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Black & Veatch Corporation

April 6, 2004

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Ms. Blanca Bayo
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0688

Ms. Bayo,

Enclosed please find fifteen copies of the 2004 Orlando Utilities Commission (OUC) Ten-Year Site Plan (TYSP). At the request of Michael Haff, the 2004 OUC TYSP is being sent directly to you.

Should you require additional copies of the 2004 OUC TYSP, or have any other questions regarding the Plan, please do not hesitate to contact me at (913) 458-7432.

Very truly yours,

Myron Rollins

Enclosure[s]

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OUC

The *Reliable* One

2004 Ten-Year Site Plan

Orlando Utilities Commission

April 2004

OUC

The *Reliable* One®

2004 Ten-Year Site Plan
Orlando Utilities Commission

B&V File Number
136933.0040

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1.0 Executive Summary

This report documents the 2004 Orlando Utilities Commission (OUC) Ten-Year Site Plan pursuant to Section 186.801 Florida Statutes and Section 25-17.0852 of Florida Administrative Code. The Ten-Year Site Plan provides information required by this rule, and consists of ten main sections:

Utility System Description (Section 2.0)
Strategic Issues (Section 3.0)
Forecast of Peak Demand and Energy Consumption (Section 4.0)
Demand-Side Management (Section 5.0)
Forecast of Facilities Requirements (Section 6.0)
Development of Supply-Side Alternatives (Section 7.0)
Analysis and Results (Section 8.0)
Environmental and Land Use Information (Section 9.0)
Conclusions (Section 10.0)
Ten-Year Site Plan Schedules (Section 11.0)

This Plan also integrates the power sales, purchases, and loads for the City of St. Cloud into the OUC Plan.

OUC is a member of the Florida Municipal Power Pool (FMPP) which consists of OUC, Lakeland Electric (Lakeland), and the Florida Municipal Power Agency (FMPA) All-Requirements Project. Power for OUC is supplied by OUC jointly owned generation and power purchases. OUC's total installed generating capacity, including units in which it has joint ownership as well as the diesel generation owned by the City of St. Cloud, is 1,215 MW (summer) and 1,276 MW (winter), as of January 1, 2004. The existing supply system has a broad range of generation technology and fuel diversity, with coal providing the largest portion (approximately 60 percent) of OUC's energy requirements.

In 1999, OUC sold the Indian River Steam Units to Reliant. As part of the agreement with Reliant and described in Section 2.0, OUC received a power purchase agreement (PPA) through September 30, 2003, with an extension option for up to four additional years.

Load forecasts for OUC and the City of St. Cloud have been integrated into one forecast, and details of the aggregated load forecast are provided in Section 4.0. A banded forecast is provided with base case growth, high growth, and low growth scenarios. This analysis, considering the forecasted growth, existing units, retiring units, purchase power contracts, and reserve margin requirements, indicates an initial need for additional capacity beginning in the summer of 2008.

Stanton Energy Center Unit A (Stanton A) began commercial operation on October 1, 2003. Stanton A is jointly owned by OUC, Kissimmee Utility Authority (KUA), FMPA, and Southern Company – Florida LLC (Southern-Florida), with OUC owning 28 percent, KUA and FMPA each owning 3.5 percent, and Southern-Florida owning the remaining 65 percent of Stanton A capacity.

OUC, KUA, and FMPA will purchase all of Southern-Florida's 65 percent capacity share of Stanton A pursuant to an executed PPA for ten years, although the utilities retain the right to reduce the capacity purchased from Southern-Florida by 50 MW each year, beginning in the sixth year of the PPA, as long as the total reduction in capacity purchased does not exceed 200 MW. Additionally, OUC, KUA, and FMPA have options to purchase all of Southern-Florida's capacity for an additional 20 years. Considerations of the Stanton A PPA as they impact the analysis of the Ten-Year Site Plan are presented in more detail in Section 2.2.

Three alternative power plant technologies including combustion turbines, combined cycles, and coal units were considered for capacity additions. The alternatives were modeled in Black & Veatch's POWROPT and POWRPRO optimal generation expansion and chronological production costing programs to rank the expansion plans according to total cumulative present worth costs over a ten-year (2004 through 2013) planning period. Several sensitivity analyses were performed to determine their impact on the least-cost alternatives as well. Based on the detailed modeling of the OUC system, the forecast of electrical demand and energy, the forecast of fuel prices and availability, and environmental considerations, Table 1-1 presents the least-cost capacity expansion plan for the base case. As discussed in Section 10.0, variations to this expansion plan may develop as the time required for OUC to commit to this plan approaches.

Table 1-1.
OUC Least-Cost Base Case Expansion Plan[1]

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2004)	$218,061	$218,061
2005	Terminate 300 MW Reliant Power Purchase (09/30/2005)	$219,849	$421,625
2006		$205,980[2]	$598,219
2007		$218,058	$771,321
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008)	$233,255	$942,770
2009	40 MW Reduction in Southern-Florida Power Purchase (01/01/2009)	$252,370	$1,114,529
2010	40 MW Reduction in Southern-Florida Power Purchase (01/01/2010) 156 MW GE 7FA Simple Cycle CT (06/01/2010)	$261,149	$1,279,098
2011	40 MW Reduction in Southern-Florida Power Purchase (01/01/2011)	$273,665	$1,438,778
2012	40 MW Reduction in Southern-Florida Power Purchase (01/01/2012) 156 MW GE 7FA Simple Cycle CT (06/01/2012)	$294,908	$1,598,108
2013	156 MW GE 7FA Simple Cycle CT (06/01/2013)	$322,585	**$1,759,481**

1. Capacity is stated at average annual temperature for OUC.
2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District (12/31/2005), under which OUC supplies a significant amount of capacity and energy.

2.0 Utility System Description

2.1 OUC Structure

At the turn of the twentieth century, John M. Cheney, an Orlando judge, organized the Orlando Water and Light Company and supplied electricity on a part-time basis with a 100 kilowatt generator. Twenty-four hour service began in 1903. The City's population had grown to roughly 10,000 by 1922 and Cheney, realizing the need for wider services than his company was capable of supplying, urged his friends to work and vote for a $97,500 bond issue to enable the citizens of Orlando to purchase and municipally operate his privately owned utilities. The bond issue carried almost three to one, as did a subsequent issue for additional improvements. The citizens of Orlando took over Cheney's company and its 2,795 electricity customers and 5,000 water customers for a total initial investment of $1.5 million.

In 1923, the Orlando Utilities Commission (OUC) was created by an act of the State Legislature and full authority was granted to OUC to operate the plant as a municipal utility. The business was a paying venture from the start, and by 1924, the number of customers had more than doubled and OUC contributed $53,000 to the City. When Orlando citizens took over operations of their utility, the population was less than 10,000; by 1925, it had grown to 23,000. In 1925, more than $165,000 was transferred to the City and in 1926 an additional $111,000 was transferred. One outside private utility offered $3 million to purchase the utility in 1928.

Between 1928 and 1931 there was a great deal of talk both for and against the sale of the utility. On August 18, 1931, an election was held and the people voted 1,033 to 140 not to sell the utility; 1,030 to 160 not to mortgage the utility, 744 to 436 not to issue tax notes; and 919 to 158 not to lease the utility. However, the question as to whether or not Orlando's utility should remain under municipal ownership did not end with the vote of the people in 1931. A year later a $5 million offer was made for the plant, $2 million more than the actual physical value at the time.

Today, OUC operates as a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City of Orlando. OUC has the full authority over the management and control of the electric and water works plants in the City of Orlando and has been approved by the Florida Legislature to offer these services in Osceola County as well as Orange County. OUC's charter allows it to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission, and distribution systems, as well as water production, transmission, and distribution systems in order to meet the requirements of its customers.

In 1997, OUC entered an Interlocal Agreement with the City of St. Cloud in which OUC took over responsibility for supplying all of St. Cloud's loads for the 25-year term of the agreement, which added an additional 150 square miles of service area. OUC also took over management of St. Cloud's existing generating units and purchase power contracts.

OUC's electric system consisted of a year-end average of 155,613 active services for 2003. Of these, 134,340 were residential services, 16,057 were general service non-demand services, and the remaining 5,216 were general service demand services. St. Cloud's service area consisted of a year-end average of 19,501 active services for 2003.

2.2 Generation System

OUC presently has ownership interests in the following five electric generating plants, which are further described below. Table 2-1 summarizes OUC's generating facilities.

Indian River Plant Combustion Turbine Units A, B, C, and D.

Stanton Energy Center Units 1 and 2, and Stanton A.

Florida Power Corporation Crystal River Unit 3 Nuclear Generating Facility.

Lakeland Electric McIntosh Unit 3.

Florida Power and Light Company St. Lucie Unit 2 Nuclear Generating Facility.

The Stanton Energy Center is located 12 miles southeast of Orlando, Florida. The 3,280 acre site contains Units 1 and 2, as well as Stanton A, and the necessary supporting facilities. Stanton 1 was placed in commercial operation on July 1, 1987, followed by Stanton 2, which was placed in commercial operation on June 1, 1996. Both units are fueled by pulverized coal and operate at emission levels that are within the Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FDEP) requirement standards for SO_2, NO_x, and particulates. Stanton 1 is a 444 MW net coal-fired facility, of which OUC has a 68.6 percent ownership share providing 302 MW of capacity to the OUC system. Stanton 2 is a 446 MW net coal-fired generating facility, of which OUC maintains a 71.6 percent (319 MW) ownership share. OUC has entered into an agreement with KUA, FMPA, and Southern-Florida governing the ownership of Stanton A, a combined cycle unit at the Stanton Energy Center which began commercial operation on October 1, 2003. OUC, KUA, FMPA, and Southern-Florida are joint owners of Stanton A with OUC maintaining a 28 percent ownership share, KUA and FMPA each maintaining 3.5 percent ownership shares, and Southern-Florida maintaining the remaining 65 percent of Stanton A's capacity.

Table 2-1.
Summary of OUC Generation Facilities

Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Net Capability[1]	
				Pri	Alt	Pri	Alt			Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	FO2	PL	TK	06/89	Unknown	18	23.4
Indian River	B	Brevard	GT	NG	FO2	PL	TK	07/89	Unknown	18	23.4
Indian River	C	Brevard	GT	NG	FO2	PL	TK	08/92	Unknown	85.3	100.3
Indian River	D	Brevard	GT	NG	FO2	PL	TK	10/92	Unknown	85.3	100.3
Stanton Energy Center	1	Orange	ST	BIT	---	RR	---	07/87	Unknown	301.6	303.7
Stanton Energy Center	2	Orange	ST	BIT	---	RR	---	06/96	Unknown	319.3	319.3
Stanton Energy Center	A	Orange	CC	NG	FO2	PL	TK	10/03	Unknown	167.9	183.5
McIntosh	3	Polk	ST	BIT	---	RR	---	09/82	Unknown	133	136
Crystal River	3	Citrus	NP	UR	---	TK	---	03/77	Unknown	13	13
St. Lucie[2]	2	St. Lucie	NP	UR	---	TK	---	06/83	Unknown	51	52
St. Cloud[3]	1	Osceola	IC	NG	FO2	PL	TK	07/82	10/06	2	1.825
	2		IC	NG	FO2	PL	TK	12/74	10/06	5.85	5
	3		IC	NG	FO2	PL	TK	09/82	10/06	2	1.825
	4		IC	NG	FO2	PL	TK	08/61	10/06	3	3
	6		IC	NG	FO2	PL	TK	03/67	10/06	3	3
	7		IC	NG	FO2	PL	TK	09/82	10/06	6	6
	8		IC			PL	TK	04/77	10/06	6	6

1. OUC ownership share.
2. OUC owns St. Lucie Unit No. 2. Reliability exchange divides 50 percent power from Unit No. 1 and 50 percent power from Unit No. 2.
3. St. Cloud No. 8 is currently not operated and in standby, therefore, OUC receives no capacity from this unit. St. Cloud owns the units, but OUC controls their operation.

Stanton A is a 2x1 combined cycle utilizing General Electric combustion turbines. Stanton A is dual fueled with natural gas as the primary fuel and No. 2 oil as the backup fuel. Stanton A uses evaporative coolers, duct burning, and power augmentation for additional output during peak periods and uses treated sewage effluent for cooling water.

OUC, KUA, and FMPA will purchase all of Southern-Florida's capacity under an executed PPA for 10 years with options to purchase all of Southern-Florida's capacity for an additional 20 years. Under the initial contract, OUC is scheduled to purchase 80 percent of Southern-Florida's ownership of Stanton A, with KUA and FMPA each purchasing equal shares of the remaining capacity. However, beginning on the first day of the sixth year of the PPA, OUC, KUA, and FMPA may elect to reduce the amount of capacity purchased from Southern-Florida by a total of 50 MW per year. This reduction in capacity is available to the utilities in years six through ten of the PPA, although the total reduction in capacity between the three utilities may not exceed 200 MW. Given the fact that OUC will be purchasing 80 percent of the Stanton A capacity owned by Southern-Florida, for evaluation purposes it has been assumed that OUC can elect to reduce its capacity allocations as described above in 40 MW increments (i.e. 80 percent of 50 MW), with the total reduction not to exceed 160 MW.

The Indian River Plant is located four miles south of Titusville on US Highway 1. The 160-acre Indian River Plant site contains three steam electric generating units (No. 1, 2, and 3) and four combustion turbine units (A, B, C, and D). The three steam turbine units were sold to Reliant in 1999 and as part of the sale, OUC has signed a power purchase agreement (PPA) with Reliant, the details of which are presented in Section 2.3 herein. The combustion turbine units are primarily fueled by natural gas, with No. 2 fuel oil as an alternative. OUC has a partial ownership share of 48.8 percent, or 36 MW, in Indian River Units A and B as well as a partial ownership share of 79 percent (170 MW) in Indian River Units C and D.

Crystal River Unit 3 is an 835 MW net nuclear generating facility operated by Progress Energy Florida, formerly Florida Power Corporation. OUC has a 1.6015 percent ownership share in this facility, providing approximately 13 MW to the OUC system.

McIntosh Unit 3 is a 340 MW net coal-fired unit operated by Lakeland Electric. McIntosh Unit 3 has supplementary oil and refuse-derived fuel burning capability and also is capable of burning up to 20 percent petroleum coke. Lakeland Electric has ceased burning refuse-derived fuel at McIntosh Unit 3 for operational and landfill reasons. For purposes of the Ten-Year Site Plan analyses, it is assumed that McIntosh Unit 3 will burn coal priced identical to that used for Stanton 1 and 2. OUC has a 40 percent ownership share in McIntosh Unit 3, providing approximately 133 MW of capacity to the OUC system.

St. Lucie Unit 2 is a net 853 MW nuclear generating facility operated by the Florida Power and Light Company. OUC has a 6.08951 percent ownership share in this facility, providing approximately 51 MW of generating capacity to OUC. A reliability exchange with St. Lucie Unit 1 results in half of the capacity being supplied from St. Lucie Unit 1 and half provided by St. Lucie Unit 2.

As part of the Interlocal Agreement with St. Cloud, OUC has operating control of St. Cloud's seven internal combustion generating units, which have a total summer rating of 27.85 MW. One of the seven St. Cloud internal combustion generating units (Unit 8) is not operated and instead is kept in standby, so the resulting net summer generating capacity from St. Cloud's internal combustion units is 21.85 MW. All of the St. Cloud units are scheduled to retire in October, 2006.

2.3 Purchase Power Resources

As part of the sale of the Indian River steam units, OUC entered into a power purchase agreement with Reliant (Reliant Agreement) for capacity and energy from the Indian River steam units. The term of the Reliant Agreement extended through September 30, 2003, with the cost of the capacity and energy based on a demand and energy charge. The energy charge is based on a fixed heat rate and a specified split of natural gas and oil for fuel.

Through September 30, 2003, OUC purchased the maximum amount available from the Reliant PPA (577.5 MW), and has elected to purchase various amounts during fiscal years 2004 and 2005. The maximum capacity available to OUC through the extension option with Reliant is 500 MW per year. The 500 MW can be reduced in 100 MW increments annually over the duration of the four-year option term through proper notice from OUC, but cannot increase from the previous year. For fiscal year 2004, OUC has nominated 500 MW, and has nominated 300 MW for fiscal year 2005. Beyond fiscal year 2005, OUC will not purchase capacity under the Reliant PPA.

Additionally, St. Cloud has a Partial Requirements (PR) contract with Tampa Electric Company (TECO). As a result of the Interlocal Agreement with St. Cloud, OUC schedules the TECO PR purchase. The annual capacities associated with the Reliant Agreement and St. Cloud's TECO power purchase agreements are summarized in Table 2-2.

Table 2-2.
Power Purchase Agreements

Company	Capacity	Duration
TECO PR	15 MW	Through 12/31/2012
Reliant	500 MW	10/01/2003 – 09/30/2004
Reliant	300 MW	10/01/2004 – 09/30/2005

2.4 Power Sales Contracts

OUC is contractually obligated to supply power to three different purchasers for various durations of time. These power sales contracts are classified as either unit power sales or system power sales, and details of each of these contracts are summarized below.

2.4.1 Unit Power Sales.

OUC has had a unit power sale contract in place with FMPA since May 1, 1986, which expires December 31, 2006. The capacity is available from the Indian River Plant and can be provided by OUC's other units if the capacity is available. Under this contract, OUC is obligated to supply 65 MW in the summer of 2004, 43 MW in the summer of 2005, and 22 MW in the summer of 2006. Further, OUC will sell 44 MW of capacity to FMPA during the winter of 2004/05 and 34 MW during the winter of 2005/06.

Additionally, OUC has had a unit power sales contract with Seminole Electric Cooperative (SEC) since January 1, 1996, which will expire May 31, 2004. The SEC unit power sale is from the Indian River Steam Units and the Indian River Combustion Turbines and calls for OUC to provide 75 MW of capacity annually.

2.4.2 System Power Sales.

OUC has been involved in a partial requirements power sales contract with Reedy Creek Improvement District (RCID) since January 1, 1999. The RCID partial requirements contract expires December 31, 2005. OUC will provide 101 MW to RCID during the summer of 2004 and 113 MW during the summer of 2005. For winter 2004/05, OUC will provide 101 MW to RCID, and 84 MW will be sold during the winter of 2005/06.

2.5 Transmission System

OUC's existing transmission system consists of 28 substations interconnected through approximately 338 miles of 230 kV, 115 kV, and 69 kV lines and cables. OUC is fully integrated into the state transmission grid through its thirteen 230 kV and two 69 kV interconnections with other generating utilities that are members of the Florida Reliability Coordinating Council (FRCC) as summarized in Table 2-3. Additionally, OUC is now responsible for St. Cloud's three substations as well as approximately 31 miles of 230 kV and 69 kV lines and cables. As presented in Table 2-4, the St. Cloud transmission system includes three interconnections. OUC's transmission system, including St. Cloud, is shown in Figure 2-1.

The 69 kV interconnection with Progress Energy Florida (PEF) at the Magnolia Ranch substation was completed in June, 2002, and in January, 2003, the addition of the Grant to Robinson 115 kV transmission line was completed. Additionally, prior to the commercial operation of Stanton A, circuit breakers were added to the Stanton 230 kV bus, effectively splitting the bus and providing available fault current and line loading relief. To maintain reliable and economic service, OUC has developed the following schedule of transmission system upgrades.

- 230 kV interconnection with PEF at OUC's Metrowest substation in the summer of 2004.
- Addition of distribution transformers at the existing Kaley substation in the fall of 2004.
- Addition of a new Lake Nona 230/15 kV substation in the fall of 2004.
- Addition of the St. Cloud South substation and associated 69 kV transmission lines, including an upgrade of the 69 kV line from KUA to St. Cloud. Expected completion date is in the summer of 2006.

Table 2-3.
OUC Transmission Interconnections

Utility	kV	Number of Interconnections
FPL (2 circuits)	230	1
PEF	230	6
KUA	230	2
KUA/FMPA	230	1
Lakeland	230	1
TECO	230	1
TECO/RCID	230	1
PEF	69	1
STC	69	1

FMPA - Florida Municipal Power Agency
FPL - Florida Power & Light
KUA - Kissimmee Utility Authority
PEF – Progress Energy Florida
RCID - Reedy Creek Improvement District
STC – St. Cloud
TECO - Tampa Electric Company

Table 2-4.
STC Transmission Interconnections

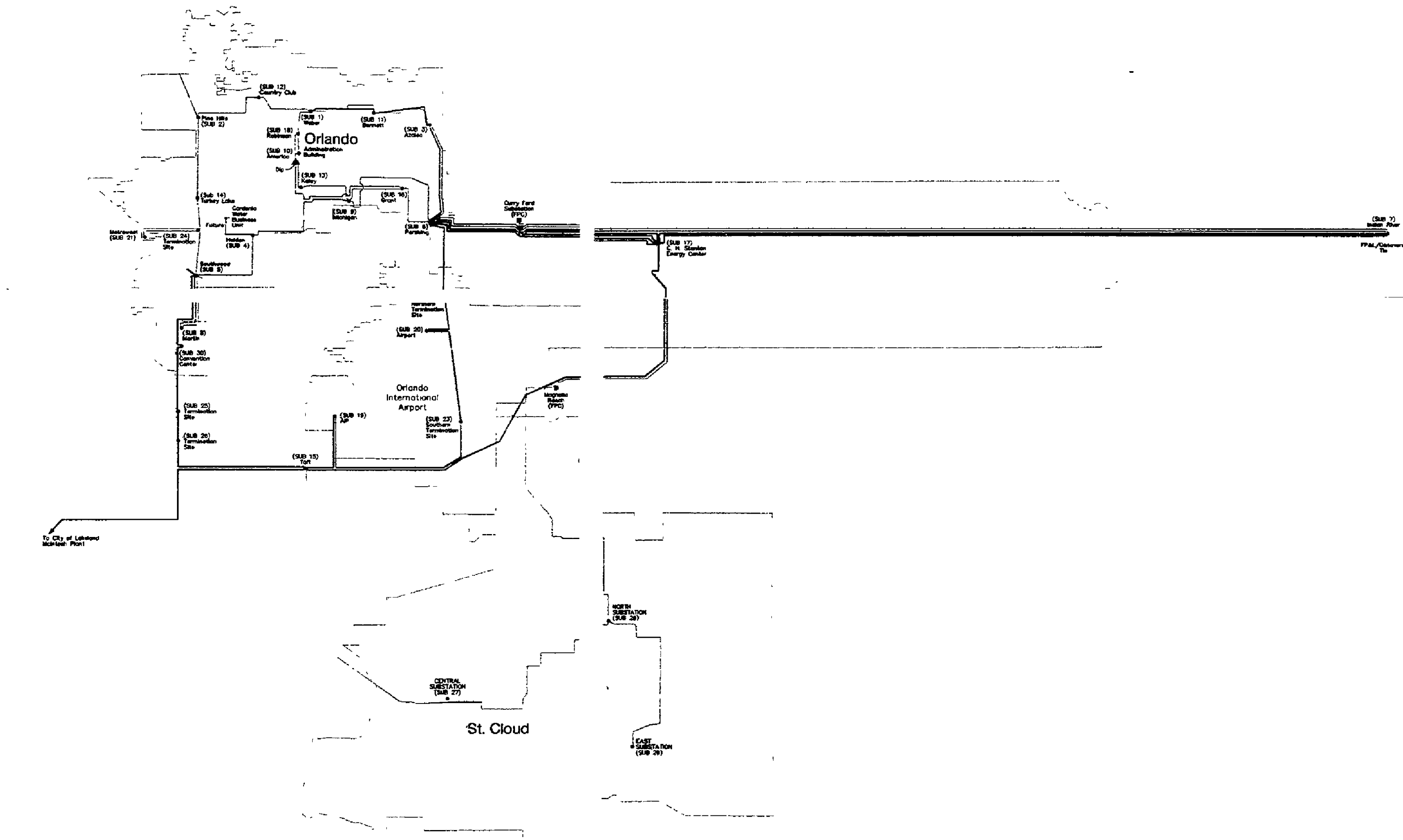
Utility	kV	Number of Interconnections
OUC	69	1
PEF	230	1
KUA	69	1

KUA - Kissimmee Utility Authority
OUC – Orlando Utilities Commission
PEF – Progress Energy Florida

Orlando Utilities Commission
Transmission Lines

Legend

- 115 KV Transmission Line
- 115 KV U.G. Transmission Line
- 230 KV Transmission Line
- 230 KV U.G. Transmission Line
- 69 kv Transmission Line
- 69 kv U.G. Transmission Line
- Orlando Electric Service Boundary
- St. Cloud Electric Service Boundary
- Orlando Utilities Substation
- Orlando Utilities Generating Plant
- Railroad



ORLANDO UTILITIES COMMISSION
SERVICE TERRITORY (TRANSMISSION LINES)

3.0 Strategic Issues

OUC incorporates a number of strategic considerations while planning for the electrical system. This section provides an overview of a number of these strategic considerations.

3.1 Strategic Business Units

As the entire electric utility industry faces deregulation, OUC is aggressively developing strategies to be competitive in a deregulated environment. One strategy already implemented was to reorganize OUC into the following strategic business units, which consist of the Power Resources Business Unit and the Energy Delivery Business Unit.

3.1.1 Power Resources Business Unit.

The Power Resources Business Unit (PRBU) has structured its operations based on a competitive environment that assumes that even OUC's customers are not captive. The PRBU will only be profitable if it can produce electricity that is competitively priced in the open market. In line with this strategy, OUC is continually studying strategic options to improve or reposition its generating assets, such as the sale of the Indian River Steam Units in 1999 and the addition of new units and power purchase agreements. In addition, OUC formally instituted its Energy Risk Management Program in 2000, which ultimately saved OUC customers $2 million in fiscal year 2003.

OUC's generating system has been designed over the years to take advantage of fuel diversity and the resultant system reliability and economic benefits. OUC's long-standing intent to achieve diversity in its fuel mix is evidenced by its participation in other generating facilities in the State of Florida. The first such endeavor occurred in 1977 when OUC secured a share of the Crystal River Unit 3 nuclear plant, followed by the acquisition of an ownership share in Lakeland Electric's McIntosh Unit 3 coal-fired unit in 1982. In 1983, OUC also acquired a share of the St. Lucie Unit 2 nuclear unit. OUC's current capacity mix is summarized in Table 3-1.

Coal represents approximately 60 percent of the generating capacity either wholly or jointly owned by OUC. This strategy ensures against interruptions in supply and increases in the cost of oil and natural gas. Additional details of OUC's generating facilities are presented in Schedule 1 of Section 11.

Table 3-1.
Generation Capacity (MW) Owned by OUC by Fuel Type (as of January 1, 2003)

	Winter Capacity				Summer Capacity			
Plant Name	Coal	Nuclear	Gas/Oil	Total	Coal	Nuclear	Gas/Oil	Total
Stanton	623		184	807	621		168	789
Indian River			247	247			207	207
Crystal River		13		13		13		13
C.D. McIntosh Jr.	136			136	133			133
St. Lucie		52		52		51		51
Total (MW)	759	62	431	1,255	754	64	375	1,193
Total (percent)	60.48	5.18	34.34	100	63.20	5.36	31.43	100

OUC's use of alternative or renewable fuels is further enhanced by burning a mixture of petroleum coke in McIntosh Unit 3, along with coal. Petroleum coke is a waste by-product of the refining industry and in addition to the benefits of using a waste product, petroleum coke's lower price results in significant savings over coal. Tests have been done that indicate the unit has the ability to use petroleum coke for approximately 20 percent of the fuel input. Permits have been modified and approved for this level of use and petroleum coke is being burned in the unit.

OUC's fuel diversity and use of renewable and waste fuels is further enhanced through the burning of landfill gas from the Orange County Landfill at Stanton Energy Center. The use of landfill gas not only reduces fuel costs, but also reduces the emission of greenhouse gases.

OUC's diversified mix of generating units provides protection against disruption of supply while simultaneously providing economic opportunities to reduce cost to customers. The ability to burn a variety of fuels is enhanced through the Indian River purchase power agreement, which utilizes a specified proportion of natural gas and oil which can be adjusted annually.

3.1.2 Energy Delivery Business Unit.

OUC's Energy Delivery Business Unit (EDBU) focuses on providing OUC's customers with the most reliable electric service possible. Formerly called the Electric Distribution Business Unit, the unit was renamed after merging with OUC's Electric Transmission Business Unit, which was being phased out with the anticipated creation of a regional independent transmission organization.

OUC's leadership in providing reliable electric distribution service is demonstrated by its commitment to making initial investments in high quality material and equipment. Additionally, nearly 50 percent of OUC's distribution system is underground, protecting it from trees and high winds. OUC's dependability is also attributable to its proactive maintenance programs to identify and correct potential problems, proactive replacement of old equipment, and a tree trimming program that minimizes tree-related service disruptions. OUC's reliability is demonstrated by the fact that during 2002, the average annual customer interruption for the combined Orlando-St. Cloud service area was well below that of OUC's competition.

During 2003, OUC spent $35 million in new capital investments, and OUC is planning to spend $17 million in the City of St. Cloud on distribution projects over the next five years. Additionally, OUC will spend $15 million in the next two years on a new substation and transmission line project. Such investments have resulted in OUC maintaining its reputation for reliability, evidenced by receiving recognition outside of the State of Florida. PA Consulting Group, a leading management and technology consulting firm, named OUC the most reliable utility in the southeastern United States for the second straight year. The award was bestowed upon OUC based on an audit of OUC's power-restoration and reliability data.

3.2 Reposition of Assets

As a strategic consideration, OUC has been working on repositioning its assets. One major issue is the sale of its Indian River power plant steam units to Reliant Energy in 1999. The agreement provided OUC with a four-year PPA, with OUC maintaining options to extend the PPA duration, which allowed OUC to elect to continue to receive power from the Indian River steam generation units while excess power generated by the plant will be sold by Reliant to other utilities. With the proceeds of the sale and by purchasing power, OUC is better able to diversify its generation portfolio and better take advantage of changing market conditions. The sale offered OUC the ability to replace the less competitive oil and gas steam units with more competitive combined cycle generation, as well as providing the alternative of purchasing power when it is more economical for OUC customers.

3.3 Florida Municipal Power Pool

In 1988, OUC joined with Lakeland Electric and the Florida Municipal Power Agency's (FMPA) All-Requirements Project members to form the Florida Municipal Power Pool (FMPP). Later, Kissimmee Utility Authority (KUA) joined FMPP. Through time, FMPA's All-Requirements Project has added members as well. FMPP is an operating-type electric pool, which dispatches all the pool members' generating resources in the most economical manner to meet the total load requirements of the pool. The central dispatch is providing savings to all parties because of reduced commitment costs and lower overall fuel costs. OUC serves as the FMPP dispatcher and handles all accounting for the allocation of fuel expenses and savings. The term of the pool agreement is one year and automatically renews from year to year until terminated by the consent of all participants.

OUC's participation in FMPP provides significant savings from the joint commitment and dispatch of FMPP's units. Participation in FMPP also provides OUC with a ready market for any excess energy available from OUC's generating units.

3.4 Security of Power Supply

OUC currently maintains interchange agreements with other utilities in Florida to provide electrical energy during emergency conditions. The reliability of the power supply is also enhanced by thirteen 230 kV and two 69 kV interconnections with other Florida utilities, including seven interconnections with Progress Energy Florida (formerly Florida Power Corporation), three with Kissimmee Utility Authority, and one each with Florida Power and Light, Tampa Electric Company, Reedy Creek Improvement District, Lakeland Electric, and the City of St. Cloud. In addition to enhancing reliability, these interconnections also facilitate the marketing of electric energy by OUC to and from other electric utilities in Florida.

3.5 Environmental Performance

As the quality of the environment is important to Florida, and especially important to the tourist-attracted economy in Central Florida, OUC is committed to protecting human health and preserving the quality of life and the environment in Central Florida. To demonstrate this commitment, OUC has chosen to operate their generating units with emission levels below those required by permits and licenses by equipping its power plants with the best available environmental protection systems. As a result, even with a second unit in operation, the Stanton Energy Center is one of the cleanest coal-fired generating stations in the nation. Unit 2 is the first of its size and kind in the nation to use Selective Catalytic Reduction (SCR) to remove nitrogen oxides (NO_x). Using SCR and Low-NO_x burner technology, Stanton 2 successfully meets the stringent air quality requirements imposed upon it. Stanton A, OUC's newest generating unit, incorporates the most environmentally advanced technology available and enables OUC to diversify its fuel mix while adding more flexibility to OUC's portfolio of owned generation and purchased power.

This superior environmental performance not only preserves the environment, but also results in many economic benefits, which help offset the costs associated with the superior environmental performance. For example, the high quality coal burned at Stanton contributes to the high availability of the units as well as low heat rate.

Further demonstrating its environmental commitment to clean air, OUC has signed a contract to burn the methane gas collected from the Orange County landfill adjacent to Stanton Energy Center. Methane gas, when released into the atmosphere, is considered to be 20 times worse than carbon dioxide in terms of possible global warming effects. Both Stanton units have the capability of burning methane.

In addition to its commitment to clean air, OUC is also equally committed to minimizing the environmental and aesthetic impacts on land used for and adjacent to new construction projects. In planning the new transmission line to link Stanton and St. Cloud, OUC employed the best management practices in route selection and design. OUC used low-impact construction and clearing techniques to further minimize the environmental and aesthetic impacts of the project. As a result, the state required no additional mitigation measures.

OUC has also voluntarily implemented a product substitution program not only to protect workers' health and safety but also to minimize hazardous waste generation and to prevent environmental impacts. The Environmental Affairs and the Safety Division constantly review and replace products to eliminate the use of hazardous substances. To further prevent pollution and reduce waste generation, OUC also reuses and recycles many products.

OUC is also pursuing programs demonstrating alternate fuels for transportation. OUC has purchased two minivans which have been retrofitted with battery powered motors. They will be used in the normal daily activities of OUC's Conservation and Office Services Divisions. One of the vehicles is also equipped with solar photovoltaic panels on the roof to power cooling fans. The vehicles are powered by 10 large gel cell batteries and 27 horsepower, high torque drive motors. OUC purchased these vehicles to learn as much as possible about their operating and recharge characteristics and to demonstrate the new technology to customers. OUC has also donated two vehicles to the University of Central Florida's Alternate Fuels Research Program for purposes of conducting research on alternative fuel sources for transportation.

3.6 Community Relations

Owned by the City of Orlando and its citizens, OUC is especially committed to being a good corporate citizen and neighbor in the areas it serves or impacts.

In Orange, Osceola, and Brevard Counties, where OUC serves customers and/or has generating units, OUC gives its wholehearted support to education, diversity, the arts, and social-service agencies. An active Chamber of Commerce participant in all three counties, OUC also supports area Hispanic Chambers and the Metropolitan Orlando Urban League. As a United Arts trustee, OUC has allowed its historic Lake Ivanhoe

Power Plant to be turned into a performing arts center. OUC is also a corporate donor for WMFE public television and a co-sponsor of the "Power Station" exhibit at the Orlando Science Center.

Demonstrating its commitment to community service, in 2003 OUC continued to provide assistance to various nonprofit agencies. OUC's annual charity golf tournament raised $25,000 for Quest, Inc., an organization that provides much-needed services to the developmentally disabled. Company-wide, OUC employees donated time and money to causes including the Heart of Florida United Way, the Juvenile Diabetes Research Foundation, the United Arts, and the Osceola Foundation for Education, among other organizations.

OUC received the 2003 Community Service Award in the Florida Municipal Electric Association's (FMEA) large utilities category, which applies to public power systems serving more than 50,000 customers. The award was bestowed upon OUC for enriching Central Florida in the areas of education, the environment, charitable donations, and other community outreach activities. FMEA recognized OUC for more than 30 of OUC's programs, including its charitable support of local health and human service agencies, its comprehensive tree-care management program, its hurricane preparedness materials for the public, and its energy efficiency rebate programs for customers.

4.0 Forecast of Peak Demand and Energy Consumption

OUC has retained Regional Economic Research, Inc. (RER) to develop forecasts of peak demand and energy consumption. The forecast scope was to develop a sales forecast for OUC budgeting and financial planning process. The objective was thus to develop a forecast model that could be used successfully for forecasting both short and long-term energy and peak demand. The events of September 11, 2001, and the subsequent national economic slowdown have continued to impact the tourist-related aspects of this forecast.

4.1 Forecast Methodology

There are two primary forecasting approaches used in forecasting electricity requirements; econometric-based modeling (such as linear regression) and end-use models (such as EPRI's REEPS and COMMEND models). In general, econometric forecast models provide better forecasts in the short-term time frame and end-use models are better at capturing long-term structural change resulting from competition across fuels, and changes in appliance stock and efficiency.

The difficulty of end-use modeling is that end-use models are extremely data-intensive and provide relatively poor short-term forecasts. End-use models require detailed information on appliance ownership, efficiency of the existing stock, new purchase behavior, utilization patterns, commercial floor-stock estimates by building type, and commercial end-use saturations and intensities in both new and existing construction. It typically costs several hundred thousand dollars to update and to maintain such a detailed database. Lack of detailed end-use information precluded developing end-use forecasts for the OUC/St. Cloud service territories. Further, given that there is little to no retail natural gas in the OUC service territory, end-use modeling would add little in terms of accounting for cross-fuel competition - one of the primary benefits of end-use modeling.

Since end-use modeling was not an option, the approach adopted was to develop linear regression sales models. To capture long-term structural changes, end-use concepts are blended into the regression model specification. This approach, known as a Statistically Adjusted Engineering (SAE) model, entails specifying end-use variables (heating, cooling, and base use) and utilizing these variables in sales regression models. While the SAE approach loses some end-use detail, it performs well forecasting short-term energy requirements, and it provides reasonable structure for forecasting energy requirements over the long-term.

4.1.1 Residential Sector Model.

The residential model consists of both an average use per household model and a customer forecast model. Monthly average use models are estimated over the period encompassing 1996 to 2002. This provides seven years of historical data, with more than enough observations to estimate strong regression models. Once models are estimated, the residential energy requirements in month T is calculated as the product of the customer and average use forecast:

$$Residential\ Sales_T = Average\ User\ Per\ Household_T * Number\ of\ Customers_T$$

4.1.1.1 Residential Customer Forecast. The number of customers is forecasted as a simple function of household projections for the Orlando Metropolitan Statistical Area (MSA). Models were estimated using MSA-level data, as county level economic data is only available on an annual basis. Not surprisingly, the historical relationship between OUC customers and households in the Orlando MSA is extremely strong. The OUC customer forecast model has an adjusted R^2 of 0.999 with an in-sample Mean Absolute Percent Error (MAPE) of 0.4 percent. For St. Cloud, the model performance is not as strong, given the "noise" in the historical monthly billing data. The adjusted R^2 is 0.82 with an in-sample MAPE of 4.0 percent. Given that St. Cloud is a relatively small part of OUC's service territory, the 4.0 percent average customer forecast error represents a relatively small number of total system customers. Combined, the average model error (the Mean Absolute Deviation) is about 1,400 customers. The combined error is less than 1 percent.

4.1.1.2 Average Use Forecast. To incorporate end-use structure into the residential sales model, average use is disaggregated into its primary end-use components - heating, cooling, and base-use requirements:

$$Average\ Use_t = Heat_t + Cooling_t + BaseUse_t$$

Each end use is defined in terms of both an appliance index variable, which indicates relative saturation and efficiency of the existing stock, and a utilization variable, which reflects how the stock is utilized. The end-use variables are defined as:

$$Cooling_t = CoolIndex_t * CoolUse_t$$
$$Heating_t = HeatIndex_t * HeatUse_t$$
$$BaseUse_t = BaseIndex_t * OtherUse_t$$

4.1.1.3 End-Use Index Variables. The end-use index variables (*CoolIndex*, *HeatIndex*, and *BaseIndex*) are designed to capture both increases in appliance saturation and changes in the relative efficiency of the stock.

The indices are calculated as the ratio of the appliance saturation to average efficiency of the existing appliance stock. To generate a relative index, the ratio is divided by the estimated value for 1995. Thus, the index has a value of 1.0 in 1995. The indices are defined as:

$$CoolIndex_t = (CoolSat_t/CoolEff_t) \ / \ (CoolSat_{1995}/CoolEff_{1995})$$
$$HeatIndex_t = (HeatSat_t/HeatEff_t) \ / \ (HeatSat_{1995}/HeatEff_{1995})$$
$$BaseIndex_t = (BaseSat_t/BaseEff_t) \ / \ (HeatSat_{1995}/CoolEff_{1995})$$

OUC appliance saturation surveys from 1990 and 1994 were used to develop the indices. Appliance saturation and efficiency trends were projected using the EPRI REEPS (Residential End-Use Planning System) model. The projections are based on OUC saturation estimates and price projections, and on national default appliance stock age distribution, efficiency characteristics, and future efficiency standards.

Given that there is little residential gas availability in the OUC service territory, the saturation of electric space heat was over 80 percent in 1994. Similarly, given the heat and humidity in Orlando, there is nearly a 98 percent saturation of air conditioning. OUC is already starting out with an appliance stock that is highly sensitive to variation in weather conditions. For heating, while the saturation trend continues to increase, the overall index actually declines over the forecast period, as less efficient heating technologies (electric furnace and room heating) are replaced with more efficient heat pumps. Similarly, residential cooling load resulting from increases in central air conditioning saturation is largely mitigated by expected heat pump and central air conditioning efficiency gains. The overall cooling index is relatively flat throughout the forecast period. The implication of these index trends is that, despite a high saturation of electric heat and cooling, residential average use should be less sensitive to changes in temperature through the forecast period, with increasing end-use efficiency slowing residential average use growth. Improvements in efficiency of nonweather-sensitive appliances (including refrigerators, ranges, washers, and dryers) also help to mitigate residential electricity growth.

4.1.1.4 Utilization Variables. The utilization variables ($CoolUse_t$, $HeatUse_t$, and $BaseUse_t$) are designed to capture energy demand driven by use of the appliance stock (the end-use index variables). The utilization drivers include:

Weather conditions (as captured by heating and cooling degree days).
Electricity prices.
Household income.
Household size.

The typical modeling approach is simply to specify an average use model with the variables above on the "right-hand side" of the regression model. Due to multicollinearity, however, it is often impossible to isolate the impact of one variable on average use from the impact of another variable. This is because the variables are moving in the same direction – household income is increasing while price and household size are declining. While generally not a problem in a short-term forecast (the price impact will often be simply ignored), it is desirable to capture how changes in these variables impact the forecast over the longer term. To allow each of these drivers to impact usage, elasticities for the driver variables are imposed during the construction of the utilization variables. The utilization variables are defined as:

$$CoolUse_t = (Price_t \wedge (-.20)) * (Inc\_per\_HH_t \wedge .20) * (HH\_Size_t \wedge 0.25) * CDD$$
$$HeatUse_t = (Price_t \wedge (-.20)) * (Inc\_per\_HH_t \wedge .20) * (HH\_Size_t \wedge 0.25) * HDD$$
$$OtherUse_t = (Price_t \wedge (-.20)) * (Inc\_per\_HH_t \wedge .15) * (HH\_Size_t \wedge 0.20)$$

In this functional form, the values shown in the specifications are, in effect, elasticities. The elasticities give the percent change in utilization (*CoolUse*, *HeatUse*, and *BaseUse*) given a 1 percent change in the forecast drivers - price, household income, and household size. The elasticities imposed are relatively small, but reasonable. Changes in price, household income, and household size will have a small, but reasonable, impact on changes in the utilization variables. Over the historical period, heating and cooling use are dominated by month-to-month variation in cooling and heating degree days (CDD and HDD).

4.1.1.5 Estimate Models. To estimate the forecast models, monthly average residential usage is regressed on *Cooling*, *Heating*, and *BaseUse*. Lagged *Use* variables are also included in the specification because the *Use* variables are constructed with calendar-month weather data, but the dependent variable (residential average use) is based on revenue-month sales. July residential sales, for example, reflect usage in both calendar months June and July. The end-use variables proved to work extremely well in the regression models. For OUC, the residential adjusted R^2 is 0.95 with an in-sample MAPE of less than 4 percent. The standard error of the regression model is 55.21 kWh compared with residential monthly average usage of 1,067 kWh. All the model coefficients are highly significant (exhibiting P-values less than 0.09). The St. Cloud model explains slightly less of the variation in average use, with an adjusted R^2 of 0.94 and an in-sample MAPE of 4.3 percent. The model coefficients are highly significant.

4.1.2 Nonresidential Sector Models.

The nonresidential sector is segmented into two revenue classes:

Small General Service (GS Nondemand or GSND)
Large General Service (GS Demand or GSD)

The GSND class consists of small commercial customers with a measured demand of less than 50 kW. The GSD class consists of those customers with monthly maximum demand exceeding 50 kW.

4.1.2.1 GSND Models. The GSND models are developed along lines similar to the residential forecast with the GSND monthly energy demand calculated as:

$$GSND_T = GSND\ Average\ Use_T * GSND\ Customers_T$$

4.1.2.1.1 GSND Customers. GSND customers are forecasted using a simple regression model that relates GSND customers to Orlando MSA nonmanufacturing employment projections. An AR1 correction term was added to the specification to correct for serial correlation. The OUC customer model was estimated using monthly customer counts for the period January, 1996, through December, 2002. For OUC, the overall model adjusted R^2 is 0.965 with an in-sample MAPE of 0.33 percent. Again, the customer model for St. Cloud did not perform as well due to significant "noise" in the month-to-month variation in customer counts. The adjusted R^2 is 0.82, with an in-sample MAPE of 4.15 percent. An AR1 correction was added to the St. Cloud model to help account for month-to-month swings in customer counts. The model coefficients in both the OUC and St. Cloud models are all highly significant.

A similar SAE modeling approach is used in specifying the GSND average use model. Where average GSND use is defined as:

$$Average\ Use_t = Heating_t + Cooling_t + BaseUse_t$$

Cooling, *Heating*, and *BaseUse* are defined as the product of an end-use stock index and utilization variable:

$$Cooling_t = CoolIndex_t * CoolUse_t$$
$$Heating_t = HeatIndex_t * HeatUse_t$$
$$BaseUse_t = BaseIndex_t * OtherUse_t$$

4.1.2.1.2 Nonresidential End-Use Index Variables. For the nonresidential models, saturation and efficiency trends are accounted for by the change in annual energy intensities (kWh per square foot) over the forecast horizon. Energy intensity estimates are derived using the EPRI COMMEND model. The national default COMMEND model was modified to reflect OUC heating and cooling saturation estimates and long-term electric price forecasts. The commercial building type mix in the OUC/St. Cloud service territory is assumed to look like that of the national default model. In the OUC service territory, the base-year electric heating saturation is nearly 80 percent, and cooling saturation is 100 percent. The high electric saturation again reflects limited natural gas alternatives. The index is calculated using 1995 as the base year:

$$Index_t = Energy\ Intensity_t / Energy\ Intensity_{95}$$

With 100 percent saturation and constant real electricity prices over the long term, annual cooling intensities (i.e., use per square foot) are relatively flat and thus affect the Cooling Index very little over the forecast horizon. Similarly, the Other Use Index shows relatively slow growth through the forecast period. The heating index increases through 2010, as electric heat saturation continues to gain the remaining market share; however, as there are relatively few days of actual commercial heating (utilization of the heating stock), the heating index has relatively little impact on overall GSND average use.

4.1.2.1.3 GSND Usage Variables. The usage variables (*CoolUse*, *HeatUse*, and *OtherUse*) are designed to capture GSND end-use utilization. Where household size and income are the primary economic variables used in driving residential utilization, employment and output are used to drive nonresidential utilization. The Use variables are defined as:

$$CoolUse = (Price^{-.20}) * (Output\ per\ Employee^{.20}) * (CDD)$$

$HeatUse = (Price^{\wedge}\text{-}.20)*(Output\ per\ Employee^{\wedge}.20)*(HDD)$
$OtherUse = (Price^{\wedge}\text{-}.20)*(Output\ per\ Employee^{\wedge}.20)$

The assumed utilization elasticities are relatively small, but reasonable. The price elasticity is set at -0.20; a 1 percent decrease in price causes a 0.2 percent increase in the use variables. Similarly the productivity elasticity is set at 0.2 percent; a 1 percent increase in productivity leads to a 0.2 percent increase in the end-use utilization.

The *Use* variables are multiplied by the *Index* variables to generate *Cooling*, *Heating*, and *BaseUse*. Since 1992, GSND average use for OUC has actually been declining. This is largely because GSND customers tend to be larger (when compared with St. Cloud), and they are typically migrated to the GSD classification as soon as customers exceed the GSND usage limit. To account for the downward trend, a trend variable interactive with the *BaseUse* is incorporated into the average use specification; the variable has a negative sign and is highly significant. All the GSND model variables are highly significant. The adjusted R^2 for the OUC GSND average use model is 0.99 with an in-sample MAPE of 4.1 percent. For St. Cloud the GSND average use model has an adjusted R^2 of 0.94, with an in-sample MAPE of 4.8 percent.

4.1.2.2 GSD Models. The general service demand class represents the largest nonresidential customer class. Over the last five years, OUC has seen the strongest sales gains in the GSD customer class, with GSD sales growth averaging 4.5 percent for the combined OUC and St. Cloud service territories. While overall sales growth will slow significantly over the forecast period, GSD sales are expected to continue to show relatively strong sales growth through the forecast horizon.

Because the GSD class represents such a diverse customer base, an aggregate sales model is used in place of an average use model. Again, end-use variable concepts are incorporated into the model specification where:

GSD $Sales_t = f(BaseUse_t, CoolUse_t, \text{and } HeatUse_t)$

Where

$Cooling_t = CoolIndex_t * (Price_t^{\wedge}\text{-}.20) * (GSP_t^{\wedge}.20) * CDD_t$
$Heating_t = HeatIndex_t * (Price_t^{\wedge}\text{-}.20) * (GSP_t^{\wedge}.20) * HDD_t$
$BaseUse_t = BaseIndex_t * (Price_t^{\wedge}\text{-}.20) * (GSP_t^{\wedge}.20) * HDD_t$

The index variables are the same as those used in estimating the GSND model. GSP, or Gross "State" Product, is the total economic output in the Orlando MSA. (GSP is the term used to describe total economic output at the state level. However, the nomenclature is kept the same at the MSA level for consistency.)

In the OUC model, the end-use variables are all highly significant (except for the lagged heating variable). The adjusted R^2 is 0.95 with an in-sample MAPE of 2.7 percent. In the St. Cloud model, all the variables except the heating end-use variables are highly significant. The adjusted R^2 is 0.97 with a MAPE of 2.9 percent. The low t-statistics on the heating variables indicate that there is relatively little electric space heating in the GSD class.

In 1999, GSD saw a significant jump in sales as a result of the opening of Universal Studios' *Islands of Adventure*, which is expected to continue contributing strong growth to the GSD rate class. While the large load increase in 1999 is partially captured by the regression model with a binary variable (*Aug99_Later*), it is impossible to capture future large incremental load additions that cannot be directly related to regional output data. Expected near-term sales growth from *Islands of Adventure* and other large development projects are added to the GSD statistical baseline forecast. Exogenous load adjustments include the airport expansion, the new convention center, the continued expansion of Orlando area hotels, and major medical centers.

4.1.2.2.1 Street Lighting Sales. Street lighting sales are forecasted using a simple trend model. It is assumed that street lighting sales will continue to increase at the rate experienced over the last seven years. The forecast also includes sales from the *OUC Convenient Lighting Program*, which targets outdoor lighting use in the GSD sector. The lighting program absorbs sales that would otherwise be billed in the GSD tariffs; as such, the lighting program does not represent any new load growth. It is assumed that the *Convenient Lighting Program* will grow by about 3.0 GWh a year through the forecast period.

4.1.3 Hourly Load and Peak Forecast.

The system hourly load forecast is based on a set of hourly load models using load data covering the period January, 1996, to December, 2002. To forecast hourly loads, historical hourly loads are expressed as a percentage of the total daily energy:

$$Fraction_{hd} = Load_{hd}/Energy_d$$

Where

$Load_{hd}$= *the system load in hour h and day d*

$Energy_d$ = *the system energy in day d*

Hourly percent models are then estimated for each hour using Ordinary Least Squares (OLS) regression. The hourly models are specified as a function of daily weather conditions, months, day of the week, and holidays.

The hourly load forecast is driven by the long-term retail energy forecast. Hourly loads are forecasted as the product of the daily energy forecast and forecasted hourly fraction. Thus the forecast for hour (h) equals:

$$Load_h = Fraction_h * DailyEnergyForecast_d$$

The daily energy forecast is generated from the long-term monthly retail sales forecast. Monthly retail energy forecasts are translated to daily system energy requirements through the conversion variable $DaykWh_t$, which is calculated by dividing actual system daily energy by a retail sales trend based on actual monthly retail sales:

$$DaykWh_d = System\ Energy_d / SalesTrend_m$$
$$SalesTrend_m = ResTrend_m + NonResTrend_m$$

Where:

$ResSaleTrend_m$ = *12-month moving average (Residential Sales)*
$NonResTrend_m$ = *12-month moving average (Nonresidential Sales)*

A regression model to forecast $DaykWh_d$ is then estimated that relates $DaykWh_d$ to daily weather conditions, day of the week, holidays, and season. Forecasted daily energy in period T is then calculated as:

$$DailyEnergyForecast_T = KWperKWh_T * SalesTrend_T$$

Where:

$SalesTrend_T$ *is calculated from retail monthly sales forecast*

Normal daily average temperatures are used to forecast hourly demand. Normal daily temperatures are calculated by ranking each historical year from the hottest to coldest average daily temperature. The ranked data are then averaged to generate the hottest average temperature day to the coolest average temperature day. Daily normal temperatures are then mapped back to a representative calendar day based on a typical daily weather pattern. The hottest normal temperature is mapped to July and the coldest normal temperature to January.

One surprising element is that under normal daily weather conditions OUC is just as likely to experience a winter peak as it is a summer peak. OUC experiences a "needle-like" peak in the winter months on the one or two days where the low temperature falls below freezing. The needle peak is driven by back-up resistant heat built into residential heat pumps. With heat pumps continuing to gain market share, winter peaks are projected to grow slightly faster than summer peaks during the forecast horizon.

A separate hourly load forecast is estimated for St. Cloud. Given that St. Cloud is dominated by the residential sector, St. Cloud is even more likely to peak during the winter season.

The hourly OUC and St. Cloud forecast is aggregated to yield a total system hourly load requirement. Forecasted seasonal peaks are derived by then finding the maximum hourly demand in January (for the winter peak) and July (for the summer peak).

4.2 Forecast Assumptions

The forecast is driven by a set of underlying demographic, economic, weather, and price assumptions. Given long-term economic uncertainty, the approach was to develop a set of reasonable, but conservative, set of forecast drivers.

4.2.1 Economics.

The economic assumptions are derived from forecasts from Economy.com and the University of Florida. Economy.com's monthly economic forecast for the Orlando MSA is used to drive the forecast.

4.2.1.1 Employment and Regional Output. The nonresidential forecast models are driven by nonmanufacturing and regional output forecasts. Economy.com's employment forecasts were used. Table 4-1 shows the annual employment and gross state product projections.

4.2.1.2 Population, Households, and Income. The primary economic drivers in the residential forecast model are population, the number of households, and real personal income. Economy.com's projections for the Orlando MSA were used.

Table 4-1.
Nonmanufacturing Employment (Thousands) and Gross Regional Product Projections (Billion $)

Year	Retail	Wholesale	Services	Financial Services	Government	Gross Product (Billion $)
1995	139.4	38.6	288.2	42.2	79.6	39.6
1996	146.7	41.3	304.4	44.5	81.6	41.8
1997	154.2	44.3	329.7	46.0	83.9	44.6
1998	159.6	45.9	352.4	49.7	86.7	48.2
1999	166.5	48.0	371.4	54.0	89.1	51.7
2000	170.6	49.7	393.5	51.3	91.9	53.9
2005	177.5	56.0	436.8	57.6	100.5	61.7
2013	199.0	67.5	576.8	66.0	114.1	84.1
Change	Percent	Percent	Percent	Percent	Percent	Percent
1996	5.2	7.0	5.6	5.5	2.5	5.6
1997	5.1	7.3	8.3	3.3	2.8	6.7
1998	3.5	3.6	6.9	8.0	3.3	8.1
1999	4.3	4.6	5.4	8.7	2.8	7.3
00-05	0.8	2.4	2.1	2.3	1.8	2.7
05-13	1.4	2.4	3.5	1.7	1.6	3.9

4.2.2 Price Assumption.

An aggregate retail price series was used as a proxy for effective prices in each of the model specifications. Since retail rates (across rate schedules) have generally moved in the same direction, an average retail price variable captures price movement across all the customer classes.

The price series is calculated by first deflating historical monthly revenues by the Consumer Price Index. Real revenues are then divided by retail sales to yield a monthly revenue per kWh value. Since revenue is itself a function of sales, it is inappropriate to regress sales directly on revenue per kWh. To generate a price series, a 12-month moving average of the real revenue per kWh series was calculated. This is a more appropriate price variable, as it assumes that households and businesses respond to changes in electricity prices that have occurred over the prior year.

Since 1992, real prices have been trending downward. No increases in nominal rates are assumed, thus real prices continue to trend downward. The average annual price series is provided in Table 4-3.

Table 4-2.
Population, Household, and Income Projections

Year	Real Income per HH	Households (Thousands)	Population (Thousands)
1992	55,383	499	1,324
1993	56,021	510	1,363
1994	56,515	523	1,399
1995	57,487	538	1,434
1996	58,555	557	1,476
1997	60,033	577	1,525
1998	62,522	597	1,571
1999	64,666	609	1,614
2000	66,180	627	1,663
2005	66,774	712	1,874
2013	74,044	862	2,222
Change	Percent	Percent	Percent
1993	1.2	2.2	2.9
1994	0.9	2.5	2.6
1995	1.7	2.9	2.5
1996	1.9	3.5	2.9
1997	2.5	3.6	3.3
1998	4.1	3.5	3.0
1999	3.4	2.0	2.7
00-05	0.2	2.6	2.4
05-13	1.3	2.4	2.2

Table 4-3.
Historical and Forecasted Price Series
Average Annual Price

Year	Real Price (cents/kWh)
1992	6.7
1993	6.7
1994	6.7
1995	6.4
1996	6.2
1997	6.0
1998	5.8
1999	5.4
2000	5.3
2005	4.8
2013	4.4
Change	Percent
1993	0.0
1994	0.0
1995	-4.5
1996	-3.1
1997	-3.2
1998	-3.3
1999	-6.9
00-05	-2.0
05-13	-1.1

4.2.3 Weather.

Weather is a key factor affecting electricity consumption for indoor cooling and heating. Monthly cooling degree-days (CDD) are used to capture cooling requirements while heating degree-days (HDD) account for variation in usage due to electric heating needs. CDD and HDD are calculated from daily average temperatures for Orlando.

CDD is calculated using a 65 F base. First, a daily CDD is calculated as:

$$CDD_d = (AvgTemp_d - 65) * (AvgTemp_d >= 65)$$

CDD_d has a value equal to the average daily temperature minus 65 when temperatures are greater than or equal to 65 °F, and 0 °F if average daily temperature is less than 65 °F. The daily CDD values are then aggregated to yield a monthly CDD:

$$CDD_m = \Sigma CDD_{md}$$

For each month, a normal CDD estimate is calculated using a 10-year average of the monthly values calculated from 1990 through 1999:

$$CDD_{nm} = \Sigma CDD_m / 10$$

Heating degree-days are calculated in a similar manner. Daily HDD is first derived using a base temperature of 65 °F:

$$HDD_d = (65 - AvgTemp_d) * (AvgTemp_d <= 65)$$

HDD_d equals 65 °F minus the average daily temperature, if the average daily temperature is less than or equal to 65 °F, and equals 0 °F if the daily temperature is greater than 65 °F. Aggregate monthly HDD (HDD_m) is then calculated by summing daily HDD over each month:

$$HDD_m = \Sigma HDD_{md}$$

The monthly normal HDD is calculated as a 10-year average of the calendar month HDD:

$$HDD_{nm} = \Sigma HDD_m / 10$$

4.3 Base Case Load Forecast

A short-term monthly budget forecast was estimated through 2003, with a long-term annual forecast through 2013. As outlined in the methodology section, the sales forecast is developed from a set of structured regression models that can be used for both forecasting monthly sales and customers for the OUC budget period and over the longer term, 10-year forecast horizon. Forecast models are estimated for each of the major rate classifications including:

- Residential.
- General Service Non-Demand (Small Commercial Customers).
- General Service Demand (Large Commercial and Industrial Customers).
- Street Lighting.

Models are estimated using monthly sales data covering the period 1996 through 2002. A separate set of forecast models are estimated for the OUC and St. Cloud service territories.

To support production-costing modeling, an 8,760 hourly load forecast is derived for each of the forecast years. The hourly load forecasts are based on a set of hourly and daily energy statistical models. The models are estimated from hourly system load data over the period January, 1996, to December, 2002. A separate set of models is estimated for OUC and St. Cloud. Seasonal peak demand forecasts are derived as the maximum hourly demand forecast occurring in the summer and winter months. Table 4-4 summarizes the annual sales and peak forecast for the combined OUC and St. Cloud service territories.

4.3.1 Base Case Economic Outlook.

Between 1995 and 2000, population has grown at an average annual rate of 3.0 percent and gross output has grown at 6.4 percent. Orlando's economic growth has consistently exceeded economic growth in both the state and nation. Orlando is expected to exceed overall state economic growth throughout the next ten years.

Much of this growth has been fueled by significant gains in the service sector, which has seen employment expand by nearly 100 percent since 1990. Moreover, employment in the service sector accounts for approximately 52 percent of total employment. Hotels and tourism-related activities, as well as call-centers, have continued to grow.

Table 4-4.
System Peak (Summer and Winter) and
Net Energy Forecast (Total of OUC and St. Cloud)

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	808	731	4,174
1995	861	876	4,377
1996	852	969	4,471
1997	917	849	4,566
1998	988	814	4,909
1999	1,055	965	5,011
2000	1,025	971	5,290
2005	1,227	1,218	6,108
2013	1,553	1,578	7,763
Change	Percent	Percent	Percent
95-00	3.5	2.1	3.9
00-05	3.7	4.6	2.9
05-13	3.0	3.3	3.0

Two of the largest regional employers are Walt Disney and Universal Studios. Universal Studios has doubled in size with the recent addition of *Islands of Adventure*, *CityWalk*, and the related hotel complex. The expanded Orange County convention center opened in 2003, which will help increase regional convention and tourism activity.

To accommodate growing convention, tourism, and regional business activity, the Orlando International Airport (OIA) is an anticipating a major expansion program that will ultimately double the capacity of the airport. In 2001, OIA served 28 million passengers. The airport has seen a decrease in number of passengers since September 11, 2001. Moving forward the OIA expects strong growth of over 3 percent a year over the next decade.

4.3.1.1 Economic Projections. While the economy is projected to slow from the torrid pace experienced over the last few years, relatively inexpensive labor and housing costs and strong in-migration from both other states and other nations will continue to fuel the regional economic expansion long into the future. The number of households in the Orlando MSA is projected to increase from 627,000 in 2000 to 862,000 by 2013, representing an average annual growth rate of 2.5 percent. Employment is projected to grow at 2.3 percent over the long-term.

Traditionally, the cost of doing business in Orlando has been below the average cost throughout the United States, with the cost of living in Orlando slightly lower than the average cost of living in the United States. The combination of these and other factors will sustain Orlando as one of the fastest growing metropolitan areas in the U.S. Long-term growth will be driven by the high quality of life, the relatively low costs of both doing business and living, strong net migration, and an environment that is conducive to business development. Increasing concentrations of high-tech and defense-related industries will help to diversify the local economy.

Economic projections are based on Economy.com's economic outlook for Orlando and the state of Florida. Projections are in line with economic projections by the University of Florida.

4.3.2 Forecast Results.

Based upon the previously discussed economic assumptions, total retail sales for OUC are expect to increase from 4,696 GWh in 2000 to 6,844 GWh by 2013. St. Cloud sales are projected to increase from 343 GWh to 595 GWh over this same period. Sales and customer projections are summarized in Tables 4-5 through 4-8.

4.3.2.1 Residential Forecast. With high electric end-use saturation, coupled with projected appliance efficiency-gains, residential average use is projected to increase relatively slowly over the forecast period. For OUC, average use per customer is forecasted to grow at 0.6 percent. Residential sales growth will be driven largely by the addition of new customers. With relatively strong population projections for the region, residential customers are expected to increase at a 2.4 percent rate for OUC and 3.7 percent rate for St. Cloud between 2000 and 2013. The OUC and St. Cloud residential sales forecasts are shown in Tables 4-5 through 4-8, respectively.

4.3.2.2 Small Commercial Sales Forecast. GSND sales are projected to grow at an average annual rate of 0.5 percent and 4.5 percent for OUC and St. Cloud, respectively, between 2000 and 2013. Projected GSND sales are driven by regional nonmanufacturing employment and output growth. Average use is projected to be relatively flat (particularly for OUC). Average use growth is partly constrained by size limitation; as customers exceed the 50 kW rate-class cut-off, they are migrated to the appropriate GSD rate. For OUC, average GSND use has actually trended downward over the last few years. Small commercial customer growth accounts for most of the GSND sales gains. The GSND customer forecast is driven by regional nonmanufacturing employment projections. The number of GSND customers is projected to grow at an average annual growth rate of 1.0 percent and 3.0 percent, respectively, for OUC and St. Cloud from 2000 to 2013. Tables 4-5 through 4-8 show annual GSND forecasts for OUC and St. Cloud.

4.3.2.3 ***Large Nonresidential Sales Forecast.*** General Service Demand (GSD) represents the largest commercial and industrial customers. Over the last couple of years, OUC has experienced phenomenal growth from this sector with GSD sales up 7.1 percent in 1999 and 4.8 percent in 2000. While sales are projected to slow significantly from this pace, sales are projected to continue to show relatively strong gains as a result of new major developments coming on line and overall strong regional output growth. Average use actually declines somewhat over the forecast period as smaller customers migrate from GSND to GSD. The GSD customer forecast is driven by total employment projections and total sales by projected regional gross output. Tables 4-5 through 4-8 summarize the GSD forecast.

Table 4-5.
OUC Long-Term Sales Forecast (GWh)

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St. Lts.	OUC Use	Total Retail
1995	1,380	316	2,157	27	-	55	3,935
1996	1,419	318	2,211	28	-	53	4,030
1997	1,377	322	2,280	29	-	56	4,063
1998	1,583	311	2,410	27	-	93	4,423
1999	1,504	308	2,581	30	-	76	4,498
2000	1,583	293	2,705	31	-	84	4,696
2005	1,831	291	3,136	36	9	103	5,406
2013	2,327	313	4,006	43	29	126	6,844
Change	Percent	Percent	Percent	Percent	Percent	Percent	Percent
1996	2.8	0.5	2.5	3.1	-	-3.6	2.4
1997	-3.0	1.2	3.1	2.3	-	5.7	0.8
1998	15.0	-3.5	5.7	-5.4	-	66.1	8.9
1999	-5.0	-0.9	7.1	11.8	-	-18.3	1.7
00-05	3.0	-0.1	3.0	3.0	-	4.2	2.9
05-13	3.0	0.9	3.1	2.2	15.8	2.6	3.0

Table 4-6.
OUC Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	108,702	14,572	2,965	126,239
1996	111,241	14,855	3,120	129,216
1997	113,669	15,065	3,438	132,172
1998	117,868	15,168	3,793	136,829
1999	121,173	15,659	3,865	140,697
2000	125,891	15,506	4,412	145,809
2005	141,607	16,344	5,182	163,133
2013	171,429	17,696	6,155	195,280
Change	Percent	Percent	Percent	Percent
1996	2.3	1.9	5.2	2.4
1997	2.2	1.4	10.2	2.3
1998	3.7	0.7	10.3	3.5
1999	2.8	3.2	1.8	2.8
00-05	2.4	1.1	3.3	2.3
05-13	2.4	1.0	2.2	2.2

Table 4-7. St. Cloud Sales Forecast (GWH)					
Year	Residential	GS Nondemand	GS Demand	St. Lighting	Total Retail
1995	180	19	56	-	254
1996	190	18	62	-	270
1997	192	19	67	1	278
1998	221	20	72	3	316
1999	221	22	73	3	318
2000	238	26	76	3	343
2005	314	33	99	3	449
2013	417	47	127	4	595
Change	Percent	Percent	Percent	Percent	Percent
1996	5.5	-1.5	11.0	-	6.2
1997	0.8	1.1	9.4	200.0	3.0
1998	15.2	9.4	7.1	-	13.7
1999	0.2	6.9	0.7	-	0.6
00-05	5.7	4.9	5.4	0.0	5.5
05-13	3.6	4.5	3.2	3.7	3.6

Table 4-8. St. Cloud Average Number of Customers Forecast				
Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	13,659	1,293	120	15,072
1996	14,158	1,311	138	15,607
1997	14,527	1,359	142	16,028
1998	15,010	1,427	150	16,586
1999	15,550	1,511	152	17,212
2000	16,470	1,610	163	18,242
2005	20,844	1,946	219	23,009
2013	26,400	2,376	281	29,057
Change	Percent	Percent	Percent	Percent
1996	3.7	1.4	15.1	3.6
1997	2.6	3.6	3.0	2.7
1998	3.3	5.0	5.3	3.5
1999	3.6	6.6	1.4	3.8
00-05	4.8	3.9	6.1	4.8
05-13	3.0	2.5	3.2	3.0

4.4 Net Peak Demand and Net Energy for Load

Hourly load models are used to forecast each of the 8,760 hours of each of the forecast years. Underlying hourly load growth is driven by the aggregate energy forecast. Thus, forecasted peaks grow at roughly the same rate as the energy forecast. Tables 4-9 and 4-10 show seasonal peak demands and net energy for load forecasts for OUC and St. Cloud.

Table 4-9.
OUC Net Peak Demand (Summer and Winter) and
Net Energy for Load: History and Forecast

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	749	674	3,926
1995	798	800	4,103
1996	788	885	4,186
1997	846	773	4,271
1998	907	746	4,578
1999	969	873	4,674
2000	941	882	4,922
2005	1,107	1,093	5,634
2013	1,395	1,411	7,135
Change	Percent	Percent	Percent
95-00	3.3	2.0	3.7
00-05	3.3	4.4	2.7
05-13	2.9	3.2	3.0

Table 4-10.
St. Cloud Net Peak Demand (Summer and Winter) and
Net Energy for Load: History and Forecast

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	59	57	249
1995	63	76	274
1996	64	84	285
1997	71	76	295
1998	81	68	331
1999	86	92	337
2000	84	89	369
2005	120	125	474
2013	158	167	628
Change	Percent	Percent	Percent
95-00	6.0	3.2	6.1
00-05	7.4	7.0	5.1
05-13	3.5	3.7	3.6

4.5 High and Low Load Scenarios

In addition to the base case, two long-term forecast scenarios were developed in order to bound the potential demand outcome. Modifying the base case economic assumptions developed the high and low case scenarios. The primary drivers that were modified are regional population and employment. Table 4-11 show a comparison of the high, base, and low load scenarios.

4.5.1 High Load Scenario.

The high load scenario is based upon assumptions of continued strong economic growth. It has been assumed that through 2013, area population growth does not slow, but continues to expand at a rate experienced over the last few years. The University of Florida's high and low population projections were used to help bound the population growth assumptions. Stronger population growth allows for continued expansion of the labor force; this in turn translates into stronger employment and total output growth.

4.5.2 Low Load Scenario.

The low load scenario assumes that there is a significant slowdown in regional population growth. The University of Florida's high and low population projections were used to help bound the population growth assumptions.

Table 4-11.
Scenario Peak Forecasts
Orlando Utilities Commission and St. Cloud

Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
High Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,254	1,245	6,242
2013	1,587	1,613	7,934
95-00	3.6%	2.1%	3.9 %
00-05	4.1%	5.1%	3.4%
05-13	3.0%	3.3%	3.0%
Base Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,227	1,218	6,108
2013	1,553	1,578	7.763
95-00	3.5%	2.1%	3.9%
00-05	3.7%	4.6%	2.9%
05-13	3.0%	3.3%	3.0%
Low Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,200	1,191	5,974
2013	1,519	1,543	7,592
95-00	3.5%	2.1%	3.9%
00-05	3.2%	4.2%	2.5%
05-13	3.0%	3.3%	3.0%

5.0 Demand-Side Management

Throughout its history, OUC has demonstrated a strong commitment to serve its customers' conservation needs. OUC has undertaken many conservation programs to meet customer needs and expectations. OUC's demand-side management (DSM) goals were approved by the FPSC on March 23, 2000, by Order No. PSC-00-0587-FOF-EG. The evaluations for this docket indicated that there were no cost-effective conservation measures available for OUC. As a result, the FPSC approved zero goals for OUC for the residential and commercial/industrial sectors as presented in Table 5-1. Nevertheless, OUC proposed to continue existing programs feeling that they were in the overall best interest of OUC's customers. The FPSC goals for OUC and the programs implemented to meet these goals are presented briefly in this section and in greater detail in OUC's 2000 Demand-Side Management Plan filed in Docket No. 990722-EG.

Table 5-1.
Total Conservation Goals Approved by the FPSC

	Residential			Commercial / Industrial		
Year	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

5.1 Existing Conservation Programs

The demand-side management programs voluntarily continued and offered by OUC to its customers during 2003 included programs which result in energy and/or demand reductions that are quantifiable, as well as programs that are not quantifiable but aid OUC's customers in reliability, energy conservation, and education. Table 5-2 presents a listing of the programs which were offered by OUC in 2003, and the remainder of this section provides a description of each of these programs.

Table 5-2. Conservation Programs Offered by OUC - 2003
Quantifiable Conservation Programs
Residential Energy Survey Program (Walk-Through, Video or CD, and On-Line).
Residential Energy Efficiency Rebate Program (Duct Repair, Attic Insulation, Weatherization).
Residential Low-Income Home Energy Fix-Up Program.
Residential Insulation Billed Solution Program.
Residential Efficient Electric Heat Pump Program.
Residential Gold Ring Program.
Non-Quantifiable Conservation Programs
Residential Night Security Lighting Program.
Residential Energy Conservation Rate.
Commercial OUConsumption Online Program.
Commercial OUConvenient Lighting Program.
Commercial Power Quality Analysis Program.
Commercial Infrared Inspections Program.
Commercial Single- and Three-Phase Service Program.
OUCooling.
Residential Night Security Lighting Program.
Residential Energy Conservation Rate.
Commercial OUConsumption Online Program.

The decrease in cost-effectiveness of DSM programs is a result of numerous factors. As each program continues, participation tends to gradually decrease because the market for the program becomes saturated since most of the customers that are willing to participate will have done so early in the program; government mandates have forced manufacturers to increase their efficiency standards, thereby decreasing the incremental amount of energy savings achievable; the efficiency of new generation has increased and the cost of installing new generation has decreased; and with interest rates at all-time lows, the carrying costs of power plants have been greatly reduced. All of these factors have resulted in it becoming more difficult for DSM to be cost-effective and to achieve high levels of customer participation.

5.1.1 Residential Energy Survey Program.

This program is designed to provide residential customers with recommended energy efficiency measures and practices. The Residential Energy Survey Program consists of three measures, including the Residential Energy Walk-Through Survey, the Residential Energy Survey Video and CD, and an interactive On-Line Energy Survey.

The Residential Energy Walk-Through Survey includes a complete examination of the attic, HVAC, air duct and air returns, window caulking, weather stripping, water heater, faucets, toilets, and lawn sprinkler systems. Literature on other OUC programs is also provided to the residential customers. The participant is given a choice to receive either a low-flow showerhead or a compact fluorescent bulb. OUC Energy Analysts are presently using this walk-through type audit as a means of motivating OUC customers to participate in other conservation programs and qualify for appropriate rebates.

The Residential Energy Survey Video was first offered in 2000 by OUC and in November, 2001, became available to OUC customers in CD-ROM format. The video (or CD-ROM) is free and is distributed to OUC customers by request. The measure was developed to further assist OUC customers in surveying their home for potential energy saving opportunities. The video walks the customer through a complete visual assessment of energy and water efficiency in the customer's home. A checklist brochure to guide the customer through the audit accompanies the video. The video has many benefits over the walk-through survey, including the convenience of viewing the video at any time without a scheduled appointment and the ability to watch the video numerous times.

In addition to the Energy Walk-Through and the Video/CD Surveys, OUC offers customers an interactive On-Line Energy Survey complete with their previous billing information. The interactive On-Line Energy Survey is available on OUC's website, www.OUC.com.

One of the primary benefits of the Residential Energy Survey Program is providing education to the customer on energy conservation measures and ways their lifestyle can directly impact their use of energy. Customers participating in the Residential Energy Survey Program are made aware of conservation measures which they can implement. Customers will benefit from the increased efficiency in their homes, which will decrease their electric and water bills.

Participation in the Walk-Through Energy Survey has been consistently strong over the past ten years and interest in both the Energy Survey Video and CD, as well as the interactive On-Line Energy Survey, has been high since the measures were first introduced. Feedback from customers that have taken advantage of the surveys has been very positive.

5.1.2 Residential Energy Efficiency Rebate Program.

This program rewards customers who have invested in weather stripping, insulation, duct repairs, or other energy-saving measures for their single-family home. OUC will rebate customers up to $75 for the purchase of caulking, weather stripping, window tinting, and solar screening. Additionally, OUC offers customers a rebate of up to $75 for repairs made to leaking ducts. Furthermore, OUC offers a rebate of $100 to upgrade the customer's attic insulation to R-19.

5.1.3 Residential Low-Income Home Energy Fix-Up Program.

This program targets residential customers with a total annual family income of less than $25,000. Every participant must request a free Residential Energy Survey. Audit recommendations usually require the customer to spend money replacing or adding energy conservation measures, which low-income customers may not have the discretionary income to implement.

The program pays 85 percent of the total contract cost for home weatherization for the following measures:

- attic insulation
- exterior and interior caulking
- weather-stripping doors and windows
- minor air conditioning / heating supply and return air duct repairs
- water heater and hot water pipe insulation
- minor water leakage repair
- installation of water flow restrictors
- minor electrical repairs

Under this program, OUC will arrange for a licensed, approved contractor to perform the necessary repairs and will pay for 85 percent of the bill. The remaining 15 percent can be paid for on the participant's monthly electric bill. The purpose of the program is to reduce the energy cost for low-income households, particularly those households with elderly persons, disabled persons, and children, by improving the energy efficiency of their homes and ensuring a safe and healthy community.

Through this program, OUC helps to lower the bills of low-income customers who may have difficulty paying their bills. Reducing the bill of the low-income customer may improve the customer's ability to pay the bill, thereby decreasing costly service disconnect fees and late charges. OUC believes this will help to achieve and maintain high customer satisfaction.

5.1.4 Residential Insulation Billed Solutions Program.

This measure is available to OUC residential customers who utilize some type of electric heat and/or air conditioning. To qualify, customers must request a free Residential Energy Survey and have a satisfactory credit rating with OUC. The program allows customers who insulate their attics to an R-19 level to pay for the insulation on their monthly utility bill for up to two years without being required to put any money down and, in addition, the customer will receive a $100 rebate. OUC directly pays the total cost for installation when the customer makes payments to OUC as part of their monthly utility bill. Feedback from customers that have taken advantage of the program has been very positive.

5.1.5 Residential Efficient Electric Heat Pump Program.

This program provides rebates to qualifying customers who install heat pumps having a SEER of 11 (or greater). Customers will be able to obtain rebates ranging from $100 to $300, depending upon the SEER rating of the heat pump selected. Customers will benefit from the increased energy conservation in their home, which will decrease their electric bills. One of the main benefits of this program is the duct work and insulation level improvements made by contractors when installing the energy efficient heat pumps.

5.1.6 Residential Gold Ring Program.

The Residential Gold Ring Program works closely with Energy Star Ratings. In developing the program, OUC has partnered with local home builders to construct new homes according to OUC's Gold Ring energy and water efficiency standards. Features include high efficiency heat pumps, heat recovery water heaters, R-30 attic insulation, interior air ducts, window shading, etc.

The contractor is required to install R-30 insulation and include four other conservation measures from a list of conservation measures developed by OUC. In return for each Gold Ring home built, the builder receives a free Energy Star Home Rating and Blower Door Test. In addition, the builder receives $225 toward advertising costs. The advertising must include a reference to the high efficiency Gold Ring homes available. However, OUC is in the process of exploring modifications to the program which would eliminate the advertising payment to the home builders but continue to highlight the builders' participation in the program through OUC's own advertising for any new builder wanting to participate in the program.

Gold Ring Homes can use 20 to 30 percent less energy than other homes. Gold Ring homeowners benefit from lower energy bills and qualification for all FHA, VA, and

Energy Efficient Mortgage Programs. This allows the homeowner to increase their income to debt ratio by two percent and makes it easier to qualify for a mortgage.

5.1.7 Commercial Energy Survey Program.

This program is focused on increasing the energy efficiency and energy conservation of commercial buildings and includes a survey comprised of a physical walk-through inspection of the commercial facility performed by highly-trained and experienced energy experts. The commercial customer having a Commercial Energy Survey receives a report at the time of the survey and the book 'Business Energy Efficiency Guide' that shows more ways for businesses to profit from energy management. Within 30 days of the audit, the customer receives a written report detailing cost-effective recommendations to make the facility more energy and water efficient. Customers are encouraged to participate in other OUC commercial programs and directly benefit from the energy conservation, which decreases their electric bills.

5.1.8 Commercial Indoor Lighting Retrofit Program.

This program reduces energy consumption for the commercial customer through the replacement of older fluorescent and incandescent lighting with newer, more efficient lighting technologies. A special alliance between OUC and the lighting contractor enables OUC to offer the customer a discounted project cost. An additional feature of the program allows the customer to pay for the retrofit through the monthly savings that the project generates. Up-front capital funding is not required to participate in this program. The project payment appears on the participating customer's utility bill as a line-item. After the project has been paid for in full, the participating customer's annual energy bill will decrease by the approximate amount of the energy cost savings.

5.1.9 Residential Night Security Lighting Program.

OUC allows residential customers to pay for the cost of security lighting on their monthly utility bill. The customer is allowed to continue doing so for up to one year. The costs covered include the fixtures, bulbs, materials, labor, and warranty. Lighting is to be installed by licensed contractors who will supply a warranty for the fixtures and the work.

5.1.10 Residential Energy Conservation Rate.

Beginning in October, 2002, OUC modified its residential rate structure to a two-tiered block structure in order to encourage energy conservation. Residential customers using more than 1,000 kWh per month will pay a higher rate for the additional energy usage. The purpose of this rate structure is to make OUC customers more energy-aware and to encourage conservation of energy resources.

5.1.11 Commercial OUConsumption Online Program.

This program enables businesses to check their energy usage and demand from a desktop computer, thereby allowing businesses to manage their energy load. Customers are able to analyze the metered interval load data for multiple locations, compare energy usage among facilities, and measure the effectiveness of various energy efficiency efforts. The data can also be downloaded for further analysis. Participants must cover the cost of additional infrastructure at the meter(s) and are responsible for a $35.00 per month per channel fee for this service.

5.1.12 Commercial OUConvenient Lighting Program.

OUConvenient Lighting provides complete outdoor lighting services for commercial applications including industrial parks, sports complexes, and residential developments. Each lighting package is customized for each participant, allowing the participant to choose among light fixtures. OUC handles all of the up-front financial costs and maintenance. The participant then pays a low monthly fee for each fixture. OUC also retrofits existing fixtures to new light sources or higher output units, increasing efficiency in addition to providing preventive and corrective maintenance.

During 2003, OUC installed over 2,500 lights through its *OUConvenient Lighting Program*. Additionally, lighting agreements were reached with several notable residential communities including Baldwin Park in Orlando, Harmony in Osceola County, and the Reunion Resort and Club near Walt Disney World. New lighting contracts were also negotiated with shopping centers, office buildings, sports facilities, and other commercial customers. The number of customers seeking OUC indoor lighting expertise has also increased.

5.1.13 Commercial Power Quality Analysis Program.

This program enables OUC to ensure the highest possible power quality to commercial customers. There are five general categories of power irregularities including over voltage, under voltage, outages, electric noise, and harmonic distortion. Under the Power Quality Analysis program, trained and experienced service personnel will help the customer isolate any problems and find appropriate solutions. The goals of this program include making the maximum effort to solve power quality problems through monitoring and interpretive analysis, identifying solutions that will lead to corrective action, and providing on-going follow-up services to monitor results.

5.1.14 Commercial Infrared Inspections Program.

This program was developed to help customers uncover potential reliability and power quality problems. A highly trained and experienced technician performs the inspection using state-of-the-art equipment. The infrared inspection detects thermal energy and measures the temperature of wires, breakers, and other electrical equipment components. The information is transferred into actual images and those images reveal potential problem areas and hot spots that are invisible to the naked eye. This information allows the customer to make repairs to faulty equipment and prevent untimely breakdowns, equipment damage, and lost profits. Following the inspection, the customer receives a detailed analysis and written report which includes a complete description of diagnostic recommendations.

5.1.15 Commercial Single- and Three-Phase Service Program.

The purpose of this program is to help customers protect their electrical equipment. While most homes and small businesses generally utilize single-phase service, other customers such as large industries, shopping centers, and even some homes have electrical equipment that requires three-phase service. Because this setup requires three energized lines in order to run properly, three-phase equipment needs added protection to prevent damage due to service interruptions resulting from lightning, falling tree limbs, wind, or electrical problems within the customer's home or facility. Although three-phase equipment typically relies on fuses, breakers, or overload devices, there may not be sufficient protection in the event such power outages occur. A licensed electrician can install monitoring relays to protect against phase loss, phase imbalance, reversal, under-voltage, and over-voltage conditions.

5.1.16 OUCooling.

OUCooling is a program offered by OUC which helps to lower air conditioning-related electric charges and reduce capital and operating costs. OUCooling will fund, install, and maintain a central chiller plant for each business district participating in the program. The main benefits to the businesses are lower energy consumption, increased reliability, and no environmental risks associated with the handling of chemicals. Other benefits for the businesses include avoided initial capital cost, maintenance costs, a smaller mechanical room (therefore more rental space), no insurance requirements, improved property resale value, and relief of maintenance personnel for other duties.

OUC's first chiller plant was installed at Lockheed Martin Corp. The plant was built in 1999 and serves eight customers. OUC next began operation of a chilled water system serving downtown Orlando. In 1999, the downtown project won three awards. In

2000, the Downtown Orlando Partnership gave its Award of Excellence to OUC based on the chilled water plant. The downtown Orlando "district cooling" division now provides air conditioning service to more than a dozen large commercial customers with a combined two million square feet of space. *OUCooling* is developing a North Chiller Plant in downtown Orlando which will eventually be connected to the existing South Plant.

During 2003, OUC extended its chilled water lines to the Hughes Square project, which includes the 150,000 square foot Hughes Supply Inc. headquarters, 25,000 square feet of retail space, and the 266-unit City View apartments. By the end of 2003, *OUCooling* had many potential new clients considering outsourcing their chilled water production. The Sanctuary Downtown off Lake Eola and the Eola Park Place Condos (formerly the Four Points Sheraton) have signed agreements with *OUCooling*, while the Florida A&M School of Law, the condominiums at 55 West, and a new CNL office tower are all close to committing to *OUCooling*.

In 2002, the International District Energy Association (IDEA) awarded OUCooling a first-place award for signing up more customer square footage for its chilled-water business than any other company in 2001. OUCooling brought on nine million square feet of new customer space in 2001. IDEA is an association representing more than 900 district heating and cooling executives, managers, engineers, consultants, and equipment suppliers from 20 countries.

In January 2000, OUC signed a 20-year agreement to design, build, own, and operate a chiller plant for Vistana, a leading developer and operator of vacation ownership resorts. *OUCooling* currently serves the Sheraton Vistana Villages timeshare development in south Orange County. Additionally, *OUCooling* provides service to the new Mall at Millenia and has brought online a 17.6 million gallon chilled water tank at the newly expanded Orange County Convention Center. The new tank works in tandem with 20 water chillers and feeds a cooling loop that can handle over 33,000 gallons of 38-degree water per minute. The system also serves a nearby Lockheed Martin facility.

OUC envisions building other chiller plants serving commercial campuses, hotels, retail shopping centers, and tourist attractions. OUC recently received three awards from the Associated Builders and Contractors Inc. for one of the top construction projects in Orlando. The Awards were the Eagle Award for mechanical work, General Contractor Award of Merit, and the Subcontractor Award of Merit. *OUCooling* was also featured in the January-February 2003 issue of *Relay – Florida's Energy and Electric Utility Magazine.*

6.0 Forecast of Facilities Requirements

6.1 Existing Capacity Resources and Requirements

6.1.1 Existing Generating Capacity.

As shown in Tables 6-1 and 6-2 which are presented at the end of this section, OUC and St. Cloud together have an existing generating capability of 1,215 MW in the summer and 1,276 MW of winter generating capability. The existing generating capability consists of OUC's joint ownership share of Stanton Energy Center (Units 1 and 2, as well as Stanton A) and the Indian River combustion turbines operated by OUC, OUC's joint ownership share of Crystal River 3, McIntosh 3, and St. Lucie 2 operated by Progress Energy Florida, Lakeland Electric, and FPL, respectively, as well as St. Cloud's diesels (which are scheduled to retire in October, 2006).

6.1.2 Power Purchase Agreements.

As described in detail in Section 2.3, OUC has a power purchase agreement in place with Reliant and schedules St. Cloud's purchase power from TECO. For purposes of the Ten-Year Site Plan, it has been assumed that OUC will exercise its extension option from the Reliant PPA, purchasing 500 MW in fiscal year 2004, 300 MW in fiscal year 2005, and discontinuing the PPA beginning in fiscal year 2006.

Additionally, OUC has entered into a ten-year agreement to purchase capacity from Southern-Florida's ownership share of Stanton A. The terms of this agreement specify that OUC will purchase 80 percent of Southern-Florida's 65 percent ownership share of Stanton A (312 MW during the summer months and 341 MW during the winter months). However, beginning on the first day of the sixth year of the PPA and extending through the tenth year of the PPA, OUC, KUA, and FMPA collectively may elect to reduce the amount of capacity purchased by a total of 50 MW each year, with the total reduction in capacity not to exceed 200 MW. Because OUC will purchase 80 percent of Southern-Florida's ownership share of Stanton A, it has been assumed for purposes of the Ten-Year Site Plan that OUC may elect to reduce the amount of capacity purchased under the PPA by 40 MW each year, beginning with the sixth year of the PPA and extending through the tenth year of the PPA, with the total reduction not to exceed 160 MW. The SEC A PPA capacity presented in Tables 6-1 and 6-2 does not reflect OUC exercising the PPA capacity reduction option. At the expiration of the 10-year agreement, OUC retains the option to extend the term of its purchase from Southern-Florida for 20 additional years, structured into four five-year increments.

6.1.3 Power Sales Agreements.

As described in more detail in Section 2.4, OUC has entered into power sales contracts with FMPA and RCID for various amounts of capacity and energy during the ten-year planning horizon.

6.1.4 Modifications and Retirements of Generating Facilities.

OUC has not scheduled any unit modifications or retirements over the next ten years, but will continue to evaluate options on an ongoing basis. However, the diesel units owned by St. Cloud are scheduled to retire in October, 2006.

6.2 Reserve Margin Criteria

The Florida Reliability Coordinating Council (FRCC) has set a minimum planned reserve margin criteria of 15 percent. The Florida Public Service Commission (FPSC) has established a minimum planned reserve margin criterion of 15 percent in 25-6.035 (1) Florida Administrative Code as well for the purposes of sharing responsibility for grid reliability. The 15 percent minimum planned reserve margin criteria is generally consistent with practice throughout much of the industry. OUC has adopted the 15 percent minimum reserve margin requirement as its planning criterion.

6.3 Future Resource Needs

6.3.1 Generator Capabilities and Requirements Forecast.

Since OUC has elected to use a 15 percent reserve margin criterion, OUC applies it to St. Cloud's load as well as partial requirements (PR) purchases and sales. Tables 6-1 and 6-2 (presented at the end of this section) display the forecast reserve margins for the combined OUC and St. Cloud systems for the winter and summer seasons, respectively. The Stanton A purchase power capacity (labeled as SEC PPA in Tables 6-1 and 6-2) does not reflect any reductions in the amount of capacity OUC may elect to purchase as described in Section 6.1.2.

Table 6-1 indicates that additional capacity will not be needed until the winter of 2009/10. However, the need for capacity additions to satisfy forecast summer peak demand occurs earlier. OUC's forecast reserve margin indicates the initial need for capacity additions occurs in the summer of 2008, at which time OUC is forecast to require 12 MW of additional capacity. Beyond the summer of 2008, the need for capacity additions increases annually.

6.3.2 Transmission Capability and Requirements Forecast.

OUC continuously monitors and upgrades the bulk power transmission system as necessary to provide reliable electric service to their customers. OUC has adopted the North American Electric Reliability Council (NERC) Planning Standards as the basis for its and the City of St. Cloud's electric power transmission system planning. For the purposes of planning studies, OUC utilizes certain criteria that pertain to voltage and line and transformer loading. A criterion of 95 percent and 105 percent of nominal system voltage establishes the lower and upper limits of acceptable voltage. Transmission lines are not allowed to exceed 100 percent of their continuous ratings during normal conditions or 100 percent of their emergency ratings during contingency outages. The bus tie transformer loading guideline is 100 percent of the unit's 65 °C rating.

OUC's transmission group continually reviews the need and options for increasing the capability of the transmission system based on the following planning criteria. During the course of a planning study, the OUC and St. Cloud transmission systems are subjected to a single contingency analysis which involves outaging each of the 69 kV through 230 kV transmission line. Bus tie transformers, tie lines with neighboring utilities, and off-system facilities known to cause internal problems are included as well. If a violation of the voltage or loading criteria occurs a permanent solution is determined in the form of an upgrade or new construction. The revised system containing the improvement is then subjected to the same analysis as the original to insure that no voltage or loading violations remain. Recently, OUC has had a change in planning philosophy when the voltage or loading criteria is exceeded. Instead of an operational procedure being the first step to correcting the problem, OUC in the future will investigate permanent solutions such as new construction. In the short term, operational remedies will continue to be used until new facilities can be put into service.

OUC has developed a schedule of transmission system upgrades based on the above criteria as well as economic and reliability factors. The schedule is presented in Section 2.5.

Table 6-1.
OUC and St. Cloud (STC) Forecast Winter Reserve Requirements – Base Case without Capacity Additions

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)		Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[4] (MW)
	OUC	STC	RCID P R	FMPA I R.		Installed[1]	SEC A PPA	Reliant PPA	TECO P R	Total	Required[2]	Available[3]	
2004/05	1,093	125	101	44	1,363	1,276	341	300	15	1,932	198	597	403
2005/06	1,126	129	76	34	1,365	1,276	341	0	15	1,632	200	269	69
2006/07	1,161	134	0	22	1,317	1,255	341	0	15	1,611	194	296	102
2007/08	1,199	139	0	0	1,338	1,255	341	0	15	1,611	201	275	74
2008/09	1,241	144	0	0	1,385	1,255	341	0	15	1,611	208	228	20
2009/10	1,280	150	0	0	1,430	1,255	341	0	15	1,611	215	183	(31)
2010/11	1,322	155	0	0	1,477	1,255	341	0	15	1,611	222	136	(85)
2011/12	1,367	161	0	0	1,528	1,255	341	0	15	1,611	229	85	(144)
2012/13	1,411	167	0	0	1,578	1,255	341	0	15	1,611	237	35	(202)
2013/14	1,456	173	0	0	1,629	1,255	341	0	0	1,596	244	(33)	(277)

1 Includes OUC's equity portion of SEC A. as well as St Cloud's diesel units (which are scheduled to retire in October, 2006)
2. "Required Reserves" include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract
3 "Available Reserves" equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P R purchase
4. Calculated as the difference between available reserves and required reserves

Table 6-2.
OUC and St. Cloud (STC) Forecast Summer Reserve Requirements – Base Case without Capacity Additions

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)		Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[4] (MW)
	OUC	STC	RCID P R	FMPA I R		Installed[1]	SEC A PPA	Reliant PPA	TECO P R	Total	Required[2]	Available[3]	
2004	1,076	116	101	65	1,358	1,215	312	500	15	2,042	194	686	492
2005	1,107	120	113	43	1,383	1,215	312	300	15	1,842	201	461	260
2006	1,136	124	0	22	1,282	1,215	312	0	15	1,542	189	262	73
2007	1,167	128	0	0	1,295	1,193	312	0	15	1,520	194	227	33
2008	1,201	133	0	0	1,334	1,193	312	0	15	1,520	200	188	(12)
2009	1,239	137	0	0	1,376	1,193	312	0	15	1,520	206	146	(60)
2010	1,275	142	0	0	1,417	1,193	312	0	15	1,520	213	105	(108)
2011	1,315	148	0	0	1,463	1,193	312	0	15	1,520	219	59	(160)
2012	1,355	153	0	0	1,508	1,193	312	0	15	1,520	226	14	(212)
2013	1,395	158	0	0	1,553	1,193	312	0	0	1,505	233	(48)	(281)

1 Includes OUC's equity portion of SEC A, as well as St Cloud's diesel units (which are scheduled to retire in October, 2006)
2 "Required Reserves" include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract
3 "Available Reserves" equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P R purchase
4 Calculated as the difference between available reserves and required reserves

7.0 Development of Supply-Side Alternatives

This section provides the description of supply-side generating unit alternatives considered by OUC. Black & Veatch has estimated the capital cost, performance, and O&M costs for various technologies being considered as supply-side alternatives, including pulverized coal, combined cycle, and simple cycle.

Table 7-1 presents the supply-side alternatives considered by OUC for future capacity additions. The table includes the type of unit being considered, its probable location, its net capacity, and the earliest date it can achieve commercial operation (C.O.D.). As indicated in the table, specific manufacturers were used for the combustion turbine and combined cycle alternatives to provide output and performance data. The use of specific manufacturers is not intended to limit the alternatives to those manufacturers. Several manufacturers providing similar equipment could be utilized.

Table 7-1.
Generation Expansion Candidates

Technology	Description	Location	Net Capacity[1]	C.O.D.
Simple Cycle	General Electric 7FA	Stanton	156 MW	06/06
Combined Cycle	General Electric 2x1 7FA	Stanton	607 MW	06/08
	General Electric 2x1 7FA[2]	Stanton	304 MW	06/08
Solid Fuel	Pulverized Coal	Stanton	446 MW	06/10
	Pulverized Coal[2]	Stanton	223 MW	06/10

1. Capacity is stated at average annual temperature for OUC and includes degradation.
2. Supply-side alternatives included assumption that OUC would be able to jointly develop either the combined cycle or pulverized coal options, receiving 50 percent of the unit's output and being responsible for 50 percent of the unit's cost.

7.1 Performance Estimates

Performance estimates have been compiled for each of the alternatives listed in Table 7-1. The estimates provide representative values for each generation alternative and show expected trends in performance within a given technology as well as between technologies. Actual unit performance and availability will vary based on ambient temperature, regulatory requirements, and operation practices. The economic evaluation of an option involves consideration of a number of performance criteria, which are explained below.

7.1.1 Net Plant Output (NPO).

Net plant output is equal to the gross plant output less the plant auxiliary power. In this analysis, net plant output estimates are provided at the annual average temperature for Orlando.

7.1.2 Equivalent Availability (EA).

Equivalent availability is a measure of the ability of a generating unit to produce power over a period of time, taking into account limitations such as equipment failures, unit deratings, and maintenance activities. The equivalent availability is equal to the maximum possible capacity factor for a unit as limited by forced, scheduled, and maintenance outages and deratings. The equivalent availability is the capacity factor that a unit would achieve if the unit were to generate every megawatt-hour it was available to generate.

7.1.3 Equivalent Forced Outage Rate (EFOR).

The equivalent forced outage rate is a reliability index which reflects the probability that a unit will not be capable of providing power when called upon. It is determined by dividing the sum of forced outage hours plus equivalent forced outage hours by the sum of forced outage hours plus service hours. Equivalent forced outage hours take into account the effect of partial outages and are equal to the number of full forced outage hours that would result in the same lost generation as actually experienced during partial outage hours.

7.1.4 Planned Maintenance Outage.

This measure is an estimate of the time (number of days) required each year to perform scheduled maintenance.

7.1.5 Startup Fuel.

Estimates for startup fuel, where applicable, in millions of Btu (MBtu), are based on the fuel required to bring the unit from a cold condition to the speed at which synchronization is first achievable under normal operating conditions.

7.1.6 Net Plant Heat Rate (NPHR).

The net plant heat rate is a measure of generating station thermal efficiency, generally expressed in Btu/kWh. It can be computed by dividing the total Btu content of the fuel burned for electric generation by the resulting net kWh generation. Estimates for net plant heat rates are based on the higher heating values of the fuel. In this analysis, heat rate estimates are provided for average annual temperature conditions for combustion turbines and combined cycle units. Heat rates may vary as a result of factors such as turbine selection, fuel properties, plant cooling method, auxiliary power consumption, air quality control system, hours of operation, and local site conditions.

7.1.7 Degradation.

Power plant output and heat rate performance can degrade with hours of operation due to factors such as blade wear, erosion, corrosion, and increased leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance from the new and clean performance.

Approximations for output and performance degradation applied to the new and clean performance estimates of the combined cycle and simple cycle alternatives vary from unit to unit. Table 7-2 presents the degradation factors used for the General Electric simple cycle (GE 7FA) and the combined cycle (GE 2x1 7FA) units. Output and performance for the pulverized coal unit were developed incorporating degradation.

Table 7-2.
Degradation Factors

Unit	Net Output (%)	Heat Rate (%)
GE 7FA Simple Cycle	-4.04	2.87
GE 2x1 7FA Combined Cycle	-3.72	1.84

7.2 Pulverized Coal

The pulverized coal unit is developed to be identical to Stanton 2 and considers the existing infrastructure included in the Stanton 1 project sufficient to incorporate future pulverized coal unit additions.

7.2.1 Pulverized Coal Capital Cost Estimates.

The capital cost estimate for the pulverized coal alternative is presented in Table 7-3. This cost is based on the current market for construction of a third pulverized coal unit at Stanton, identical to the existing Stanton 2.

7.2.2 Pulverized Coal O&M Costs and Performance Estimates.

Fixed O&M costs include operating staff salary costs, basic plant supplies, and administrative costs. Staffing estimates are based on Stanton 2 experience. Variable operating costs include an assumed reagent cost for flue gas desulfurization (FGD), waste disposal, and ammonia. Variable maintenance costs are the costs associated with the inspection and maintenance of plant components based on the operating time of the plant, such as steam turbine inspection costs and catalyst replacement.

Performance estimates for the pulverized coal alternative are based on the actual performance of Stanton 2. Table 7-3 presents these estimates, as well as the fixed and variable O&M estimates for the pulverized coal units.

Table 7-3.
Generating Unit Characteristics - 446 MW Pulverized Coal Unit
(Unless otherwise specified, all costs are in 2004 dollars)

Total Capital Cost[1], ($1000)	$586,800
O&M Cost - Baseload Duty	
Fixed O&M Cost ($/kW-yr)	15.72
Variable O&M Cost ($/MWh)	4.14
Equivalent Forced Outage Rate (percent)	3.00
Planned Maintenance (days/year)	30
Construction Period (months)	42
Net kW Output/Net Plant Heat Rate (NPHR), HHV (Btu/kWh)	446,000/9,979 329,710/10,125 187,430/10,911 117,060/12,463

1. Includes permitting and licensing.
Note: Capital cost estimate does not include interest during construction.

7.3 General Electric 2x1 7FA Combined Cycle

Typical combined cycle units consist of one or more combustion turbine generators (CTGs), an equal number of heat recovery steam generators (HRSGs), and normally a single steam turbine generator (STG). Fuel is supplied to the CTG(s) where it is mixed with compressed air and combusted. The combustion gases flow through a turbine that turns a generator to produce power. The CTG exhaust gas flows through the HRSG(s) where water is turned into steam. The steam created is run through the STG to produce power. The total power output of the unit is the combination of the power from the CTG(s) and the STG.

Cost and performance estimates for the GE 7FA 2x1 combined cycle options (both full and joint ownership) were based on the construction of a replication of Stanton A, with capital costs updated to reflect current market conditions. The facility would consist of two General Electric 7FA combustion turbine generators, two heat recovery steam generators, and a single steam turbine generator. The CTGs would be complete with dry low NO_x combustors, evaporative coolers, and power augmentation. They would be dual fueled units firing natural gas as the primary fuel and fuel oil as the secondary fuel. The HRSGs would be complete with supplemental firing capability and selective catalytic reduction (SCR). To allow for simple cycle operation, a steam bypass system would be included in lieu of bypass stacks and dampers, and cooling will be achieved through the use of a mechanical draft cooling tower.

7.3.1 General Electric 2x1 7FA Combined Cycle Capital Costs.

The total capital cost of a plant is the summation of direct and indirect costs. Interest during construction (IDC) is not included in these estimates. Capital cost estimates were developed on the basis of the current costs observed in the competitive generation market for a unit designed as a replication of SEC A, and are presented in Table 7-4. The competitive generation market currently indicates that combustion turbines can be procured for significantly less than as recently as two years ago. Because the capital cost estimates consider this low procurement cost, it is important to note that a sustained recovery in the competitive generation market will impact these capital costs, causing an overall increase as compared to what is shown in Table 7-4.

7.3.1.1 General Assumptions.

- Land and right of ways are not included.
- Raw and makeup water are assumed to be provided.
- Construction power is assumed to be provided.
- A continuous emissions monitoring system is included.
- Permitting and licensing are included.

7.3.1.2 Direct Cost Assumptions.

- Combustion turbine assumptions include:
  - Dry low NO_x combustion system.
  - Fire detection and protection system.
  - Turbine control panel.
  - Generator control panel.
  - Control and protection system.
  - Operator training.
- Condensing steam turbine generator assumptions include:
  - Generator control system.
  - Emergency trip system.
  - Operator training.

- Heat recovery steam generator assumptions include:
  - Duct burners.
  - Exhaust stack.
- Fuel gas scrubber/filter included for each combustion turbine.
- Selective catalytic reduction (SCR) system is included.
- Mechanical draft cooling tower is included.
- Full capacity steam turbine bypass system is included.
- Combustion turbines and steam turbines will have remote control stations.
- Start-up spare parts are included.
- Shop fabricated tanks include:
  - Acid storage.
  - HRSG blowdown.
  - Fuel gas scrubber drains.
  - Air receiver.
  - Closed cycle cooling water head tank.
- Field erected tanks include:
  - Fuel oil storage tank.
  - Demineralized water storage tank.

7.3.1.3 Indirect Cost Assumptions.

- General indirects are included.
- Insurance costs include:
  - General liability.
  - Builder's risk.
  - Liquidated damages.
- Engineering and related services are included.
- Field construction management services are included.

7.3.2 General Electric 2x1 7FA Combined Cycle O&M Costs and Performance.

O&M estimates were developed based on those of Stanton Energy Center A.

Table 7-4. Generating Unit Characteristics General Electric 2x1 7FA Combined Cycle (replication of SEC A) (Unless otherwise specified, all costs are in 2004 dollars)	
Total Capital Cost[1], ($1000)	$246,800
O&M Cost – Baseload Duty	
Fixed O&M Cost ($/kW-yr)[2]	52,190
Variable O&M Cost ($/MWh)	3.77
Equivalent Forced Outage Rate (percent)	4.00
Planned Maintenance (days/year)	14
Construction Period (months)	18
Net kW Output/Net Plant Heat Rate (NPHR), HHV (Btu/kWh)	609,881/7,363
	594,264/7,226
	496,855/6,868
	490,323/6,875
	385,570/7,207
	284,291/7,864

1. Includes permitting and licensing.
2. Fixed O&M includes incremental natural gas transportation costs necessary to support fuel requirements of an additional combined cycle.

Note: Capital cost does not include interest during construction.

7.4 General Electric 7FA Simple Cycle Combustion Turbine

Simple cycle .combustion turbine generators are supplied with fuel, which is mixed with compressed air and combusted. The combustion gases flow through a turbine that turns a generator to produce power.

The GE 7FA combustion turbine is dual fueled with specifications for performance and operating costs based on natural gas operation. Part load performance information is also presented. For purposes of the Ten-Year Site Plan, it has been assumed that the GE 7FA simple cycle combustion turbine option will operate on No. 2 fuel oil as the primary fuel. This assumption was made to reflect the fact that addition of a combustion turbine may require more natural gas than OUC has available per existing Florida Gas Transmission (FGT) contracts, and given the fact that No. 2 fuel oil has a higher cost per MBtu than natural gas, it reflects a "worse case" scenario. That is, if the

GE 7FA combustion turbine proves economical when firing No. 2 fuel oil, it will be even more cost-effective firing the lower cost natural gas.

The simple cycle combustion turbine option further assumes that emission requirements will be met with dry low NO_x combustors when burning natural gas and water injection when burning No. 2 oil. Natural gas compressors are not included in the cost estimates because natural gas pipeline pressure is assumed adequate.

In December, 2001, OUC developed detailed capital cost estimates for a pair of combustion turbines to be installed at either the Stanton site or a new site. Installation at the Stanton site resulted in lower capital costs and therefore those costs are used as a basis in the Ten-Year Site Plan. Final decisions regarding the location of new combustion turbines have not been made. The capital cost estimates developed in December, 2001, assume that each site would include two identical combustion turbines. For purposes of the Ten-Year Site Plan, these estimates have been adjusted to appropriately consider the fact that only a single combustion turbine would be installed, and have been updated to account for the current competitive generation market.

Since the detailed capital cost estimates were developed in December, 2001, the overall slowdown in the competitive generation market has led to a substantial decrease in the procurement cost for a combustion turbine. This reduction has been considered in the updated capital cost estimate provided in Table 7-5. However, should the market experience a sustained recovery, the capital cost for the GE 7FA combustion turbine will likely increase significantly.

7.4.1 General Electric 7FA Combustion Turbine Generator Capital Costs.

The total capital cost of a plant is the summation of direct and indirect costs, and does not include interest during construction (IDC). The capital cost estimate for the addition of a single GE 7FA combustion turbine at the existing Stanton Energy Center is presented in Table 7-5.

7.4.1.1 General Assumptions.

- The plant will contain one dual fueled combustion turbine.
- The combustion turbines will be capable of firing natural gas or No. 2 fuel oil.
- All permitting, fuel supplies, and interconnections supplied by the utility and others shall be in place to support the schedule.
- Land and rights-of-way are to be provided.
- Costs of unloading and delivery to the project site are included.
- Raw water is assumed to be provided.
- Construction power is assumed to be provided.

- Natural gas is assumed to be available at the site boundary at the required pressure.
- Transmission interconnection costs are included.
- Permitting and licensing costs are included.

7.4.1.2 Direct Cost Assumptions.

- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' service.
- Direct costs include sitework, concrete, architecture, metals, piping, insulation, mechanical equipment, electrical, and controls.
- Direct costs include dry low NO_x burners.
- Direct costs include a 3-day supply fuel oil storage tank for backup fuel.
- Direct costs include an allowance for startup spares.
- Fire protection is included.

7.4.1.3 Indirect Cost Assumptions.

- General indirects are included.
- Insurance costs include:
    - Worker's compensation.
    - Employer liability.
    - Comprehensive general liability.
    - Auto liability.
    - Excess liability.
- Engineering and related services are included.
- Field construction management services are included.

7.4.2 General Electric 7FA Combustion Turbine Generator O&M Costs.

For the GE 7FA combustion turbine, O&M estimates are based on a maintenance cycle of 25 years with an assumed capacity factor of ten percent. Fixed O&M costs are those that do not directly vary according to plant electrical production. The largest fixed costs are wages and wage-related overheads for the permanent plant staff. The fixed O&M analysis assumes that the fixed costs will remain constant over the life of the plant. Variable O&M costs change as a function of plant generation. Variable O&M costs include consumables, chemicals, lubricants, water, and maintenance repair parts.

O&M estimates for the GE 7FA combustion turbine, shown in Table 7-5, were based on the following assumptions:

- Assumed cycle life of 25 years.

- Primary fuel is natural gas.
- Unit will run at peak load operation with a capacity factor of 10 percent.
- Annual number of starts for the combustion turbine is 200.
- NO_x control method – dry low NO_x combustors when burning natural gas and water injection when burning No. 2 oil.
- CTG maintenance estimated costs provided by manufacturer.
- CTG specialized labor cost estimated at $35/man-hour, provided by manufacturer.
- CTG initial operational spares, combustion spares, and hot gas path spares are not included.
- Balance-of-plant costs based on Black & Veatch experience.
- Five additional staff are estimated for the 7FA.
- Staff supplies and materials are estimated to be ten percent of staff salary.
- Rental equipment and contract labor costs are estimated by Black & Veatch. Rental equipment includes costs for heavy mobile equipment required for specific maintenance activities.
- Routine maintenance costs are estimated based on Black & Veatch experience and include maintenance costs for services not included in balance-of-plant costs or maintenance that is not directly part of power production.
- Contract services include costs for services not directly related to power production.
- Insurance, training fees, and bonuses are not included.
- Fuel costs are not included.
- Employee training costs are not included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and takes into account replacement and refurbishment costs.

Table 7-5.
Generating Unit Characteristics
156 MW General Electric 7FA Combustion Turbine
(Unless otherwise specified, all costs are in 2004 dollars)

Total Capital Cost[1]. ($1000)	$43,300
O&M Cost - Baseload Duty	
Fixed O&M Cost ($/kW-yr)	5.69
Variable O&M Cost ($/MWh)	2.01
Equivalent Forced Outage Rate (percent)	1.96
Planned Maintenance (days/year)	7
Construction Period (months)	12
Net kW Output/Net Plant Heat Rate (NPHR), HHV (Btu/kWh)	156,120 / 10,940
	117,090 / 11,878
	78,060 / 12,896
	39,030 / 14,002

1. Includes permitting and licensing.
Note: Capital cost does not include interest during construction.

8.0 Analysis and Results

8.1 Analysis Methodology

8.1.1 Methodology.

The economic evaluation used to determine OUC's least-cost capacity expansion plan is based on the cumulative present worth of annual costs for capital costs, non-fuel O&M costs, fuel costs, and purchase power demand and energy costs. Capital costs are included for new unit additions only, as capital costs for existing units represent sunk costs and are the same for every plan. Annual capital costs for new unit additions are determined by applying an annual fixed charge rate to the capital costs for each unit beginning in the first year of commercial operation. Non-fuel O&M costs include fixed and variable O&M costs; however fixed O&M costs are not included for existing units since these costs are the same for every plan.

Evaluation of the generating unit alternatives was performed using POWROPT and POWRPRO, Black & Veatch's optimal generation expansion planning and production costing models. POWROPT evaluates all combinations of generating unit and power purchase alternatives and selects the alternatives that provide the lowest cumulative present worth revenue requirements. POWROPT uses an hourly chronological approach to determine the least-cost capacity expansion plan, and the results of POWROPT are input into POWRPRO to develop the associated production costs. The production costing results of several scenarios, as well as the methodology supporting the determination of such results, are contained later in this section.

8.1.2 Economic Parameters.

8.1.2.1 General Inflation and Escalation Rates. The general inflation rate applied is assumed to be 2.5 percent. The escalation rate for capital costs and operation and maintenance (O&M) expenses is assumed to be 2.5 percent.

8.1.2.2 Cost of Capital. OUC uses a weighted average cost of capital for economic evaluations. The weighted average cost of capital is based on the debt/equity ratio, which is approximately 70/30, the embedded debt rate, which is approximately 6.6 percent, and the return on equity, which is approximately 10.3 percent. The weighted average cost of capital is thus approximately 7.7 percent. For economic evaluation purposes, the weighted average cost of capital is rounded to 8.0 percent.

8.1.2.3 Present Worth Discount Rate. OUC's present worth discount rate is assumed to be equal to the weighted average cost of capital of 8.0 percent.

8.1.2.4 Interest During Construction Interest Rate. The interest during construction rate is assumed to be 6.0 percent.

8.1.2.5 Levelized Fixed Charge Rate. The levelized fixed charge rate is assumed to be the sum of the capital recovery rate and the insurance rate. Based on the weighted average cost of capital of 8.0 percent, a 1.0 percent annual insurance cost, and a capital recovery period of 20 years, the levelized fixed charge rate is assumed to be 11.19 percent.

8.2 Fuel Price Projections

This section presents the fuel price projections for coal, natural gas, No. 2 fuel oil, No. 6 fuel oil, and nuclear fuel. OUC provided its most recent fuel forecasts for natural gas and coal. The forecasts for No. 6 and No. 2 fuel oils were developed by Black & Veatch based on the differential costs between the forecast prices for each fuel versus natural gas presented in the 2003 OUC Ten-Year Site Plan.

Fuel prices are highly volatile and are dependent not only on supply and demand, but also political stability and interdependent markets. Even the best forecasters face a tough job of forecasting in such a volatile market. Figure 8-1 shows long-term historical U.S. fuel prices and the wide range of fluctuations and responses to market conditions. Due to the difficulty of forecasting in this environment, a high fuel price scenario and a low fuel price scenario were also developed for use in the Ten-Year Site Plan.

8.2.1 Base Case Fuel Price Projections.

OUC provided projections for the prices of natural gas and coal. These forecasts were developed on a nominal basis and are discussed in more detail below. Also discussed are the forecasts for No. 6 and No. 2 fuel oils, as well as for nuclear fuel, which were each developed by Black & Veatch.

The past several years have provided a strong example of the volatility associated with the price of natural gas, particularly on the spot market. Recent seasonal spikes in the price of natural gas have further illustrated the difficulty associated with developing a forecast for natural gas (and fuel oil, for that matter) on even a short-term basis. OUC recognizes the fact that, given the current supply and demand issue and, in particular, the current worldwide political climate, this volatility is likely to continue. However, OUC feels confident that, to the best of its knowledge, the fuel price forecast presented in this Ten-Year Site Plan is adequate and appropriate for planning purposes.

8.2.1.1 Coal. The base case coal forecast is presented in Table 8-1. The forecast presented is for delivered coal and is based on a weighted average from various sources and suppliers, including spot market purchases.

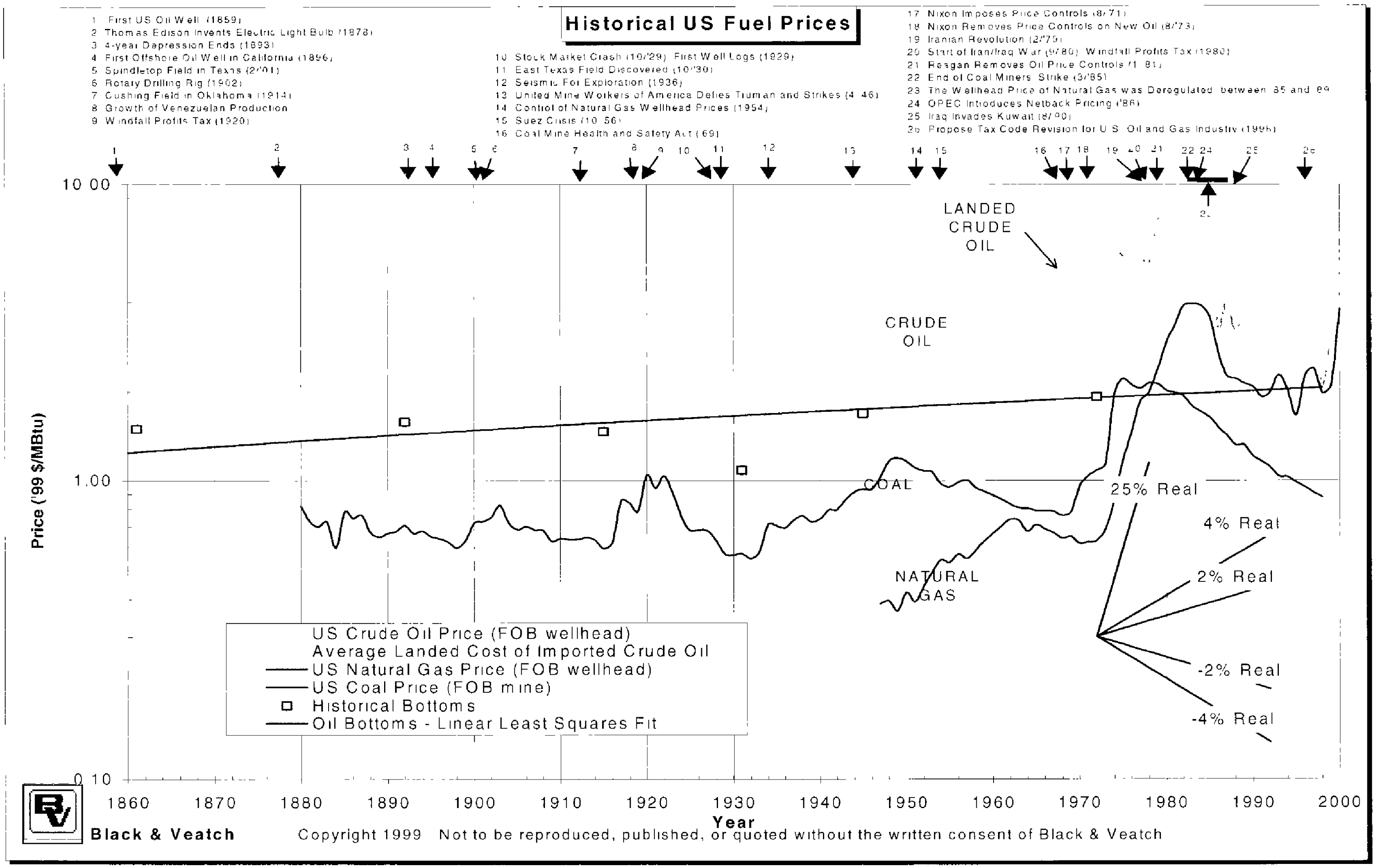


Figure 8-1. Historical U.S. Fuel Price Analysis

8.2.1.2 Natural Gas. The base case forecast for delivered natural gas is presented in Table 8-1. OUC has natural gas transportation capability from Florida Gas Transmission Company (FGT) under FTS-1 and FTS-2 tariffs. The FTS-2 tariff is expected to change as additional expansions are conducted on the FGT system (described in Section 8.3.4). In general, it is expected that the FTS-2 tariff rates will decrease as additional system expansions are added. Also impacting the natural gas transportation situation is the Gulfstream pipeline project (described in Section 8.3.5). Increased competition would be expected to increase pressure to lower transportation costs. Finally, the impacts of transportation capacity being bought and sold on the secondary market will also influence the average natural gas transportation costs.

8.2.1.3 No. 6 Fuel Oil. The forecast for No. 6 fuel oil used in this Ten-Year Site Plan was developed by Black & Veatch. The methodology used in doing so was to calculate the percent difference for each year's No. 6 fuel oil forecast compared to the corresponding year's forecast natural gas price as presented in the 2003 OUC Ten-Year Site Plan. This percent difference was then applied to the annual natural gas forecast developed by OUC for use in this year's Ten-Year Site Plan.

Although OUC does not own any generating units that rely on No. 6 fuel oil as the unit's primary fuel, the purchase power agreement with Reliant (the Reliant Agreement, described in Section 2.3) is based on utilizing specified proportions of No. 6 fuel oil and natural gas. As such, the No. 6 fuel oil forecast is only used during the term of the Reliant Agreement, which expires September 30, 2005.

8.2.1.4 No. 2 Fuel Oil. The methodology used to develop the forecast for No. 2 fuel oil was identical to that described above for No. 6 fuel oil, with percent differences calculated based on the forecasts for natural gas and No. 2 fuel oil presented in the 2003 OUC Ten-Year Site Plan. The resulting forecast for No. 2 fuel oil was used in the analysis of the GE 7FA simple cycle combustion turbine presented in Section 7.0 in order to reflect the fact that the addition of a combustion turbine may require more natural gas than OUC has available under existing FGT contracts. Because the forecast for No. 2 fuel oil is higher per MBtu than the forecast for natural gas, such an analysis reflects a "worse case" scenario. That is, if the addition of a GE 7FA combustion turbine proves economical when firing No. 2 fuel oil, it will be even more cost-effective firing the lower cost natural gas.

8.2.1.5 Nuclear Fuel. The forecast for nuclear fuel remains unchanged from that used for the 2003 OUC Ten-Year Site Plan for the years 2004 through 2012. The forecast for 2013 was developed by applying the general inflation rate of 2.5 percent to the 2012 forecast. The nuclear fuel price forecast is presented in Table 8-1.

Table 8-1
Base Case Fuel Price Forecast Summary (delivered nominal $/MBtu)

Year	Coal	Natural Gas	No. 6 Oil	No. 2 Oil	Nuclear
2004	$1.99	$5.68	$4.61	$5.98	$0.41
2005	$2.08	$5.32	$4.35	$5.62	$0.42
2006	$2.13	$5.36	$4.32	$5.56	$0.43
2007	$2.15	$5.40	$4.36	$5.61	$0.44
2008	$2.31	$5.44	$4.43	$5.70	$0.45
2009	$2.38	$5.48	$4.52	$5.80	$0.46
2010	$2.42	$5.53	$4.60	$5.94	$0.47
2011	$2.48	$5.58	$4.68	$6.05	$0.49
2012	$2.60	$5.62	$4.76	$6.19	$0.50
2013	$2.67	$5.67	$4.83	$6.27	$0.51

8.2.2 High and Low Fuel Price Projections.

In order to address the uncertainty surrounding forecasting fuel prices ten years into the future, OUC developed high and low fuel price forecasts for coal and natural gas. The high and low natural gas forecasts were subsequently used to develop high and low forecasts for No. 6 and No. 2 fuel oils, based on the methodology presented in Section 8.2.1.3. For nuclear fuel, the base case average annual escalation rate was increased by 2.0 percentage points (high case) and decreased by 2.0 percentage points (low case). The resulting high fuel price forecast is presented in Table 8-2, and the resulting low fuel price forecast is presented in Table 8-3.

Table 8-2.
High Case Fuel Price Forecast Summary (delivered nominal $/MBtu)

Year	Coal	Natural Gas	No. 6 Oil	No. 2 Oil	Nuclear
2004	$2.01	$6.50	$5.28	$6.84	$0.41
2005	$2.15	$6.68	$5.47	$7.06	$0.43
2006	$2.25	$6.77	$5.46	$7.02	$0.45
2007	$2.34	$6.85	$5.53	$7.12	$0.47
2008	$2.49	$6.94	$5.65	$7.27	$0.49
2009	$2.62	$7.03	$5.79	$7.44	$0.51
2010	$2.72	$7.12	$5.92	$7.65	$0.53
2011	$2.81	$7.22	$6.06	$7.83	$0.56
2012	$3.08	$7.31	$6.20	$8.05	$0.58
2013	$3.22	$7.41	$6.31	$8.20	$0.61

Table 8-3.
Low Case Fuel Price Forecast Summary (delivered nominal $/MBtu)

Year	Coal	Natural Gas	No. 6 Oil	No. 2 Oil	Nuclear
2004	$1.98	$3.70	$3.01	$3.89	$0.41
2005	$2.04	$3.99	$3.27	$4.21	$0.41
2006	$2.08	$4.00	$3.23	$4.15	$0.41
2007	$2.09	$3.97	$3.20	$4.13	$0.42
2008	$2.25	$3.94	$3.21	$4.13	$0.42
2009	$2.31	$3.92	$3.22	$4.14	$0.42
2010	$2.34	$3.89	$3.23	$4.18	$0.42
2011	$2.38	$3.86	$3.24	$4.19	$0.42
2012	$2.47	$3.84	$3.25	$4.23	$0.43
2013	$2.53	$3.82	$3.25	$4.23	$0.43

8.3 Fuel Availability

Plentiful coal and natural gas reserves exist both in the United States and North American mainland and coastal regions. Large coal reserves within the east, central, and western United States are adequate to supply power generation needs for the foreseeable future. Oil reserves are dependent upon both domestic and offshore production and imports. Natural gas reserves are mostly dependent on domestic production. Increasing demand for natural gas as a fuel for both home heating and power production is contributing to the volatility of its price, which in turn has provided incentives for increased production. A somewhat cyclic effect is expected, where short-term demand and price volatility will drive increased production and future price stability.

8.3.1 Service to Proposed Plant Site.

FGT's 26-inch pipeline is located approximately 2.5 miles south of the Stanton Energy Center site which, as discussed in Section 7.0, is the assumed location of the generating alternatives considered in the Ten-Year Site Plan.

8.3.2 Florida Gas Transmission Company.

FGT is an open access interstate pipeline company transporting natural gas for third parties through its 4,900 mile pipeline system extending from south Texas to Miami, Florida. FGT is owned by Citrus Corporation, which in turn is held 50 percent by Enron and 50 percent by Southern Natural, an El Paso Corporation affiliate. Recently, CrossCountry Energy Corporation was formed to hold Enron's interest in and operate three major North American natural gas pipeline businesses, including Citrus Corporation.

The FGT pipeline system accesses a diverse array of natural gas supply regions, including:

- Anadarko Basin (Texas, Oklahoma, and Kansas).
- Arkona Basin (Oklahoma and Arkansas).
- Texas and Louisiana Gulf Areas (Gulf of Mexico).
- Black Warrior Basin (Mississippi and Alabama).
- Louisiana – Mississippi – Alabama Salt Basin.
- Mobile Bay.

FGT's total receipt point capacity is in excess of 3.0 billion cubic feet per day and includes connections with ten interstate and ten intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a current delivery capability to Peninsular Florida of 2.1 billion cubic feet per day.

8.3.3 Florida Gas Transmission Market Area Pipeline System.

The FGT multiple pipeline system corridor enters the Florida Panhandle in northern Escambia County and runs east to a point in southwestern Clay County, where the pipeline corridor turns south to pass west of the Orlando area. The mainline corridor then turns to the southeast to a point in southern Brevard County where it turns south, generally paralleling Interstate Highway 95 to the Miami area. A major lateral line (the St. Petersburg Lateral) extends from a junction point in southern Orange County west to terminate in the Tampa-St. Petersburg-Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through western Peninsular Florida to connect to the St. Petersburg Lateral system in northeastern Hillsborough County. Each of the above major corridors includes stretches of multiple pipelines (loops) to provide flow redundancy and transport capability. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

8.3.4 Florida Gas Transmission Expansions.

The Phase IV Expansion project, completed May 1, 2001, added 134 miles of underground pipeline and more than 38,000 horsepower of compression to FGT's existing underground natural gas transmission system. The expansion allows FGT to transport approximately 200 million cubic feet per day (MMcf/d) of additional natural gas for use in electric power generation and to supply natural gas to homes and businesses through local distribution companies.

FGT's Phase V expansion faced many changes that caused it to file an amended project application with FERC. After the Florida Supreme Court ruling that limited the ability of nonutility merchant plants to use the Florida Electrical Power Plant Siting Act, two major Phase V customers, Enron and Dynergy, withdrew from Phase V. However, FGT subsequently gained back some of the lost market by signing a long-term contract with Tampa Electric Company as a Phase V customer. FERC granted preliminary approval to the expansion in November of 2000. The Phase V expansion received final environmental approval in the summer of 2001.

As of April, 2002, FGT had completed and placed into service the second stage of its four-stage Phase V expansion project. Completed in mid-2003, the Phase V project added approximately 167 miles of new pipeline and 132,615 horsepower of compression to the existing system. This expansion resulted in the addition of more than 428 MMcf/d of incremental mainland natural gas capacity to Florida.

On November 15, 2001, FGT filed an application with FERC to expand its existing transmission system (the Phase VI Expansion). The Phase VI Expansion, which was placed into service November 1, 2003, added approximately 33 miles of new pipeline and 18,600 horsepower of additional compression to the existing FGT system. The nearly $100 million project was supported by long-term firm service agreements for the additional 121 MMcf/d of incremental firm transportation capacity. Remaining compressor station modifications associated with the Phase VI Expansion should be completed during the spring of 2004.

8.3.5 Gulfstream Pipeline.

In April, 2000, FERC granted preliminary approval for the construction of two natural gas pipelines capable of servicing Peninsular Florida. The Buccaneer gas pipeline (to be jointly developed by Williams Energy and Duke Energy) and the Gulfstream pipeline (to be developed by Coastal Corporation) each received one of the two required approvals from FERC in September, 2000. Shortly thereafter (in November, 2000), Williams Energy and Duke Energy announced their intent to purchase the Gulfstream project from Coastal Corporation, subject to federal regulatory approvals and conditioned upon completion of the Coastal Corporation/El Paso Energy Corporation merger. Federal regulatory approval was subsequently granted and the Coastal/El Paso merger was finalized as well.

Plans for the Buccaneer pipeline were dropped by Williams and Duke, who instead focused on the Gulfstream pipeline. The $1.6 billion pipeline project won FERC approval, subject to environmental review, on April 24, 2000. FERC issued its final Environmental Impact Statement in January 2001, with its final order issued in February, 2001. The first major acquisition of right-of-way occurred July 20, 2000, with a signed agreement between Coastal Corporation and the Manatee County Port Authority. The Gulfstream pipeline gained permanent right-of-way easement to cross through Port

Manatee. Construction of the pipeline began May 31, 2001, and the Gulfstream pipeline was placed into service May 28, 2002.

The Gulfstream pipeline represents the first new natural gas pipeline in the State of Florida in over 40 years, and is the largest pipeline in the Gulf of Mexico with a capacity of approximately 1.1 billion cubic feet per day. Gulfstream spans a total of 581 miles, originating near Pascagoula, Mississippi and Mobile, Alabama, crossing the Gulf of Mexico with 419 miles of 36-inch diameter pipeline to Manatee County, Florida. Once onshore, 130 miles of pipeline ranging in diameter from 36 inches to 16 inches crosses Manatee, Hardee, Polk, and Osceola counties. FERC has certified an additional 173 miles of 24-inch, 30-inch, and 36-inch diameter onshore mainland pipe. Gulfstream is supplied with its natural gas in Mobile Bay, East Louisiana, and Mississippi, which have total natural gas supply area reserves of 22.7 trillion cubic feet.

8.4 Results for Capacity Expansion Plans

8.4.1 Methodology.

The supply-side evaluation of generating unit alternatives was performed using POWROPT, an optimal generation expansion model developed by Black & Veatch. Developed as an alternative to and benchmarked against other optimization programs, POWROPT has proven to be an effective modeling program. POWROPT has been used in several Need for Power proceedings before the Florida Public Service Commission.

POWROPT operates on an hourly chronological basis and is used to determine a set of capacity expansion plans based on capacity requirements, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of available generating unit alternatives and purchase power options to maintain user-defined reliability criteria. The reserve requirement utilized was a minimum reserve margin of 15 percent. All capacity expansion plans were analyzed over a ten-year period from 2004 through 2013.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's detailed chronological production costing program, POWRPRO, was used to obtain the annual production cost for the expansion plan. For purposes of expansion planning, POWROPT and POWRPRO consider the combined systems of OUC and St. Cloud.

8.4.2 Expansion Candidates.

The expansion candidates for the POWROPT evaluation are presented in Section 7.0. OUC's elected amounts of capacity through extension of the Reliant PPA for fiscal year 2004 and fiscal year 2005 (described in Section 2.3) have been included among the existing generation resources and are not considered as capacity addition alternatives.

8.4.3 Results of the Economic Analysis.

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and planned reserve margins. The evaluations were based upon the cost and performance characteristics of the generating unit alternatives described in detail in Section 7.0. Production costs were modeled to account for seasonal variations in unit ratings, as appropriate, for summer, winter, and shoulder periods. Winter and summer unit ratings were used to determine capacity requirements. Table 8-4 represents the least-cost capacity addition plan for the combined OUC and St. Cloud system under the base case scenario, while Tables 8-5 and 8-6 present the forecast reserve margins for the combined OUC and St. Cloud system after implementation of the expansion plan presented in Table 8-4 for the winter and summer seasons, respectively. Examination of the annual costs shows a decrease between 2005 and 2006, which is attributable to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District, under which OUC supplies a significant amount of capacity and energy.

Table 8-4.
OUC Least-Cost Base Case Expansion Plan[1]

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2004)	$218,061	$218,061
2005	Terminate 300 MW Reliant Power Purchase (09/30/2005)	$219,849	$421,625
2006		$205,980[2]	$598,219
2007		$218,058	$771,321
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008)	$233,255	$942,770
2009	40 MW Reduction in Southern-Florida Power Purchase (01/01/2009)	$252,370	$1,114,529
2010	40 MW Reduction in Southern-Florida Power Purchase (01/01/2010) 156 MW GE 7FA Simple Cycle CT (06/01/2010)	$261,149	$1,279,098
2011	40 MW Reduction in Southern-Florida Power Purchase (01/01/2011)	$273,665	$1,438,778
2012	40 MW Reduction in Southern-Florida Power Purchase (01/01/2012) 156 MW GE 7FA Simple Cycle CT (06/01/2012)	$294,908	$1,598,108
2013	156 MW GE 7FA Simple Cycle CT (06/01/2013)	$322,585	**$1,759,481**

1. Capacity is stated at average annual temperature for OUC.
2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District (12/31/2005), under which OUC supplies a significant amount of capacity and energy.

Table 8-5.
OUC and St. Cloud (STC) Forecast Winter Reserve Requirements – Base Case After Capacity Additions

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)		Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[4] (MW)
	OUC	STC	RCID P R	FMPA I R		Installed[1]	SEC A PPA	Reliant PPA	TECO P R	Total	Required[2]	Available[3]	
2004/05	1,093	125	101	44	1,363	1,276	341	300	15	1,932	198	597	403
2005/06	1,126	129	76	34	1,365	1,276	341	0	15	1,632	200	269	69
2006/07	1,161	134	0	22	1,317	1,255	341	0	15	1,611	194	318	124
2007/08	1,199	139	0	0	1,338	1,255	341	0	15	1,611	201	275	74
2008/09	1,241	144	0	0	1,385	1,430	301	0	15	1,746	208	363	155
2009/10	1,280	150	0	0	1,430	1,430	261	0	15	1,706	215	278	64
2010/11	1,322	155	0	0	1,477	1,605	221	0	15	1,841	222	366	145
2011/12	1,367	161	0	0	1,528	1,605	181	0	15	1,801	229	275	46
2012/13	1,411	167	0	0	1,578	1,780	181	0	15	1,976	237	400	163
2013/14	1,456	173	0	0	1,629	1,955	181	0	0	2,136	244	507	263

1 Includes OUC's equity portion of SEC A, as well as St Cloud's diesel units (which are scheduled to retire in October, 2006)
2 "Required Reserves" include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract
3 "Available Reserves" equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P R. purchase
4 Calculated as the difference between available reserves and required reserves.

Table 8-6.
OUC and St. Cloud (STC) Forecast Summer Reserve Requirements – Base Case After Capacity Additions

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)		Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[4] (MW)
	OUC	STC	RCID P R	FMPA I R.		Installed[1]	SEC A PPA	Reliant PPA	TECO P.R	Total	Required[2]	Available[3]	
2004	1,076	116	101	65	1,358	1,215	312	500	15	2,042	194	686	492
2005	1,107	120	113	43	1,383	1,215	312	300	15	1,842	201	461	260
2006	1,136	124	0	22	1,282	1,215	312	0	15	1,542	189	262	73
2007	1,167	128	0	0	1,295	1,193	312	0	15	1,520	194	227	33
2008	1,201	133	0	0	1,334	1,333	312	0	15	1,660	200	328	128
2009	1,239	137	0	0	1,376	1,333	272	0	15	1,620	206	246	40
2010	1,275	142	0	0	1,417	1,473	232	0	15	1,720	213	305	92
2011	1,315	148	0	0	1,463	1,473	192	0	15	1,680	219	219	0
2012	1,355	153	0	0	1,508	1,613	152	0	15	1,780	226	274	48
2013	1,395	158	0	0	1,553	1,753	152	0	0	1,905	233	352	119

1 Includes OUC's equity portion of SEC A, as well as St Cloud's diesel units (which are scheduled to retire in October, 2006)
2 "Required Reserves" include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract
3 "Available Reserves" equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P.R purchase
4 Calculated as the difference between available reserves and required reserves

8.5 Sensitivity Analysis

Several sensitivity analyses were performed to measure the impact of key assumptions. The sensitivity analyses include high and low fuel price scenarios as well as high load and energy growth and low load and energy growth scenarios. The sensitivity analyses were performed over a ten-year planning horizon, similar to the base case economic evaluation, with a projection of both annual and cumulative present worth costs.

8.5.1 High Fuel Price Scenario.

The high fuel price forecast is provided in Table 8-2. Table 8-7 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price sensitivity case.

8.5.2 Low Fuel Price Scenario.

The low fuel price forecast is provided in Table 8-3. Table 8-8 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price sensitivity case.

8.5.3 High Load and Energy Growth.

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. When compared to the base case, the high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 4.0. Tables 8-9 and 8-10 indicate the summer and winter need for capacity based upon the high load and energy growth forecast.

Analysis of Tables 8-9 and 8-10 show that under the high load and energy growth scenario, OUC would not require additional generating capacity to satisfy winter requirements until winter 2008/09. Additionally, OUC will have sufficient summer generating capacity through the summer of 2006, with the need for additional summer capacity initiating during the summer of 2007 and increasing annually thereafter. Table 8-11 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity.

8.5.4 Low Load and Energy Growth.

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 4.0. Tables 8-12 and 8-13 indicate the summer and winter need for capacity based upon the low load and energy forecast, and show that under the low load and energy growth scenario OUC would not need additional capacity until the summer of 2009, assuming no reduction to the amount of capacity purchased under the Stanton A Southern-Florida power purchase agreement. Table 8-14 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity.

Table 8-7.
OUC Least-Cost High Fuel Sensitivity Expansion Plan[1]

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2004)	$229,993	$229,993
2005	Terminate 300 MW Reliant Power Purchase (09/30/2005)	$240,175	$452,377
2006		$225,414	$645,633
2007		$241,799	$837,581
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008)	$259,197	$1,028,098
2009	40 MW Reduction in Southern-Florida Power Purchase (01/01/2009)	$285,938	$1,222,703
2010	40 MW Reduction in Southern-Florida Power Purchase (01/01/2010) 156 MW GE 7FA Simple Cycle CT (06/01/2010)	$298,559	$1,410,846
2011	40 MW Reduction in Southern-Florida Power Purchase (01/01/2011)	$313,857	$1,593,978
2012	40 MW Reduction in Southern-Florida Power Purchase (01/01/2012) 156 MW GE 7FA Simple Cycle CT (06/01/2012)	$346,505	$1,781,184
2013	156 MW GE 7FA Simple Cycle CT (06/01/2013)	$382,787	**$1,972,673**

1. Capacity is stated at average annual temperature for OUC.
2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District (12/31/2005), under which OUC supplies a significant amount of capacity and energy.

Table 8-8.
OUC Least-Cost Low Fuel Sensitivity Expansion Plan[1]

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2004)	$190,947	$190,947
2005	Terminate 300 MW Reliant Power Purchase (09/30/2005)	$201,323	$377,358
2006		$190,328	$540,533
2007		$200,792	$699,928
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008)	$213,095	$856,559
2009	40 MW Reduction in Southern-Florida Power Purchase (01/01/2009)	$226,469	$1,010,690
2010	40 MW Reduction in Southern-Florida Power Purchase (01/01/2010) 156 MW GE 7FA Simple Cycle CT (06/01/2010)	$233,487	$1,157,827
2011	40 MW Reduction in Southern-Florida Power Purchase (01/01/2011)	$243,949	$1,300,169
2012	40 MW Reduction in Southern-Florida Power Purchase (01/01/2012) 156 MW GE 7FA Simple Cycle CT (06/01/2012)	$259,944	$1,440,609
2013	156 MW GE 7FA Simple Cycle CT (06/01/2013)	$281,456	**$1,581,407**

1. Capacity is stated at average annual temperature for OUC.
2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District (12/31/2005), under which OUC supplies a significant amount of capacity and energy.

Table 8-9.
OUC and St. Cloud (STC) Forecast Winter Reserve Requirements – High Load without Capacity Additions

Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)		Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[4] (MW)
	OUC and STC	RCID P.R	FMPA I.R.		Installed[1]	SEC A PPA	Reliant PPA	TECO P R	Total	Required[2]	Available[3]	
2004/05	1,245	101	44	1,364	1,276	341	300	15	1,932	198	570	372
2005/06	1,286	76	34	1,396	1,276	341	0	15	1,632	204	238	34
2006/07	1,328	0	22	1,328	1,255	341	0	15	1,611	199	285	86
2007/08	1,372	0	0	1,372	1,255	341	0	15	1,611	206	241	35
2008/09	1,417	0	0	1,417	1,255	341	0	15	1,611	213	196	(17)
2009/10	1,464	0	0	1,464	1,255	341	0	15	1,611	220	149	(70)
2010/11	1,512	0	0	1,512	1,255	341	0	15	1,611	227	101	(126)
2011/12	1,562	0	0	1,562	1,255	341	0	15	1,611	234	52	(183)
2012/13	1,613	0	0	1,613	1,255	341	0	15	1,611	242	0	(242)
2013/14	1,666	0	0	1,666	1,255	341	0	0	1,596	250	(70)	(320)

1 Includes OUC's equity portion of SEC A, as well as St Cloud's diesel units (which are scheduled to retire in October, 2006)
2 "Required Reserves" include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract
3 "Available Reserves" equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P R purchase
4 Calculated as the difference between available reserves and required reserves

Table 8-10.
OUC and St. Cloud (STC) Forecast Summer Reserve Requirements – High Load without Capacity Additions

Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)		Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[4] (MW)
	OUC and STC	RCID P R	FMPA I R		Installed[1]	SEC A PPA	Reliant PPA	TECO P.R.	Total	Required[2]	Available[3]	
2004	1,192	101	65	1,358	1,215	312	500	15	2,042	194	686	492
2005	1,254	113	43	1,410	1,215	312	300	15	1,842	205	434	229
2006	1,291	0	22	1,313	1,215	312	0	15	1,542	194	230	37
2007	1,330	0	0	1,330	1,193	312	0	15	1,520	200	192	(8)
2008	1,370	0	0	1,370	1,193	312	0	15	1,520	205	152	(53)
2009	1,411	0	0	1,411	1,193	312	0	15	1,520	212	111	(100)
2010	1,453	0	0	1,453	1,193	312	0	15	1,520	218	69	(149)
2011	1,496	0	0	1,496	1,193	312	0	15	1,520	224	26	(199)
2012	1,541	0	0	1,541	1,193	312	0	15	1,520	231	(19)	(250)
2013	1,587	0	0	1,587	1,193	312	0	0	1,505	238	(82)	(320)

1 Includes OUC's equity portion of SEC A, as well as St Cloud's diesel units (which are scheduled to retire in October, 2006)
2 "Required Reserves" include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract.
3 "Available Reserves" equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P.R. purchase
4 Calculated as the difference between available reserves and required reserves

Table 8-11.
OUC Least-Cost High Load and Energy Growth Sensitivity Expansion Plan[1]

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2004)	$218,061	$218,061
2005	Terminate 300 MW Reliant Power Purchase (09/30/2005)	$225,099	$426,486
2006		$212,254	$608,459
2007	156 MW GE 7FA Simple Cycle CT (06/01/2007)	$225,413	$787,400
2008		$243,506	$966,384
2009	40 MW Reduction in Southern-Florida Power Purchase (01/01/2009)	$259,241	$1,142,819
2010	40 MW Reduction in Southern-Florida Power Purchase (01/01/2010) 156 MW GE 7FA Simple Cycle CT (06/01/2010)	$268,589	$1,312,075
2011		$284,793	$1,478,250
2012	40 MW Reduction in Southern-Florida Power Purchase (01/01/2012) 156 MW GE 7FA Simple Cycle CT (06/01/2012)	$305,437	$1,643,268
2013	156 MW GE 7FA Simple Cycle CT (06/01/2013)	$332,913	**$1,809,807**

1. Capacity is stated at average annual temperature for OUC.
2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District (12/31/2005), under which OUC supplies a significant amount of capacity and energy.

Table 8-12.
OUC and St. Cloud (STC) Forecast Winter Reserve Requirements – Low Load without Capacity Additions

Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)		Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[4] (MW)
	OUC and STC	RCID P R	FMPA I R		Installed[1]	SEC A PPA	Reliant PPA	TECO P.R	Total	Required[2]	Available[3]	
2004/05	1,191	101	44	1,310	1,276	341	300	15	1,932	190	624	434
2005/06	1,230	76	34	1,340	1,276	341	0	15	1,632	196	294	98
2006/07	1,271	0	22	1,271	1,255	341	0	15	1,611	191	343	152
2007/08	1,312	0	0	1,312	1,255	341	0	15	1,611	197	301	104
2008/09	1,356	0	0	1,356	1,255	341	0	15	1,611	203	258	54
2009/10	1,400	0	0	1,400	1,255	341	0	15	1,611	210	213	3
2010/11	1,446	0	0	1,446	1,255	341	0	15	1,611	217	167	(50)
2011/12	1,494	0	0	1,494	1,255	341	0	15	1,611	224	119	(105)
2012/13	1,543	0	0	1,543	1,255	341	0	15	1,611	231	70	(161)
2013/14	1,594	0	0	1,594	1,255	341	0	0	1,596	239	2	(237)

1 Includes OUC's equity portion of SEC A, as well as St Cloud's diesel units (which are scheduled to retire in October, 2006)
2. "Required Reserves" include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract
3 "Available Reserves" equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P R purchase
4. Calculated as the difference between available reserves and required reserves

Table 8-13.
OUC and St. Cloud (STC) Forecast Summer Reserve Requirements – Low Load without Capacity Additions

Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)		Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[4] (MW)
	OUC and STC	RCID P R	FMPA I R		Installed[1]	SEC A PPA	Reliant PPA	TECO P R	Total	Required[2]	Available[3]	
2004	1,192	101	65	1,358	1,215	312	500	15	2,042	194	686	492
2005	1,200	113	43	1,356	1,215	312	300	15	1,842	197	488	291
2006	1,236	0	22	1,258	1,215	312	0	15	1,542	185	286	101
2007	1,273	0	0	1,273	1,193	312	0	15	1,520	191	249	58
2008	1,311	0	0	1,311	1,193	312	0	15	1,520	197	211	14
2009	1,350	0	0	1,350	1,193	312	0	15	1,520	203	172	(31)
2010	1,390	0	0	1,390	1,193	312	0	15	1,520	209	131	(77)
2011	1,432	0	0	1,432	1,193	312	0	15	1,520	215	90	(125)
2012	1,475	0	0	1,475	1,193	312	0	15	1,520	221	47	(174)
2013	1,519	0	0	1,519	1,193	312	0	0	1,505	228	(14)	(242)

1 Includes OUC's equity portion of SEC A, as well as St Cloud's diesel units (which are scheduled to retire in October, 2006)
2 "Required Reserves" include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract
3 "Available Reserves" equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P R purchase
4 Calculated as the difference between available reserves and required reserves

Table 8-14.
OUC Least-Cost Low Load and Energy Growth Sensitivity Expansion Plan[1]

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2004)	$218,061	$218,061
2005	Terminate 300 MW Reliant Power Purchase (09/30/2005)	$214,132	$416,332
2006		$200,830	$588,511
2007		$212,693	$757,354
2008		$225,902	$923,399
2009	40 MW Reduction in Southern-Florida Power Purchase (01/01/2009) 156 MW GE 7FA Simple Cycle CT (06/01/2009)	$243,764	$1,089,301
2010		$255,597	$1,250,370
2011	40 MW Reduction in Southern-Florida Power Purchase (01/01/2011) 156 MW GE 7FA Simple Cycle CT (06/01/2011)	$267,950	$1,406,716
2012	40 MW Reduction in Southern-Florida Power Purchase (01/01/2012)	$288,358	$1,562,507
2013	156 MW GE 7FA Simple Cycle CT (06/01/2013)	$314,447	**$1,719,809**

1. Capacity is stated at average annual temperature for OUC.
2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District (12/31/2005), under which OUC supplies a significant amount of capacity and energy.

9.0 Environmental and Land Use Information

The Stanton Energy Center, originally certified for 2,000 MW, currently consists of two pulverized coal units, which went into service in 1987 and 1996, and a 2x1 combined cycle unit (Stanton A) which began commercial operation in 2003. Extensive environmental and land use information was filed with the Site Certification Application for Stanton 1 and additional information was filed with the Supplemental Site Certification Applications for Stanton 2 and Stanton A. The original and supplemental Site Certification Applications were submitted to all the agencies and for the sake of brevity have not been reproduced for inclusion in this Ten-Year Site Plan. The identification of the GE 7FA combustion turbines in Section 8.0 herein as part of the least-cost expansion plan is considered indicative at this point, and no formal plans have been developed for their construction at this time. However, should future studies continue to indicate construction of these units is cost-effective for OUC, they will likely be constructed at the Stanton Energy Center site or a new site. Specific site layouts have been developed and existing infrastructure is available to support the 7FA combustion turbines at the Stanton Site. The following information focuses on future combustion turbines which are assumed to be installed at the Stanton Site.

9.1 Status of Site Certification

Ultimate certification for 2,000 MW was obtained with the Site Certification for Stanton 1. Stanton 2 was certified under the Supplemental Site Certification provisions of the Florida Electrical Power Plant Siting Act (Act). Stanton A received final site certification on September 18, 2001 and construction began in November, 2001. Stanton A began commercial operation on October 1, 2003.

9.2 Land and Environmental Features

The Stanton Energy Center is located in Orange County, Florida, with approximately 3,280 acres. The Econlockhatchee River is about three-fourths of one mile east of the northeast corner of the site boundary. The Orange County Solid Waste Disposal facility is adjacent to the site along the west boundary.

A natural gas pipeline connects Stanton A to the Florida Gas Transmission (FGT) system. The pipeline is 2.5 miles in total length, connecting with FGT's system south of the Stanton site. The pipeline is routed in the existing transmission and railroad spur right-of-way. The pipeline has been sized to accommodate additional natural gas fired generation at the Stanton Site.

Extensive details regarding land and environmental features are contained in the Site Certification Application for Stanton 1 and the Supplemental Site Certification Applications for Stanton 2 and Stanton A.

9.3 Air Emissions

GE 7FA combustion turbines utilize low NO_x combustors to reduce NO_x emissions when burning natural gas and water injection to reduce NO_x when firing No. 2 fuel oil. NO_x emissions while firing natural gas are approximately nine parts per million (ppm) and approximately 42 ppm while firing No. 2 fuel oil. SO_2 emissions will be controlled by limiting the sulfur content of the oil.

9.4 Water and Wastewater

The use of simple cycle technology minimizes the amount of water required. Water for water injection for NO_x control for simple cycle combustion turbines located at Stanton would be supplied from the existing demineralized water system which currently uses groundwater. The volume of demineralized water consumed is expected to be minimal due to the low annual hours of operation and the lack of need for water injection whenever the combustion turbines are operated on natural gas.

The Stanton site is designed to reuse wastewater to the extent possible. When wastewater cannot be reused, it is evaporated with a brine concentrator/crystallizer; thus, the Stanton site is truly a zero discharge site. The very small amount of wastewater generated by simple cycle combustion turbines would be disposed using the existing wastewater treatment facilities.

10.0 Conclusions

The results of the base case and all of the sensitivity analyses indicate that General Electric 7FA combustion turbines represent the least-cost generating unit additions for OUC's system based on the alternatives evaluated. This is an expected result given OUC's current generation mix consisting primarily of coal fueled and combined cycle generation. However, the high current and projected cost of natural gas makes additional coal fueled generation increasingly more competitive. A plan that installs a 50 percent ownership in a pulverized coal unit in 2010 results in only a 1.8 percent increase in cumulative present worth costs over the base case for the ten-year evaluation period ending in 2013. This percent difference is even less in total system costs and would be even smaller if the evaluation period was extended to allow more years of benefits of the lower production costs of the coal fueled generation.

The lead time required for the permitting/licensing and construction of a large coal unit is approximately six years. The shorter construction period for smaller coal units can reduce the lead time to five years.

Commitment to construct a coal unit has a number of strategic issues associated with it. A major issue is the large capital commitment. A second significant issue is the uncertainty of future environmental regulations and their potential effect on the competitiveness of coal fueled generation.

At this point in time, following the base case plan allows OUC to maintain the ability to install coal fueled generation in the 2010 to 2011 time frame without the need for a major financial commitment during 2004. This allows additional time to determine the outlook for future natural gas prices and for future environmental regulations to become more certain.

Examination of the base case expansion plan leads to a couple of conclusions. First, the base case plan assumes the retirement of the St. Cloud diesels in October, 2006. This retirement reduces OUC's available generating capacity by 22 MW (summer) which in turn causes a 12 MW need for additional capacity in the summer of 2008. While the St. Cloud diesels are reaching the end of their useful lives with current ages from 21 to 42 years, the actual required retirement date contains some flexibility. Retirements of units such as the St. Cloud diesels is based on a number of factors including availability of parts, staffing requirements, emissions, and a number of other factors. A significant or catastrophic failure requiring large repair expenses generally results in a decision to retire a unit that is reaching the end of its useful life. If the St. Cloud diesels' retirement date can be extended two years to October, 2008, the need for capacity addition would be deferred until June of 2009 based on the current load forecast. Deferring the addition of a 7FA combustion turbine results in a projected $3.5 million cumulative present worth savings over the evaluation period. This savings would be reduced by any additional expenses necessary to maintain the operation of the St. Cloud diesels.

An alternative to the extension of the retirement date of the St. Cloud diesels would be to purchase a small amount of power for the summer 2008 season. While it is premature to contract for this seasonal power purchase at this time, assuming that 12 MW of power can be purchased in 2008 with the performance characteristics of a 7FA combustion turbine and a capacity charge of three times OUC's carrying cost, the resulting cumulative present worth savings are estimated to be $4.4 million.

The lead time for permitting/licensing and construction of a 7FA combustion turbine is approximately two years. Thus, a commitment by OUC is not required until June, 2006, to meet the base case capacity addition requirement for June, 2008. The evaluations of deferring the retirement of the St. Cloud diesels and of purchasing a small amount of power indicate a high likelihood that the base case June, 2008, capacity need can be deferred at some savings from the costs in the base case plan.

A second conclusion resulting from examination of the base case is the projected savings from reducing the Stanton A purchase power in accordance with the contract. The base case includes four annual 40 MW capacity reductions beginning in 2009. A comparison of an expansion plan without these capacity reductions results in an increase in cumulative present worth costs of only 0.8 percent. This optional capacity reduction provides great flexibility to OUC and can easily contribute to the delay of generating capacity additions when appropriate.

Smaller combustion turbines are also available to OUC. These combustion turbines can better match the capacity addition requirements. The 7FA combustion turbine was chosen for evaluation since it generally is among the most competitive simple cycle combustion turbine alternatives. Historically, OUC has mitigated the effect of large unit additions through the sale of purchase power or joint ownership in the units. These mitigation measures may also be used as OUC installs future generating capacity.

In summary, the base case represents a reasonable expansion plan for OUC. Commitments to the expansion plan are not required by OUC until June, 2006. It is likely that additional refinements to the base case expansion plan will be available by the time commitment to the expansion plan is necessary.

11.0 Ten-Year Site Plan Schedules

This section presents the schedules required by the Ten-Year Site Plan rules for the Florida Public Service Commission (FPSC). For each table the FPSC Schedule number is included in parenthesis. The information contained within the FPSC Schedules is representative of the combined OUC and City of St. Cloud systems, consistent with all Sections of the 2004 OUC Ten-Year Site Plan.

Table 11-1 (Schedule 1).
OUC and St. Cloud Existing Generating Facilities as of December 31, 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)
				Primary Fuel		Alternate Fuel		Alt Fuel	Commercial	Expected	Gross Capability[1]		Net Capability[1]	
Plant Name	Unit No	Location	Unit Type	Fuel Type	Transport Method	Fuel Type	Transport Method	Storage (Days Burn)	In-Service MM/YYYY	Retirement MM/YYYY	Summer MW	Winter MW	Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	PL	DFO	TK	0 2	06/1989	Unknown	18 30	23 50	18 00	23 30
Indian River	B	Brevard	GT	NG	PL	DFO	TK	0 2	07/1989	Unknown	18 30	23 50	18 00	23 30
Indian River	C	Brevard	GT	NG	PL	DFO	TK	0 2	08/1992	Unknown	86 10	101 10	85 30	100 30
Indian River	D	Brevard	GT	NG	PL	DFO	TK	0 2	10/1992	Unknown	86.10	101 10	85 30	100 30
Stanton Energy Center	1	Orange	ST	BIT	RR	NA	UN	UN	07/1987	Unknown	320 13	322 19	301 62	303 68
Stanton Energy Center	2	Orange	ST	BIT	RR	NA	UN	UN	06/1996	Unknown	335 76	335 76	319 29	319 29
Stanton Energy Center	A	Orange	CC	NG	PL	DFO	TK	3	10/2001	Unknown	180 60	198 00	167.85	183 53
McIntosh	3	Polk	ST	BIT	REF	NA	UN	UN	09/1982	Unknown	146 00	146 00	136 80	136 80
Crystal River	3	Citrus	ST	NUC	TK	NA	UN	UN	03/1977	Unknown	14 03	14 27	13 36	13 64
St Lucie [2]	2	St Lucie	ST	NUC	TK	NA	UN	UN	08/1983	Unknown	54 20	54 20	51 09	51 94
St Cloud	1	Osceola	IC	NG	PL	DFO	TK	5	07/1982	11/2004	1 825	1 825	1 825	1 825
St. Cloud	2	Osceola	IC	NG	PL	DFO	TK	5	12/1974	11/2004	5 000	5 000	5 000	5 000
St Cloud	3	Osceola	IC	NG	PL	DFO	TK	5	09/1982	11/2004	1 825	1 825	1 825	1 825
St Cloud	4	Osceola	IC	NG	PL	DFO	TK	5	08/1961	11/2004	3 000	3 000	3 000	3 000
St Cloud	6	Osceola	IC	NG	PL	DFO	TK	5	03/1967	11/2004	3 000	3 000	3 000	3 000
St Cloud	7	Osceola	IC	NG	PL	DFO	TK	5	09/1982	11/2004	6 000	6 000	6 000	6 000
St Cloud[3]	8	Osceola	IC	NG	PL	DFO	TK	5	04/1977	11/2004	6 000	6 000	6 000	6 000

1 OUC ownership share
2 Reliability exchange divides 50% power from Unit 1 and 50% power from Unit 2
3. St Cloud Unit 8 has never been connected to the grid and therefore is not included in the summation of existing generating capacity

Table 11-2 (Schedule 2.1).
OUC and St. Cloud History and Forecast of Energy Consumption and Number of Customers by Customer Class[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					General Service Non-Demand		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
1994	312,400	2.59	1,454	120,813	12,035	335	15,678	21,368
1995	315,900	2.56	1,560	123,351	12,647	335	15,953	20,999
1996	321,600	2.56	1,609	125,617	12,809	336	16,221	20,714
1997	330,000	2.55	1,568	129,433	12,114	341	16,416	20,772
1998	341,000	2.55	1,804	133,732	13,490	331	16,597	19,943
1999	351,400	2.55	1,725	137,815	12,517	330	17,066	19,337
2000	362,000	2.56	1,821	141,546	12,865	318	17,172	18,519
2001	372,200	2.55	1,893	145,762	12,987	316	17,281	18,286
2002	383,200	2.55	1,973	150,365	13,121	314	17,681	17,759
2003	391,500	2.54	2,033	153,841	13,215	297	17,993	16,506
Forecast								
2004	403,200	2.54	2,079	158,462	13,120	320	17,187	18,619
2005	413,400	2.54	2,146	162,451	13,210	324	17,519	18,494
2006	422,200	2.54	2,208	165,977	13,303	328	17,674	18,558
2007	431,800	2.54	2,271	169,752	13,378	331	17,869	18,524
2008	442,000	2.54	2,337	173,816	13,445	336	18,087	18,577
2009	453,600	2.54	2,411	178,319	13,521	341	18,347	18,586
2010	465,600	2.54	2,490	183,087	13,600	345	18,636	18,513
2011	478,100	2.54	2,574	188,044	13,688	350	18,976	18,444
2012	490,400	2.54	2,657	192,876	13,776	355	19,374	18,324
2013	503,000	2.54	2,745	197,829	13,876	360	19,705	18,269

1. Historical and forecast data includes both OUC and the City of St. Cloud.

Table 11-3 (Schedule 2.2).
OUC and St. Cloud History and Forecast of Energy Consumption and Number of Customers by Customer Class[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	General Service Demand			Railroads and Railways	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
Year	GWh	Average No. of Customers	Average kWh Consumption per Customer				
1994	2,185	2,872	760,794	0	24	5	4,003
1995	2,263	3,072	736,654	0	24	5	4,187
1996	2,321	3,245	715,254	0	26	5	4,297
1997	2,399	3,597	666,945	0	26	5	4,339
1998	2,569	3,956	649,393	0	25	5	4,734
1999	2,725	4,078	668,220	0	28	5	4,813
2000	2,859	4,418	647,199	0	28	6	5,032
2001	2,967	4,774	621,557	0	31	6	5,213
2002	3,031	4,981	608,512	0	40	6	5,364
2003	3,136	5,413	579,346	0	37	6	5,509
Forecast							
2004	3,236	5,258	615,443	0	38	6	5,679
2005	3,333	5,401	617,108	0	41	6	5,850
2006	3,427	5,514	621,509	0	45	6	6,014
2007	3,526	5,633	625,954	0	48	6	6,182
2008	3,641	5,754	632,777	0	51	6	6,371
2009	3,770	5,882	640,938	0	55	6	6,583
2010	3,879	6,015	644,888	0	58	6	6,778
2011	4,001	6,155	650,041	0	62	6	6,993
2012	4,133	6,301	655,928	0	66	6	7,217
2013	4,253	6,436	660,814	0	70	6	7,434

1. Historical and forecast data includes both OUC and the City of St. Cloud.

Table 11-4 (Schedule 2.3).
OUC and St. Cloud History and Forecast of Energy Consumption and Number of Customers by Customer Class[1]

(1) Year	(2) Sales for Resale[2] GWh	(3) Utility Use & Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers (Average No.)	(6) Total No. of Customers[3]
1994	0	141	4,144	0	139,363
1995	0	188	4,375	0	142,376
1996	0	174	4,471	0	145,083
1997	0	226	4,565	0	149,446
1998	0	175	4,909	0	154,285
1999	0	198	5,011	0	158,959
2000	0	259	5,291	0	163,135
2001	969	191	6,373	0	167,817
2002	821	211	6,396	0	173,027
2003	920	253	6,682	0	177,247
Forecast	0				
2004	706	250	6,635	0	180,907
2005	703	258	6,811	0	185,371
2006	24	264	6,302	0	189,165
2007	0	273	6,455	0	193,254
2008	0	282	6,653	0	197,657
2009	0	291	6,874	0	202,548
2010	0	301	7,079	0	207,738
2011	0	311	7,304	0	213,175
2012	0	319	7,536	0	218,551
2013	0	329	7,763	0	223,970

1. Historical and forecast data includes both OUC and the City of St. Cloud.
2. To maintain consistency with the FRCC Forms, the "Sales for Resale" forecast includes OUC's forecast GWh sales to FMPA, KUA, SEC, and RCID. Historical "Sales for Resale" includes GWh sales to FMPA, KUA, SEC, and RCID for 2001, 2002, and 2003, as in the FERC forms.
3. Total No. of Customers includes aggregate of Rural & Residential, General Service Non-Demand, and General Service Demand.

Table 11-5 (Schedule 3.1).
OUC and St. Cloud History and Forecast of Summer Peak Demand (Base Case)[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Residential	Commercial/Industrial		
Year	Total[2]	Wholesale[3]	Retail	Interruptible	Load Management	Load Management	Conservation	Net Firm Demand
1994	808	0	808	0	0	0	0	808
1995	862	0	862	0	0	0	0	862
1996	852	0	852	0	0	0	0	852
1997	917	0	917	0	0	0	0	917
1998	988	0	988	1	0	0	0	987
1999	1,055	0	1,055	0	0	0	0	1,055
2000	1,026	0	1,026	1	0	0	0	1,025
2001	1,382	341	1,041	1	0	0	0	1,381
2002	1,408	319	1,089	1	0	0	0	1,407
2003	1,381	303	1,078	1	0	0	0	1,380
Forecast								
2004	1,359	166	1,193	1	0	0	0	1,358
2005	1,384	156	1,228	1	0	0	0	1,383
2006	1,283	22	1,261	1	0	0	0	1,282
2007	1,296	0	1,296	1	0	0	0	1,295
2008	1,335	0	1,335	1	0	0	0	1,334
2009	1,377	0	1,377	1	0	0	0	1,376
2010	1,418	0	1,418	1	0	0	0	1,417
2011	1,464	0	1,464	1	0	0	0	1,463
2012	1,509	0	1,509	1	0	0	0	1,508
2013	1,554	0	1,554	1	0	0	0	1,553

1. Historical data includes both OUC and the City of St. Cloud for 1994 and beyond. Forecast data includes both OUC and the City of St. Cloud.
2. Includes conservation.
3. To maintain consistency with the FRCC Forms, the "Wholesale" forecast includes OUC's forecast MW sales to FMPA, KUA, SEC, and RCID. Historical "Wholesale" includes MW sales to FMPA, KUA, SEC, and RCID for 2001, 2002, and 2003, as in the FRCC forms.

Table 11–6 (Schedule 3.2).
OUC and St. Cloud History and Forecast of Winter Peak Demand (Base Case)[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Residential	Commercial/Industrial		
Year	Total[2]	Wholesale[3]	Retail	Interruptible	Load Management	Load Management	Conservation	Net Firm Demand
1993/94	731	0	731	0	0	0	0	731
1994/95	876	0	876	0	0	0	0	876
1995/96	969	0	969	0	0	0	0	969
1996/97	851	0	851	0	0	0	0	851
1997/98	814	0	814	1	0	0	0	813
1998/99	1,030	0	1,030	1	0	0	0	1,029
1999/00	1,060	0	1,060	1	0	0	0	1,059
2000/01	1,066	0	1,066	1	0	0	0	1,065
2001/02	1,345	302	1,044	1	0	0	0	1,345
2002/03	1,414	277	1,137	1	0	0	0	1,413
2003/04	1,420	241	1,178	1	0	0	0	1,419
Forecast								
2004/05	1,364	145	1,219	1	0	0	0	1,363
2005/06	1,366	110	1,256	1	0	0	0	1,365
2006/07	1,318	22	1,296	1	0	0	0	1,317
2007/08	1,339	0	1,339	1	0	0	0	1,338
2008/09	1,386	0	1,386	1	0	0	0	1,385
2009/10	1,431	0	1,431	1	0	0	0	1,430
2010/11	1,478	0	1,478	1	0	0	0	1,477
2011/12	1,529	0	1,529	1	0	0	0	1,528
2012/13	1,579	0	1,579	1	0	0	0	1,578
2013/14	1,630	0	1,630	1	0	0	0	1,629

1. Historical data includes both OUC and the City of St. Cloud for 1993/94 and beyond. Forecast data includes both OUC and the City of St. Cloud.
2. Includes conservation.
3. To maintain consistency with the FRCC Forms, the "Wholesale" forecast includes OUC's forecast MW sales to FMPA, KUA, SEC, and RCID. Historical "Wholesale" includes MW sales to FMPA, KUA, SEC, and RCID for 2001/02, 2002/03, and 2003/04, as in the FERC forms.

Table 11–7 (Schedule 3.3).
OUC and St. Cloud History and Forecast of Annual Net Energy for Load – GWH (Base Case)[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	Total[2]	Conservation	Retail	Wholesale[3]	Utility Use & Losses	Net Energy for Load	Load Factor[4] (%)
1994	4,144	0	4,003	0	141	4,144	58.5
1995	4,375	0	4,187	0	188	4,375	57.9
1996	4,471	0	4,297	0	174	4,471	59.9
1997	4,565	0	4,339	0	226	4,565	56.8
1998	4,909	0	4,734	0	175	4,909	56.8
1999	5,011	0	4,813	0	198	5,011	54.2
2000	5,291	0	5,032	0	259	5,291	58.9
2001	6,373	0	5,213	969	191	6,373	52.7
2002	6,396	0	5,364	821	211	6,396	58.5
2003	6,682	0	5,509	920	253	6,682	55.2
Forecast			-		-		
2004	6,635	0	5,679	706	250	6,635	55.8
2005	6,811	0	5,850	703	258	6,811	56.2
2006	6,302	0	6,014	24	264	6,302	56.1
2007	6,455	0	6,182	0	273	6,455	56.9
2008	6,653	0	6,371	0	282	6,653	56.9
2009	6,874	0	6,583	0	291	6,874	57.0
2010	7,079	0	6,778	0	301	7,079	57.0
2011	7,304	0	6,993	0	311	7,304	57.0
2012	7,536	0	7,217	0	319	7,536	57.0
2013	7,763	0	7,434	0	329	7,763	57.1

1. Historical data includes both OUC and the City of St. Cloud for 1994 and beyond. Forecast data includes both OUC and the City of St. Cloud.
2. Includes conservation.
3. To maintain consistency with the FRCC Forms, the "Wholesale" forecast includes OUC's forecast GWh sales to FMPA, KUA, SEC, and RCID. Historical "Wholesale" includes MW sales to FMPA, KUA, SEC, and RCID for 2001 and 2002, as in the FERC forms.
4. Forecast load factor calculation considers all retail and wholesale peak demand and energy.

Table 10-7 (Schedule 4).
OUC and St. Cloud Previous Year and Two Year Forecast of Retail Peak Demand and Net Energy for Load by Month[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Month	Actual – 2003		2004 Forecast		2005 Forecast	
	Peak Demand[2] MW	NEL GWh	Peak Demand[2] MW	NEL GWh	Peak Demand[2] MW	NEL GWh
January	1,421	545	1,394	499	1,337	514
February	1,039	435	1,113	448	1,103	474
March	1,211	510	1,105	512	1,035	523
April	1,180	499	1,170	516	1,088	517
May	1,304	635	1,285	585	1,222	597
June	1,353	601	1,255	599	1,264	613
July	1,373	665	1,357	669	1,383	686
August	1,336	639	1,310	669	1,319	684
September	1,282	611	1,215	590	1,222	603
October	1,223	550	1,132	537	1,142	556
November	1,164	488	1,059	496	1,064	511
December	1,152	503	1,105	515	1,112	532

1. Includes OUC and City of St. Cloud peak demand and NEL as well as wholesale sales to FMPA, KUA, SEC, and RCID (MW and NEL) for historical 2003 and forecast 2004 and 2005. Forecast 2004 and 2005 also includes OUC wholesale sales to FMPA, KUA, SEC, and RCID.
2. Includes Load Management, Conservation and Interruptible Load.

**Table 11-9 (Schedule 5).
Fuel Requirements[1]**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		Units	Actual 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Nuclear		Trillion BTU	5	5	5	5	5	5	5	5	5	5	5
(2)	Coal		1000 Ton	1,997	1,866	1,992	1,951	1,998	1,999	1,928	2,009	2,135	2,165	2,172
(3)	Residual[2]	Total	1000 BBL	10	4	3	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	10	0	0	0	0	0	0	0	0	0	0
(7)	Distillate[3]	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)		Steam	1000 BBL	20	0	0	0	0	0	0	0	0	0	0
(9)		CC	1000 BBL	3	0	0	0	0	50	144	74	185	313	427
(10)		CT	1000 BBL	23	0	0	0	0	0	0	0	0	0	0
(11)	Natural Gas	Total	1000 MCF	61	19	13	5	5	5	9	9	10	12	0
(12)		Steam	1000 MCF	4,354	12,878	11,932	8,943	8,934	10,461	12,338	12,972	11,381	11,647	12,812
(13)		CC	1000 MCF	203	0	56	502	797	371	864	586	1,194	1,552	2,091
(14)		CT	1000 MCF	4,606	12,897	12,001	9,450	9,736	10,838	13,210	13,568	12,585	13,211	14,904
(15)	Other		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0

1. Includes fuel required for OUC and the City of St. Cloud.
2. Residual includes #4, #5 and #6 oil.
3. Distillate includes #1, #2 oil, kerosene, jet fuel and amounts used at coal burning plants for flame stabilization and on start up.

Table 11-10 (Schedule 6.1).
Energy Sources (GWH)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Annual Firm Inter-region Interchange		GWH	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWH	536	469	501	489	471	501	489	471	483	489	489
(3)	Residual	Total	GWH	0	28	18	0	0	0	0	0	0	0	0
(4)		Steam	GWH	0	28	18	0	0	0	0	0	0	0	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)	Distillate	Total	GWH	15	0	0	0	0	0	0	0	0	0	0
(8)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	GWH	1	0	0	0	0	26	74	38	95	161	221
(10)		CT	GWH	15	0	0	0	0	0	0	0	0	0	0
(12)	Natural Gas	Total	GWH	441	1,742	1,610	1,237	1,258	1,427	1,739	1,807	1,647	1,716	1,908
(12)		Steam	GWH	0	19	13	5	5	5	9	9	10	12	0
(13)		CC	GWH	425	1,724	1,592	1,190	1,185	1,392	1,660	1,752	1,542	1,583	1,744
(14)		CT	GWH	16	0	5	42	68	30	70	46	95	122	163
(15)	Coal	Steam	GWH	5,218	4,396	4,681	4,572	4,698	4,697	4,569	4,764	5,079	5,168	5,144
(16)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0
(17)	Hydro		GWH	0	0	0	0	0	0	0	0	0	0	0
(18)	Other	Purchases	GWH	0	0	0	0	0	0	0	0	0	0	0
		Sales	GWH	0	0	0	0	0	0	0	0	0	0	0
		Total	GWH	0	0	0	0	0	0	0	0	0	0	0
(19)	Net Energy for Load[1]		GWH	6,666	8,378	8,420	7,539	7,714	8,080	8,613	8,886	8,951	9,252	9,671

1. Variation in Net Energy for Load between Schedule 3.3 and Schedule 6.1 can be attributed to rounding error.

Table 11-11 (Schedule 6.2).
Energy Sources (%)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Annual Firm Inter-region Interchange		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(2)	Nuclear		GWH	8.04%	5.60%	5.95%	6.49%	6.11%	6.20%	5.68%	5.30%	5.39%	5.29%	5.06%
(3)	Residual	Total	GWH	0.00%	0.34%	0.21%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(4)		Steam	GWH	0.00%	0.34%	0.21%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(6)		CT	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)	Distillate	Total	GWH	0.23%	0.00%	0.00%	0.00%	0.00%	0.32%	0.86%	0.42%	1.06%	1.74%	2.28%
(8)		Steam	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	GWH	0.21%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	GWH	0.02%	0.00%	0.00%	0.00%	0.00%	0.32%	0.86%	0.42%	1.06%	1.74%	2.28%
(12)	Natural Gas	Total	GWH	6.62%	20.80%	19.12%	16.41%	16.31%	17.66%	20.19%	20.33%	18.40%	18.55%	19.73%
(12)		Steam	GWH	0.00%	0.22%	0.16%	0.06%	0.06%	0.06%	0.11%	0.10%	0.12%	0.12%	0.00%
(13)		CC	GWH	6.38%	20.57%	18.90%	15.79%	15.37%	17.23%	19.28%	19.72%	17.23%	17.11%	18.04%
(14)		CT	GWH	0.24%	0.00%	0.06%	0.56%	0.88%	0.37%	0.81%	0.51%	1.06%	1.32%	1.69%
(15)	Coal	Steam	GWH	78.28%	52.47%	55.59%	60.64%	60.90%	58.13%	53.05%	53.61%	56.74%	55.86%	53.19%
(16)	NUG		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(17)	Hydro		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(18)	Other	Purchases	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Sales	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Total	GWH	0.00%	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		GWH	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Table 11-12 (Schedule 7.1).
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity[1]	Firm Capacity Import[2]	Firm Capacity Export[3]	QF	Total Capacity Available	System Firm Peak Demand[4]	Reserve Margin Before Maintenance[5,6]		Scheduled Maintenance	Reserve Margin After Maintenance[5,6]	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2004	1,215	827	166	0	1,876	1,192	492	53%	0	492	53%
2005	1,215	627	156	0	1,998	1,227	260	34%	0	260	34%
2006	1,215	327	22	0	1,564	1,260	73	20%	0	73	20%
2007	1,215	327	0	0	1,542	1,295	33	18%	0	33	18%
2008	1,193	327	0	0	1,616	1,334	128	25%	0	128	25%
2009	1,333	287	0	0	1,520	1,376	40	18%	0	40	18%
2010	1,333	247	0	0	1,580	1,417	92	22%	0	92	22%
2011	1,473	207	0	0	1,680	1,463	0	15%	0	0	15%
2012	1,613	167	0	0	1,780	1,508	48	18%	0	48	18%
2013	1,753	152	0	0	1,905	1,553	119	23%	0	119	23%

1. Installed capacity includes the City of St. Cloud's generating units, which are scheduled to retire in October, 2006.
2. Firm capacity imports include capacity purchased from Reliant (Indian River units), capacity purchased from TECO, and capacity purchased from Southern-Florida (from Stanton A).
3. Firm capacity export includes all forecast sales to FMPA, SEC, and RCID.
4. Includes OUC peak demand and City of St. Cloud peak demand.
5. Assumes TECO purchase (15 MW) includes reserves and that OUC must include reserves to meet its retail peak demand and the City of St. Cloud's retail peak demand. Additionally, OUC must supply reserves along with the capacity sold to RCID.
6. Reserve margin percentages are calculated as the sum of installed capacity and firm capacity import (plus an additional 15% of the TECO purchase) minus the sum of OUC peak demand, St. Cloud peak demand, and firm capacity export, all divided by the sum of the forecast OUC peak demand, St. Cloud peak demand, and RCID peak demand.

Table 10-13 (Schedule 7.2).
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity[1]	Firm Capacity Import[2]	Firm Capacity Export[3]	QF	Total Capacity Available	System Firm Peak Demand[4]	Reserve Margin Before Maintenance[5,6]		Scheduled Maintenance	Reserve Margin After Maintenance[5,6]	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2004/05	1,276	656	119	0	1,813	1,363	403	46%	0	403	46%
2005/06	1,276	356	110	0	1,522	1,365	69	20%	0	69	20%
2006/07	1,255	356	0	0	1,581	1,317	124	25%	0	124	25%
2007/08	1,255	356	0	0	1,581	1,338	74	21%	0	74	21%
2008/09	1,430	316	0	0	1,746	1,385	155	26%	0	155	26%
2009/10	1,430	276	0	0	1,706	1,430	64	19%	0	64	19%
2010/11	1,605	236	0	0	1,841	1,477	145	25%	0	145	25%
2011/12	1,605	196	0	0	1,801	1,528	46	18%	0	46	18%
2012/13	1,780	196	0	0	1,976	1,578	163	25%	0	163	25%
2013/14	1,955	181	0	0	3,126	1,629	263	31%	0	263	31%

1. Installed capacity includes the City of St. Cloud's generating units, which are scheduled to retire in October, 2006.
2. Firm capacity imports include capacity purchased from Reliant (Indian River units), capacity purchased from TECO, and capacity purchased from Southern-Florida (from Stanton A).
3. Firm capacity export includes all forecast sales to FMPA, KUA, SEC, and RCID.
4. Includes OUC peak demand and City of St. Cloud peak demand.
5. Assumes TECO purchase (15 MW) includes reserves and that OUC must include reserves to meet its retail peak demand and the City of St. Cloud's retail peak demand. Additionally, OUC must supply reserves along with the capacity sold to RCID.
6. Reserve margin percentages are calculated as the sum of installed capacity and firm capacity import (plus an additional 15% of the TECO purchase) minus the sum of OUC peak demand, St. Cloud peak demand, and firm capacity export, all divided by the sum of the forecast OUC peak demand, St. Cloud peak demand, and RCID peak demand.

Table 10-14 (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)
Plant Name	Unit No.	Location	Unit Type	Fuel		Fuel Transport		Construction Start	Commercial In-Service	Expected Retirement	Gross Capability[1]		Net Capability[1]		Status
				Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	Sum MW	Win MW	Sum MW	Win MW	
Stanton	UNK	Orange	GT	NG	PL	DFO	TK	3	6/2007	6/2008	148	184	140	175	P
Stanton	UNK	Orange	GT	NG	PL	DFO	TK	3	6/209	6/2010	148	184	140	175	P
Stanton	UNK	Orange	GT	NG	PL	DFO	TK	3	6/2011	6/2012	148	184	140	175	P
Stanton	UNK	Orange	GT	NG	PL	DFO	TK	3	6/2012	6/2013	148	184	140	175	P

Table 11-15 (Schedule 9).
Status Report and Specifications of Proposed Generation Facilities

(1)	**Plant Name and Unit Number:**	Combustion Turbine 1	Combustion Turbine 2	Combustion Turbine 3	Combustion Turbine 4
(2)	**Capacity**				
	a. Summer:	140 MW	140 MW	140 MW	140 MW
	b. Winter:	175 MW	175 MW	175 MW	175 MW
(3)	**Technology Type:**	GT	GT	GT	GT
(4)	**Anticipated Construction Timing**				
	a. Field construction start-date:	06//2007	06//2009	06//2011	06//2012
	b. Commercial in-service date:	06//2008	06//2010	06//2012	06//2013
(5)	**Fuel**				
	a. Primary fuel:	NG	NG	NG	NG
	b. Alternate fuel:	DFO	DFO	DFO	DFO
(6)	**Air Pollution Control Strategy**	Low NO_x burners	Low NO_x burners	Low NO_x burners	Low NO_x burners
(7)	**Cooling Method**	NA	NA	NA	NA
(8)	**Total Site Area**	NA[1]	NA[1]	NA[1]	NA[1]
(9)	**Construction Status**	P	P	P	P
(10)	**Certification Status**	NA	NA	NA	NA
(11)	**Status with Federal Agencies**	Not begun	Not begun	Not begun	Not begun
(12)	**Projected Unit Performance Data**				
	Planned Outage Factor (POF):	1.92	1.92	1.92	1.92
	Forced Outage Factor (FOF):	1.96	1.96	1.96	1.96
	Equivalent Availability Factor (EAF):	96.2	96.2	96.2	96.2
	Resulting Capacity Factor (%):	3.1	3.9	6.1	3.1
	Average Net Operating Heat Rate (ANOHR):	11.540 Btu/kWh	11.338 Btu/kWh	11.367 Btu/kWh	11.410 Btu/kWh
(13)	**Projected Unit Financial Data**				
	Book Life (Years):	20	20	20	20
	Total Installed Cost (In-Service Year $/kW):	315	331	347	356
	Direct Construction Cost ($/kW):	278	278	278	278
	AFUDC Amount ($/kW):	5	6	6	6
	Escalation ($/kW):	32	48	64	72
	Fixed O&M ($/kW-Yr)[2]:	5.69	5.69	5.69	5.69
	Variable O&M ($/MWH)[3]:	2.01	2.01	2.01	2 01
	K Factor:	1.1865	1.1865	1.1865	1.1865

1. Because no site has been finalized for the Combustion Turbines, the site area is unknown. However, should the units be constructed at the Stanton Energy Center, the total site area would be 3,280 acres.
2. O&M projections are indicated in 2004 dollars.