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April 9, 2004

Mr. Tim Devlin, Director
Division of Economic Regulation
State of Florida Public Service Commission

Dear Mr. Devlin:

Attached are twenty-five (25) copies of the City of Tallahassee's 2004 Ten Year Site Plan. If you have any questions, please e-mail me at childsv@talgov.com or call me at 891-3122.

Sincerely,

Venus Childs

Venus Childs
Senior Engineer

Attachments
cc: KGW
GSB

AUS ____
CAF ____
CMP ____
COM ____
CTR ____
ECR Haff
GCL ____
OPC ____
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SEC 1
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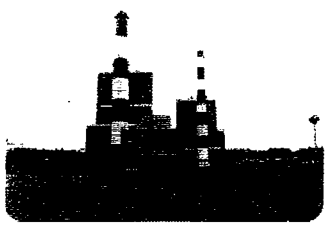
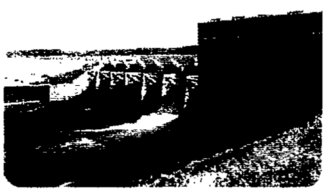
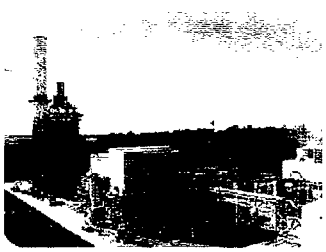
Ten Year Site Plan
2004 - 2013
City of Tallahassee
Electric Utility



Arvah B. Hopkins
Generating Station



C. H. Corn
Hydroelectric Station



Sam O. Purdom
Generating Station

Report Prepared By:
City of Tallahassee Electric Utility
System Planning

City of Tallahassee
Your Own Utilities[SM]

CITY OF TALLAHASSEE
TEN YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES
2004-2013
TABLE OF CONTENTS

III. Projected Facility Requirements

IV. Proposed Plant Sites and Transmission Lines

Appendix A

Chapter I

Description of Existing Facilities

1.0 INTRODUCTION

The City of Tallahassee (City) owns, operates, and maintains an electric generation, transmission, and distribution system that supplies electric power in and around the corporate limits of the City. The City was incorporated in 1825 and has operated since 1919 under the same charter. The City began generating its power requirements in 1902 and the City's Electric Department presently serves approximately 102,000 customers located within a 221 square mile service territory. The Electric Department operates three generating stations with a total summer season net generating capacity of 652 megawatts (MW).

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

1.1 SYSTEM CAPABILITY

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

As shown in Table 1.1 (Schedule 1), 233 MW (net summer rating) of CC generation, 48 MW (net summer rating) of steam generation and 20 MW (net summer rating) of CT generation facilities are located at the City's Sam O. Purdom Generating Station. The Arvah B. Hopkins Generating Station includes 304 MW (net summer rating) of steam generation and 36 MW (net summer rating) of CT generation facilities.

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

The City's total net summer installed generating capability is 652 MW. The corresponding winter net peak installed generating capability is 699 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. The City also has short-term capacity and energy purchase agreements with Morgan Stanley Capital Group, Incorporated for 25 MW (financially firm purchase sourced from Oglethorpe Power Corporation for the summer months (May through September of 2004) and with Southern for 15 MW (system firm purchase for February through December 2004).

City Of Tallahassee

Schedule 1
Existing Generating Facilities
As of December 31, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport		Alt. Fuel Days	Commercial In-Service	Expected Retirement	Gen. Max. Nameplate	Net Capability	
Plant	Unit No.	Location	Unit Type	Pri	Alt	Primary	Alternate	Use	Month/Year	Month/Year	(kW)	Summer (MW)	Winter (MW)
Sam O. Purdom	7	Wakulla	ST	NG	FO6	PL	WA		6/66	3/11	50,000	48	50
	8		CC	NG	FO2	PL	WA		7/00	12/40	247,743	233	262
	GT-1		GT	NG	FO2	PL	TK		12/63	3/08	15,000	10	10
	GT-2		GT	NG	FO2	PL	TK		5/64	3/09	15,000	10	10
											Plant Total	301	332
A. B. Hopkins	1	Leon	ST	NG	FO6	PL	TK		5/71	3/16	75,000	76	78
	2		ST	NG	FO6	PL	TK		10/77	3/22	259,250	228	238
	GT-1		GT	NG	FO2	PL	TK		2/70	3/15	16,320	12	14
	GT-2		GT	NG	FO2	PL	TK		9/72	3/17	27,000	24	26
											Plant Total	340	356
C. H. Corn Hydro Station	1	Leon/ Gadsden	HY	WAT	WAT	WAT	WAT		9/85	UNKNOWN	4,440	4	4
	2		HY	WAT	WAT	WAT	WAT		8/85	UNKNOWN	4,440	4	4
	3		HY	WAT	WAT	WAT	WAT		1/86	UNKNOWN	3,430	3	3
											Plant Total	11	11
TOTAL SYSTEM CAPACITY AS OF DECEMBER 31, 2003												652	699

Table 1.1

CHAPTER II

Forecast of Energy/Demand Requirements and Fuel Utilization

2.0 INTRODUCTION

Chapter II includes the City of Tallahassee's forecasts of (i) demand and energy requirements, (ii) energy sources and (iii) fuel requirements. This chapter explains the City's 2004 Load Forecast and the Demand Side Management plan filed with the Florida Public Service Commission (FPSC) on March 1, 1996. Based on the forecast, the energy sources and the fuel requirements have been projected.

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 2002 and the horizon year of 2011. Tables 2.4 through 2.12 (Schedules 3.1.1 - 3.3.3) contain historical and forecast peak demands and net energy for load for base, high, and low values. Table 2.13 (Schedule 4) compares actual and two-year forecast peak demand and energy values by month for the 2003 - 2005 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 approximately ten multi-variable linear regression models based on detailed examination of the system's historical growth, usage patterns and population statistics. Several key regression formulas utilize econometric variables.

Table 2.14 lists the econometric-based linear regression forecasting models that are used as predictors. Note that the City uses regression models with the capability of separately predicting commercial customers and consumption by rate sub-class: general service non-demand (GS), general service demand (GSD), and general service large demand (GSLD). These, along with the residential class, represent the major classes of the City's electric customers. In addition to these customer class models, the City's forecasting methodology also incorporates into the demand and energy projections estimated reductions from interruptible and curtailable customers. The key explanatory variables used in each of the models are indicated by an "X" on the table. Table 2.15 documents the City's internal and external sources for historical and forecast economic, weather and demographic data. These tables summarize the details of the models used to generate the system customer, consumption and seasonal peak load forecasts. In addition to those explanatory variables listed, a component is also included in the models that reflect the acquisition of certain Talquin Electric Cooperative (TEC) customers over the study period consistent with the territorial agreement negotiated between the City and TEC and approved by the FPSC.

The customer models are used to predict number of customers by customer class which in turn serve as input into the customer class consumption models. The customer class consumption models are aggregated to form a total base system sales forecast. The effects of demand-side management programs and system losses are incorporated in this base forecast to produce the system net energy for load (NEL) requirements. Since 1992, the City has used two econometric models to separately predict summer and winter peak demand. Table 2.14 also shows the key explanatory variables used in the demand models. Utilizing the five-year average of the actual high temperature at the time of summer peak demand, routinely updating the forecast model coefficients and making other minor model refinements have improved the accuracy of the forecast so that it is more consistent with the historical trend of growth in seasonal peak demand and energy consumption.

The most significant input assumptions for the 2003 forecast were the incremental load modifications at Florida State University (FSU), Florida A&M University (FAMU), Tallahassee Memorial Hospital (TMH) and the State Capitol Center. These four customers represent approximately 14% of the City's energy sales. Their incremental additions are highly dependent upon annual economic and budget constraints, which would cause fluctuations in their demand projections if they were projected using a model. Therefore, each entity submits their proposed incremental additions/reductions to the City and these modifications are included as submitted in the load and energy forecast. The City believes that the inclusion of these incremental additions/reductions, the routine update of forecast model coefficients and other minor model refinements have improved the accuracy of its forecast so that they are more consistent with the historical trend of growth in seasonal peak demand and energy consumption.

2.1.2 LOAD FORECAST SENSITIVITIES

Uncertainty associated with the forecast input variables and the final forecast are addressed by adjusting selected input variables in the load forecast models, to establish "high load growth" and "low load growth" sensitivity cases. For the sensitivities to the base 2004 load forecast the key explanatory variables that were changed were Leon County population, Florida population, heating degree-days and cooling degree-days for the energy forecast. For the peak demand forecasts, the Leon County population and maximum & minimum temperature on the peak days for the summer and winter, respectively, were changed.

Sensitivities on the peak demand forecasts are useful in planning for future power supply resource needs. The graph shown in Figure B3 compares summer peak demand (multiplied by 117% for reserve margin requirements) for the three cases against the City's existing and planned power supply resources. This graph allows for the review of the effect of load growth variations on the timing of new resource additions. The highest probability weighting, of course, is placed on the base case assumptions, and the low and high cases are given a smaller likelihood of occurrence.

2.1.3 ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT PROGRAMS

The City has a goal to improve the efficiency of customers' end-use of energy resources when such improvements provide a measurable economic and/or environmental benefit to the customers and the City utilities. On March 1, 1996 the City filed its

Demand Side Management (DSM) Plan with the FPSC. This plan indicated the demand and energy reductions due to conservation efforts that are expected over the period 1997-2006. The individual program measures that were selected for inclusion in the plan were identified as cost effective in Integrated Resource Planning (IRP) studies conducted by the City. During 2004 the City is planning to prepare a new DSM Plan concurrently with an updated IRP Study .

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

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

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

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 2004-2013. Figure B4 displays the percentage of energy by fuel type in 2004 and 2013.

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

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

City Of Tallahassee

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

Base Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial [2]		
Year	Population	Members Per Household	(GWh)	Average No. of Customers [1]	Average kWh Consumption Per Customer	(GWh)	Average No. of Customers [1]	Average kWh Consumption Per Customer
1994	166,890	-	799	69,907	11,429	1,205	14,277	84,401
1995	170,796	-	870	71,534	12,162	1,268	14,780	85,792
1996	175,373	-	893	72,998	12,233	1,316	15,142	86,911
1997	177,347	-	850	74,259	11,446	1,324	15,495	85,447
1998	180,725	-	940	75,729	12,413	1,396	15,779	88,472
1999	184,239	-	926	77,357	11,970	1,419	16,183	87,685
2000	186,839	-	971	79,108	12,274	[4] 1,457	15,891	91,687
2001	190,575	-	959	80,348	11,936	[4] 1,459	[5] 16,988	85,884
2002	193,941	-	1,048	81,208	12,905	1,527	16,831	90,661
2003	200,304	-	1,035	83,028	12,466	1,555	17,601	88,347
2004	203,106	-	1,066	84,386	12,632	1,625	17,853	91,021
2005	205,908	-	1,081	85,723	12,610	1,678	18,101	92,702
2006	208,789	-	1,096	87,047	12,591	1,720	18,346	93,753
2007	211,669	-	1,117	88,350	12,643	1,760	18,590	94,675
2008	214,550	-	1,137	89,634	12,685	1,792	18,832	95,157
2009	217,430	-	1,158	90,879	12,742	1,821	19,072	95,480
2010	220,311	-	1,182	92,044	12,842	1,851	19,314	95,837
2011	223,056	-	1,204	93,224	12,915	1,879	19,558	96,073
2012	225,801	-	1,226	94,420	12,985	1,908	19,804	96,344
2013	228,546	-	1,250	95,630	13,071	1,935	20,053	96,494

[1] Average end-of-month customers for the calendar year.
[2] Includes Traffic Control and Security Lighting use.
[3] Population data represents Leon County population served by City of Tallahassee Electric Utility not the general population of Leon County.
[4] Traffic control move to commerical - 3 MW in 2000 and 2001.
Initially reported in Utility use.
[5] Corrected - "other customers" excluded from total - 3/25/03

Rick Fausone of planning supplier update - 3/8/04 on the LCPOP that is served.

City Of Tallahassee

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

Base Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	(GWh)	Average No. of Customers [1]	Average kWh Consumption Per Customer	Railroads and Railways (GWh)	Street & Highway Lighting (GWh)	Other Sales to Public Authorities (GWh)	Total Sales to Ultimate Consumers (GWh)
1994	-	-	-	-	12		2,016
1995	-	-	-	-	12		2,150
1996	-	-	-	-	12		2,221
1997	-	-	-	-	12		2186
1998	-	-	-	-	12		2348
1999	-	-	-	-	13		2358
2000	-	-	-	-	13		2,441
2001					13		2,431
2002					13		2,588
2003					13		2,603
2004	-	-	-		13		2,704
2005	-	-	-		13		2,772
2006	-	-	-		13		2,829
2007	-	-	-		14		2,891
2008	-	-	-		14		2,943
2009	-	-	-		14		2,993
2010	-	-	-		14		3,047
2011	-	-	-		14		3,097
2012	-	-	-		14		3,148
2013					14		3,199

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

Table 2.2

City Of Tallahassee

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

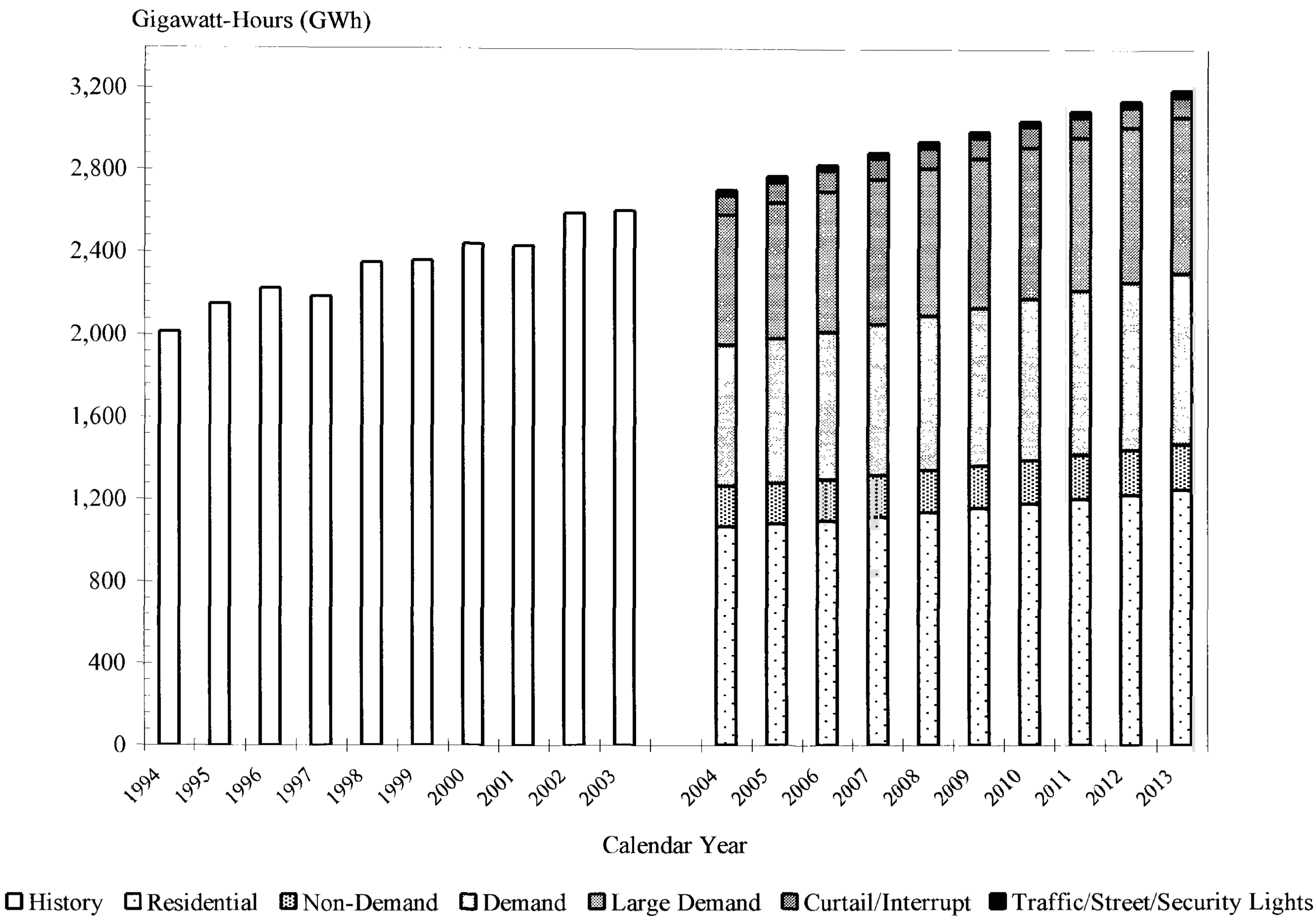
Base Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale (GWh)	Utility Use & Losses (GWh) [1]	Net Energy for Load (GWh)	Other Customers (Average No.)	Total No. of Customers [1]
1994	0	134	2,150		84,184
1995	0	142	2,292		86,314
1996	0	147	2,368		88,140
1997	0	132	2,318		89,754
1998	0	129	2,477		91,508
1999	0	139	2,497		93,540
2000	0	154	2,595		94,999
2001	0	125	2,556		97,336
2002	0	153	2,741		100,629
2003	0	152	2,755		100,629
2004	0	179	2,883		102,239
2005	0	184	2,956		103,824
2006	0	187	3,016		105,393
2007	0	191	3,082		106,940
2008	0	195	3,138		108,466
2009	0	198	3,191		109,951
2010	0	202	3,249		111,358
2011	0	205	3,302		112,782
2012	0	209	3,357		114,224
2013	0	212	3,411		115,683

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

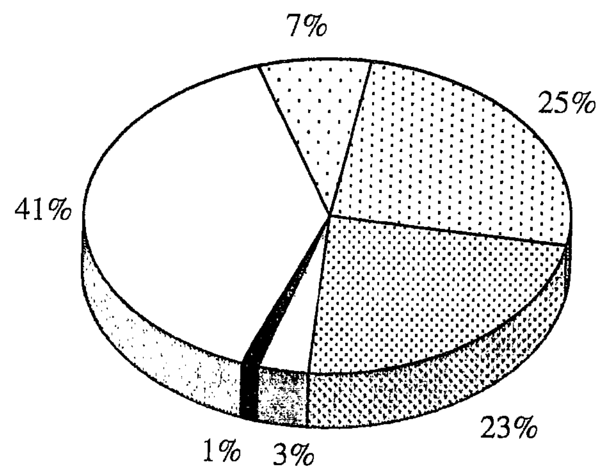
Figure B1

History and Forecast Energy Consumptior
By Customer Class



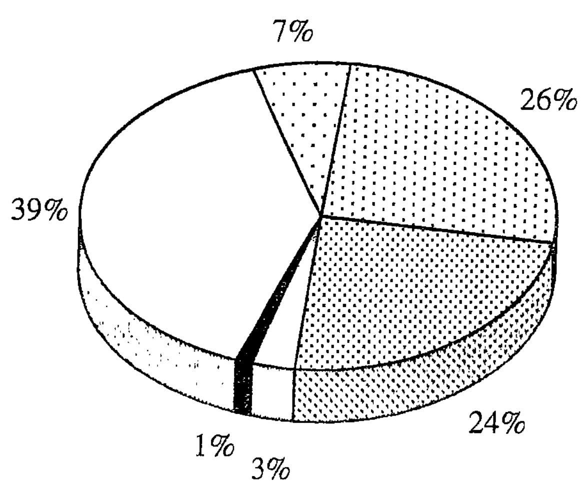
Energy Consumption By Customer Class

Calendar Year 2004



Total 2002 Sales = 2,470 GWh
Values exclude DSM impacts

Calendar Year 2013



Total 2011 Sales = 2,942 GWh
Values exclude DSM impacts

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

City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation [2]	Comm./Ind Load Management	Comm./Ind Conservation [2]	Net Firm Demand [1]
1994	433		433						433
1995	497		497						497
1996	500		500						500
1997	486		486						486
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	580		580						580
2003	550		550			1		0	549
2004	592		592			1		0	591
2005	606		606			3		1	602
2006	622		622			4		1	617
2007	632		632			4		1	627
2008	641		641			4		1	636
2009	650		650			4		1	645
2010	659		659			4		1	654
2011	667		667			4		1	662
2012	676		676			4		1	671
2013	685		685			4		1	680

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar.
[3] 2002 DSM Jan - July accumulation.

City Of Tallahassee

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation [2]	(8) Comm./Ind Load Management	(9) Comm./Ind Conservation [2]	(10) Net Firm Demand [1]
1994	433		433						433
1995	497		497						497
1996	500		500						500
1997	486		486						486
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	580		580						580
2003	550		550			1			549
2004	601		601			1			600
2005	616		616			3		1	612
2006	631		631			4		1	626
2007	641		641			4		1	636
2008	651		651			4		1	646
2009	660		660			4		1	655
2010	669		669			4		1	664
2011	677		677			4		1	672
2012	686		686			4		1	681
2013	694		694			4		1	689

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar.
[3] 2002 DSM Jan - July accumulation.

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	(7) Residential Conservation [2]	(8) Comm./Ind Load Management	(9) Comm./Ind Conservation [2]	(10) Net Firm Demand [1]
1994	433		433						433
1995	497		497						497
1996	500		500						500
1997	486		486						486
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	580		580						580
2003	550		550			1			549
2004	582		582			1			581
2005	597		597			3		1	593
2006	612		612			4		1	607
2007	622		622			4		1	617
2008	632		632			4		1	627
2009	641		641			4		1	636
2010	650		650			4		1	645
2011	658		658			4		1	653
2012	667		667			4		1	662
2013	675		675			4		1	670

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.
[3] 2002 DSM Jan - July accumulation.

City Of Tallahassee

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation [2]	(8) Comm./Ind Load Management	(9) Comm./Ind Conservation [2]	(10) Net Firm Demand [1]
1994 -1995	457		457						457
1995 -1996	533		533						533
1996 -1997	431		431						431
1997 -1998	421		421						421
1998 -1999	513		513						513
1999 -2000	497		497						497
2000 -2001	521		521						521
2001 -2002	522		522						522
2002 -2003	590		590						590
2003 -2004	514		514			5		0	509
2004 -2005	581		581			5		1	575
2005 -2006	600		600			11		1	588
2006 -2007	612		612			11		1	600
2007 -2008	624		624			11		1	612
2008 -2009	635		635			11		1	623
2009 -2010	646		646			11		1	634
2010 -2011	656		656			11		1	644
2011 -2012	667		667			11		1	655
2012 -2013	677		677			11		1	665
2013 -2014	688		688			11		1	676

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

City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation [2]	Comm./Ind Load Management	Comm./Ind Conservation [2]	Net Firm Demand [1]
1994 -1995	457		457						457
1995 -1996	533		533						533
1996 -1997	431		431						431
1997 -1998	421		421						421
1998 -1999	513		513						513
1999 -2000	497		497						497
2000 -2001	521		521						521
2001 -2002	522		522						522
2002 -2003	590		590						590
2003 -2004	514		514			5			509
2004 -2005	607		607			5		1	601
2005 -2006	626		626			11		1	614
2006 -2007	638		638			11		1	626
2007 -2008	650		650			11		1	638
2008 -2009	661		661			11		1	649
2009 -2010	672		672			11		1	660
2010 -2011	682		682			11		1	670
2011 -2012	693		693			11		1	681
2012 -2013	703		703			11		1	691
2013 -2014	714		714			11		1	702

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

City Of Tallahassee

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

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation [2]	(8) Comm./Ind Load Management	(9) Comm./Ind Conservation [2]	(10) Net Firm Demand [1]
1994 -1995	457		457						457
1995 -1996	533		533						533
1996 -1997	431		431						431
1997 -1998	421		421						421
1998 -1999	513		513						513
1999 -2,000	497		497						497
2000 -2001	521		521						521
2001 -2,002	522		522						522
2002 -2003	590		590						590
2003 -2004	514		514			5			509
2004 -2005	549		549			5		1	543
2005 -2006	568		568			11		1	556
2006 -2007	580		580			11		1	568
2007 -2008	591		591			11		1	579
2008 -2009	602		602			11		1	590
2009 -2010	613		613			11		1	601
2010 -2011	622		622			11		1	610
2011 -2012	633		633			11		1	621
2012 -2013	643		643			11		1	631
2013 -2014	655		655			11		1	643

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

City Of Tallahassee

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

(1) Year	(2) Total Sales	(3) Residential Conservation [2]	(4) Comm./Ind Conservation [2]	(5) Retail Sales [1]	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load [1]	(9) Load Factor % [1]
1994	2,016			2,016		134	2,150	57
1995	2,150			2,150		142	2,292	53
1996	2,221			2,221		147	2,368	54
1997	2,186			2,186		132	2,318	54
1998	2,349			2,349		128	2,477	53
1999	2,358			2,358		139	2,497	54
2000	2,441			2,441		154	2,595	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		153	2,741	54
2003	2,613	10	0	2,603		153	2,756	57
2004	2,711	6	1	2,704		179	2,883	56
2005	2,787	12	3	2,772		184	2,956	56
2006	2,852	18	5	2,829		187	3,016	56
2007	2,914	18	5	2,891		191	3,082	56
2008	2,966	18	5	2,943		195	3,138	56
2009	3,016	18	5	2,993		198	3,191	56
2010	3,070	18	5	3,047		202	3,249	57
2011	3,120	18	5	3,097		205	3,302	57
2012	3,171	18	5	3,148		209	3,357	57
2013	3,222	18	5	3,199		212	3,411	57

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

City Of Tallahassee

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

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year		Total Sales	Residential Conservation [2]	Comm./Ind Conservation [2]	Retail Sales [1]	Wholesale	Utility Use & Losses	Net Energy for Load [1]	Load Factor % [1]
1994	0	2,016	0	0	2,016		134	2,150	57
1995	0	2,150	0	0	2,150		142	2,292	53
1996	0	2,221	0	0	2,221		147	2,368	54
1997	0	2,186	0	0	2,186		132	2,318	54
1998	0	2,349	0	0	2,349		128	2,477	53
1999	0	2,358	0	0	2,358		139	2,497	54
2000	0	2,441	0	0	2,441		154	2,595	54
2001	0	2,431	0	0	2,431		125	2,556	56
2002	0	2,588	0	0	2,588		153	2,741	54
2003	0	2,613	10	0	2,603		153	2,756	57
2004		2,899	6	1	2,892		192	3,084	59
2005		2,978	12	3	2,963		196	3,159	59
2006		3,046	18	5	3,023		200	3,223	59
2007		3,109	18	5	3,086		204	3,290	59
2008		3,165	18	5	3,142		208	3,350	59
2009		3,218	18	5	3,195		212	3,407	59
2010		3,274	18	5	3,251		215	3,466	60
2011		3,326	18	5	3,303		219	3,522	60
2012		3,379	18	5	3,356		222	3,578	60
2013		3,433	18	5	3,410		226	3,636	60

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

City Of Tallahassee

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

(1) Year		(2) Total Sales	(3) Residential Conservation [2]	(4) Comm./Ind Conservation [2]	(5) Retail Sales [1]	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load [1]	(9) Load Factor % [1]
1994	0	2,016	0	0	2,016		134	2,150	57
1995	0	2,150	0	0	2,150		142	2,292	53
1996	0	2,221	0	0	2,221		147	2,368	54
1997	0	2,186	0	0	2,186		132	2,318	54
1998	0	2,349	0	0	2,349		128	2,477	53
1999	0	2,358	0	0	2,358		139	2,497	54
2000	0	2,441	0	0	2,441		154	2,595	54
2001	0	2,431	0	0	2,431		125	2,556	56
2002	0	2,588	0	0	2,588		153	2,741	54
2003	0	2,613	10	0	2,603		153	2,756	57
2004		2,552	6	1	2,545		169	2,714	53
2005		2,626	12	3	2,611		173	2,784	54
2006		2,689	18	5	2,666		177	2,843	53
2007		2,748	18	5	2,725		181	2,906	54
2008		2,799	18	5	2,776		184	2,960	54
2009		2,848	18	5	2,825		187	3,012	54
2010		2,898	18	5	2,875		191	3,066	54
2011		2,947	18	5	2,924		194	3,118	55
2012		2,996	18	5	2,973		197	3,170	55
2013		3,045	18	5	3,022		200	3,222	55

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

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)
	2003 Actual		**2004 Forecast [1]**		**2005 Forecast [1]**	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	590	247	509	260	575	267
February	408	191	405	199	458	204
March	365	195	384	207	433	212
April	429	202	401	212	453	217
May	487	245	517	252	527	258
June	515	248	555	261	566	268
July	539	261	591	279	602	286
August	549	270	578	285	589	292
September	517	249	547	258	557	264
October	428	216	480	227	488	233
November	421	201	366	208	413	213
December	452	230	402	235	455	242
TOTAL		2,755		2,883		2,956

[1] Peak Demand and NEL include DSM impacts.

City Of Tallahassee

2004 Electric System Load Forecast

Key Explanatory Variables

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

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

Table 2.14

Table 2.15

2004 Electric Load Forecast

Sources of Forecast Model Input Information

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

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

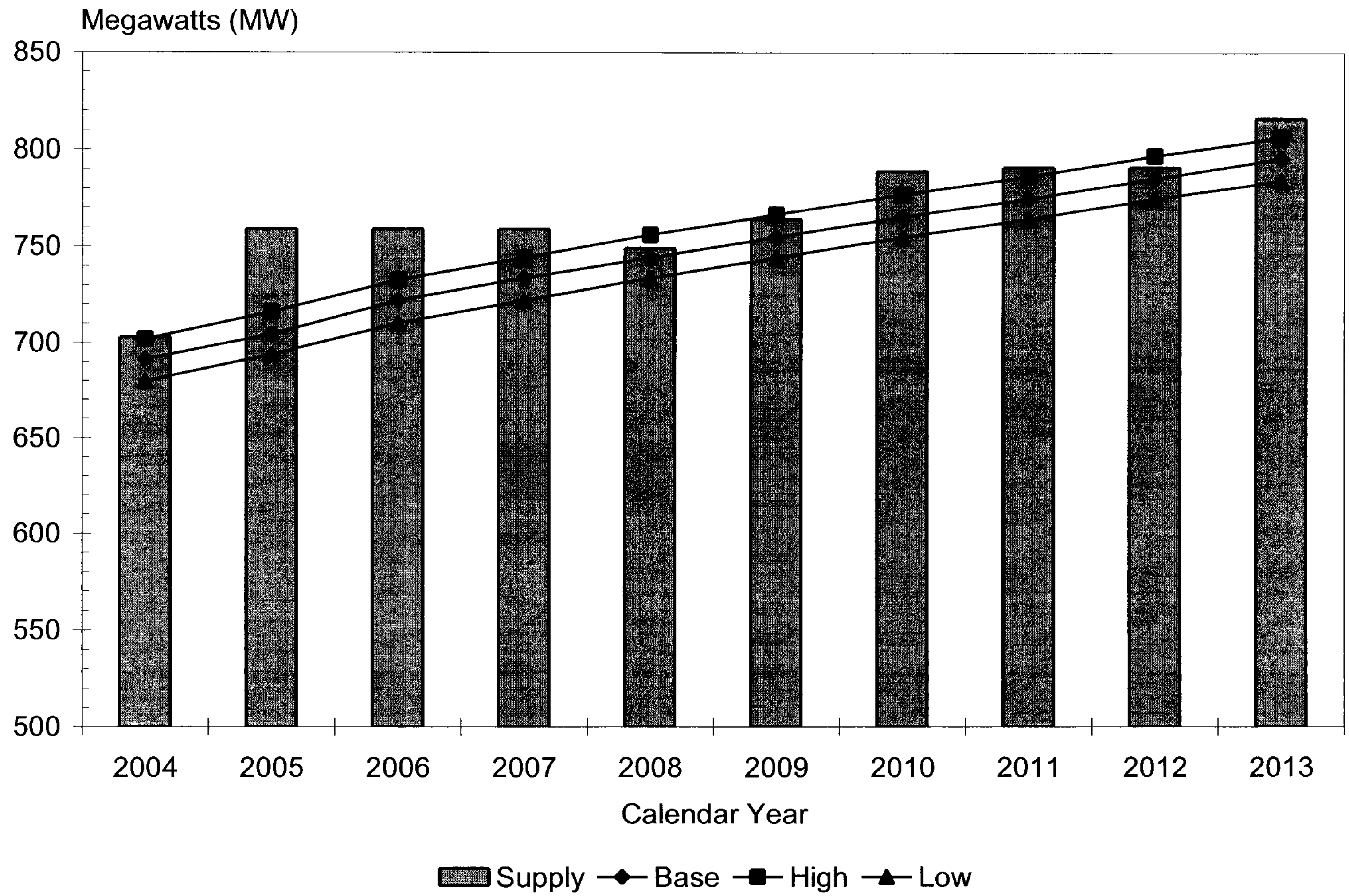


Figure B3

City Of Tallahassee

2004 Electric System Load Forecast

Projected Demand Side Management Energy Reductions [1]

Calendar Year Basis

Year	Residential Impact (MWh)	Commercial Impact (MWh)	Total Impact (MWh)
2004	6,343	1,521	7,864
2005	12,687	3,321	16,008
2006	19,030	4,842	23,872
2007	19,030	4,842	23,872
2008	19,030	4,842	23,872
2009	19,030	4,842	23,872
2010	19,030	4,842	23,872
2011	19,030	4,842	23,872
2012	19,030	4,842	23,872
2013	19,030	4,842	23,872

[1] Reductions estimated at busbar.

City Of Tallahassee

2004 Electric System Load Forecast

Projected Demand Side Management
Seasonal Demand Reductions [1]

Year		Residential Energy Efficiency Impact		Commercial Energy Efficiency Impact		Demand Side Management Total	
Summer	Winter	Summer (MW) [2]	Winter (MW) [3]	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
2004	2003-2004	1	5	0	1	1	6
2005	2004-2005	3	11	1	1	4	12
2006	2005-2006	4	11	1	1	5	12
2007	2006-2007	4	11	1	1	5	12
2008	2007-2008	4	11	1	1	5	12
2009	2008-2009	4	11	1	1	5	12
2010	2009-2010	4	11	1	1	5	12
2011	2010-2011	4	11	1	1	5	12
2012	2011-2012	4	11	1	1	5	12
2013	2021-2013	4	11	1	1	5	12

[1] Reductions estimated at busbar.
[2] Summer MW reductions based upon HVAC unit replacements
[3] Winter MW reductions based upon Home Builder Rebates for Electric to Gas appliance conversions

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 2,002	Actual 2,003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(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	91	555	1,112	1,079	1,106	468	380	247	210	204	112	0
(4)		Steam	1000 BBL	91	555	1,112	1,079	1,106	468	380	247	210	204	112	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL			0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	9	6	0	3	3	3	3	3	3	3	2	2
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	4	5	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	5	1	0	1	0	0	0	0	0	0	0	0
(12)		Diesel	1000 BBL	0	0	0	2	3	3	3	3	3	3	2	2
(13)	Natural Gas	Total	1000 MCF	19,269	16,372	15,971	16,639	17,368	20,922	22,304	23,208	23,755	24,054	24,620	25,642
(14)		Steam	1000 MCF	7,656	5,163	5,456	1,953	3,036	4,796	5,981	5,835	5,636	5,066	4,383	5,055
(15)		CC	1000 MCF	11,546	11,125	9,540	13,234	11,954	13,931	13,226	14,288	15,338	16,214	17,754	18,353
(16)		CT	1000 MCF	67	84	975	476	684	726	1,418	1,479	1,374	1,384	1,202	1,041
(17)	Other (Specify)		Trillion Btu	0	0	0	0	0	0	0	0	0	0	0	0

Table 2.18

City Of Tallahassee

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2002	Actual 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Annual Firm Interchange		GWh	140	182	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
(2)	Nuclear		GWh	0		0	0	0	0	0	0	0	0	0	0
(3)	Residual	Total	GWh	52	323	659	626	647	264	213	139	119	115	63	0
(4)		Steam	GWh	52	323	659	626	647	264	213	139	119	115	63	0
(5)		CC	GWh	0		0	0	0	0	0	0	0	0	0	0
(6)		CT	GWh	0		0	0	0	0	0	0	0	0	0	0
(7)		Diesel	GWh	0		0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	GWh	4	4	0	1	2	2	2	2	2	2	2	1
(9)		Steam	GWh	0		0	0	0	0	0	0	0	0	0	0
(10)		CC	GWh	3	4	0	0	0	0	0	0	0	0	0	0
(11)		CT	GWh	1	0	0	0	0	0	0	0	0	0	0	0
(12)		Diesel	GWh	0	0	0	1	2	2	2	2	2	2	2	1
(13)	Natural Gas	Total	GWh	2,308	2,019	1,923	2,202	2,237	2,682	2,787	2,913	2,990	3,046	3,162	3,280
(14)		Steam	GWh	690	451	519	181	285	457	567	547	526	475	411	471
(15)		CC	GWh	1,616	1,566	1,344	1,869	1,692	1,986	1,883	2,029	2,162	2,271	2,480	2,564
(16)		CT	GWh	2	2	60	41	66	71	145	153	141	141	125	109
(17)		Diesel	GWh	0	0	0	111	194	168	192	184	161	159	146	136
(18)	Hydro		GWh	14	30	9	9	9	9	9	9	9	9	9	9
(19)	Others (Specify) Market and Intra-regional		GWH	[illegible]	197										
(20)	Net Energy for Load		GWh	2,741	2,755	2,883	2,956	3,016	3,082	3,138	3,191	3,249	3,302	3,357	3,411

City Of Tallahassee

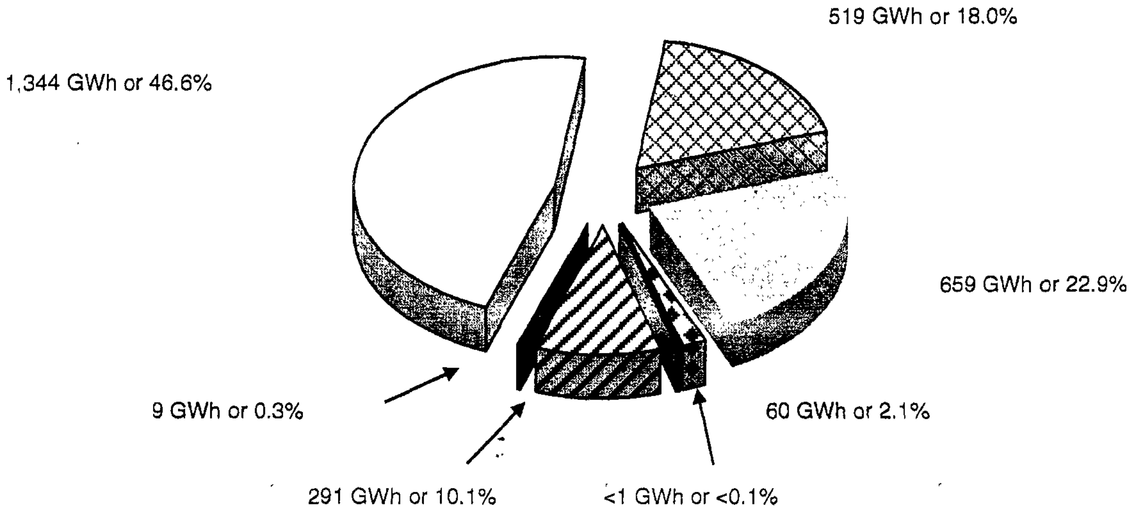
Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2002	Actual 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Annual Firm Interchange [1]		%	5.11	6.61	10.10	4.00	4.00	4.00	4.00	4.00	3.90	3.90	3.50	3.50
(2)	Nuclear		%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(3)	Residual	Total	%	1.90	11.73	22.90	21.20	21.50	8.60	6.80	4.40	3.70	3.50	1.90	0.00
(4)		Steam	%	1.90	11.73	22.90	21.20	21.50	8.60	6.80	4.40	3.70	3.50	1.90	0.00
(5)		CC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(6)		CT	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(7)		Diesel	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(8)	Distillate	Total	%	0.15	0.15	0.00	0.00	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.00
(9)		Steam	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(10)		CC	%	0.11	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(11)		CT	%	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(12)		Diesel	%	0.00	0.00	0.00	0.00	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.00
(13)	Natural Gas	Total	%	84.22	73.29	66.70	74.50	74.20	87.10	88.80	91.30	92.10	92.30	94.30	96.20
(14)		Steam	%	25.18	16.37	18.00	6.10	9.50	14.80	18.10	17.10	16.20	14.40	12.30	13.80
(15)		CC	%	58.97	56.85	46.60	63.20	56.10	64.50	60.00	63.60	66.60	68.80	73.90	75.20
(16)		CT	%	0.07	0.07	2.10	1.40	2.20	2.30	4.60	4.80	4.30	4.30	3.70	3.20
(17)	Hydro		%	0.51	1.09	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
(18)	Others (Specify) Market and Intra-regional		%	8.14	7.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(19)	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100	100

Table 2.20

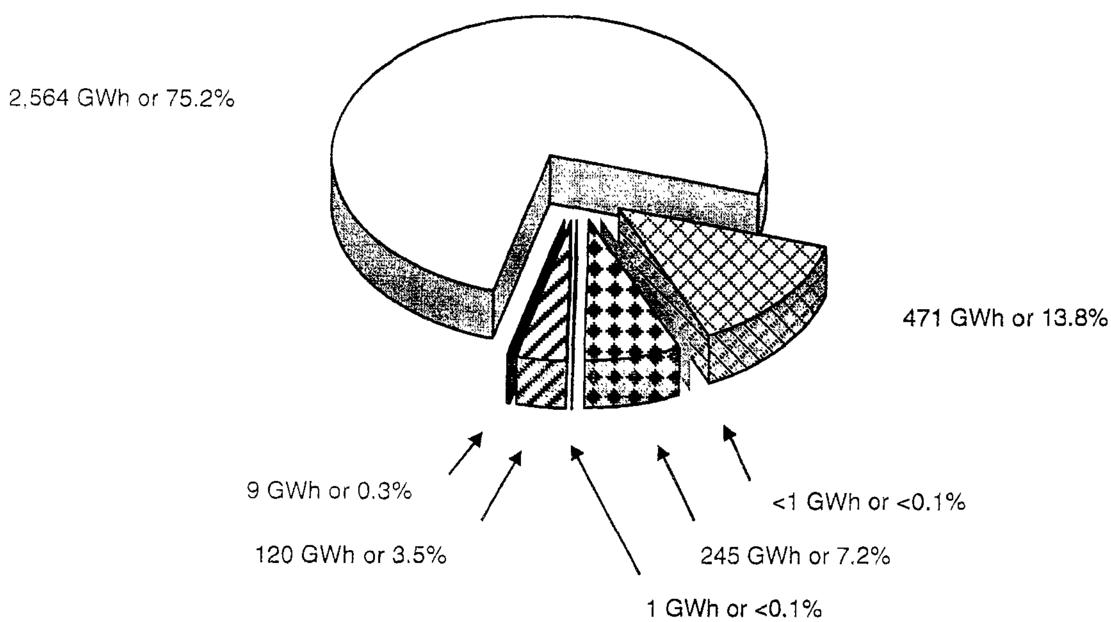
Generation By Resource/Fuel Type

Calendar Year 2004



Total 2004 NEL =

Calendar Year 2013



Total 2013 NEL = 3,410

□CC - Gas ⊠ Steam - Gas Steam - Oil ◼ CT/Diesel - Gas □ CT/Deisel - Oil ◪ Purch ■ Hydro

Chapter III

Projected Facility Requirements

3.0 INTRODUCTION

The review and approval by the City Commission of the electric utility's recommended resource plan is guided by the objectives in the City's Energy Policy:

> *It is the policy of the City of Tallahassee to provide a reliable, economically-competitive energy system which meets citizens' energy needs and reduces total energy requirements. These requirements will be reduced through energy conservation, public education, and appropriate technologies. The energy system will protect and improve the quality of life and the environment.*

3.1 PLANNING PROCESS

The City and Black & Veatch Consultants concluded Phase I of a comprehensive integrated resource planning (IRP) study in June 2002. The purpose of this study was to review future power supply options that are consistent with the objectives of the City's Energy Policy stated above in Section 3.0. The City's proposed generation expansion plan described in Section 3.2 is based in part on the results of that study.

Electric utility planning staff has continued to review the results of the 2002 IRP Study as directed by the City Commission. This review process included updating options with regard to the availability, performance and pricing of electric generating equipment, new power purchase agreements and investigation of options available to the City to achieve some portfolio diversity. In addition, the City continues to review and develop means to mitigate the potential impacts of significant events in the electric utility industry. Among these considerations are the collapse of Enron, other former energy trading companies and merchant generators and the subsequent impact on energy sector investment and financial markets, the ongoing initiatives for the formation of regional transmission organizations (RTO) and possible federal legislation related to electric utility industry restructuring. The City will further refine/revise/screen/analyze the available resource alternatives and plan combinations as necessary in consideration of these developments. A new IRP Study will be conducted during 2004 to assess the impact of these and other changes on the City's future power supply portfolio.

3.2 PROJECTED RESOURCE REQUIREMENTS

3.2.1 TRANSMISSION LIMITATIONS

The City has projected that additional resources will be required during the 2004-2013 Ten Year Site Plan time frame to maintain a reliable electric system. The City's projected transmission import capability is a major determinant of the type and timing of future power resource additions. The City has worked with its neighboring utilities, Progress and Southern, to plan and maintain sufficient transmission import capability to allow the City to make emergency power purchases in the event of the most severe single contingency, the loss of the system's largest generating unit. As has been seen in other parts of the country since the passage of the Energy Policy Act of 1992, there has been little investment in the regional transmission system around Tallahassee. Consequently, the City's internal transmission studies have reflected a gradual deterioration of the system's transmission import (and export) capability into the future, due in part to this lack of investment in facilities as well as the impact of an increasing level of unscheduled power flow-through on the City's transmission system. The prospects for significant expansion of the regional transmission system around Tallahassee hinges on (i) the City's ongoing discussions with Progress and Southern, (ii) the RTO development activities of GridFlorida, and (iii) the alternative mechanisms envisioned by proposed federal legislation on electric industry restructuring. Unfortunately, none of these efforts is expected to produce substantive improvements to the City's transmission import/export capability in the time frame of the system's short-term resource needs. The City continues to discuss the limitations of the existing transmission grid in the panhandle region with Progress, and a joint study of possible alternatives to address these limitations and constraints should be completed by the summer of 2004. Therefore, in consideration of the City's projected transmission import capability reductions and the associated grid limitations, the results of the 2002 IRP Study and recent analysis of options tend to favor local generation alternatives as the means to satisfy future power supply requirements.

3.2.2 Reserve Requirements

Historically, the City has planned to maintain a load reserve margin of 17%. However, in previous Ten Year Site Plan reports, the City has discussed the possibility of increasing its reserve margin criterion. The perceived need to evaluate alternative reliability criteria/levels arose primarily from three considerations: (i) the projected deterioration of the City's transmission import capability discussed in the previous section, (ii) the stipulation made by the state's three investor-owned utilities (Florida Power & Light, Progress Energy Florida and Tampa Electric Company) to increase their respective reserve margins to 20% by 2004 in response to the FPSC's reserve margin docket of 1998, and (iii) the size of the City's individual generating units as a percent of its total supply resource capability. However, as mentioned in the 2003 Ten Year Site Plan report, the City evaluated various reliability measures and determined that the 17% reserve margin continues to be appropriate for planning purposes. Assuming the base case load forecast, and recognizing the peaking capacity under construction, additional power supply need to maintain a 17% planning reserve margin first occurs in the summer of 2009; assuming the high load forecast, additional power supply would be needed a year earlier, in the summer of 2008. The City is currently reviewing the scheduled retirement dates for the gas turbines at the Purdom Plant (retirements in 2008 and 2009 as shown in Schedule 1) and may elect to extend the life of those units. If life extension of this 20 MW of peaking capacity proves economic, absent any other changes on the system the first year in which resources would need to be added to maintain a 17% reserve margin (using the base case load forecast) is 2011.

3.2.3 Near Term Resource Additions

In order to meet the year 2005 capacity shortfalls identified in the 2002 IRP, the City is moving forward with the addition of 97 MW (nominal) of new peaking capacity. This new capacity will utilize the combination of a single dual fuel simple cycle combustion turbine and nine (9) dual fuel reciprocating engines. The new generation will be added at two locations within the City's electric system.

The combustion turbine that is being added is a General Electric LM-600 Sprint combustion turbine with a summer rating of 47 MW (94° F, firing natural gas with chiller in service). The reciprocating engines are Wartsila 32VDF dual fuel engines with a summer rating of 5.3 MW each. All of the new generation will be dual fuel with the ability to utilize natural gas or clean low sulfur diesel as their primary fuel. Each of these units are designed to be on line and at full load within ten (10) minutes of initiation of the start sequence.

The combustion turbine and six (6) of the reciprocating engines are to be installed at the A. B. Hopkins Generation Station. Three (3) of the reciprocating engines are to be installed at the City's existing Substation 12 which serves critical community service facility loads such as Tallahassee Memorial Hospital, Florida Department of Law Enforcement and Tallahassee Police Department. In addition, Sub 12 can feed Capital Regional Medical Facility. Utilization of the Sub 12 site will allow the City to: (i) meets its supply side resource needs; and (ii) enhance these critical community services facilities during catastrophic situations like a hurricane or loss of major substation equipment.

The purchse of the prime mover equipment has been approved and engineering is underway on this project. The base project schedule calls for permitting to be complete by the end of 2004 and construction to commence immediately following permit issuance. The initial 50 MW of capacity is scheduled to be in commercial operation in June of 2005.

3.2.4 Purchased Power Alternatives

Purchase contracts could provide some of the diversity desired in the City's power supply resource portfolio. Resource diversity, particularly with regard to fuels, has long been sought after by the City because of the system's heavy reliance on natural gas as its primary fuel source and has received even greater emphasis in light of the volatility in natural gas prices seen over recent years. The City has also attempted to address this concern by implementing an Energy Risk Management (ERM) program in an effort to limit the City's exposure to energy price fluctuations. The ERM program established a new 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.

3.2.5 Renewable Resources

As part of its continuing commitment to explore clean energy alternatives, the City has continued to invest in opportunities to develop viable solar photovoltaic (PV) projects as part of our efforts to offer "green power" to our customers. The City believes that offering a green power alternative to its customers is a sound business strategy: it will provide for a measure of supply diversification, reduce dependence on fossil fuels, promote cleaner energy sources, and enhance the City's already strong commitment to protecting the environment and the quality of life in Tallahassee. Currently we have a portfolio of 40kW of solar PV dedicated to supporting our *Green For You* program, a retail offering which uses tradable renewable certificates (green tags) to promote development of green power projects. Since its inception in November 2002, *Green For You* has been revised to include both local and regionally-based product blends that offer customers an opportunity to support clean renewable power for a little as 33 cents/day.

The City's existing solar power resources consist of both solar PV and solar thermal installations: a 10 kW PV system on the Trousdell Aquatics Center bathhouse; an 18 kW PV system located behind the Florida Public Service Commission conference center; a 6 kW PV system at the FAMU/FSU Engineering School; a 6 kW PV system at the Center for Advanced Power Systems (CAPS); and several solar domestic hot water systems at various City facilities. The City is also developing some integrated solar energy systems into a planned expansion of the Jack McLean Park, included a solar pool heating system, a 6 kW PV system, and a solar domestic hot water system. In addition to these solar energy resources, the City also operates an 11 MW hydroelectric generating station at Lake Talquin, which represents the largest component of our renewable energy portfolio.

3.2.6 Future Power Supply Resources

The City's currently proposed resource addition to meet system needs in the summer of 2009 and beyond is represented in this report as an increasing ownership/purchase of capacity and energy from the equivalent of a new 1-on-1 combined cycle (CC) unit. Possible CC alternatives include a self-built unit; an asset modification (repowering of an existing conventional oil and gas-fired steam unit to combined cycle operation); an alliance purchase by wire (if transmission is available) or a combination thereof. The City will be continuing its evaluation of the different CC alternatives and update the FPSC in future TYSP reports.

The CC ownership/purchase reflected in this report begins with 25 MW in 2009. The CC ownership/purchase increases to 50 MW by the summer of 2010, to 100 MW by the summer of 2011 to 125 MW by the summer of 2013 to meet the balance of needs throughout the 2004-2013 study period.

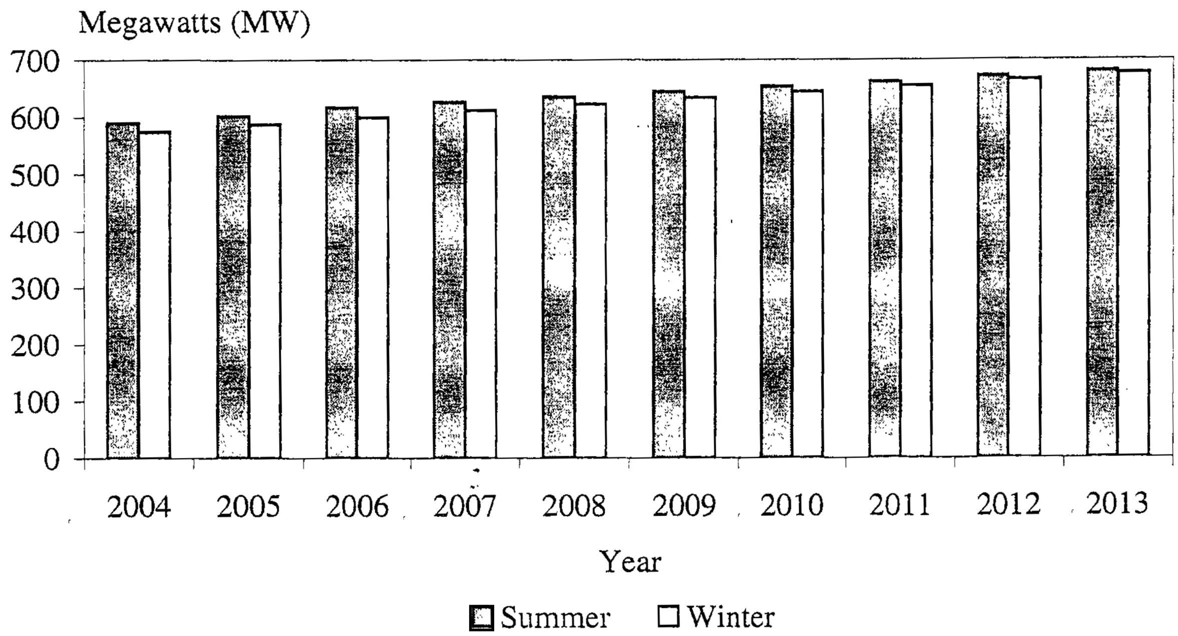
Tables 3.1 and 3.2 (Schedules 7.1 and 7.2) provide information on the resources and reserve margins during the next ten years for the City's system. The City has specified its planned capacity additions, retirements and changes on Table 3.3 (Schedule 8). These capacity resources have been incorporated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

In addition to this future combined cycle unit addition, as a part of the 2004 IRP study the City is evaluating some other alternatives that would increase the effective capacity of our existing power supply resources and thereby defer the need for new resource additions, such as inlet chilling on Purdom Unit 8 or steam turbine upgrades at Hopkins Unit 2. These alternatives could provide a very cost-effective increase in system capacity with relatively short lead times, and would give the City more flexibility in meeting its future power supply requirements.

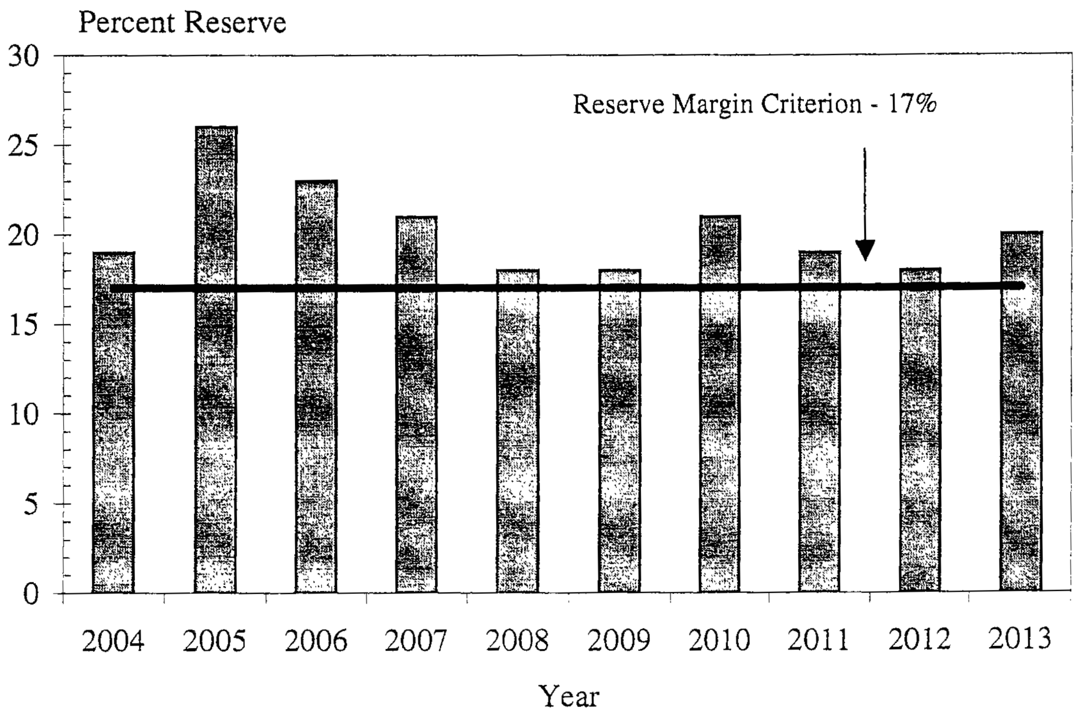
The City is also reviewing the scheduled retirement dates for the gas turbines at the Purdom Plant and may elect to extend the life of those units. Currently these units are projected to retire in 2008 and 2009 (see Schedule 1). Postponing these planned retirements may give the City additional flexibility in future power supply plans. For example, if life extension of this 20 MW of peaking capacity proves economic, absent any other changes on the system the first year in which resources would need to be added to maintain a 17% reserve margin (using the base case load forecast) is 2011, a deferral of two years compared to the proposed generation expansion plan. The assessment of this retirement deferral should be completed during the IRP study planned for the later part of 2004.

Figure C

System Peak Demands Net of Conservation



Summer Reserve Margin



City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	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
2004	652	51			703	591	112	19		112	19
2005	748 [1]	11			759	602	157	26		157	26
2006	748 [1]	11			759	617	142	23		142	23
2007	748 [1]	11			759	627	132	21		132	21
2008	738 [1]	11			749	636	113	18		113	18
2009	753 [1]	11			764	645	119	18		119	18
2010	778 [1]	11			789	654	135	21		135	21
2011	780 [1]	11			791	662	129	19		129	19
2012	780 [1]	11			791	671	120	18		120	18
2013	805 [1]	11			816	680	136	20		136	20

[1] All installed and firm import capacity changes are included in the proposed generation expansion plan.

Table 3.1

City Of Tallahassee

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% of Peak	(MW)	(MW)	% of Peak
2003/04 [2]	699	26			725	509	216	42		216	42
2004/05	699	11			710	575	135	23		135	23
2005/06	800 [1]	11			811	588	223	38		223	38
2006/07	800	11			811	600	211	35		211	35
2007/08	800	11			811	612	199	33		199	33
2008/09	790 [1]	11			801	623	178	29		178	29
2009/10	805 [1]	11			816	634	182	29		182	29
2010/11	830 [1]	11			841	644	197	31		197	31
2011/12	830 [1]	11			841	655	186	28		186	28
2012/13	830 [1]	11			841	665	176	26		176	26
2013/14	855 [1]	11			866	676	190	28		190	28

[1] All installed capacity changes are included in the proposed generation expansion plan. (see Section 3.1 for details).

[2] 2003/04 winter is actual peak

City Of Tallahassee

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Net Capability		
	Unit		Unit	Fuel		Fuel Transportation		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Mo/Yr	Mo/Yr	Mo/Yr	(kW)	(MW)	(MW)	Status
Hopkins	3	Hopkins	GT	NG	DFO	PL	TK	Unknown	May-05			48	50	P
Distributed Gen [1]	A-C	Sub 12	IC	NG	DFO	PL	TK	Unknown	May-05			16	17	P
Hopkins [2]	A-F	Hopkins	IC	NG	DFO	PL	TK	Unknown	May-05			32	34	P
CC [3]	A	Undetermined	CC	NG	DFO	PL	TK	Unknown	May-09			25	25	P
									May-10			50	25	P
									May-11			100	100	P
									May-13			125	125	P

[1] DG will consist of 3 units located at Sub 12 designated 'A' through 'C', each with a peak output of 5.3MW (summer).
[2] Hopkins IC will consist of 6 units designated 'A' through 'F', each with a peak output of 5.3MW (summer.
[3] This combined cycle capability is reflected as an alliance ownership/purchase beginning with 25 MW in May 2009, increasing to 50 MW in 2010, 100 MW in 2011 and 125 MW in 2013. This capacity could take the form of a new, self-build unit; an asset modification (repowering of an existing conventional oil and gas-fired steam unit to combined cycle operation); an alliance purchase "by wire" (if transmission is available) and/or joint generation project; or a combination thereof. The City's back up plan for this capacity would be to self-build a combined cycle unit.

Acronym	Definition
IC	Internal Combustion
GT	Gas Turbine
PRI	Primary Fuel
ALT	Alternate Fuel
NG	Natural Gas
DFO	Diesel Fuel Oil
PL	Pipeline
TK	Truck
P	Planned
kW	Kilowatts
MW	Megawatts

City Of Tallahassee

Generation Expansion Plan

	Load Forecast & Adjustments											
Year	Fcst Peak Demand (MW)	DSM [1] (MW)	Net Peak Demand (MW)	Existing Capacity Net (MW)	Firm Imports (MW)	Morgan Stanley Purchase (MW)	Southern Purchase (MW)	Firm Exports (MW)	Resource Additions (Cumulative) (MW)	Total Capacity (MW)	Res %	New Resources
2004	592	1	591	652	11	25 [2]	15 [2]			703	19	
2005	607	4	603	652	11				96	759	26	[3]
2006	622	5	617	652	11				96	759	23	
2007	632	5	627	652	11				96	759	21	
2008	641	5	636	642 [4]	11				96	749	18	
2009	650	5	645	632 [5]	11				121	764	18	[7]
2010	659	5	654	632	11				146	789	21	[7]
2011	667	5	662	584 [6]	11				196	791	19	[7]
2012	677	5	672	584	11				196	791	18	
2013	685	5	680	584	11				221	816	20	[7]

[1] DSM = Demand Side Management
[2] Purchase in summer 2004 for 25 MW from Morgan Stanley Capital Group May 1 - Sept 30.
Southern purchase Jan 1 - Dec 31 2004.
[3] New resources are to be one 48 MW (Summer Net) GE LM6000 aeroderivative CT and multiple 5.3 MW (Summer Net) IC generating units. Model as one (1) 48 MW CT with 9.9 MMBtu/MWh heat rate and nine (9) 5.3 MW IC units with 9.1 MMBtu/MWh heat rate.
Three IC units will be placed at Sub 12 as distributed generation. Six IC units will be placed at Hopkins as peaking units.
[4] Purdom CT 1 official retirement currently scheduled for March 2008.
[5] Purdom CT 2 official retirement currently scheduled for March 2009.
[6] Purdom 7 official retirement currently scheduled for March 2011.
[7] This combined cycle capability is reflected as an alliance ownership/purchase beginning with 25 MW in May 2009, increasing to 50 MW in 2010, 100 MW in 2011 and 125 MW in 2013. This capacity could take the form of a new, self-build unit; an asset modification (repowering of an existing conventional oil and gas-fired steam unit to combined cycle operation); an alliance purchase "by wire" (if transmission is available) and/or joint generation project; or a combination thereof. The City's back up plan for this capacity would be to self-build a combined cycle unit.

Chapter IV

Proposed Plant Sites and Transmission Lines

4.1 PROPOSED PLANT SITE

The City's proposed resource addition to meet system needs in the summer 2009 and beyond is an increasing ownership/purchase of capacity and energy from a new 1-on-1 combined cycle unit beginning with 25 MW in 2009. The ownership increases to 50 MW by the summer of 2010, to 100 MW by the summer of 2011 and to 125 MW by the summer of 2013 to meet the balance of needs throughout the 2004-2013 study period. This is a proposed resource addition as previously mentioned and is not final. Other possible combined cycle opportunities include a self-built unit, an asset modification (repowering of an existing conventional oil and gas-fired steam unit to combined cycle operation) and an alliance purchase by wire (if transmission is available) or a combination thereof. In addition to the CT and DG units previously discussed, any of the contemplated combined cycle unit options could be accommodated at the City's existing Hopkins Plant Site. It is also possible that a new "green field" site might be identified if the self–build option is pursued (see Schedule 9).

4.2 TRANSMISSION LINE ADDITIONS/UPGRADES

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

Over the last decade, the City has experienced significant growth and development, and a corresponding increase in the demand for electricity. This has been especially true in the fast growing eastern portion of the City and adjacent Leon County where development has outpaced the construction of electric transmission lines and substations. The current capacity of the transmission and substation network in this large and rapidly growing part of the City's service area creates a reliability concern. The only acceptable and permanent way of providing a reliable source of electricity and providing for continuing growth to the eastern part of Tallahassee is to reinforce this area with the proper substation and transmission infrastructure. The City is currently planning and is in some cases in the process of constructing several new substations on the east side of its system. These are intended to serve future load in this rapidly growing area. The new substations (14, 15, 17, and 18) will be connected to the City's 115 kV transmission system, which is the standard voltage throughout the City's service territory. When complete, the area will be served by two reliable "loops" between substations 7 and 9 and between substations 9 and 5. The anticipated in-service dates for these new substations and lines are shown on Figure D1.

In the mid 1990's, the Electric Utility determined which areas would be the most beneficial to locate substation facilities to support this load growth and, after several years of negotiation with the landowner, the City obtained property for two proposed substations. Staff reviewed alternative transmission line routes, made a preliminary selection, and obtained a right-of-way permit from the Florida Department of Transportation in 2000. However, continued concern about environmental issues and public acceptance prompted further investigation and an effort to obtain more community input to the process.

To provide information and involve the residents of the area in the transmission line route selection process, Electric Utility staff conducted public workshops. At the request of the neighborhoods, City Electric staff attended and made presentations at several Homeowners meetings. In addition, a route study was conducted by EDAW/Exponential Engineering Company from June 2002 to June 2003. The Final Report from the route consultant was submitted to the City in late September 2003. On December 10, 2003 the City Commission considered the issue and requested staff to conduct a third public workshop, which was held on January 6, 2004. On February 11, 2004 the City Commission held a public hearing on the route selection and requested staff to consider a further route option and return with a recommendation in no more than four months.

The Electric Utility anticipates the construction of the Eastern Transmission Line (connecting substation 9 to the proposed substation 17), to be complete by the end of 2005 or early 2006, pending selection of a route by mid-2004.

As discussed in Section 3.2, the City has been working with its neighboring utilities, Progress and Southern, to identify improvements to assure the continued reliability and commercial viability of the transmission systems in and around Tallahassee. At a minimum, the City attempts to plan for and maintain sufficient transmission import capability to allow for emergency power purchases in the event of the most severe single contingency, the loss of the system's largest generating unit. The City's internal transmission studies have reflected a gradual deterioration of the system's transmission import (and export) capability into the future. This reduction in capability is driven by lack of investment in facilities in the panhandle region as well as the impact of an increasing level of unscheduled power flow-through on the City's transmission system. The City is committed to continue to work with Progress and Southern and the developing GridFlorida RTO 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.

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Hopkins	3
(2)	Capacity a.) Summer: b.) Winter:	 48 50	
(3)	Technology Type:	CT	
(4)	Anticipated Construction Timing a.) Field Construction start - date: b.) Commercial in-service date:	 Unknown May-05	
(5)	Fuel a.) Primary fuel: b.) Alternate fuel:	 NG DFO	
(6)	Air Pollution Control Strategy:	Unknown	
(7)	Cooling Status:	Unknown	
(8)	Total Site Area:	Unknown	
(9)	Construction Status:	Planned	
(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):	Data dependent on selected unit manufacturer, nature of contracts, etc. To be determined.	
(13)	Projected Unit Financial Data Book Life (Years) Total Installed Cost (In-Service Year $/kW) Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O & M ($kW-Yr): Variable O & M ($/MWH): K Factor:		

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Distributed Generation - Sub 12	A-C
(2)	Capacity		
	a.) Summer:	15.9	
	b.) Winter:	17.1	
(3)	Technology Type:	IC	
(4)	Anticipated Construction Timing		
	a.) Field Construction start - date:	Unknown	
	b.) Commercial in-service date:	May-05	
(5)	Fuel		
	a.) Primary fuel:	NG	
	b.) Alternate fuel:	DFO	
(6)	Air Pollution Control Strategy:	Unknown	
(7)	Cooling Status:	Unknown	
(8)	Total Site Area:	Unknown	
(9)	Construction Status:	Planned	
(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:		

Data dependent on selected unit manufacturer, nature of contracts, etc. To be determined.

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Hopkins IC	A-F
(2)	Capacity		
	a.) Summer:	31.8	
	b.) Winter:	34.2	
(3)	Technology Type:	IC	
(4)	Anticipated Construction Timing		
	a.) Field Construction start - date:	Unknown	
	b.) Commercial in-service date:	May-05	
(5)	Fuel		
	a.) Primary fuel:	NG	
	b.) Alternate fuel:	DFO	
(6)	Air Pollution Control Strategy:	Unknown	
(7)	Cooling Status:	Unknown	
(8)	Total Site Area:	Unknown	
(9)	Construction Status:	Planned	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data	Data dependent on selected unit manufacturer, nature of contracts, etc. To be determined.	
	Planned Outage Factor (POF):		
	Forced Outage Factor:		
	Equivalent Availability Factor (EAF):		
	Resulting Capacity Factor (%):		
	Average Net Operating Heat Rate (ANOHR):		
(13)	Projected Unit Financial Data		
	Book Life (Years)		
	Total Installed Cost (In-Service Year $/kW)		
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O & M ($kW-Yr):		
	Variable O & M ($/MWH):		
	K Factor:		

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

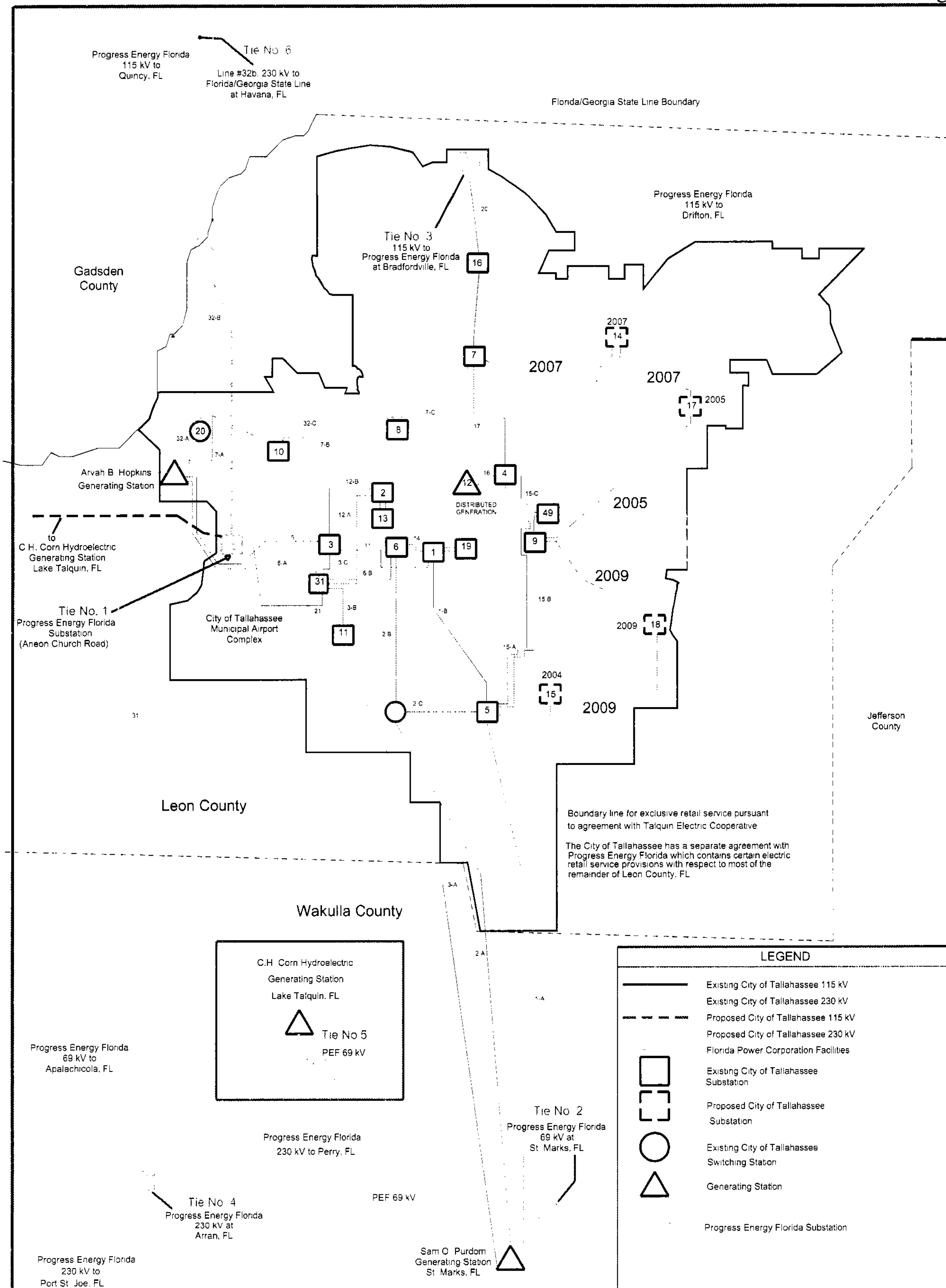
(1)	Plant Name and Unit Number:	CC A
(2)	Capacity a.) Summer: b.) Winter:	Note [1]
(3)	Technology Type:	Combined Cycle
(4)	Anticipated Construction Timing a.) Field Construction start - date: b.) Commercial in-service date:	 Unknown Unknown
(5)	Fuel a.) Primary fuel: b.) Alternate fuel:	 Natural Gas No. 2 Diesel Fuel
(6)	Air Pollution Control Strategy:	Unknown
(7)	Cooling Status:	Unknown
(8)	Total Site Area:	Unknown
(9)	Construction Status:	Planned
(10)	Certification Status:	
(11)	Status with Federal Agencies:	N/A
(12)	Projected Unit Performance Data Planned Outage Factor (POF): Forced Outage Factor: Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	Data dependent on selected unit manufacturer, nature of contracts, etc. To be determined.
(13)	Projected Unit Financial Data Book Life (Years) Total Installed Cost (In-Service Year $/kW) Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O & M ($kW-Yr): Variable O & M ($/MWH): K Factor:	

[1] This combined cycle capability is reflected as an alliance ownership/purchase beginning with 25 MW in May 2009 increasing to 50 MW in 2010, 100 MW in 2011 and 125 MW in 2013 This capacity could take the form of a new, self-build unit; an asset modification (repowering of an existing conventional oil and gas-fired steam unit to combined cycle operation), an alliance purchase "by wire" (if transmission is available) and/or joint generation project, or a combination thereof The City's back up plan for this capacity would be to self-build a combined cycle unit

City Of Tallahassee

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

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



PROPOSED TRANSMISSION SYSTEM 2005 - 2014	City of Tallahassee Electric Transmission System 2005 - 2014

APPENDIX A
Supplemental Data

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

Existing Generating Unit Operating Performance

(1)	(2)	(3)		(4)		(5)		(6)	
		Planned Outage Factor (POF)		Forced Outage Factor (FOF)		Equivalent Availability Factor (EAF)		Average Net Operating Heat Rate (ANOHR)	
Plant Name	Unit No.	Historical	Projected	Historical	Projected	Historical	Projected	Historical	Projected
Existing Units									
Corn	1 (1)	NA	0.075	NA	0.037	NA	0.888	NA	NA
Corn	2 (1)	NA	0.075	NA	0.037	NA	0.888	NA	NA
Corn	3 (1)	NA	0.075	NA	0.037	NA	0.888	NA	NA
Hopkins	1	0.028	0.072	0.004	0.026	0.944	0.894	12,695	12,179
Hopkins	2	0.069	0.121	0.002	0.034	0.923	0.827	10,951	10,843
Hopkins	GT-1 (2)	0.167	0.051	0.017	0.031	0.815	0.917	NA	15,991
Hopkins	GT-2 (2)	0.153	0.058	0.011	0.028	0.834	0.913	NA	14,903
Purdom	7	0.008	0.072	0.023	0.026	0.915	0.894	12,788	13,124
Purdom	8	0.020	0.078	0.039	0.022	0.925	0.857	7,408	7,337
Purdom	GT-1 (2)	0.069	0.051	0.157	0.031	0.773	0.917	NA	21,272
Purdom	GT-2 (2)	0.115	0.051	0.004	0.031	0.880	0.917	NA	20,797
Future Units									
Hopkins	HC3A-F	NA	0.024	NA	0.041	NA	0.935	NA	9,105
Hopkins	HC4	NA	0.058	NA	0.028	NA	0.913	NA	9,739
Substation 12	S12A-C	NA	0.024	NA	0.041	NA	0.935	NA	9,110
Unsited	CC2	NA	0.078	NA	0.022	NA	0.857	NA	7,669

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

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	%
2001	NA	NA	NA	32.07	509	-	NA	NA	NA
2002	NA	NA	NA	34.92	554	8.9%	NA	NA	NA
2003	NA	NA	NA	32.68	519	-6.4%	NA	NA	NA
2004	NA	NA	NA	33.69	535	3.1%	NA	NA	NA
2005	NA	NA	NA	30.50	484	-9.4%	NA	NA	NA
2006	NA	NA	NA	31.34	497	2.7%	NA	NA	NA
2007	NA	NA	NA	32.30	513	3.1%	NA	NA	NA
2008	NA	NA	NA	33.37	530	3.3%	NA	NA	NA
2009	NA	NA	NA	34.34	545	2.9%	NA	NA	NA
2010	NA	NA	NA	35.43	562	3.2%	NA	NA	NA
2011	NA	NA	NA	36.46	579	2.9%	NA	NA	NA
2012	NA	NA	NA	37.66	598	3.3%	NA	NA	NA
2013	NA	NA	NA	38.82	616	3.1%	NA	NA	NA

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

(1) Actual fiscal year 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	%
2001	NA	NA	NA	32.07	509	-	NA	NA	NA
2002	NA	NA	NA	34.92	554	8.9%	NA	NA	NA
2003	NA	NA	NA	32.68	519	-6.4%	NA	NA	NA
2004	NA	NA	NA	33.69	535	3.1%	NA	NA	NA
2005	NA	NA	NA	31.34	498	-6.9%	NA	NA	NA
2006	NA	NA	NA	32.99	524	5.2%	NA	NA	NA
2007	NA	NA	NA	34.82	553	5.6%	NA	NA	NA
2008	NA	NA	NA	36.85	585	5.8%	NA	NA	NA
2009	NA	NA	NA	38.84	617	5.4%	NA	NA	NA
2010	NA	NA	NA	41.04	651	5.7%	NA	NA	NA
2011	NA	NA	NA	43.27	687	5.4%	NA	NA	NA
2012	NA	NA	NA	45.77	726	5.8%	NA	NA	NA
2013	NA	NA	NA	48.32	767	5.6%	NA	NA	NA

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

(1) Actual fiscal year average cost of oil burned.

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	%
2001	NA	NA	NA	32.07	509	-	NA	NA	NA
2002	NA	NA	NA	34.92	554	8.9%	NA	NA	NA
2003	NA	NA	NA	32.68	519	-6.4%	NA	NA	NA
2004	NA	NA	NA	33.69	535	3.1%	NA	NA	NA
2005	NA	NA	NA	29.66	471	-11.9%	NA	NA	NA
2006	NA	NA	NA	29.73	472	0.2%	NA	NA	NA
2007	NA	NA	NA	29.90	475	0.6%	NA	NA	NA
2008	NA	NA	NA	30.15	479	0.8%	NA	NA	NA
2009	NA	NA	NA	30.27	480	0.4%	NA	NA	NA
2010	NA	NA	NA	30.47	484	0.7%	NA	NA	NA
2011	NA	NA	NA	30.60	486	0.4%	NA	NA	NA
2012	NA	NA	NA	30.84	489	0.8%	NA	NA	NA
2013	NA	NA	NA	31.01	492	0.6%	NA	NA	NA

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

(1) Actual fiscal year average cost of oil burned.
(2) Consensus forecast of City's Wholesale Energy Services and System Planning Divisions.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas (3)		
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
2001	40.41	697	-	465	4.84	-
2002	34.99	603	-13.4%	372	3.87	-20.0%
2003	35.82	618	2.4%	530	5.52	42.6%
2004	41.75	720	16.5%	658	6.84	24.1%
2005	37.63	649	-9.9%	625	6.50	-5.0%
2006	35.62	614	-5.3%	591	6.15	-5.5%
2007	35.27	608	-1.0%	578	6.01	-2.2%
2008	36.49	629	3.4%	565	5.88	-2.3%
2009	37.70	650	3.3%	559	5.81	-1.1%
2010	41.22	711	9.3%	570	5.93	2.0%
2011	43.45	749	5.4%	580	6.03	1.7%
2012	44.85	773	3.2%	593	6.17	2.3%
2013	47.10	812	5.0%	606	6.30	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) Consensus forecast of City's Wholesale Energy Services and System Planning Divisions.
(3) Delivered gas price reflects 3/3/04 supply cost at Henry Hub increased by 3.25% for compression losses, $0.0364 usage fee and seasonal interruptible transportation

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas (3)		
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
2001	40.41	697	-	465	4.84	-
2002	34.99	603	-13.4%	372	3.87	-20.0%
2003	35.82	618	2.4%	530	5.52	42.6%
2004	41.75	720	16.5%	658	6.84	24.1%
2005	38.67	667	-7.4%	642	6.67	-2.5%
2006	37.58	648	-2.8%	623	6.47	-3.0%
2007	38.15	658	1.5%	625	6.50	0.3%
2008	40.42	697	5.9%	626	6.51	0.2%
2009	42.77	737	5.8%	635	6.60	1.4%
2010	47.83	825	11.8%	663	6.90	4.5%
2011	51.62	890	7.9%	691	7.19	4.2%
2012	54.57	941	5.7%	724	7.53	4.8%
2013	58.67	1012	7.5%	759	7.89	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) Consensus forecast of City's Wholesale Energy Services and System Planning Divisions.
(3) Delivered gas price reflects 3/3/04 supply cost at Henry Hub increased by 3.25% for compression losses, $0.0364 usage fee and seasonal interruptible transportation fees.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas (3)		
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
2001	40.41	697	-	465	4.84	-
2002	34.99	603	-13.4%	372	3.87	-20.0%
2003	35.82	618	2.4%	530	5.52	42.6%
2004	41.75	720	16.5%	658	6.84	24.1%
2005	36.58	631	-12.4%	609	6.33	-7.5%
2006	33.72	581	-7.8%	560	5.83	-8.0%
2007	32.55	561	-3.5%	534	5.55	-4.7%
2008	32.85	566	0.9%	509	5.29	-4.8%
2009	33.12	571	0.8%	490	5.10	-3.6%
2010	35.38	610	6.8%	488	5.07	-0.5%
2011	36.42	628	2.9%	484	5.03	-0.8%
2012	36.68	632	0.7%	483	5.02	-0.2%
2013	37.60	648	2.5%	482	5.01	-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) Consensus forecast of City's Wholesale Energy Services and System Planning Divisions.
(3) Delivered gas price reflects 3/3/04 supply cost at Henry Hub increased by 3.25% for compression losses, $0.0364 usage fee and seasonal interruptible transportation fees.

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
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2004	53.28	222	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
2005	51.36	214	-3.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2006	49.44	206	-3.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2007	46.52	194	-5.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2008	44.16	184	-5.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2009	44.42	185	0.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2010	44.69	186	0.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2011	44.96	187	0.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2012	45.32	189	0.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2013	45.68	190	0.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA

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

(1) Coal is not currently, and is not expected to be, a part of the City's generation fuel mix. However, it's forecast price is important to the City's resource planning efforts as it will allow for the evaluation of coal-based purchase options.

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
2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2003	45.39	222	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
2004	45.74	222	0.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2005	46.09	220	-1.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2006	46.48	217	-1.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2007	46.68	209	-3.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2008	47.66	204	-2.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2009	48.68	210	3.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2010	49.72	217	3.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2011	50.80	224	3.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2012	51.92	231	3.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2013	52.92	239	3.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA

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

(1) Coal is not currently, and is not expected to be, a part of the City's generation fuel mix. However, it's forecast price is important to the City's resource planning efforts as it will allow for the evaluation of coal-based purchase options.

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	2001	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2002	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2003	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast (2)	2004	45.74	222	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2005	46.09	208	-6.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	46.48	195	-6.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	46.68	179	-8.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2008	47.66	165	-7.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	48.68	162	-1.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	49.72	159	-1.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	50.80	156	-1.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	51.92	154	-1.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	52.92	151	-1.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA

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

(1) Coal is not currently, and is not expected to be, a part of the City's generation fuel mix. However, it's forecast price is important to the City's resource planning efforts as it will allow for the evaluation of coal-based purchase options.
(2) Consensus forecast of City's Wholesale Energy Services and System Planning Divisions.

Nominal, Delivered Nuclear Fuel and Firm Purchases

(1)	(2)	(3)	(4)	(5)
	Nuclear		Firm Purchases(1)	
Year	c/MBTU	Escalation %	$/MWh	Escalation %
2001	NA	NA	41.36	-
2002	NA	NA	36.92	-10.7%
2003	NA	NA	43.24	17.1%
2004	NA	NA	42.94	-0.7%
2005	NA	NA	42.00	-2.2%
2006	NA	NA	42.00	0.0%
2007	NA	NA	42.00	0.0%
2008	NA	NA	43.26	3.0%
2009	NA	NA	44.56	3.0%
2010	NA	NA	45.89	3.0%
2011	NA	NA	47.27	3.0%
2012	NA	NA	48.69	3.0%
2013	NA	NA	50.15	3.0%

(1) Historical data is for all purchases, firm and non-firm

Financial Assumptions
Base Case

AFUDC RATE	5.5%	
CAPITALIZATION RATIOS:		
DEBT	165.88%	(1)
PREFERRED	N/A	(2)
ASSETS	58.84%	(3)
EQUITY	111.10%	
RATE OF RETURN		
DEBT	1.22%	(4)
PREFERRED	N/A	(2)
ASSETS	0.43%	(5)
EQUITY	0.82%	
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%	
DISCOUNT RATE:	4.00% - 5.50%	
TAX DEPRECIATION RATE:	N/A	(6)

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

Financial Escalation Assumptions

(1) Year	(2) General Inflation %	(3) Plant Construction Cost %	(4) Fixed O&M Cost %	(5) Variable O&M Cost %
2004	2.7	2.7	2.7	2.7
2005	2.6	2.6	2.6	2.6
2006	2.5	2.5	2.5	2.5
2007	2.6	2.6	2.6	2.6
2008	2.6	2.6	2.6	2.6
2009	2.6	2.6	2.6	2.6
2010	2.7	2.7	2.7	2.7
2011	2.7	2.7	2.7	2.7
2012	2.7	2.7	2.7	2.7

Monthly Peak Demands and Date of Occurrence for 2001 - 2003

	Calendar Year 2001				
		Hour	Daily Temp. (^{o}F)		Peak Demand
Month	Date	Ending	Min.	Max.	(MW)
January	10-Jan	8:00 A.M.	20	58	521
February	6-Feb	8:00 A.M.	31	72	394
March	8-Mar	8:00 A.M.	32	72	356
April	13-Apr	4:00 P.M.	68	89	394
May	17-May	5:00 P.M.	65	94	456
June	4-Jun	4:00 P.M.	71	94	489
July	9-Jul	5:00 P.M.	74	99	520
August	28-Aug	4:00 P.M.	68	96	519
September	5-Sep	5:00 P.M.	69	96	475
October	23-Oct	3:00 P.M.	61	90	403
November	2-Nov	4:00 P.M.	61	82	351
December	27-Dec	9:00 A.M.	22	58	406

	Calendar Year 2002				
		Hour	Daily Temp. (^{o}F)		Peak Demand
Month	Date	Ending	Min.	Max.	(MW)
January	4-Jan	9:00 A.M.	21	51	510
February	28-Feb	8:00 A.M.	18	53	489
March	5-Mar	8:00 A.M.	21	61	500
April	25-Apr	6:00 P.M.	62	89	453
May	8-May	5:00 P.M.	70	94	490
June	3-Jun	4:00 P.M.	70	97	535
July	19-Jul	4:00 P.M.	75	101	580
August	23-Aug	5:00 P.M.	72	96	535
September	4-Sep	6:00 P.M.	70	95	524
October	7-Oct	5:00 P.M.	69	91	498
November	11-Nov	7:00 P.M.	75	86	391
December	2-Dec	8:00 A.M.	29	62	422

Historical and Projected Heating and Cooling Degree Days

	Year	Heating Degree Days (HDD)	Cooling Degree Days (CDD)
History	1994	1,249	2,616
	1995	1,614	2,807
	1996	1,807	2,470
	1997	1,427	2,515
	1998	1,272	3,148
	1999	1,461	2,768
	2000	1,640	2,757
	2001	1,429	2,451
	2002	1,418	2,813
	2003	1,642	2,551
Forecast	2004	1,660	2,681
	2005	1,660	2,681
	2006	1,660	2,681
	2007	1,660	2,681
	2008	1,660	2,681
	2009	1,660	2,681
	2010	1,660	2,681
	2011	1,660	2,681
	2012	1,660	2,681

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)
1994	52.76	47.68	51.37	1.482
1995	53.66	48.78	50.30	1.524
1996	55.24	46.92	47.66	1.569
1997	55.14	46.75	47.80	1.605
1998	52.98	45.96	45.06	1.630
1999	51.32	42.87	43.67	1.666
2000	52.47	45.63	43.62	1.722
2001	52.48	44.04	43.17	1.771
2002	45.22	37.08	42.50	1.799
2003	50.55	41.94	43.29	1.840
2004	50.55	41.94	43.29	
2005	50.55	41.94	43.29	
2006	50.55	41.94	43.29	
2007	50.55	41.94	43.29	
2008	50.55	41.94	43.29	
2009	50.55	41.94	43.29	
2010	50.55	41.94	43.29	
2011	50.55	41.94	43.29	
2012	50.55	41.94	43.29	
2013	50.55	41.94	43.29	

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

(2) For the City's 2004 Load Forecast, it was assumed that the future real price of electricity would remain constant at the FY 2003 level. While fuel prices are projected to increase in real terms, as in past load forecasts, it was assumed that these price increases would be offset by more efficient generation, reduced operation and maintenance costs,

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

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

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