19	19	126	124

[1] Reductions estimated at busbar.

City Of Tallahassee

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2007	Actual 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(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	166	12	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	166	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	2	3	0	0	0	0	0	0	0	0	0	0
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	1	3	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	18,865	19,393	20,593	22,982	22,897	21,635	20,035	20,091	20,340	20,270	20,354	20,869
(14)		Steam	1000 MCF	7,499	2,645	2,010	301	442	676	780	1,022	630	477	99	0
(15)		CC	1000 MCF	10,362	16,110	16,617	21,776	21,298	19,856	18,594	18,074	19,244	19,332	19,209	19,644
(16)		CT	1000 MCF	1,004	638	1,966	905	1,157	1,103	661	995	466	461	1,046	1,225
(17)		Diesel	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(18)	Other (Specify)		Trillion Btu	0	0	0	0	0	0	0	0	0	0	0	0

City Of Tallahassee

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2007	Actual 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	Annual Firm Interchange		GWh	196	239	117	118	118	118	119	119	120	113	24	24
(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	97	7	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWh	97	7	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWh	1	1	0	0	0	0	0	0	0	0	0	0
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	1	1	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	2,165	2,424	2,677	2,701	2,721	2,730	2,567	2,478	2,502	2,521	2,591	2,591
(15)		Steam	GWh	661	228	71	69	89	88	88	103	112	110	89	89
(16)		CC	GWh	1,403	2,139	2,561	2,576	2,575	2,599	2,402	2,292	2,337	2,356	2,462	2,462
(17)		CT	GWh	100	57	45	56	57	43	77	83	53	55	40	40
(18)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Hydro		GWh	6	17	18	18	18	18	18	18	18	18	18	18
(20)	Economy Interchange		GWh	450	146	53	30	12	9	0	-24	-50	-63	-43	-43
(21)	Renewables		GWh	0	0	0	0	0	0	172	285	285	286	285	285
(22)	Net Energy for Load		GWh	2,914	2,834	2,865	2,867	2,869	2,875	2,876	2,876	2,875	2,875	2,875	2,875

Table 2.19

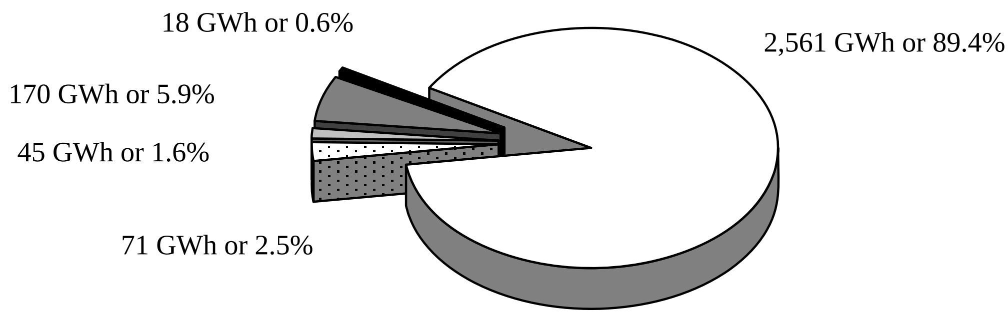
City Of Tallahassee

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 2007	Actual 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	Annual Firm Interchange		%	6.7	8.4	4.1	4.1	4.1	4.1	4.1	4.1	4.2	3.9	0.8	0.8
(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	%	3.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		Steam	%	3.3	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	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	Total	%	74.3	85.5	93.5	94.2	94.9	95.0	89.3	86.2	87.0	87.7	90.1	90.1
(15)		Steam	%	22.7	8.0	2.5	2.4	3.1	3.1	3.1	3.6	3.9	3.8	3.1	3.1
(16)		CC	%	48.2	75.5	89.4	89.9	89.8	90.4	83.5	79.7	81.3	82.0	85.6	85.6
(17)		CT	%	3.4	2.0	1.6	2.0	2.0	1.5	2.7	2.9	1.8	1.9	1.4	1.4
(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		%	0.2	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
(20)	Economy Interchange		%	15.4	5.2	1.9	1.0	0.4	0.3	0.0	-0.8	-1.7	-2.2	-1.5	-1.5
(21)	Renewables		%	0.0	0.0	0.0	0.0	0.0	0.0	6.0	9.9	9.9	9.9	9.9	9.9
(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

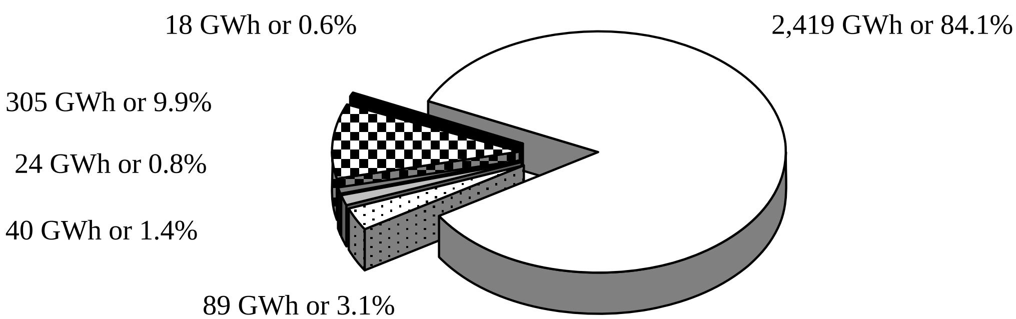
Calendar Year 2009*



Total 2009 NEL = 2,865 GWh

*Other than hydro and demand-side solar PV, the City has no renewable sources in 2009.

Calendar Year 2018



Total 2018 NEL = 2,875

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

Chapter III

Projected Facility Requirements

3.1 PLANNING PROCESS

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

As reported in the 2008 TYSP, the resource plan identified in the 2006 IRP Study included the the repowering of Hopkins Unit 2 to combined cycle operation, renewable energy purchases, a commitment to an aggressive DSM portfolio and the latter year addition of peaking resources to meet energy demand over the next ten years.

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

3.2 PROJECTED RESOURCE REQUIREMENTS

3.2.1 TRANSMISSION LIMITATIONS

The City has projected that no additional power supply resources will be required during the 2009-2018 TYSP reporting period to maintain a reliable electric system. However, the City's projected transmission import capability is a major determinant of the need for future power supply resource additions. As has been seen in other parts of the country, there has been little investment in the regional transmission system around Tallahassee. Consequently, the City's internal transmission studies have reflected a gradual deterioration of the system's transmission import (and export) capability into the future, due in part to this lack of investment in facilities as well as the impact of unscheduled power flow-through on the City's transmission system. The City has worked with its neighboring utilities, Progress and Southern, to plan and maintain, at minimum, sufficient transmission import capability to allow the City to make emergency power purchases in the event of the most severe single contingency, the loss of the system's largest generating unit. Though it is not currently expected that additional power supply resources will be needed to satisfy load and planning reserve requirements in the reporting period, the City may need new power supply resources to complement available transmission import capability.

The prospects for significant expansion of the regional transmission system around Tallahassee hinges on (i) the City's ongoing discussions with Progress and Southern, (ii) the Florida Reliability Coordinating Council's (FRCC) regional transmission planning process, (iii) the evolving set of mandatory reliability standards issued by the North American Electric Reliability Corporation (NERC), and (iv) alternative mechanisms envisioned by recent actions of the U.S. Department of Energy (DOE) regarding key transmission corridors. Unfortunately, none of these efforts is expected to produce substantive improvements to the City's transmission import/export capability in the short-term. The City continues to discuss the limitations of the existing transmission grid in the Florida panhandle region with Progress. In consideration of the City's projected transmission import capability reductions and the associated grid limitations, the results of the 2006 IRP Study and other internal analysis of options tend to favor local generation alternatives as the means to satisfy future power supply requirements.

3.2.2 Reserve Requirements

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

3.2.3 Near Term Resource Additions

At their October 17, 2005 meeting the City Commission gave the Electric Utility approval to proceed with the repowering of Hopkins Unit 2 to combined cycle operation. The repowering was completed and the unit began commercial operation in June 2008. The former

Hopkins Unit 2 boiler was retired and replaced with a combustion turbine generator (CTG) and a heat recovery steam generator (HRSG). The Hopkins 2 steam turbine and generator is now powered by the steam generated in the HRSG. Duct burners have been installed in the HRSG to provide additional peak generating capability. The repowering project provides additional capacity as well as increased efficiency versus the unit's capabilities prior to the repowering project. The repowered unit has achieved official seasonal net capacities of 300 MW in the summer and 330 MW in the winter.

3.2.4 POWER SUPPLY DIVERSITY

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

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

The City has entered into two purchased power agreements with renewable energy providers, both of which involve the purchase of energy when available from projects developed by private companies and located either within the City's or a neighboring utility's electric service territory (see Section 3.2.5 for details on these two purchased power agreements).

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 renewable energy purchases and an increase in customer-sited renewable energy projects (primarily solar panels) are contributing to an improvement in the City's overall resource diversity. However, diversity remains a significant issue for the City, in light of the City's heavy dependence upon natural gas as a fuel source for electric generation and pending federal and state legislation related to climate change and greenhouse gas (GHG) emissions control.

3.2.5 RENEWABLE RESOURCES

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

Currently the City has a portfolio of 51 kW of solar PV operated and maintained by the Electric Utility, and as of the end of March 2009, an additional 255 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 2008 the City added 3.8 Million BTU's of solar thermal systems at the following locations: Jack McLean Park Pool, Oak Ridge Elementary School, and Fire Station #1. As reported in previous submissions, the City signed a 30-year PPA with Biomass Gas & Electric (BG&E) for up to 3.3 GWh/year of electricity and 60 million British thermal units (Btu) per hour of synthetic gas produced by BG&E's biomass-fueled synthetic gas production from a 40 MW gasification project. The original target in-service date for the electric generating facility was June 1, 2010. However, as a result of public opposition expressed during the permitting process BG&E chose to abandon its preferred site for this facility and is, as of this report, seeking an alternative site. Consequently, the City has been advised by the developer that the project cannot be completed according to its original schedule. Because the BG&E facility is to employ an emerging technology, the City will not consider the PPA as firm capacity until the facility's reliable performance has been demonstrated for a sufficient period. But given the uncertainty associated with the facility's siting, the City also does not report any energy purchased under the BG&E PPA in this TYSP. The City will provide an update on the status of the BG&E PPA in next year's TYSP report.

After the completion of the BG&E contract, the City continued its' efforts to seek additional energy derived from alternative fuels. Theses efforts lead to a 30-year PPA with Green Power Systems of Jacksonville, Florida for a 40 MW project called "Renewable Fuel Tallahassee" (RFT). 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. Permitting activities for the RFT project have not yet begun. The electric generating facility is to be constructed locally though the City has considered that RFT may well face public opposition similar to that BG&E experienced in their permitting process. The original target in service date for the facility was October 1, 2010 but, based on the foregoing and the project's progress to date, the City has assumed a more conservative in-service date of June 1, 2013. The City will provide an update on the status of the RFT PPA in next year's TYSP report.

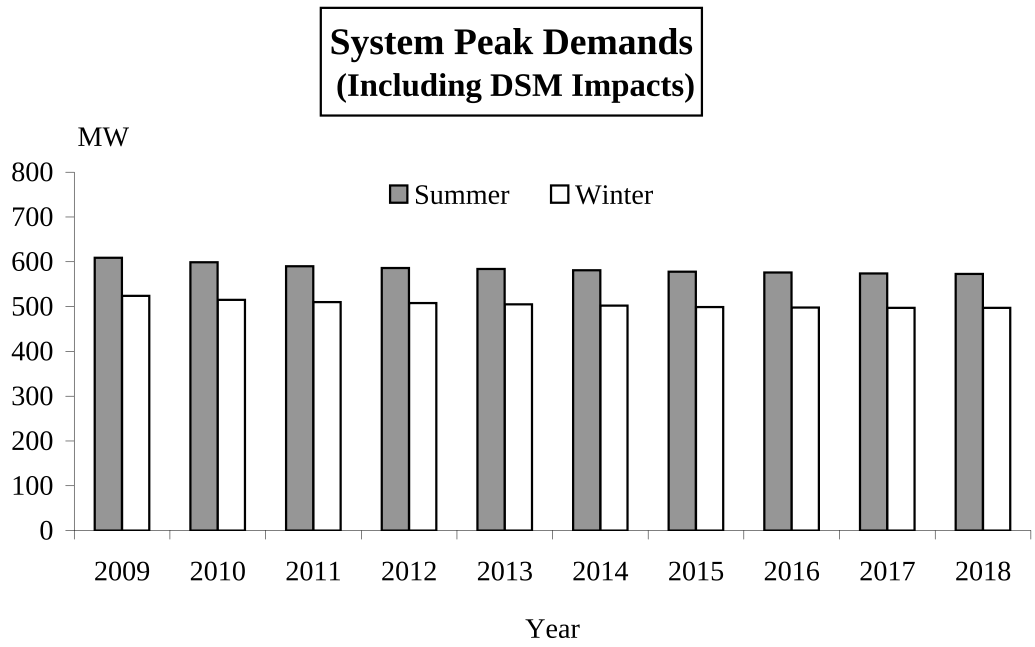
The City will mitigate the risk associated with the emerging technologies employed by BG&E and RFT by (i) having no contractual cost obligations other than to pay for the electric energy actually delivered, and (ii) not counting the purchases as firm capacity until the respective facility's reliable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

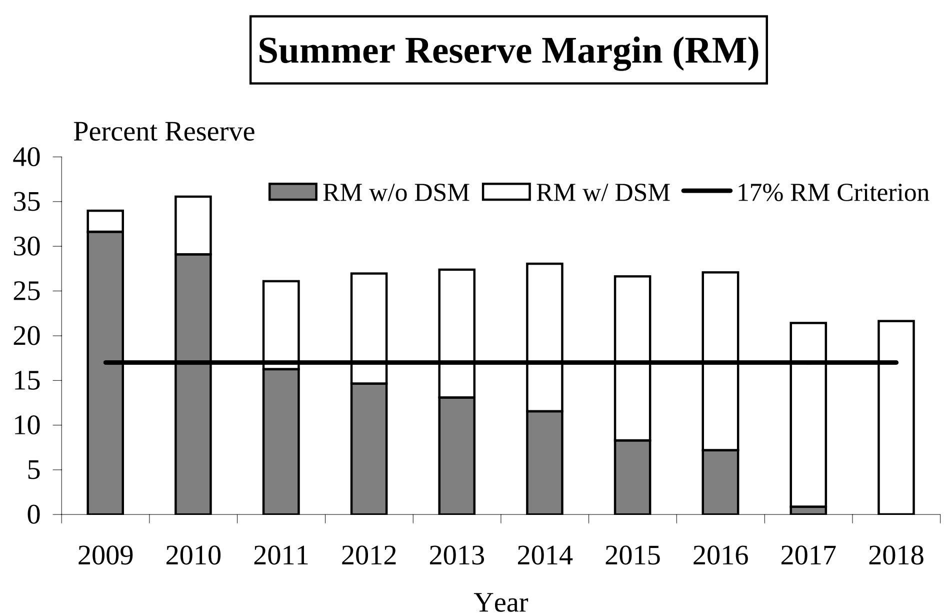
3.2.6 FUTURE POWER SUPPLY RESOURCES

The City currently projects that no power supply resource additions will be needed in this reporting period to maintain electric system adequacy and reliability. This resource plan is dependent on the aggressive DSM portfolio (described in Section 2.1.3 of this report) and the City's projected transmission import capability but, as previously discussed, does not count the two renewable energy purchase agreements toward meeting the City's planning reserve requirement. Under these base conditions, the City has sufficient reserves to meet its planning reserve requirements throughout the reporting period. If only 50% of the DSM target is achieved, the City would require no more than 10 MW to meet its planning reserve requirements in 2015. 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 purchases offer an additional level of flexibility to meet capacity requirements during the reporting period. If both the BG&E and RFT transactions achieve commercial operation and can subsequently be considered as firm capacity and 100% effectiveness of the DSM portfolio is achieved, the City would need no additional resources to meet planning reserve requirements until after 2025. The City continues to monitor closely the performance of the DSM portfolio, and will be evaluating the proposed renewable energy purchases to determine if these transactions can be included in future reserve calculations.

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


System Peak Demands
(Including DSM Impacts)
MW
800
700
600
500
400
300
200
100
0
Summer
Winter
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
Year


Summer Reserve Margin (RM)
Percent Reserve
40
35
30
25
20
15
10
5
0
RM w/o DSM
RM w/ DSM
17% RM Criterion
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
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
2009	805	11	0	0	816	609	207	34	0	207	34
2010	805	11	0	0	816	599	217	36	0	217	36
2011	737	11	0	0	748	590	158	27	0	158	27
2012	737	11	0	0	748	586	162	28	0	162	28
2013	737	11	0	0	748	584	164	28	0	164	28
2014	737	11	0	0	748	581	167	29	0	167	29
2015	725	11	0	0	736	578	158	27	0	158	27
2016	725	11	0	0	736	576	160	28	0	160	28
2017	701	0	0	0	701	574	127	22	0	127	22
2018	701	0	0	0	701	573	128	22	0	128	22

Notes

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

City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export		Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	(MW)	(MW)	(MW)	QF (MW)	(MW)	(MW)	(MW)	% of Peak	(MW)	(MW)	% of Peak
2009/10	876	11	0	0	887	524	363	69	0	363	69
2010/11	876	11	0	0	887	515	372	72	0	372	72
2011/12	806	11	0	0	817	510	307	60	0	307	60
2012/13	806	11	0	0	817	508	309	61	0	309	61
2013/14	806	11	0	0	817	505	312	62	0	312	62
2014/15	806	11	0	0	817	502	315	63	0	315	63
2015/16	792	11	0	0	803	499	304	61	0	304	61
2016/17	792	0	0	0	792	498	294	59	0	294	59
2017/18	766	0	0	0	766	497	269	54	0	269	54
2018/19	766	0	0	0	766	497	269	54	0	269	54

Notes

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

City Of Tallahassee

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Net Capability		
	Unit		Unit	Fuel		Fuel Transportation		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Mo/Yr	Mo/Yr	Mo/Yr	(kW)	(MW)	(MW)	Status
Purdom	CT-1	Wakulla	GT	NG	DFO	PL	TK	NA	12/63	3/11	15000	-10	-10	RT
Purdom	CT-2	Wakulla	GT	NG	DFO	PL	TK	NA	5/64	3/11	15000	-10	-10	RT
Purdom	7	Wakulla	ST	NG	RFO	PL	WA	NA	6/66	3/11	50000	-48	-50	RT
Hopkins	CT-1	Leon	GT	NG	DFO	PL	TK	NA	2/70	3/15	16320	-12	-14	RT
Hopkins	CT-2	Leon	GT	NG	DFO	PL	TK	NA	9/72	3/17	27000	-24	-26	RT

Acronyms

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

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
2009	620	11	609	805		11			816	34	[6]
2010	629	30	599	805		11			816	36	
2011	640	50	590	737		11			748	27	
2012	649	63	586	737	[3]	11			748	28	
2013	658	74	584	737		11			748	28	
2014	667	86	581	737		11			748	29	
2015	676	98	578	725	[4]	11			736	27	
2016	683	107	576	725		11			736	28	
2017	691	117	574	701	[5]				701	22	
2018	699	126	573	701					701	22	

Notes

[1] Demand Side Management includes energy efficiency and demand response/control measures. Identified as maximum achieveable reductions in the City's integrated resource planning (IRP) study completed in December 2006.

[2] Firm imports include 11 MW purchase from Progress Energy Florida (formerly Florida Power Corporation). Expires 12/3/2016.

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

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

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

[6] No City generation additions are projected in the 2009-2018 TYSP reporting period.

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Chapter IV

Proposed Plant Sites and Transmission Lines

4.1 PROPOSED PLANT SITE

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

4.2 TRANSMISSION LINE ADDITIONS/UPGRADES

Internal studies of the transmission system have identified a number of system improvements and additions that will be required to reliably serve future load. The majority of these improvements are planned to the City's 115kV transmission network.

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

Beyond assessing import and export capability, the City also conducts annual studies of its transmission system to identify further improvements and expansions to provide increased reliability and respond more effectively to certain critical contingencies both on the system and in the surrounding grid in the panhandle. These evaluations indicate that additional infrastructure projects are needed to address either (i) improvements in capability to deliver power from the Hopkins Plant (on the west side of the City's service territory) to the load center, or (ii) the strengthening of the system on the east side of the City's service territory to improve the voltage profile in that area and enhance response to contingencies.

For this TYSP, the City's most recent system transmission expansion planning studies indicate that, if the aggressive DSM portfolio does not perform as expected throughout the planning window, a 230 kV loop around the City would be necessary by summer 2016 to ensure reliable service consistent with current and anticipated FERC and NERC requirements. For this proposed transmission project, the City intends to tap its existing Hopkins-PEF Crawfordville 230kV transmission line and extend a 230 kV transmission line to the east terminating at the existing Substation BP-5 as the first phase of the project to be in service as early as summer 2012 (if DSM performance warrants), and then upgrade existing 115kV lines to 230 kV from Substation BP-5 to Substation BP-4 to Substation BP-7 as the second phase of the project completing the loop by summer 2016. This new 230 kV line would address a number of potential line overloads for the single contingency loss of other key transmission lines in the City's system. Possible locations for 230/115 kV transformation along the new 230 kV line include Substations BP-5 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 2010 is currently ongoing, and any revisions to project budgets in the electric utility will not be finalized until the summer of 2009. Some of the preliminary engineering and design work for the aforementioned 230 kV transmission projects has been authorized and is currently underway. If these improvements do not remain on the approved project list, or if other budget priorities result in the postponement of budgeted but not initiated projects, the City has prepared operating solutions to mitigate adverse system conditions that might occur as a result of the delay in the in-service date of these improvements.

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	No City generation additions are projected in the 2009-2018 TYSP reporting period.
(2)	Capacity a.) Summer: b.) Winter:	
(3)	Technology Type:	
(4)	Anticipated Construction Timing a.) Field Construction start - date: b.) Commercial in-service date:	
(5)	Fuel a.) Primary fuel: b.) Alternate fuel:	
(6)	Air Pollution Control Strategy:	
(7)	Cooling Status:	
(8)	Total Site Area:	
(9)	Construction Status:	
(10)	Certification Status:	
(11)	Status with Federal Agencies:	
(12)	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor: Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	
(13)	Projected Unit Financial Data Book Life (Years) Total Installed Cost (In-Service Year $/kW) Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O & M ($kW-Yr): Variable O & M ($/MWH): K Factor:	

Figure D-1 – Hopkins Plant Site

Figure D-2 – Purdom Plant Site

City Of Tallahassee

Planned Transmission Projects, 2009-2018

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	12/31/09	115	3.0
	Line 26	Sub 17	7517	Sub 14	7514	2/28/10	115	4.0
	Line 25	Sub 21	7521	Sub 17	7517	2/28/10	115	6.0
	Line 27	Sub 14	7514	Sub 7	7507	3/31/11	115	6.0
	230 Loop Phase I	Hopkins S	7610	Sub 5	7605	6/1/12	230	8.0
	231 Loop Phase II	Sub 5	7605	Sub 7	7607	6/1/16	230	12.8
Line Rebuild/ Reconductor	Line 2C	Switch St	7553	Sub 5	7505	11/30/09	115	1.6
	Line 12A	Sub 2	7502	Sub 31	7531	12/31/09	115	4.3
	Line 3C	Sub 3	7503	Sub 31	7503	12/31/09	115	0.4
	Line 7A	Hopkins	7550	Sub 10	7510	3/31/10	115	5.0
	Line 15C	Sub 9	7509	Sub 4	7504	6/1/11	115	4.0
	Line 15B	Sub 5	7505	Sub 9	7509	6/1/11	115	6.0
	Line 15A	Sub 5	7505	Sub 4	7504	6/1/11	115	9.0
	Line 21	Sub 31	7531	Tallahas	3136	6/1/12	115	4.0
Transformers	Sub 7 230/115 Auto	Sub 7 230	7607	Sub 7 115	7507	12/1/09	NA	NA
Interconnections	Talquin Woodville	SECI Woodville	7554	Woodville	7020	12/31/09	115	< 1.0
	Hopkins - PEF Tallahassee	Hopkins	7550	Tallahas	3136	6/1/12	115	4.0
Substations	Sub 21 (Bus 7521)	NA	NA	NA	NA	6/1/10	115	NA
	Sub 14 (Bus 7514)	NA	NA	NA	NA	9/30/10	115	NA
	Sub 17 (Bus 7517)	NA	NA	NA	NA	9/30/10	115	NA
	Sub 22 (Bus 7522)	NA	NA	NA	NA	6/1/12	115	NA
	Sub 23 (Bus 7523)	NA	NA	NA	NA	9/30/13	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 [1]:	Start: 2009 End: 2012
(7)	Anticipated Capital Investment:	$9.86 million
(8)	Substations:	Hopkins South (tap Hopkins-Crawfordville 230 kV) [2]
(9)	Participation with Other Utilities:	None

Notes

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

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

City Of Tallahassee

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

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

<u>Notes</u>

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

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APPENDIX A

SUPPLEMENTAL DATA

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Existing Generating Unit Operating Performance

(1)	(2)		(3)		(4)		(5)		(6)	
			Planned Outage Factor (POF)		Forced Outage Factor (FOF)		Equivalent Availability Factor (EAF)		Average Net Operating Heat Rate (ANOHR)	
Plant Name	Unit No.		Historical	Projected	Historical	Projected	Historical	Projected	Historical	Projected
Existing Units										
Corn	1	[1]	NA	8.37%	NA	2.95%	NA	88.36%	NA	NA
Corn	2	[1]	NA	8.37%	NA	2.95%	NA	88.36%	NA	NA
Corn	3	[1]	NA	8.37%	NA	2.95%	NA	88.36%	NA	NA
Hopkins	1		4.57%	5.00%	0.04%	2.57%	95.40%	91.86%	12,332	12,228
Hopkins	ST 2	[2]	23.27%	NA	1.90%	NA	74.84%	NA	NA	NA
Hopkins	CT 2A	[2]	0.00%	NA	1.85%	NA	98.15%	NA	NA	NA
Hopkins	CC 2	[2]	NA	6.53%	NA	3.33%	NA	86.40%	10,443	7,966
Hopkins	GT-1		0.62%	4.43%	0.00%	4.80%	99.38%	87.75%	24,106	22,334
Hopkins	GT-2		2.12%	3.71%	0.12%	3.13%	97.76%	89.01%	26,601	18,961
Hopkins	GT-3		2.71%	3.71%	0.80%	3.13%	96.49%	89.01%	9,606	9,904
Hopkins	GT-4		1.26%	3.71%	0.25%	3.13%	98.49%	89.01%	10,407	9,880
Purdom	7		0.71%	5.00%	5.97%	2.57%	93.32%	91.86%	12,839	14,928
Purdom	8		7.47%	6.53%	4.36%	3.33%	88.17%	86.40%	7,411	7,463
Purdom	GT-1		0.06%	4.43%	0.06%	4.80%	99.88%	87.75%	40,455	28,936
Purdom	GT-2		0.05%	4.43%	1.43%	4.80%	98.52%	87.75%	33,644	28,937

Future Units

No City generation additions are projected in the 2009-2018 Ten Year Site Plan reporting period.

NOTES: Historical - average of past three fiscal years

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

[1] The City does not track the planned outage, forced outage or equivalent availability factors for the Corn Hydro units.

[2] TAL's former Hopkins 2 steam unit was repowered and began commercial operation as a combined cycle (CC) in June 2008. Therefore, the unit's performance data is in three parts: steam turbine/generator (ST 2), combustion turbine/generator (CT 2A), and combined cycle (CC 2). Historical values for ST 2 reflect those for October 2005 through September 2008 (before and after completion the repowering project); historical values for CT 2A reflect those for CT added as part of repowering project for June through September 2008. Historical ANOHR and all forecast values are for CC2. The higher historical POF value for ST 2 reflects the extended unit outage required to accomplish the repowering project.

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]	2006	NA	NA	NA	54.80	870	-	NA	NA	NA
	2007	NA	NA	NA	57.91	919	5.7%	NA	NA	NA
	2008	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
Forecast	2009	NA	NA	NA	41.33	656	-29.6%	NA	NA	NA
	2010	NA	NA	NA	42.40	673	2.6%	NA	NA	NA
	2011	NA	NA	NA	43.47	690	2.5%	NA	NA	NA
	2012	NA	NA	NA	44.54	707	2.5%	NA	NA	NA
	2013	NA	NA	NA	45.68	725	2.5%	NA	NA	NA
	2014	NA	NA	NA	46.81	743	2.5%	NA	NA	NA
	2015	NA	NA	NA	47.94	761	2.4%	NA	NA	NA
	2016	NA	NA	NA	49.14	780	2.5%	NA	NA	NA
	2017	NA	NA	NA	50.40	800	2.6%	NA	NA	NA
	2018	NA	NA	NA	51.66	820	2.5%	NA	NA	NA

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

[1]   Actual average cost of oil burned.

Nominal, Delivered Residual Oil Prices
High Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Residual Oil (By Sulfur Content)								
		Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
	Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History [1]	2005	NA	NA	NA	54.80	870	-	NA	NA	NA
	2006	NA	NA	NA	57.91	919	5.7%	NA	NA	NA
	2007	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
Forecast [2]	2008	NA	NA	NA	41.33	656	-29.6%	NA	NA	NA
	2009	NA	NA	NA	43.43	689	5.1%	NA	NA	NA
	2010	NA	NA	NA	45.62	724	5.0%	NA	NA	NA
	2011	NA	NA	NA	47.88	760	5.0%	NA	NA	NA
	2012	NA	NA	NA	50.30	798	5.0%	NA	NA	NA
	2013	NA	NA	NA	52.80	838	5.0%	NA	NA	NA
	2014	NA	NA	NA	55.40	879	4.9%	NA	NA	NA
	2015	NA	NA	NA	58.17	923	5.0%	NA	NA	NA
	2016	NA	NA	NA	61.11	970	5.1%	NA	NA	NA
	2017	NA	NA	NA	64.17	1019	5.0%	NA	NA	NA

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

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

Nominal, Delivered Residual Oil Prices
Low Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Residual Oil (By Sulfur Content)								
		Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
	Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History [1]	2005	NA	NA	NA	54.80	870	-	NA	NA	NA
	2006	NA	NA	NA	57.91	919	5.7%	NA	NA	NA
	2007	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
Forecast [2]	2008	NA	NA	NA	41.33	656	-29.6%	NA	NA	NA
	2009	NA	NA	NA	41.37	657	0.1%	NA	NA	NA
	2010	NA	NA	NA	41.38	657	0.0%	NA	NA	NA
	2011	NA	NA	NA	41.36	657	0.0%	NA	NA	NA
	2012	NA	NA	NA	41.38	657	0.0%	NA	NA	NA
	2013	NA	NA	NA	41.37	657	0.0%	NA	NA	NA
	2014	NA	NA	NA	41.34	656	-0.1%	NA	NA	NA
	2015	NA	NA	NA	41.34	656	0.0%	NA	NA	NA
	2016	NA	NA	NA	41.37	657	0.1%	NA	NA	NA
	2017	NA	NA	NA	41.37	657	0.0%	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]	2006	77.72	1340	-	916	9.52	-
	2007	75.34	1299	-3.1%	834	8.62	-9.4%
	2008	70.44	1214	-6.5%	1,085	11.22	30.1%
Forecast	2009	55.68	960	-21.0%	948	9.86	-12.1%
	2010	58.06	1001	4.3%	836	8.69	-11.8%
	2011	62.12	1071	7.0%	756	7.86	-9.6%
	2012	64.32	1109	3.5%	756	7.86	0.0%
	2013	65.95	1137	2.5%	771	8.02	2.0%
	2014	67.57	1165	2.5%	780	8.11	1.2%
	2015	69.25	1194	2.5%	794	8.26	1.8%
	2016	70.99	1224	2.5%	812	8.44	2.3%
	2017	72.79	1255	2.5%	833	8.66	2.6%
	2018	74.59	1286	2.5%	851	8.85	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 3% for compression losses plus firm transportation cost.

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil [2]			Natural Gas [3]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2005	77.72	1340	-	916	9.53	-
	2006	75.34	1299	-3.1%	834	8.67	-9.0%
	2007	70.44	1214	-6.5%	1,085	11.28	30.1%
Forecast [4]	2008	55.68	960	-21.0%	948	9.86	-12.6%
	2009	59.45	1025	6.8%	860	8.94	-9.3%
	2010	65.09	1122	9.5%	799	8.31	-7.1%
	2011	69.03	1190	6.0%	819	8.52	2.5%
	2012	72.50	1250	5.0%	856	8.90	4.5%
	2013	76.10	1312	5.0%	887	9.22	3.7%
	2014	79.89	1377	5.0%	925	9.62	4.3%
	2015	83.90	1447	5.0%	969	10.08	4.8%
	2016	88.12	1519	5.0%	1,018	10.59	5.1%
	2017	92.50	1595	5.0%	1,066	11.09	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 3% for compression losses plus firm transportation cost.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil [2]			Natural Gas [3]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2005	77.72	1340	-	916	9.53	-
	2006	75.34	1299	-3.1%	834	8.67	-9.0%
	2007	70.44	1214	-6.5%	1,085	11.28	30.1%
Forecast [4]	2008	55.68	960	-21.0%	948	9.86	-12.6%
	2009	56.67	977	1.8%	812	8.45	-14.3%
	2010	59.21	1021	4.5%	714	7.43	-12.1%
	2011	59.83	1032	1.0%	696	7.24	-2.5%
	2012	59.85	1032	0.0%	693	7.21	-0.5%
	2013	59.83	1031	0.0%	684	7.11	-1.3%
	2014	59.82	1031	0.0%	679	7.06	-0.7%
	2015	59.83	1031	0.0%	677	7.04	-0.2%
	2016	59.85	1032	0.0%	678	7.05	0.1%
	2017	59.83	1032	0.0%	675	7.02	-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 3% for compression losses plus firm transportation cost.

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	2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2008	62.88	262	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	63.60	265	1.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	62.88	262	-1.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	61.20	255	-2.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	60.48	252	-1.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	62.88	262	4.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	64.32	268	2.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	65.04	271	1.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	63.60	265	-2.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	61.92	258	-2.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA

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

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

Nominal, Delivered Coal Prices [1]
High Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
		Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
	Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
History	2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2008	45.74	262	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	46.09	272	3.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	46.48	275	1.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	46.68	275	-0.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	47.66	278	1.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	48.68	296	6.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	49.72	311	4.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	50.80	322	3.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	51.92	323	0.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	52.92	322	-0.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA

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

Nominal, Delivered Coal Prices [1]
Low Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
		Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
	Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
History	2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2008	45.74	262	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	46.09	258	-1.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	46.48	249	-3.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	46.68	236	-5.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	47.66	227	-3.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	48.68	231	1.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	49.72	230	-0.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	50.80	227	-1.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	51.92	216	-4.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	52.92	205	-5.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA

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

[2] For the 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	2006	NA	NA	66.77	-
	2007	NA	NA	47.22	-29.3%
	2008	NA	NA	56.60	19.9%
Forecast	2009	NA	NA	57.19	1.0%
	2010	NA	NA	58.76	2.7%
	2011	NA	NA	60.42	2.8%
	2012	NA	NA	62.14	2.8%
	2013	NA	NA	63.88	2.8%
	2014	NA	NA	65.74	2.9%
	2015	NA	NA	67.62	2.9%
	2016	NA	NA	70.66	4.5%
	2017	NA	NA	144.43	104.4%
	2018	NA	NA	148.04	2.5%

Financial Assumptions
Base Case

AFUDC RATE		5.25%	
CAPITALIZATION RATIOS:			
	DEBT	116.64%	[1]
	PREFERRED	N/A	[2]
	ASSETS	63.00%	[3]
	EQUITY	170.13%	[3]
RATE OF RETURN (6)			
	DEBT	0.58%	[4]
	PREFERRED	N/A	[2]
	ASSETS	0.32%	[5]
	EQUITY	0.85%	[5]
INCOME TAX RATE:			
	STATE	N/A	[6]
	FEDERAL	N/A	[6]
	EFFECTIVE	N/A	[6]
OTHER TAX RATE:			
Sales Tax (< $5,000)		7.00%	[7]
Sales Tax (> $5,000)		6.00%	[7]
DISCOUNT RATE:		2.75% - 5.25%	
TAX DEPRECIATION RATE:		N/A	[6]

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

Financial Escalation Assumptions

(1) Year	(2) General Inflation %	(3) Plant Construction Cost %	(4) Fixed O&M Cost %	(5) Variable O&M Cost %
2009	2.5	2.5	2.5	2.5
2010	2.5	2.5	2.5	2.5
2011	2.5	2.5	2.5	2.5
2012	2.5	2.5	2.5	2.5
2013	2.5	2.5	2.5	2.5
2014	2.5	2.5	2.5	2.5
2015	2.5	2.5	2.5	2.5
2016	2.5	2.5	2.5	2.5
2017	2.5	2.5	2.5	2.5
2018	2.5	2.5	2.5	2.5

Monthly Peak Demands and Date of Occurrence for 2006 - 2008

	Calendar Year 2006				
		Hour	Daily Temp. (^{o}F)		Peak Demand
Month	Date	Ending	Min.	Max.	(MW)
January	19-Jan	8:00 A.M.	28	78	465
February	14-Feb	8:00 A.M.	22	82	537
March	21-Mar	4:00 P.M.	29	91	406
April	20-Apr	4:00 P.M.	38	93	502
May	30-May	5:00 P.M.	48	96	524
June	22-Jun	4:00 P.M.	54	98	572
July	19-Jul	6:00 P.M.	61	99	577
August	8-Aug	4:00 P.M.	68	97	576
September	1-Sep	5:00 P.M.	47	95	539
October	2-Oct	5:00 P.M.	35	92	473
November	20-Nov	7:00 A.M.	33	82	406
December	8-Dec	9:00 P.M.	21	79	528

	Calendar Year 2007				
		Hour	Daily Temp. (^{o}F)		Peak Demand
Month	Date	Ending	Min.	Max.	(MW)
January	29-Jan	8:00 A.M.	27	50	493
February	17-Feb	9:00 A.M.	18	61	504
March	28-Mar	5:00 P.M.	53	87	441
April	27-Apr	5:00 P.M.	63	85	464
May	22-May	6:00 P.M.	61	90	497
June	11-Jun	6:00 P.M.	65	101	576
July	18-Jul	5:00 P.M.	70	99	601
August	22-Aug	5:00 P.M.	75	99	621
September	6-Sep	5:00 P.M.	74	93	559
October	10-Oct	5:00 P.M.	70	91	512
November	1-Nov	6:00 P.M.	62	83	398
December	18-Dec	8:00 A.M.	31	57	437

	Calendar Year 2008				
		Hour	Daily Temp. (^{o}F)		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	4:00 P.M.	70	96	548
July	21-Jul	5:00 P.M.	75	97	587
August	6-Aug	4:00 P.M.	73	98	556
September	15-Sep	5:00 P.M.	69	93	542
October	4-Oct	8:00 P.M.	53	87	520
November	19-Nov	8:00 A.M.	25	56	465
December	3-Dec	8:00 A.M.	27	59	468

Historical and Projected Heating and Cooling Degree Days

	Year	Heating Degree Days (HDD)	Cooling Degree Days (CDD)
History	1999	1,461	2,768
	2000	1,640	2,757
	2001	1,429	2,451
	2002	1,504	2,910
	2003	1,645	2,578
	2004	1,646	2,705
	2005	1,509	2,743
	2006	1,464	2,595
	2007	1,562	2,873
	2008	1,547	2,700
Forecast	2009	1,547	2,700
	2010	1,547	2,700
	2011	1,547	2,700
	2012	1,547	2,700
	2013	1,547	2,700
	2014	1,547	2,700
	2015	1,547	2,700
	2016	1,547	2,700
	2017	1,547	2,700
	2018	1,547	2,700

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	1999	51.32	42.87	43.67	1.666
	2000	52.47	45.63	43.62	1.722
	2001	52.48	44.04	43.17	1.771
	2002	45.22	37.08	42.50	1.799
	2003	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	67.36	56.04	61.05	2.153
Forecast [2]	2009	67.36	56.04	60.57	
	2010	67.36	56.04	60.57	
	2011	67.36	56.04	60.57	
	2012	67.36	56.04	60.57	
	2013	67.36	56.04	60.57	
	2014	67.36	56.04	60.57	
	2015	67.36	56.04	60.57	
	2016	67.36	56.04	60.57	
	2017	67.36	56.04	60.57	
	2018	67.36	56.04	60.57	

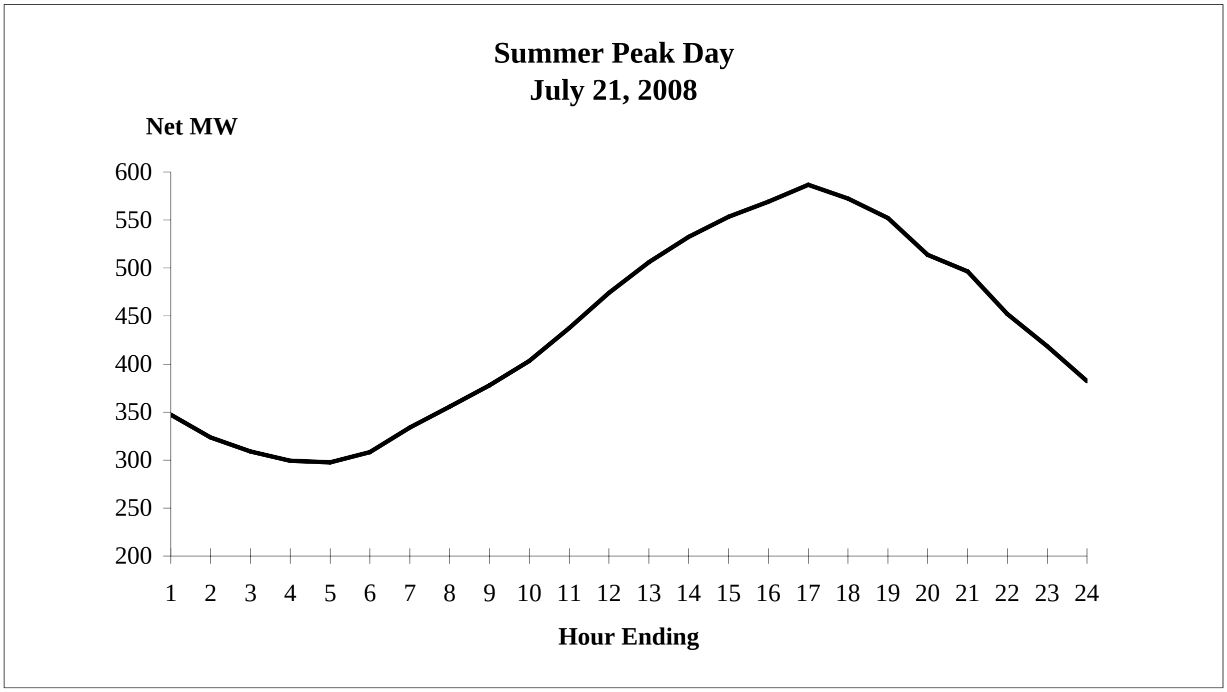
[1] Deflator is CPI Index per U. S. Dept. of Labor Bureau of Labor Stats. ('82 Dollars).

[2] For the City's 2008 Load Forecast, it was assumed that the future real price of electricity for commercial customers would remain constant at the 2007 level. While fuel prices are projected to increase in real terms, as in past load forecasts, it was assumed that these price increases would be offset by more efficient generation, reduced operations and maintenance costs, and the effects of competition.

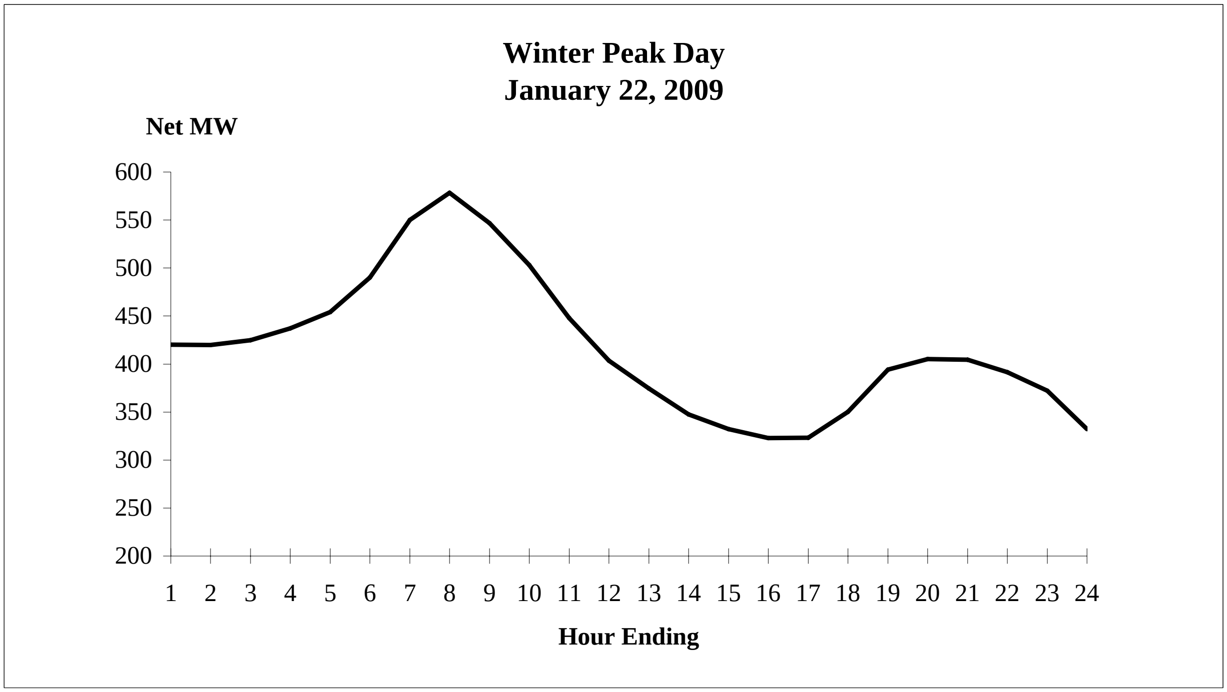
Loss of Load Probability, Reserve Margin, and Expected Unserved Energy Base Case Load Forecast

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

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



Hour Ending	Net Load (MW)	Hour Ending	Net Load (MW)
1	347	13	506
2	324	14	533
3	309	15	553
4	299	16	569
5	298	17	**587**
6	308	18	572
7	334	19	552
8	356	20	514
9	378	21	496
10	403	22	452
11	437	23	419
12	474	24	382



Hour Ending	Net Load (MW)	Hour Ending	Net Load (MW)
1	420	13	374
2	420	14	348
3	425	15	332
4	437	16	323
5	454	17	323
6	490	18	350
7	550	19	394
8	**579**	20	405
9	547	21	404
10	503	22	392
11	448	23	372
12	403	24	332