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Black & Veatch Corporation

March 28, 2002

Mr. Michael Haff
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee FL 32399-0688

020000-PU

Michael,

Enclosed please find twenty (20) copies of the 2002 Orlando Utilities Commission (OUC) Ten-Year Site Plan (TYSP). Per your request, the 2002 OUC TYSP has also been distributed directly to the following individuals:

Paul Darst
Department of Community Affairs

Buck Oven
Department of Environmental Protection

Doug Bailey
Fish and Wildlife Conservation Commission

Dr. David Block
Florida Solar Energy Center

Kris Davis
St. Johns River Water Management District

Greg Golgowski
East Central Florida Regional Planning Council

Anthony (Tony) Cotter
Orange County Government Florida

Should you require additional copies of the OUC 2002 TYSP, please do not hesitate to contact me at (913) 458-7432.

Very truly yours,

Myron Rollins

Myron Rollins

Enclosure[s]

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The *Reliable* One

2002 Ten-Year Site Plan

Orlando Utilities Commission

April 2002

2002 Ten-Year Site Plan

Orlando Utilities Commission

April 2002

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1.0 Executive Summary

This report documents the 2002 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. The Plan consists of 9 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, Results, and Conclusions (Section 8.0)
- Environmental and Land Use Information (Section 9.0)
- Ten-Year Site Plan Schedules (Section 10.0)

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), Kissimmee Utility Authority (KUA), and the Florida Municipal Power Agency (FMPA) All-Requirements Project. Power for OUC is supplied by OUC jointly owned generation and power purchases. The total installed generating capacity based on OUC's ownership share (including the generating units owned by the City of St. Cloud) is 1,092 MW winter and 1,047 MW summer as of January 1, 2002. The existing supply system has a broad range of generation technology and fuel diversity, with coal providing the largest portion of OUC's energy requirements.

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

Load forecasts for OUC and the City of St. Cloud have been integrated into one forecast and are provided. 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, indicates a need for additional capacity beginning in the summer of 2003. The load forecast was prepared prior to the events of September 11, 2001. Current indications are that actual loads will likely be less than those forecasted prior to September 11, 2001. These lower loads will likely eliminate the need for all or substantially all of the reserve capacity required for the summer of 2003.

Final site certification for Stanton A was issued September 18, 2001. Construction began in November 2001 on Stanton A, a 633 MW combined cycle unit to be built at Stanton Energy Center with an October 1, 2003 commercial operation date. Stanton A will be jointly owned by OUC, KUA, FMPA and Southern Company – Florida LLC (Southern-Florida) as follows:

- OUC 28 percent
- KUA 3.5 percent
- FMPA 3.5 percent
- Southern-Florida 65 percent

OUC, KUA, and FMPA will purchase all of Southern-Florida's capacity in 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.

Three alternative power plant technologies were considered for capacity additions in addition to the optional PPA from Reliant. 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 10-year 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.

Table 1-1
OUC Least-Cost Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2002	577.5 MW Reliant Power Purchase	$146,419	$146,419
2003	30 MW Unspecified Purchase* (06/01/2003 – 09/30/2003) Terminate 577.5 MW Reliant Power Purchase (09/30/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	$162,293	$296,691
2004	Start 100 MW Reliant Power Purchase (10/01/2004)	$192,800	$461,986
2005		$202,170	$622,476
2006	Terminate 100 MW Reliant Power Purchase (09/30/2006) 156 MW GE 7FA Simple Cycle CT (10/01/2006)	$211,193	$777,709
2007		$233,469	$936,604
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (11/01/2008)	$240,604	$1,088,225
2009		$260,426	$1,240,181
2010	40 MW Reduction in Southern-Florida Power Purchase (11/01/2010)	$265,064	$1,383,387
2011	40 MW Reduction in Southern-Florida Power Purchase (11/01/2011)	$252,994	**$1,509,947**

Note: Capacity is stated at average annual temperature for OUC.
* Available purchase power alternatives are discussed in Section 6.3.1. Lower loads resulting from the events of September 11, 2001 may actually eliminate the need for this purchase.

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, and 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 148,556 active services for 2001. Of these, 128,314 are residential services, 15,648 are general service non-demand services, and the remaining 4,594 are general service demand services. St. Cloud's service area consisted of a year-end average of 19,261 active services for 2001.

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.
- 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 Stanton 1 and 2 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 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.

The Indian River Plant is located 4 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. 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. The combustion turbine units are primarily fueled by natural gas, with No. 2 fuel oil as an

Table 2-1
Summary of OUC Generation Facilities

Plant Name	Unit No.	Location (County)	Unit Type	Fuel Pri	Fuel Alt	Fuel Transport Pri	Fuel Transport Alt	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max Nameplate MW	Net Capability[1] Summer MW	Net Capability[1] Winter MW
Indian River	A	Brevard	GT	NG	FO2	PL	TK	06/89	Unknown	41.400	18	23.4
Indian River	B	Brevard	GT	NG	FO2	PL	TK	07/89	Unknown	41.400	18	23.4
Indian River	C	Brevard	GT	NG	FO2	PL	TK	08/92	Unknown	122.040	85.3	100.3
Indian River	D	Brevard	GT	NG	FO2	PL	TK	10/92	Unknown	122.040	85.3	100.3
Stanton Energy Center	1	Orange	ST	BIT	---	RR	---	07/87	Unknown	464.580	301.6	303.7
Stanton Energy Center	2	Orange	ST	BIT	---	RR	---	06/96	Unknown	464.580	319.3	319.3
McIntosh	3	Polk	ST	BIT	REF	RR	TK	09/82	Unknown	363.870	133	136
Crystal River	3	Citrus	NP	UR	---	TK	---	03/77	Unknown	890.460	13	13
St. Lucie[2]	2	St. Lucie	NP	UR	---	TK	---	08/83	Unknown	839.000	51	52
St. Cloud[3]	1	Osceola	IC	NG	FO2	PL	TK	07/82	11/04	2.000	2	1.825
	2		IC	NG	FO2	PL	TK	12/74	11/04	5.850	5.85	5
	3		IC	NG	FO2	PL	TK	09/82	11/04	2.000	2	1.825
	4		IC	NG	FO2	PL	TK	08/61	11/04	3.750	3	3
	6		IC	NG	FO2	PL	TK	03/67	11/04	3.750	3	3
	7		IC	NG	FO2	PL	TK	09/82	11/04	6.300	6	6
	8		IC	NG	FO2	PL	TK	04/77	11/04	6.445	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 has never been connected to the grid and, therefore, OUC receives no capacity from this unit. St. Cloud owns the units, but OUC controls their operation.

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 the 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 fuel burning capability and also is capable of burning up to 20 percent petroleum coke. For purposes of the Ten-Year Site Plan analyses, it is assumed that McIntosh Unit 3 will burn coal identical to that used for Stanton 1 and 2. OUC has a 40 percent ownership share in this unit, 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 maintains 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, with a total summer rating of 27.85 MW. Unit 8 has never been connected to the grid, so the resulting net summer generating capacity from St. Cloud's internal combustion units is 21.85 MW.

OUC has entered into an agreement with KUA, FMPA, and Southern-Florida for the construction and ownership of Stanton A, a 633 MW combined cycle unit to be constructed at Stanton Energy Center with a planned commercial operation date of October 1, 2003. Final site certification for Stanton A was issued September 18, 2001, with construction commencing in November 2001. OUC, KUA, FMPA will be joint owners of Stanton A as follows:

OUC	28 percent
KUA	3.5 percent
FMPA	3.5 percent
Southern-Florida	65 percent

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. 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.

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

2.3 Purchase Power Resources

As part of the sale of 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 extends from October 1, 2001, through September 30, 2003. OUC also has an option to extend the Reliant Agreement an additional 4 years. 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. The capacities from the Power Purchase Agreements are summarized in Table 2-2. The capacity from the Reliant Agreement shown in Table 2-2 from October 1, 2001, through September 30, 2003, is 525 MW, but has an option for an additional 10 percent capacity. Thus, the capacity shown in Table 2-2 is the maximum available.

The maximum capacity available should OUC exercise its additional 4-year option with Reliant is 500 MW per year. The 500 MW can be reduced in 100 MW increments annually over the duration of the 4-year option term through proper notice from OUC, but cannot increase from the previous year. The cost of the capacity and energy is 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.

Table 2-2
Power Purchase Agreements

Company	Capacity	Duration
TECO PR	15 MW	Through 12/31/2012
Reliant	577.5 MW	10/01/2001 - 09/30/2003

As shown in Table 2-3, OUC is also planning to purchase KUA's excess capacity from KUA's entitlement in Stanton A during the first 3 years of the unit's commercial operation.

Table 2-3 Excess KUA Entitlement Purchased By OUC	
Period	MW[1]
10/1/2003 - 9/30/2004	40
10/1/2004 - 9/30/2005	24
10/1/2005 - 9/30/2006	10
[1]Source: Stanton Energy Center Unit A Need for Power Application.	

2.4 Power Sales Contracts

OUC is contractually obligated to supply power to a number of different purchasers for various durations of time. These power sales contracts are classified as either unit power sales or system power sales.

2.4.1 Unit Power Sales.

OUC has two separate unit power sales contracts in place with FMPA. The first of these contracts has been in place since May 1, 1986, and 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. The second such contract with FMPA has been in place since January 1, 1989, and is scheduled to expire December 31, 2003. This contract is based on providing power from the highest fuel cost unit operating on OUC's system at the time that energy is scheduled.

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.

2.4.2 System Power Sales.

OUC has had a system power sales contract in place with KUA since January 1, 1989, which will expire December 31, 2003. In addition, OUC has been involved in a partial requirements power sales contract with Reedy Creek Improvement District (RCID) since January 1, 1999. The contract is scheduled to expire December 31, 2005, but has an option for extension through 2010. For evaluation purposes, the contract is assumed to extend through December 31, 2010.

2.5 Transmission System

OUC's existing transmission system consists of 26 substations interconnected through approximately 302 miles of 230 kV and 115 kV lines and cables. OUC is fully integrated into the state transmission grid through its thirteen 230 kV interconnections with other generating utilities that are members of the Florida Reliability Coordinating Council (FRCC) as summarized in Table 2-4. OUC's service area and transmission system are shown in Figure 2-1.

Table 2-4
OUC Transmission Interconnections

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

FPL - Florida Power & Light
FPC - Florida Power Corporation
KUA - Kissimmee Utility Authority
TECO - Tampa Electric Company
RCID - Reedy Creek Improvement District
FMPA - Florida Municipal Power Agency

Additionally, OUC is now responsible for approximately 50 miles of St. Cloud's transmission system, including the 69 kV interconnection from St. Cloud's Central Substation to KUA's Carl Wall Substation, and a 230 kV interconnection from St. Cloud's East Substation to Florida Power Corporation's (FPC) Holopaw Substation.

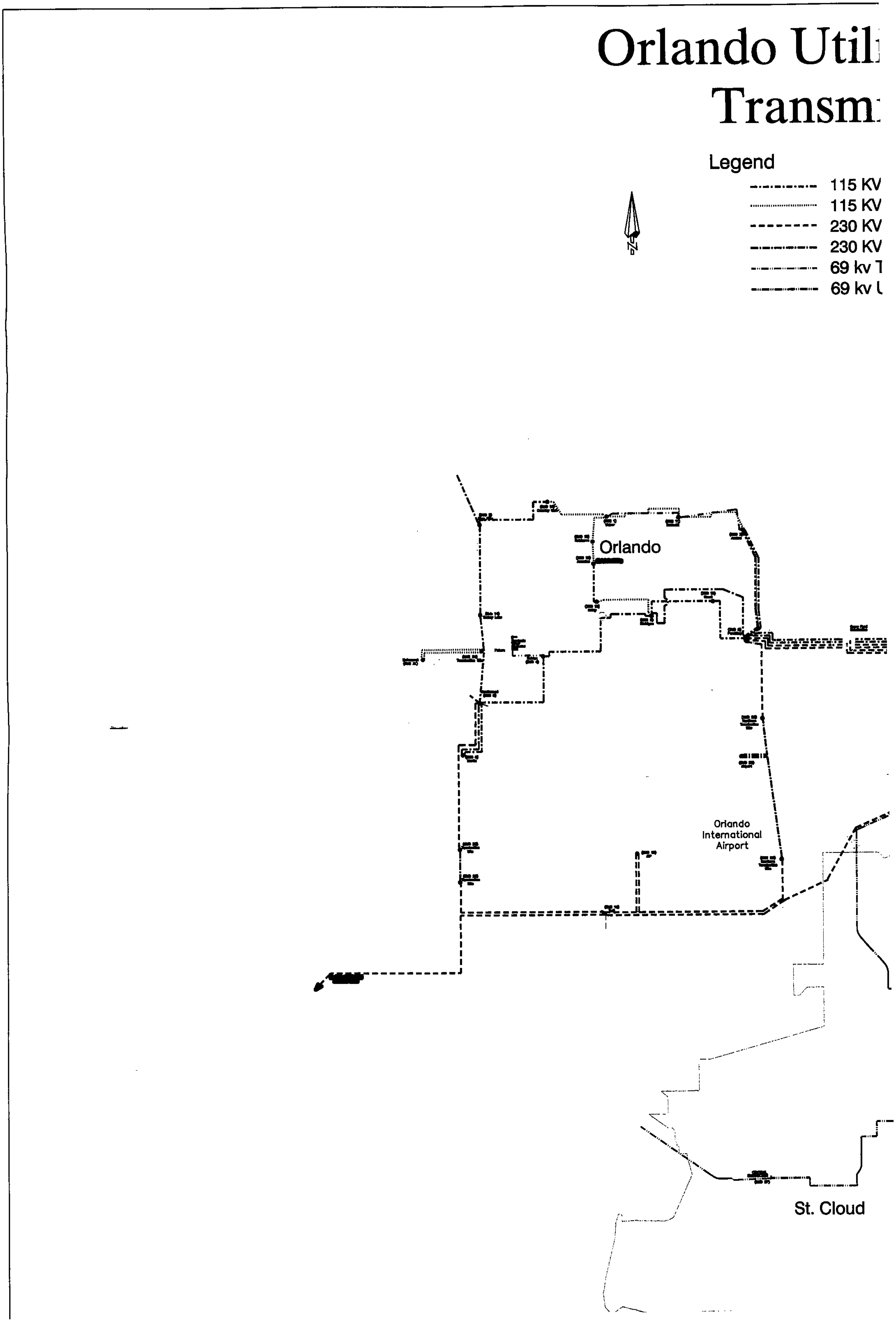
OUC has developed the following schedule of upgrades to maintain reliable and economic service:

- Addition of the Grant to Robinson 115 kV transmission line. Expected completion date is in October 2002.
- 69KV interconnection with FPC at their Magnolia Ranch substation in June 2002.
- Addition of circuit breakers on the Stanton 230KV bus effectively splitting the bus and providing available fault current and line loading relief. Completion will be prior to Stanton A coming on-line.
- 230KV interconnection with FPC at OUC's Metrowest substation in spring of 2004.

- Upgrade the 69 kV line from KUA to the City of St. Cloud. Expected completion date has yet to be determined.

2.6 Service Area

OUC's service area encompasses approximately 394 square miles. This estimate includes the City of St. Cloud service area, which is served under a partnership formed in 1997. This 25-year agreement is precedent setting, as OUC has become the first municipal electric utility in the state to manage, operate, and maintain another municipal utility.



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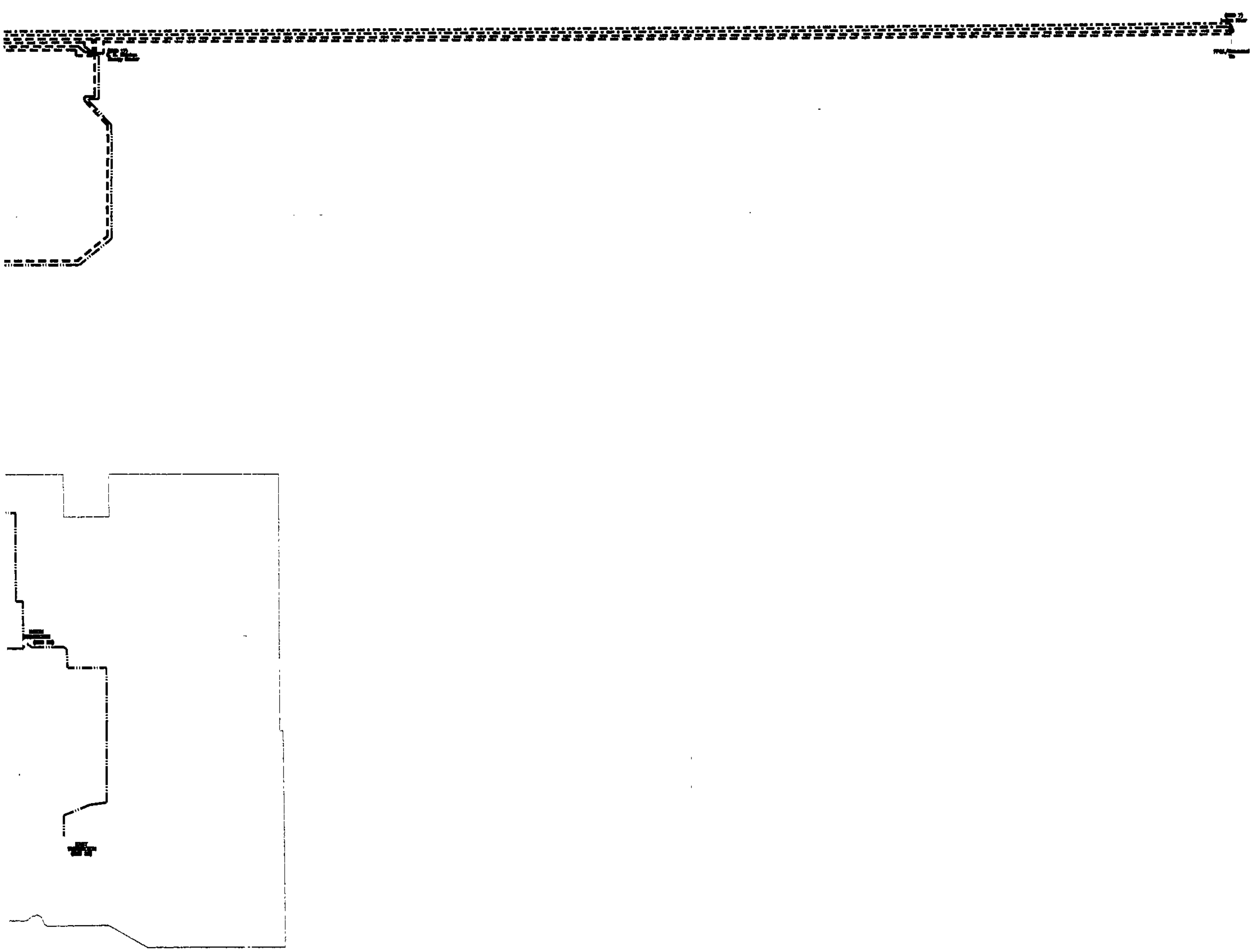

3.0 Strategic Issues

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 is to reorganize OUC into the following strategic business units, which are described below.

- Power Resource Business Unit
- 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 their generating assets, such as the sale of the Indian River Steam Units and the addition of new units and power purchase agreements.

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.

Table 3-1
Generation Capacity Owned by OUC by Fuel Type (MW)

	Winter Capacity				Summer Capacity			
Plant Name	Coal	Nuclear	Gas/Oil	Total	Coal	Nuclear	Gas/Oil	Total
Stanton	623			623	621			621
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	247	1,071	754	64	207	1,025
Total (percent)	70.87	6.07	23.06	100	73.56	6.24	20.20	100

Coal represents more than 70 percent of OUC's capacity. 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 on Schedule 1 of Section 10.

Another example of OUC's commitment to fuel diversity is the use of alternative fuels, such as refuse derived fuel (RDF) at the McIntosh Unit 3 facility. The plant is designed to burn a mixture of RDF and coal. 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 and RDF. 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 is 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.

Based on the reliability reports filed with the Florida Public Service Commission (FPSC) for the investor owned utilities in the state, during 2001, the OUC and St. Cloud service areas experienced the best reliability in the State of Florida. OUC has an excellent record for the time it takes to restore outages, a measure of reliability required by the FPSC to be reported on a calendar year basis. The average time to restore outages has been reduced from 62 minutes in 1999 to 59 minutes in 2000 to 58 minutes in 2001. The average time for OUC to restore outages during these years has been considerably less than that for investor owned utilities in the State of Florida.

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. Through a four-year PPA, Indian River steam generation units will continue to provide power to OUC 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 offers 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.

OUC continues to evaluate the repositioning of its assets. OUC is currently evaluating the sale of the Indian River Combustion Turbine Units A – D and the replacement of the capacity with a combination of purchase power and new combustion turbines. If these evaluations are favorable, OUC will likely move forward with this repositioning scenario.

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 interconnections with other Florida utilities, including six interconnections with Florida Power Corporation (FPC), three with Kissimmee Utility Authority (KUA), and one each with Florida Power and Light (FPL), Tampa Electric Company (TECO), Reedy Creek Improvement District (RCID), and Lakeland Electric. In addition to enhancing reliability, these interconnections also facilitate the marketing of electric energy by OUC to and from other electric utilities in Florida. Through its agreement with St. Cloud, OUC is also now responsible for St. Cloud's 230 kV interconnection to FPC and 69 kV interconnection to KUA.

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.

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. Each day, the methane gas burned at Stanton provides enough electricity for 10,000 homes while reducing methane gas emissions from the landfill. The methane gas displaces more than 3 percent of the coal required for either Stanton Unit 1 or Stanton Unit 2, saving OUC about $1.25 million a year in fuel costs.

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.

Each year, OUC lends a helping hand to charities and civic organizations across Central Florida. In its quest to make a difference, OUC supports the Heart of Florida United Way, United Arts, March of Dimes, Orlando Humane Society, Orlando/UCF Shakespeare Festival, Salvation Army, and Second Harvest Food Bank, among many others. OUC employees routinely volunteer their valuable free time to participate in such fundraisers as the Junior Achievement Bowl-A-Thon and the American Cancer Society's Relay for Life.

OUC is also a major sponsor of Habitat for Humanity, the Minority/Women Business Enterprise Alliance, Inc., and the Foundations for Education in both Orange and Osceola counties.

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.

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 the 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. It should be noted that the forecasts of peak demand and energy consumption were developed prior to September 11, 2001. The events of September 11, 2001 may lead to an overall decrease in the forecasts of peak demand and energy consumption presented in this Section and used throughout the 2002 OUC Ten-Year Site Plan.

4.1 Forecast Methodology

There are two primary forecasting approaches used in forecasting electricity requirements - econometric-based modeling (such as linear regression) or 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 two equations – an average use per household model, and a customer forecast model. Monthly average use models are estimated over the period 1992 to 2000. This provides 9 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 0.998 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 0.57 with an in-sample MAPE of 4.7 percent. Given that St. Cloud is a relatively small part of OUC's service territory, the 4.7 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 1,100 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 is 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 0.94 with an in-sample MAPE of less than 4 percent. The standard error of the regression model is 48.75 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 0.93 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 October 1990 through 2000. For OUC, the overall model adjusted R^2 is 0.995 with an in-sample MAPE of 0.21 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 0.67, with an in-sample MAPE of 4.63 percent. An AR1 and AR2 correction were 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:

$$CoolUse = (Price\char`^-.20)*(Output\ per\ Employee\char`^.20)*(CDD)$$
$$HeatUse = (Price\char`^-.20)*(Output\ per\ Employee\char`^.20)*(HDD)$$
$$OtherUse = (Price\char`^-.20)*(Output\ per\ Employee\char`^.20)$$

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 3.1 percent. For St. Cloud the GSND average use model has an adjusted R^2 of 0.89, with an in-sample MAPE of 4.5 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:

$$\text{GSD Sales}_t = f(\text{BaseUse}_t, \text{CoolUse}_t, \text{and HeatUse}_t)$$

Where

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

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 0.93 with an in-sample MAPE of 2.8 percent. In the St. Cloud model, all the variables except the heating end-use variables are highly significant. The adjusted R^2 is 0.84 with a MAPE of 4.7 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, and the continued expansion at Universal Studios.

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 7 years. The forecast also includes sales from a new OUC program called 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 1992 to December 2000. 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 1 or 2 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 Regional Financial Associates (RFA), which is now doing business under the name Economy.com, and the University of Florida. RFA'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. RFA employment forecasts were used through 2005, with employment growth over this period consistent with the University of Florida's outlook. After 2005, RFA projects regional employment and output growth that continues to exceed RFA's Florida forecast and are somewhat more optimistic than the University of Florida. For the longer term (after 2005 to 2011), employment is assumed to continue to grow at the more conservative state growth rate forecasted by RFA. 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. RFA's projections for the Orlando MSA were used through 2005. Between 2005 and 2011 the number of households and real income are assumed to grow at the slower state rate. Household projections are then calculated by dividing population projections by household size (number of household members) projections. Table 4-2 shows annual the population, household, and real income forecasts.

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. For the first 5 years of the forecast (2000 to 2005) no increases in nominal rates are assumed, thus real prices continue to trend downward. After 2005, real prices are assumed constant. The average annual price series is provided in Table 4-3.

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

Year	Retail	Wholesale	Services	Financial Services	Government	Gross Product (Billion Real $)
1995	139.4	38.6	288.2	42.2	79.6	37.5
1996	146.7	41.3	304.4	44.5	81.6	39.6
1997	154.2	44.3	329.7	46.0	83.9	42.7
1998	159.6	45.9	352.4	49.7	86.7	46.4
1999	166.7	48.6	371.6	58.0	89.2	50.1
2000	175.2	51.5	396.6	61.7	92.0	53.1
2005	186.4	57.5	468.7	69.0	98.9	64.4
2011	203.6	66.6	574.3	78.2	107.5	79.5
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	7.8
1998	3.5	3.6	6.9	8.0	3.3	8.6
1999	4.4	5.9	5.5	16.7	2.9	8.0
00-05	1.3	2.2	3.4	2.2	1.5	3.9
05-11	1.5	2.5	3.4	2.1	1.4	3.6

Table 4-2
Population, Household, and Income Projections

Year	Real Income per HH	Households (Thousands)	Population (Thousands)
1992	56,270	491	1,307
1993	57,309	499	1,338
1994	58,187	508	1,367
1995	59,552	520	1,394
1996	61,005	534	1,428
1997	62,974	551	1,469
1998	65,772	567	1,507
1999	68,061	580	1,539
2000	69,212	592	1,570
2005	74,411	656	1,733
2011	79,467	742	1,945
Change	Percent	Percent	Percent
1993	1.9	1.6	2.4
1994	1.5	1.8	2.2
1995	2.4	2.4	2.0
1996	2.4	2.7	2.4
1997	3.2	3.2	2.9
1998	4.4	2.9	2.6
1999	3.5	2.3	2.1
00-05	1.5	2.1	2.0
05-11	1.1	2.1	1.9

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	5.2
2011	5.2
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	-0.4
05-11	0.0

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 2002, with a long-term annual forecast through 2011. 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, 20-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 1991 through 2000. 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 1992 to December 1999. 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.

The Orlando area has seen some of the strongest economic growth in the nation. RFA ranked Orlando as number 16 (out of 321 MSAs) in terms of current and expected employment growth. RFA projects continued strong growth for the region well into the next decade.

Between 1995 and 2000, population has grown at an average annual rate of 2.4 percent and real gross output has grown at 7.2 percent. Orlando's economic growth has consistently exceeded economic growth in both the state and nation. Florida, over the same period, experienced population and gross output growth of 2.2 percent and 6.9 percent, respectively. Orlando is expected to exceed overall state economic growth throughout the next 10 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 42 percent of total employment. Hotels and tourism-related activities, as well as call-centers, have continued to grow. OUC is also seeing increasing interest in establishing internet-support and switching centers.

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	1,232	1,216	6,176
2011	1,416	1,398	7,142
Change	Percent	Percent	Percent
95-00	3.5	2.1	3.9
00-05	3.8	4.6	3.1
05-11	1.9	1.9	2.0

In recent years, the area has reaped the benefits of a booming national economy and the associated upturn in tourism. 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. Several new hotels are currently under construction. A new hotel, the Hard Rock Hotel and complex, recently opened. The new Orlando convention center is expected to open during the forecast period, further fueling regional convention and tourism activity.

To accommodate growing convention, tourism, and regional business activity, the Orlando International Airport (OIA) is in the process of a major expansion program that will ultimately double the capacity of the airport. In 1999, OIA served 29 million passengers - nearly 10 percent over the prior year. OIA projects continued strong passenger volume growth for the region well into the next decade.

4.3.1.1 Economic Projections. While the economy is projected to slow from the torrid pace experienced over the last 5 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 592,000 in 2000 to 742,000 by 2011, representing an average annual growth rate of 2.1 percent. Employment is projected to grow at 2.6 percent over the long-term.

RFA ranks Orlando at 99 percent (with respect to the US average of 100 percent) in terms of the cost of doing business. Similarly, Orlando is ranked at 97 percent for cost of living, implying a slightly lower-than-average cost of living in the area. The combination of these and other factors will sustain Orlando as one of the fastest growing metropolitan areas in the US. 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 RFA'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 expected to increase from 4,696 GWh in 2000 to 6,349 GWh by 2011. St. Cloud sales are projected to increase from 343 GWh to 479 GWh. 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 0.7 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 1.9 percent rate for OUC and 2.2 percent rate for St. Cloud between 2000 and 2011. 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 1.1 percent and 3.2 percent for OUC and St. Cloud, respectively, between 2000 and 2011. 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 five 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 0.9 percent and 2.0 percent, respectively, for OUC and St. Cloud from 2000 to 2011. 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	1,804	311	3,231	33	11	103	5,500
2011	2,099	330	3,726	36	30	128	6,349
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	2.8	1.4	3.6	1.3	-	4.3	3.2
05-11	2.6	0.8	2.4	1.4	14.0	3.6	2.4

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	138,278	16,192	4,874	159,344
2011	154,828	17,101	5,722	177,651
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	1.9	0.9	2.0	1.8
05-11	1.9	0.9	2.7	1.8

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	280	31	90	3	404
2011	332	37	106	4	479
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	3.3	2.9	3.5	0.0	3.3
05-11	2.9	3.3	2.8	0.5	2.9

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	18,438	1,765	182	20,386
2011	21,037	1,982	211	23,230
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	2.3	2.0	6.3	2.2
05-11	2.2	1.9	2.3	2.2

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	3926
1995	798	800	4103
1996	788	885	4186
1997	846	773	4271
1998	907	746	4578
1999	969	873	4674
2000	941	882	4922
2005	1125	1102	5748
2011	1287	1261	6635
Change	Percent	Percent	Percent
95-00	3.3	2.0	3.7
00-05	3.6	4.6	3.2
05-11	2.3	2.3	2.4

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	108	114	415
2011	129	137	508
Change	Percent	Percent	Percent
95-00	6.0	3.2	6.1
00-05	5.2	5.1	2.4
05-11	3.0	3.1	3.4

4.5 High and Low Case 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.

4.5.1 High Case Scenario.

The high scenario is based upon assumptions of continued strong economic growth. It has been assumed that through 2011, 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. Tables 4-11 and 4-12 show a comparison of the high, base, and low scenarios.

4.5.2 Low Case Scenario.

The low scenario assumes that there is a significant slowdown in regional population growth, with the number of households slowing to a 1.5 percent growth rate during the first five years, and declining further to a long-term growth rate of 1.1 percent. The University of Florida's high and low population projections were used to help bound the population growth assumptions. Tables 4-11 and 4-12 show a comparison of the high, base, and low scenarios.

Table 4-11
Scenario Energy Forecast
Orlando Utilities Commission and St. Cloud

High Scenario - GWh							
Year	Residential	GSND	GSD	Street Lighting	Conv. St. Lts.	OUC Use	Total Retail
1995	1,560	335	2,212	27	--	55	4,189
2000	1,821	319	2,781	34	--	84	5,039
2005	2,255	391	3,572	37	14	103	6,372
2011	2,891	483	4,370	40	30	128	7,942
95-00	3.1%	-1.0%	4.7%	4.7%	--	8.8%	3.8%
00-05	4.4%	4.1%	5.1%	1.7%	--	4.2%	4.8%
05-11	4.2%	3.6%	3.4%	1.3%	13.5%	3.7%	3.7%
Base Scenario - GWh							
Year	Residential	GSND	GSD	Street Lighting	Conv. St. Lts.	OUC Use	Total Retail
1995	1,560	335	2,212	27	--	55	4,189
2000	1,821	319	2,781	34	--	84	5,039
2005	2,084	345	3,321	37	14	103	5,903
2011	2,431	368	3,832	40	30	128	6,828
95-00	3.1%	-1.0%	4.7%	4.7%	--	8.8%	3.8%
00-05	2.7%	1.6%	3.6%	1.7%	--	4.2%	3.2%
05-11	2.6%	1.1%	2.4%	1.3%	13.5%	3.7%	2.5%
Low Scenario - GWh							
Year	Residential	GSND	GSD	Street Lighting	Conv. St. Lts.	OUC Use	Total Retail
1995	1,560	335	2,212	27	--	55	4,189
2000	1,821	319	2,781	34	--	84	5,039
2005	1,941	337	3,127	37	14	103	5,559
2011	2,077	348	3,254	40	30	128	5,876
95-00	3.1%	-1.0%	4.7%	4.7%	--	8.8%	3.8%
00-05	1.3%	1.1%	3.6%	1.7%	--	4.2%	2.0%
05-11	1.1%	0.5%	0.6%	1.3%	13.5%	3.7%	0.9%

Table 4-12 Scenario Peak Forecast Orlando Utilities Commission and St. Cloud			
High Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,330	1,367	6,666
2011	1,648	1,628	8,309
95-00	3.6%	2.1%	3.9 %
00-05	5.4%	7.1%	4.7%
05-11	3.6%	3.0%	3.7%
Base Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,232	1,216	6,176
2011	1,416	1,398	7,142
95-00	3.5%	2.1%	3.9%
00-05	3.8%	4.6%	3.1%
05-11	1.9%	1.9%	2.0%
Low Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,160	1,144	5,814
2011	1,217	1,202	6,147
95-00	3.5%	2.1%	3.9%
00-05	2.5%	3.3%	1.9%
05-11	0.8%	0.8%	0.9%

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. The demand-side management goals for OUC 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.

5.1 Existing Conservation Programs

There have been significant changes in the market place in the last 5 years. Today there is much more emphasis on competition as the electric industry prepares for deregulation. Interest rates are at all time lows, greatly reducing the carrying costs of power plants. As a result, conservation programs are significantly less cost-effective. OUC's existing programs include the following:

- Residential Energy Survey Program.
- Residential Heat Pump Program.
- Residential Weatherization Program.
- Low Income Home Energy Fixup Program.
- Educational Outreach Program.
- Commercial Energy Survey Program.

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

5.1.1 Residential Energy Survey.

This program is designed to provide residential homeowners with recommended energy efficiency measures and practices. The Residential Energy Survey includes complete attic, air duct, and air return inspections. The customer is given a choice to receive either a low-flow showerhead or compact fluorescent bulb. OUC energy analysts are presently using this walk-through type audit as a means to get OUC customers to participate in other conservation programs and to qualify for appropriate rebates. Customers may also choose to perform their own energy audit by requesting a copy of OUC's home energy audit video. This video became available in an interactive CD format in November of 2001. Additionally, an interactive home energy audit complete with previous billing information on the customer is available on OUC's website, OUC.com.

5.1.2 Residential Heat Pump Program.

Heat pumps are marketed to the owners of existing residential strip heating systems and older, inefficient central air conditioners and heat pumps. The program requires heat pumps with a SEER of 11 (or greater) and a HSPF of 7.0 (or greater) in order to qualify for rebates. Rebates vary by equipment SEER levels. One of the main benefits of the program is the duct work and insulation level improvements made by contractors when installing the energy efficient heat pumps.

5.1.3 Residential Weatherization Program.

This program is designed for existing single family homes and promotes R-19 ceiling insulation (or higher), caulking, weather-stripping, window treatment, water heater insulation, and air condition/heating supply and return air duct repair. The customer can receive a $140 rebate for installing R-19 ceiling insulation (or higher), a $100 rebate for duct repairs, and up to $110 for other conservation measures specified above. In addition, the customer is allowed to carry payments for ceiling insulation on their electric bill for 12 or 24 months. OUC directly pays the total cost for installation when OUC provides the financing.

The program is promoted through Residential Energy Surveys, trade shows, exhibits, and neighborhood meetings.

5.1.4 Low Income Home Energy Fixup Program.

This program targets residential customers with an annual income of less than $20,000. Every customer is eligible for an energy audit. Audit recommendations usually require the customer to spend money replacing or adding energy conservation measures. Low-income customers may not have the discretionary income to make these changes.

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

- Upgrading ceiling insulation to R-19.
- Exterior and interior caulking.
- Weather-stripping doors and windows.
- Air conditioning/heating supply and return air duct repairs.
- Water heater insulation.

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.

5.1.5 Education Outreach Program.

This program is now entering its 15th year of operation. The program is very successful and has won several awards for contributions to education. The program consists of hour long classroom presentations focused on teaching students about energy and water conservation. Students are taught how electricity is generated and are encouraged to perform mini electric and water audits on their own homes.

5.1.6 Commercial Energy Survey Program.

This survey is a physical walk-through inspection of the commercial facility. The commercial customer having a Commercial Energy Survey receives a report at the time of the survey. Within 30 days of a detailed audit, the customer receives a written report. Conservation literature is provided to all customers. The program is focused on commercial customers to increase their energy efficiency and energy conservation. OUC has also developed an alliance with a large performance contractor in order to provide large commercial customers with a more complete solution to their needs.

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, OUC and St. Cloud together have existing generating capabilities of 1,047 MW in the summer and 1,092 MW in the winter. The existing generating capability consists of OUC's joint ownership share of Stanton Energy Center 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 FPC, Lakeland Electric, and FPL, respectively, as well as St. Cloud's diesels. Stanton Energy Center A, which received final site certification September 18, 2001, will add an additional 167 MW (summer) and 181 MW (winter) to OUC's generating capacity beginning October 1, 2003. Construction of Stanton A began in November 2001 in order to support its scheduled commercial operation date.

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 TYSP, it has been assumed that OUC will exercise its options from the Reliant PPA, purchasing 577.5 MW for fiscal years 2002 and 2003. Beyond fiscal year 2003, OUC can elect to purchase from Reliant up to 500 MW, in 100 MW increments, through fiscal year 2007. OUC can reduce the amount of capacity purchased through the Reliant PPA each fiscal year, also in 100 MW increments, but cannot increase the amount of capacity it purchases from the amount taken the previous fiscal year.

Additionally, OUC has entered into a 10-year agreement to purchase capacity from Southern-Florida's ownership share of Stanton A. The terms of this agreement specify that OUC will purchase 309 MW during the summer months and 336 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 TYSP 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, up to a total of 160 MW.

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 5-year increments. OUC has also entered into an agreement to purchase power from KUA's share of Stanton A during the first three years of the unit's operation.

6.1.3 Power Sales Agreements.

As described in more detail in Section 2.4, OUC has entered into power sales contracts with FMPA, SEC, KUA, and RCID for various amounts of capacity and energy.

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 November of 2004.

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) Fla. Admin. 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 methodology.

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 display the forecast reserve margins for OUC and St. Cloud for the winter and summer seasons, respectively.

Table 6-1 indicates that, considering the addition of Stanton A to OUC's generating assets and purchase power resources, additional capacity will not be needed until the winter of 2006/07. However, Table 6-2 shows that additional capacity will be necessary to satisfy forecast demand requirements for the summer of 2003. The addition of Stanton A (October 1, 2003 commercial operation) will provide enough capacity for OUC to meet forecast requirements for the summer of 2004, beyond which time the need for capacity additions increases until the assumed expiration of OUC's sale to RCID on December 31, 2010, as discussed in Section 2.4.

Table 6-2 indicates a need for 30 MW of reserve capacity for the summer of 2003 when the reserve margin would dip to 12.7 percent without additional capacity. The load forecast resulting in the 30 MW reserve requirement did not include impacts from September 11, 2001. Current indications are that actual loads will be less than those forecast prior to September 11, 2001. Equipment delivery and licensing requirements preclude OUC from constructing additional capacity for the summer of 2003 in order to meet reserve requirements. Stanton A will likely be providing significant capacity during the summer of 2003 as it undergoes startup and testing for the scheduled commercial operation date of October 1, 2003. This is especially true for the simple cycle operation of the plant which precedes combined cycle operation. In addition, OUC is evaluating four purchase power alternatives for meeting the 30 MW reserve requirement in addition to the potential early operation of Stanton A. Three of these alternatives are from existing operating units in Florida for which OUC has direct transmission interconnections and the fourth alternative is from a project which is under construction.

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 69 through 230 kV transmission line respectively. 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 Winter Reserve Requirements														
Year	Retail Peak Demand[1] (MW)	Contracted Firm Sales (MW)					Total Peak Demand (MW)	Available Capacity (MW)			Available Reserves (MW)	Required Reserves (MW)		Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
		RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed[2]	Reliant PPA	TECO P.R.		RCID	Total	
2001/02	1,126	79	130	20	35	20	1,410	1,092	577.5	15	275	12	179	96
2002/03	1,161	98	87	20	75	20	1,461	1,092	577.5	15	224	15	187	37
2003/04	1,189	91	65	20	75	20	1,460	1,650		15	205	14	190	15
2004/05	1,216	100	44				1,360	1,634		15	289	15	195	93
2005/06	1,249	107	34				1,390	1,620		15	245	16	201	43
2006/07	1,279	129	22				1,430	1,610		15	195	19	209	(14)
2007/08	1,306	132					1,438	1,610		15	187	20	213	(27)
2008/09	1,335	134					1,469	1,610		15	156	20	218	(63)
2009/10	1,366	136					1,502	1,610		15	123	20	223	(100)
2010/11	1,398	138					1,536	1,610		15	89	21	228	(140)
2011/12	1,288	141					1,429	1,610		15	196		212	(17)

1. Includes peak demand for both OUC and St. Cloud.
2. Includes OUC's equity portion of SEC A and purchase of SEC A capacity from Southern-Florida and KUA.

Table 6-2
OUC and St. Cloud Summer Reserve Requirements

Year	Retail Peak Demand[1] (MW)	Contracted Firm Sales (MW)					Total Peak Demand (MW)	Available Capacity (MW)			Available Reserves (MW)	Required Reserves (MW)		Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
		RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed[2]	Reliant PPA	TECO P.R.		RCID	Total	
2002	1,136	100	104	20	75	20	1,455	1,047	577.5	15	185	15	183	1
2003	1,177	101	87	20	75	20	1,480	1,047	577.5	15	160	15	189	(30)
2004	1,204	112	65				1,381	1,563		15	197	17	195	2
2005	1,233	121	43				1,397	1,547		15	165	18	201	(36)
2006	1,264	128	22				1,414	1,533		15	134	19	207	(73)
2007	1,294	150					1,444	1,523		15	94	23	214	(121)
2008	1,323	153					1,476	1,523		15	62	23	219	(157)
2009	1,352	155					1,507	1,523		15	31	23	224	(193)
2010	1,384	157					1,541	1,523		15	(3)	24	229	(232)
2011	1,416						1,416	1,523		15	122	0	210	(88)

1. Includes peak demand for both OUC and St. Cloud.
2. Includes OUC's equity portion of SEC A and purchase of SEC A capacity from Southern-Florida and KUA.

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 each of the following technologies being considered as supply-side alternatives:

- Pulverized Coal.
- Combined Cycle.
- Simple Cycle.

Table 7-1 presents the supply-side alternatives considered by OUC for further capacity additions. The table includes the type of unit being considered, its location, its net capacity, and the earliest date it can achieve commercial operation (C.O.D.).

Table 7-1. Generation Expansion Candidates

Technology	Description	Location	Net Capacity	C.O.D.
Simple Cycle	General Electric 7FA	Stanton	156 MW	06/04
Combined Cycle	Siemens-Westinghouse 2x1 501F	Stanton	514 MW	06/05
	Siemens-Westinghouse 2x1 501F	Stanton	610 MW	06/05
Solid Fuel	Pulverized Coal	Stanton	446 MW	06/08

Note: Capacity is stated at average annual temperature for OUC and includes degradation.

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.

7.1 Performance Estimates

Performance estimates have been compiled for each of the alternatives listed above. 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. These criteria are explained below.

7.1.1 Net Plant Output.

Net plant output (NPO) 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.

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 Siemens-Westinghouse combined cycle (WH 2x1 501F) units. Output and performance for the pulverized coal unit was developed incorporating degradation.

Table 7-2
Degradation Factors

Unit	Net Output (%)	Heat Rate (%)
GE 7FA Simple Cycle	-4.04	2.87
WH 2x1 501F 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 2002 dollars)

Total Capital Cost[1], ($1000)	$565,990
O&M Cost - Baseload Duty	
Fixed O&M Cost ($/kW-yr)	14.89
Variable O&M Cost ($/MWh)	3.92
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 Combined Cycle Units

The two combined cycle units selected by OUC as generating unit alternatives include a standard size Siemens-Westinghouse 2x1 501F as well as a Siemens-Westinghouse 2x1 501F with an oversized steam turbine to accommodate maximum duct firing.

The standard size unit is based on a steam turbine sized to utilize all steam produced during normal cool weather conditions and includes duct burners sized to fully load the steam turbine during hot weather conditions. The oversized unit is based on a steam turbine sized to accommodate the maximum duct firing possible.

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 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 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.

The combined cycle units both utilize conventional, heavy-duty, industrial type combustion turbines. This Ten-Year Site Plan limited the alternatives reviewed to "F" class CTGs based on size and because F class turbines are a proven technology. Several vendors provide combustion turbines with similar performance characteristics.

The combined cycle units would be dual fueled with natural gas as the primary fuel and No. 2 oil as the secondary fuel. Specifications for performance and operating costs are based on burning natural gas and baseload operation. The combined cycle alternatives assume that emission requirements will be met with dry low NO_x combustors on the CTGs and SCR on the HRSGs. Natural gas compressors are not included in the cost estimates because natural gas pipeline pressure is assumed adequate. The combined cycle alternatives include bypass stacks and dampers to allow simple cycle operation, and also include fuel oil and demineralized water storage tanks.

7.3.1 Siemens-Westinghouse 2x1 501F 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, and are presented in Table 7-4.

7.3.1.1 General Assumptions.

- The plant will feature two (2) dual fuel combustion turbine generators, two (2) supplementary fired heat recovery steam generators (HRSGs), and one (1) condensing reheat steam turbine.
- The combustion turbines will be capable of firing either natural gas or number 2 fuel oil. The HRSG duct burners will be capable of burning natural gas only.
- 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.
- The following buildings are included:
  - Steam turbine building (custom designed).
  - Circulating water chemical feed building (pre-engineered metal structure).
  - No costs have been included for interior furnishings.
- 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 Siemens-Westinghouse 2x1 501F Combined Cycle O&M Costs.

O&M estimates were developed based on a recent bid to a Florida municipal utility for a similar sized combined cycle unit at an existing site. The capital and O&M costs along with the performance estimates for the Siemens-Westinghouse 2x1 501F combined cycle units are presented in Table 7-4.

7.4 Simple Cycle Combustion Turbine Generator

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 indicated. The simple cycle combustion turbines assume that emission requirements will be met with dry low NO_x combustors on the CTGs. 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 in the Ten-Year Site Plan. Final decisions regarding the location of new combustion turbines have not been made.

Table 7-4. Generating Unit Characteristics
Siemens-Westinghouse 2x1 501F Combined Cycle Units
(Unless otherwise specified, all costs are in 2002 dollars)

	Standard Turbine	Oversized Turbine
Total Capital Cost[1], ($1000)	$290,713	$301,031
O&M Cost – Baseload Duty		
Fixed O&M Cost, 2002 ($/kW-yr)	6.17	5.19
Variable O&M Cost, 2002 ($/MWh)	3.59	3.59
Equivalent Forced Outage Rate (percent)	4.00	4.00
Planned Maintenance (days/year)	14	14
Construction Period (months)	24	24
Net kW Output/Net Plant Heat Rate (NPHR), HHV (Btu/kWh)	513,830/7,074	609,730/7,542
	504,570/7,039	498,990/7,118
	316,110/7,512	311,450/7,625
	251,900/7,215	299,120/7,687
	247,160/7,186	243,740/7,287
	150,990/7,863	149,350/7,950

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

The estimates were developed assuming that each site would include two identical combustion turbines. For purposes of this evaluation, it has been assumed that the final capital cost estimate for a single combustion turbine would be approximately 55 percent of the capital cost estimate developed for the two combustion turbines.

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 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 hookup 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 10 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 for combustion turbine generator (CTG).
- 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.
- Estimated additional staff is five for the 7FA.
- Staff supplies and materials are estimated to be 10 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. Routine maintenance includes 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 2002 dollars)	
Total Capital Cost[1], ($1000)	$61,463
O&M Cost - Baseload Duty	
Fixed O&M Cost ($/kW-yr)	5.39
Variable O&M Cost ($/MWh)	2.45
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. Results, and Conclusions

8.1 Analysis Methodology

8.1.1 Methodology.

The economic evaluation 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. Capital costs for existing units are not included since they 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. 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, Black & Veatch's optimal generation expansion model. 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 developing the production cost. The results of several scenarios are contained later in this section.

8.1.2 Economic Parameters.

8.1.2.1 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 interest 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. 6 fuel oil, and nuclear fuel. The base case forecasts are based on information provided by OUC. OUC provided fuel forecasts for natural gas, coal, and No. 6 fuel oil, while the forecast for nuclear fuel was developed by Black & Veatch.

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 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.

8.2.1 Base Case Fuel Price Projections.

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

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.

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 FGT's system (described in Section 8.3.2). 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 (Section 8.3.5.1). 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 developed by OUC is presented in Table 8-1. Although OUC does not own any generating units that rely on No. 6 fuel oil as the primary fuel, the power purchase agreement with Reliant (Section 2.3) is based on utilizing a specified proportion of No. 6 fuel oil and natural gas.

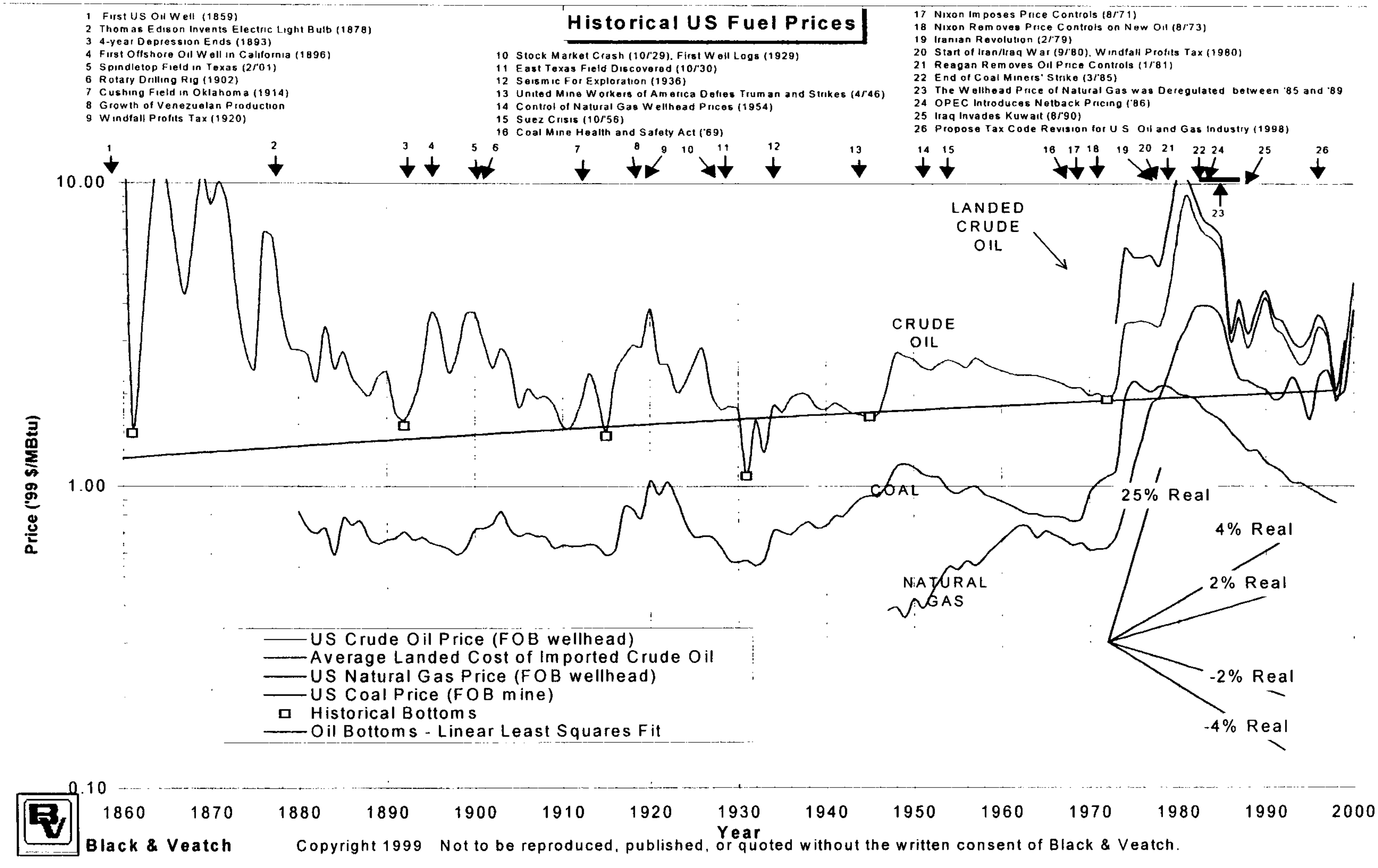
Historical US Fuel Prices
1 First US Oil Well (1859)
2 Thomas Edison Invents Electric Light Bulb (1878)
3 4-year Depression Ends (1893)
4 First Offshore Oil Well in California (1896)
5 Spindletop Field in Texas (2/'01)
6 Rotary Drilling Rig (1902)
7 Cushing Field in Oklahoma (1914)
8 Growth of Venezuelan Production
9 Windfall Profits Tax (1920)
10 Stock Market Crash (10/'29), First Well Logs (1929)
11 East Texas Field Discovered (10/'30)
12 Seismic For Exploration (1936)
13 United Mine Workers of America Defies Truman and Strikes (4/'46)
14 Control of Natural Gas Wellhead Prices (1954)
15 Suez Crisis (10/'56)
16 Coal Mine Health and Safety Act ('69)
17 Nixon Imposes Price Controls (8/'71)
18 Nixon Removes Price Controls on New Oil (8/'73)
19 Iranian Revolution (2/'79)
20 Start of Iran/Iraq War (9/'80), Windfall Profits Tax (1980)
21 Reagan Removes Oil Price Controls (1/'81)
22 End of Coal Miners' Strike (3/'85)
23 The Wellhead Price of Natural Gas was Deregulated between '85 and '89
24 OPEC Introduces Netback Pricing ('86)
25 Iraq Invades Kuwait (8/'90)
26 Propose Tax Code Revision for U S Oil and Gas Industry (1998)
LANDED CRUDE OIL
CRUDE OIL
COAL
NATURAL GAS
25% Real
4% Real
2% Real
-2% Real
-4% Real
US Crude Oil Price (FOB wellhead)
Average Landed Cost of Imported Crude Oil
US Natural Gas Price (FOB wellhead)
US Coal Price (FOB mine)
Historical Bottoms
Oil Bottoms - Linear Least Squares Fit
Price ('99 $/MBtu)
10.00
1.00
0.10
1860
1870
1880
1890
1900
1910
1920
1930
1940
1950
1960
1970
1980
1990
2000
Year
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Figure 8-1

8.2.1.4 Nuclear Fuel. The forecast for nuclear fuel was developed by escalating the average price paid by OUC in 2001 for nuclear fuel at the general inflation rate of 2.5 percent annually. The resulting 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	Nuclear
2002	1.79	3.67	3.23	0.39
2003	1.81	3.61	3.28	0.40
2004	1.85	3.69	3.28	0.41
2005	1.90	3.78	3.31	0.42
2006	1.95	3.86	3.37	0.43
2007	2.02	3.95	3.45	0.44
2008	2.10	4.05	3.52	0.45
2009	2.15	4.14	3.60	0.46
2010	2.21	4.24	3.67	0.47
2011	2.55	4.34	3.75	0.49
Average Annual Escalation	3.97%	1.87%	1.66%	2.50%

8.2.2 High and Low Fuel Price Projections.

In order to address the uncertainty surrounding forecasting fuel prices ten years into the future, high and low fuel price forecasts were developed. For each of the fuels described in Section 8.2.1, the base case average annual escalation rate was increased by 2 percentage points (high case) and decreased by 2 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 Fuel Price Forecast Summary
(Delivered nominal $/MBtu)

Year	Coal	Natural Gas	No. 6 Oil	Nuclear
2002	1.79	3.67	3.23	0.39
2003	1.90	3.81	3.35	0.41
2004	2.01	3.96	3.48	0.43
2005	2.14	4.11	3.60	0.44
2006	2.26	4.27	3.73	0.46
2007	2.40	4.44	3.87	0.49
2008	2.54	4.61	4.01	0.51
2009	2.69	4.79	4.16	0.53
2010	2.85	4.97	4.31	0.55
2011	3.02	5.17	4.47	0.58
Average Annual Escalation	5.97%	3.87%	3.66%	4.50%

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

Year	Coal	Natural Gas	No. 6 Oil	Nuclear
2002	1.79	3.67	3.23	0.39
2003	1.83	3.66	3.22	0.39
2004	1.87	3.66	3.21	0.39
2005	1.90	3.66	3.20	0.40
2006	1.94	3.65	3.19	0.40
2007	1.98	3.65	3.18	0.40
2008	2.02	3.64	3.17	0.40
2009	2.06	3.64	3.16	0.40
2010	2.10	3.63	3.15	0.41
2011	2.14	3.63	3.14	0.41
Average Annual Escalation	1.97%	-0.13%	-0.34%	0.50%

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 on 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 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.

8.3.2 Florida Gas Transmission Company.

FGT is an open access interstate pipeline company transporting natural gas for third parties through its 4,700 mile pipeline system extending from South Texas to Miami, Florida. FGT is a subsidiary of Citrus Corporation which, in turn, is jointly owned by Enron Corporation, the largest integrated natural gas company in America, and El Paso Energy Corporation, one of the largest independent producers of natural gas in the United States.

The FGT pipeline system accesses a diversity 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 10 interstate and 10 intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a current delivery capability to Peninsular Florida in excess of 1.7 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 easterly to a point in southwestern Clay County, where the pipeline corridor turns southerly 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 westerly 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 Expansion Project.

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 project, filed with the Federal Energy Regulatory Commission (FERC) on December 1, 1999, will deliver natural gas to a variety of new and current FGT customers and make natural gas available to areas that have not previously had gas service. The Phase V expansion project is intended to add approximately 167 miles of new pipeline and 132,615 horsepower of compression to the existing system. The result of this expansion will be the addition of more than 428 MMcf/d of incremental mainline capacity to Florida. With an estimated cost of $452 million, the Phase V expansion plan has a target in-service date of April 1, 2002.

The 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.

On November 15, 2001, FGT filed an application with FERC to expand its existing transmission system. The new pipeline will add approximately 33 miles of new pipeline and 18,600 horsepower of additional compression to the existing FGT system.

The purpose of the Phase VI Expansion is to deliver additional natural gas to four existing customers, including OUC. With a projected cost of $105 million, the Phase VI Expansion will provide approximately 121 MMcf/d of incremental firm transportation capacity. Phase VI is scheduled to be completed by November 1, 2003.

FERC approved in November of 2000 FGT's request for the purchase of an undivided interest in Koch Gateway Pipeline's Mobile Bay Lateral. This purchase will give FGT the right to an additional 300,000 MMcf/d of input capacity. The acquisition is set to become effective April 1, 2002.

8.3.5 Alternative Natural Gas Supply Pipelines for Peninsular Florida.

FGT is currently the only transportation company serving Peninsular Florida. Two additional pipelines, Buccaneer and Gulfstream, received preliminary approval from FERC in April of 2000. In September of 2000, both pipelines also received one of the two required approvals from FERC.

In November of 2000, the developers of the Buccaneer gas pipeline, Williams Energy and Duke Energy, announced their intent to purchase the Gulfstream pipeline from Coastal Corporation. The purchase was subject to federal regulatory approvals and conditioned upon completion of the Coastal/El Paso Energy Corporation merger.

Duke Energy and Williams Energy will collaborate on the Gulfstream pipeline in lieu of the Buccaneer pipeline. Gulfstream has precedent agreements with 10 large Florida utilities and power generation facilities representing long-term commitments for the majority of its 1.1 billion cubic feet of gas per day capacity. The Gulfstream pipeline, discussed below, was designed primarily to serve Florida utilities and power generation facilities that plan on using high efficiency natural gas turbines to meet the incremental demand for electrical energy.

8.3.5.1 Gulfstream Pipeline. The Gulfstream pipeline is a 753 mile pipeline originally proposed by the Coastal Corporation. The pipeline will originate from the Mobile Bay region, crossing the Gulf of Mexico to a landfall in Manatee County (south Tampa Bay). The pipeline is expected to supply Florida with 1.1 billion cubic feet of gas per day, serving existing and prospective electric generation and industrial projects in southern Florida.

The 1.6 billion dollar pipeline 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 of 2001. Construction of the Gulfstream pipeline began May 31, 2001, and the pipeline has an estimated operation date of June of 2002. 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 the permanent right-of-way easement to cross through Port Manatee. In addition to a payment to Port Manatee, up to 190 acres of vacant land at Port Manatee will be leased to serve as a logistics base during Gulfstream's construction phase.

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 10-year period from 2002 through 2011.

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. Additionally, the option of extending the Reliant PPAs from 2004 through 2007 (described in Section 2.3) has been included among the 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 at temperatures which closely approximate (within

2 degrees) the average annual temperature for OUC. 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 combined OUC and St. Cloud system after implementation of the expansion plan presented in Table 8-4 for the winter and summer seasons, respectively.

Table 8-4. Least-Cost Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2002	577.5 MW Reliant Power Purchase	$146,419	$146,419
2003	30 MW Unspecified Purchase* (06/01/2003 – 09/30/2003) Terminate 577.5 MW Reliant Power Purchase (09/30/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	$162,293	$296,691
2004	Start 100 MW Reliant Power Purchase (10/01/2004)	$192,800	$461,986
2005		$202,170	$622,476
2006	Terminate 100 MW Reliant Power Purchase (09/30/2006) 156 MW GE 7FA Simple Cycle CT (10/01/2006)	$211,193	$777,709
2007		$233,469	$936,604
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (11/01/2008)	$240,604	$1,088,225
2009		$260,426	$1,240,181
2010	40 MW Reduction in Southern-Florida Power Purchase (11/01/2010)	$265,064	$1,383,387
2011	40 MW Reduction in Southern-Florida Power Purchase (11/01/2011)	$252,994	**$1,509,947**

Note: Capacity is stated at average annual temperature for OUC.
* Available purchase power alternatives are discussed in Section 6.3.1. Lower loads resulting from the events of September 11, 2001 may actually eliminate the need for this purchase.

Table 8-5
OUC and St. Cloud Winter Reserve Requirements – After Base Case Expansion Plan

Year	Retail Peak Demand[1] (MW)	Contracted Firm Sales (MW)					Total Peak Demand (MW)	Available Capacity (MW)			Available Reserves (MW)	Required Reserves (MW)		Reserve Margin	
		RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed[2]	Reliant PPA	TECO P.R.		RCID	Total	MW	%
2001/02	1,126	79	130	20	35	20	1,410	1,092	577.5	15	275	12	179	96	22.97
2002/03	1,161	98	87	20	75	20	1,461	1,092	577.5	15	224	15	187	37	17.93
2003/04	1,189	91	65	20	75	20	1,460	1,650		15	205	14	190	15	16.16
2004/05	1,216	100	44				1,360	1,634	100	15	389	15	195	193	29.70
2005/06	1,249	107	34				1,390	1,620	100	15	345	16	201	143	25.58
2006/07	1,279	129	22				1,430	1,785		15	370	19	209	161	26.41
2007/08	1,306	132					1,438	1,785		15	362	20	213	148	25.30
2008/09	1,335	134					1,469	1,920		15	466	20	218	248	31.85
2009/10	1,366	136					1,502	1,920		15	433	20	223	210	28.95
2010/11	1,398	138					1,536	1,880		15	359	21	228	130	23.49
2011/12	1,288	141					1,429	1,840		15	426	0	212	214	29.94

1. Includes peak demand for both OUC and St. Cloud.
2. Includes OUC's equity portion of SEC A and purchase of SEC A capacity from Southern-Florida and KUA.

Table 8-6
OUC and St. Cloud Summer Reserve Requirements – After Base Case Expansion Plan

Year	Retail Peak Demand[1] (MW)	Contracted Firm Sales (MW)					Total Peak Demand (MW)	Available Capacity (MW)			Available Reserves (MW)	Required Reserves (MW)		Reserve Margin	
		RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed[2]	Reliant PPA[3]	TECO P.R.		RCID	Total	MW	%
2002	1,136	100	104	20	75	20	1,455	1,047	577.5	15	185	15	183	1	15.11
2003	1,177	101	87	20	75	20	1,480	1,047	607.5	15	190	15	189	0	15.00
2004	1,204	112	65				1,381	1,563		15	197	17	195	2	15.12
2005	1,233	121	43				1,397	1,547	100	15	265	18	201	64	19.72
2006	1,264	128	22				1,414	1,533	100	15	234	19	207	27	16.95
2007	1,294	150					1,444	1,663		15	234	23	214	19	16.34
2008	1,323	153					1,476	1,803		15	342	23	219	123	23.30
2009	1,352	155					1,507	1,763		15	271	23	224	47	18.11
2010	1,384	157					1,541	1,763		15	237	24	229	8	15.51
2011	1,416						1,416	1,723		15	322	0	210	112	22.88

1. Includes peak demand for both OUC and St. Cloud.
2. Includes OUC's equity portion of SEC A and purchase of SEC A capacity from Southern-Florida and KUA.
3. Includes 30 MW unspecified purchase in 2003 only. The available purchase power alternatives are discussed in Section 6.3.1. Lower loads resulting from the events of September 11, 2001 may actually eliminate the need for this purchase.

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. The sensitivity analyses were performed over a 10-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 require additional capacity beginning in the summer of 2002, with the initial need for additional winter capacity beginning winter 2003. However, since the current delivery schedule for combustion turbines combined with licensing and construction schedules precludes the addition of any generating units other than Stanton A until the summer of 2004, it is assumed that OUC would have to rely on purchased power to satisfy system requirements through this period.

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 2008. This need disappears by the summer of 2011 with the expiration of the RCID sale.

Table 8-14 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity.

8.5.5 No. 2 Fuel Oil Scenario.

The No. 2 fuel oil sensitivity examines a scenario in which the simple cycle combustion turbines candidates available to OUC would be run only on No.2 fuel oil instead of natural gas. In order to consider such a situation, a forecast had to be developed for No. 2 fuel oil. To do so, the annual difference in price between No. 2 and No. 6 fuel oils used in the Stanton Energy Center A Need for Power Application was applied to the forecast for No. 6 fuel oil presented in Table 8-1 herein. The resulting No. 2 fuel oil forecast is presented in Table 8-15, along with the results of the least-cost expansion plan under this scenario.

Table 8-7. Least-Cost Expansion Plan – High Fuel Price Scenario

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2002	577.5 MW Reliant Power Purchase	$146,419	$146,419
2003	30 MW Unspecified Purchase* (06/01/2003 – 09/30/2003) Terminate 577.5 MW Reliant Power Purchase (09/30/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	$168,629	$302,557
2004	Start 100 MW Reliant Power Purchase (10/01/2004)	$204,038	$477,486
2005		$218,191	$650,693
2006	Terminate 100 MW Reliant Power Purchase (09/30/2006) 156 MW GE 7FA Simple Cycle CT (10/01/2006)	$231,901	$821,147
2007		$259,716	$997,905
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (11/01/2008)	$271,685	$1,169,113
2009		$298,703	$1,343,403
2010	40 MW Reduction in Southern-Florida Power Purchase (11/01/2010)	$310,590	$1,511,206
2011	40 MW Reduction in Southern-Florida Power Purchase (11/01/2011)	$287,279	**$1,654,917**

Note: Capacity is stated at average annual temperature for OUC.
* Available purchase power alternatives are discussed in Section 6.3.1. Lower loads resulting from the events of September 11, 2001 may actually eliminate the need for this purchase.

Table 8-8. Least-Cost Expansion Plan – Low Fuel Price Scenario			
Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2002	577.5 MW Reliant Power Purchase	$146,419	$146,419
2003	30 MW Unspecified Purchase* (06/01/2003 – 09/30/2003) Terminate 577.5 MW Reliant Power Purchase (09/30/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	$163,435	$297,748
2004	Start 100 MW Reliant Power Purchase (10/01/2004)	$193,423	$463,577
2005		$200,795	$622,975
2006	Terminate 100 MW Reliant Power Purchase (09/30/2006) 156 MW GE 7FA Simple Cycle CT (10/01/2006)	$207,823	$775,731
2007		$226,767	$930,064
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (11/01/2008)	$230,187	$1,075,121
2009		$246,432	$1,218,912
2010	40 MW Reduction in Southern-Florida Power Purchase (11/01/2010)	$248,013	$1,352,905
2011	40 MW Reduction in Southern-Florida Power Purchase (11/01/2011)	$223,108	**$1,464,515**

Note: Capacity is stated at average annual temperature for OUC.
* Available purchase power alternatives are discussed in Section 6.3.1. Lower loads resulting from the events of September 11, 2001 may actually eliminate the need for this purchase.

Table 8-9
OUC and St. Cloud Winter Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand[1] (MW)	Contracted Firm Sales (MW)					Total Peak Demand (MW)	Available Capacity (MW)			Available Reserves (MW)	Required Reserves (MW)		Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
		RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed[2]	Reliant PPA	TECO P.R.		RCID	Total	
2001/02	1,168	79	130	20	35	20	1,452	1,092	577.5	15	273	12	185	48
2002/03	1,222	98	87	20	75	20	1,522	1,092	577.5	15	163	15	196	(33)
2003/04	1,268	91	65	20	75	20	1,539	1,650		15	126	14	202	(76)
2004/05	1,313	100	44				1,457	1,634		15	192	15	210	(18)
2005/06	1,367	107	34				1,508	1,620		15	127	16	219	(92)
2006/07	1,420	129	22				1,571	1,610		15	54	19	230	(177)
2007/08	1,468	132					1,600	1,610		15	25	20	238	(213)
2008/09	1,517	134					1,651	1,610		15	(26)	20	245	(272)
2009/10	1,570	136					1,706	1,610		15	(81)	20	254	(335)
2010/11	1,628	138					1,766	1,610		15	(141)	21	263	(404)

1. Includes peak demand for both OUC and St. Cloud.
2. Includes OUC's equity portion of SEC A and purchase of SEC A capacity from Southern-Florida and KUA.

Table 8-10
OUC and St. Cloud Summer Reserve Requirements – High Load and Energy Growth Scenario

Year	Retail Peak Demand[1] (MW)	Contracted Firm Sales (MW)					Total Peak Demand (MW)	Available Capacity (MW)			Available Reserves (MW)	Required Reserves (MW)		Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
		RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed[2]	Reliant PPA	TECO P.R.		RCID	Total	
2002	1,180	100	104	20	75	20	1,499	1,047	577.5	15	141	15	190	(49)
2003	1,238	101	87	20	75	20	1,541	1,047	577.5	15	99	15	199	(100)
2004	1,285	112	65				1,462	1,563		15	116	17	207	(92)
2005	1,330	121	43				1,494	1,547		15	68	18	215	(148)
2006	1,384	128	22				1,534	1,533		15	14	19	225	(211)
2007	1,437	150					1,587	1,523		15	(49)	23	236	(285)
2008	1,486	153					1,639	1,523		15	(101)	23	244	(345)
2009	1,536	155					1,691	1,523		15	(153)	23	251	(405)
2010	1,591	157					1,748	1,523		15	(210)	24	260	(470)
2011	1,648						1,648	1,523		15	(110)	0	245	(355)

1. Includes peak demand for both OUC and St. Cloud.
2. Includes OUC's equity portion of SEC A and purchase of SEC A capacity from Southern-Florida and KUA.

Table 8-11. Least-Cost Expansion Plan – High Load and Energy Growth Scenario

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2002	49 MW Unspecified Purchase (06/01/2002 – 09/30/2002) 577.5 MW Reliant Power Purchase (09/30/2002) 33 MW Unspecified Purchase (10/01/2002 – 02/01/2003)	$153,063	$153,063
2003	100 MW Unspecified Purchase* (06/01/2003 – 09/30/2003) Terminate 577.5 MW Reliant Power Purchase (09/30/2003) Start 100 MW Reliant Power Purchase (10/01/2003) 171 MW Stanton A(10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	$172,727	$312,995
2004		$207,430	$490,833
2005	156 MW GE 7FA Simple Cycle CT (06/01/2005)	$220,265	$665,686
2006		$236,850	$839,778
2007	156 MW GE 7FA Simple Cycle CT (06/01/2007)	$263,152	$1,018,875
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) Terminate 100 MW Reliant Power Purchase (09/30/2008)	$280,258	$1,195,484
2009	40 MW Reduction in Southern-Florida Power Purchase (11/01/2009)	$302,777	$1,372,152
2010	156 MW GE 7FA Simple Cycle CT (06/01/2010) 40 MW Reduction in Southern-Florida Power Purchase (11/01/2010)	$320,375	$1,545,241
2011	40 MW Reduction in Southern-Florida Power Purchase (11/01/2011)	$318,210	**$1,704,425**

Note: Capacity is stated at average annual temperature for OUC.
* Available purchase power alternatives are discussed in Section 6.3.1.

Table 8-12
OUC and St. Cloud Winter Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand[1] (MW)	Contracted Firm Sales (MW)					Total Peak Demand (MW)	Available Capacity (MW)			Available Reserves (MW)	Required Reserves (MW)		Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
		RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed[2]	Reliant PPA	TECO P.R.		RCID	Total	
2001/02	1,106	79	130	20	35	20	1,390	1,092	577.5	15	335	12	176	119
2002/03	1,126	98	87	20	75	20	1,426	1,092	577.5	15	259	15	181	77
2003/04	1,136	91	65	20	75	20	1,407	1,650		15	258	14	182	76
2004/05	1,144	100	44				1,288	1,634		15	361	15	184	176
2005/06	1,159	107	34				1,300	1,620		15	335	16	188	147
2006/07	1,172	129	22				1,323	1,610		15	302	19	193	109
2007/08	1,178	132					1,310	1,610		15	315	20	194	120
2008/09	1,183	134					1,317	1,610		15	308	20	195	112
2009/10	1,192	136					1,328	1,610		15	297	20	197	100
2010/11	1,201	138					1,339	1,610		15	286	21	199	87

1. Includes peak demand for both OUC and St. Cloud.
2. Includes OUC's equity portion of SEC A and purchase of SEC A capacity from Southern-Florida and KUA.

Table 8-13
OUC and St. Cloud Summer Reserve Requirements – Low Load and Energy Growth Scenario

Year	Retail Peak Demand[1] (MW)	Contracted Firm Sales (MW)					Total Peak Demand (MW)	Available Capacity (MW)			Available Reserves (MW)	Required Reserves (MW)		Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
		RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed[2]	Reliant PPA	TECO P.R.		RCID	Total	
2002	1,117	100	104	20	75	20	1,436	1,047	577.5	15	204	15	180	23
2003	1,141	101	87	20	75	20	1,444	1,047	577.5	15	196	15	184	11
2004	1,151	112	65				1,328	1,563		15	250	17	187	63
2005	1,160	121	43				1,324	1,547		15	238	18	190	48
2006	1,173	128	22				1,323	1,533		15	225	19	193	32
2007	1,186	150					1,336	1,523		15	202	23	198	4
2008	1,193	153					1,346	1,523		15	192	23	200	(8)
2009	1,200	155					1,355	1,523		15	183	23	201	(18)
2010	1,208	157					1,365	1,523		15	173	24	203	(30)
2011	1,218						1,218	1,523		15	320	0	180	139

1. Includes peak demand for both OUC and St. Cloud.
2. Includes OUC's equity portion of SEC A and purchase of SEC A capacity from Southern-Florida and KUA.

Table 8-14. Least-Cost Expansion Plan – Low Load and Energy Growth Scenario

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2002	577.5 MW Reliant Power Purchase (09/30/2002)	$143,656	$143,656
2003	Terminate 577.5 MW Reliant Power Purchase (09/30/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	$157,019	$289,044
2004		$184,584	$447,295
2005		$187,354	$596,022
2006		$193,467	$738,226
2007		$211,191	$881,960
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (11/01/2008)	$211,920	$1,015,505
2009	40 MW Reduction in Southern-Florida Power Purchase (11/01/2019)	$222,339	$1,145,237
2010	40 MW Reduction in Southern-Florida Power Purchase (11/01/2010)	$222,040	$1,265,199
2011	40 MW Reduction in Southern-Florida Power Purchase (11/01/2011)	$206,196	**$1,368,348**

Note: Capacity is stated at average annual temperature for OUC.

Table 8-15. Least-Cost Expansion Plan – No. 2 Fuel Oil Scenario

Year	No. 2 Fuel Oil ($/MBtu)[1]	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2002	4.35	577.5 MW Reliant Power Purchase	$146,419	$146,419
2003	4.31	30 MW Unspecified Purchase* (06/01/2003 – 09/30/2003) Terminate 577.5 MW Reliant Power Purchase (09/30/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	$162,293	$296,691
2004	4.26	Start 100 MW Reliant Power Purchase (10/01/2004)	$192,800	$461,986
2005	4.25		$202,170	$622,476
2006	4.29	Terminate 100 MW Reliant Power Purchase (09/30/2006) 156 MW GE 7FA Simple Cycle CT (10/01/2006)	$211,220	$777,728
2007	4.37		$233,866	$936,893
2008	4.43	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (11/01/2008)	$240,888	$1,088,693
2009	4.50		$261,114	$1,241,051
2010	4.60	40 MW Reduction in Southern-Florida Power Purchase (11/01/2010)	$265,462	$1,384,472
2011	4.67	40 MW Reduction in Southern-Florida Power Purchase (11/01/2011)	$253,210	**$1,511,140**

Note: Capacity is stated at average annual temperature for OUC.
1. No. 2 fuel oil forecast represents delivered, nominal price.
* Available purchase power alternatives are discussed in Section 6.3.1. Lower loads resulting from the events of September 11, 2001 may actually eliminate the need for this purchase.

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. 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 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 Stanton A to be installed for commercial operation on October 1, 2003 and also applies to future combustion turbines installed at Stanton.

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 to support the scheduled October 1, 2003 commercial operation date.

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.

Currently, a natural gas pipeline is planned to be installed to connect Stanton A to the Florida Gas Transmission (FGT) system. The pipeline will be approximately 2.5 miles in total length, connecting with FGT's system south of the Stanton site. The pipeline is planned to be routed in the existing transmission and railroad spur right-of-way. Other pipelines may be considered as competing pipelines are successful in getting approved for construction in the State.

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

Stanton A, a GE 7FA 2x1 combined cycle unit, will utilize lox NO_x combustors as well as selective catalytic reduction (SCR) to reduce NO_x emissions. The resulting expected NO_x emissions are 3.5 parts per million (ppm). The HRSG will be designed to include a spool piece for a CO catalyst, but installation of the CO catalyst is not required at this time. No. 2 fuel oil will be used as an alternate fuel and SO_2 emissions will be controlled by limiting the sulfur content of the oil.

9.4 Water and Wastewater

The use of combined cycle technology reduces the amount of water required by Stanton A as compared to conventional steam generation. Stanton A will obtain water in the same manner as the existing Stanton units with ground water being used for steam cycle makeup and water injection. Treated sewage effluent from the Orange County Easterly Subregional Wastewater Treatment Plant will be used for Stanton A, as it is currently used for Stanton 1 and Stanton 2 and for other Stanton A service water requirements.

The Stanton site is designed to reuse wastewater to the extent possible. When wastewater cannot be reused, it is evaporated with a brine concentrator/crystalizer; thus, the Stanton site is truly a zero discharge site. Stanton A will utilize the same wastewater treatment process as the existing Stanton units.

10.0 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 2002 OUC Ten-Year Site Plan.

Table 10-1 (Schedule 1)
OUC and St. Cloud Existing Generating Facilities as of December 31, 2001

(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
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 10-2 (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
1992	301,100	2.58	1,358	116,495	11,657	325	15,217	21,358
1993	306,300	2.59	1,406	118,452	11,870	327	15,408	21,223
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	362,043	2.56	1,821	141,546	12,865	318	17,172	18,519
2001	372,217	2.55	1,893	145,762	12,987	316	17,281	18,286
Forecast								
2002	377,317	2.55	1,928	147,765	13,048	330	17,429	18,934
2003	384,481	2.55	1,979	150,570	13,143	335	17,611	19,022
2004	392,026	2.55	2,031	153,559	13,226	341	17,782	19,177
2005	400,087	2.55	2,084	156,716	13,298	345	17,957	19,213
2006	406,821	2.55	2,134	159,390	13,389	349	18,128	19,252
2007	414,155	2.55	2,184	162,263	13,460	353	18,300	19,290
2008	422,263	2.55	2,241	165,478	13,543	356	18,487	19,257
2009	431,415	2.55	2,304	169,064	13,628	360	18,686	19,266
2010	440,237	2.55	2,368	172,561	13,723	364	18,888	19,271
2011	448,666	2.55	2,431	175,865	13,823	367	19,083	19,232

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

Table 10-3 (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				
1992	2,051	2,639	777,188	0	25	4	3,763
1993	2,075	2,752	753,997	0	25	4	3,837
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
Forecast							
2002	3,113	4,678	665,512	0	34	6	5,411
2003	3,261	4,798	679,706	0	38	6	5,619
2004	3,339	4,920	678,659	0	41	6	5,758
2005	3,420	5,050	677,228	0	45	6	5,900
2006	3,512	5,180	677,992	0	48	6	6,049
2007	3,609	5,313	679,277	0	51	6	6,203
2008	3,689	5,459	675,765	0	54	6	6,346
2009	3,776	5,615	672,484	0	58	6	6,504
2010	3,866	5,773	669,669	0	61	6	6,665
2011	3,955	5,927	667,285	0	64	6	6,823

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

Table 10-4 (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
1992	0	127	3,890	0	119,134
1993	0	175	4,012	0	121,204
1994	0	141	4,144	0	123,685
1995	0	188	4,375	0	126,423
1996	0	174	4,471	0	128,862
1997	0	226	4,565	0	133,030
1998	0	175	4,909	0	137,688
1999	0	198	5,011	0	141,893
2000	0	259	5,291	0	145,963
2001	0	95	5,308	0	150,536
Forecast					
2002	841	255	6,507	0	152,443
2003	861	264	6,744	0	155,368
2004	819	268	6,845	0	158,479
2005	812	276	6,988	0	161,766
2006	819	282	7,150	0	164,570
2007	935	290	7,428	0	167,576
2008	955	298	7,599	0	170,937
2009	968	304	7,776	0	174,679
2010	980	310	7,955	0	178,334
2011	0	320	7,143	0	181,792

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 data is not provided for these sales, as they were not previously included in the FRCC Forms.

Table 10–5 (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
1992	763	0	763	0	0	0	-	763
1993	760	0	760	0	0	0	-	760
1994	808	0	808	0	0	0	-	808
1995	862	0	862	0	0	0	-	862
1996	852	0	852	0	0	0	-	852
1997	917	0	917	0	0	0	-	917
1998	988	0	988	1	0	0	-	987
1999	1,055	0	1,055	0	0	0	-	1,055
2000	1,026	0	1,026	1	0	0	-	1,025
2001	1,040	0	1,040	0	0	0	-	1,040
Forecast								
2002	1,137	319	1,456	1	0	0	-	1,455
2003	1,178	303	1,481	1	0	0	-	1,480
2004	1,205	177	1,382	1	0	0	-	1,381
2005	1,234	164	1,398	1	0	0	-	1,397
2006	1,265	150	1,415	1	0	0	-	1,414
2007	1,295	150	1,445	1	0	0	-	1,444
2008	1,324	153	1,477	1	0	0	-	1,476
2009	1,353	155	1,508	1	0	0	-	1,507
2010	1,385	157	1,542	1	0	0	-	1,541
2011	1,417	0	1,417	1	0	0	-	1,416

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 data is not provided for these sales, as they were not previously included in the FRCC Forms.

Table 10–6 (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)
Year	Total[2]	Wholesale[3]	Retail	Interruptible	Residential Load Management	Commercial/Industrial Load Management	Conservation	Net Firm Demand
1992/93	721	0	721	0	0	0	-	721
1993/94	731	0	731	0	0	0	-	731
1994/95	876	0	876	0	0	0	-	876
1995/96	969	0	969	0	0	0	-	969
1996/97	851	0	851	0	0	0	-	851
1997/98	814	0	814	1	0	0	-	813
1998/99	1,030	0	1,030	1	0	0	-	1,029
1999/00	1,060	0	1,060	1	0	0	-	1,059
2000/01	1,066	0	1,066	1	0	0	-	1,065
2001/02*	1,127	284	1,411	1	0	0	-	1,410
Forecast								
2002/03	1,162	300	1,462	1	0	0	-	1,461
2003/04	1,190	271	1,461	1	0	0	-	1,460
2004/05	1,217	144	1,361	1	0	0	-	1,360
2005/06	1,250	141	1,391	1	0	0	-	1,390
2006/07	1,280	151	1,431	1	0	0	-	1,430
2007/08	1,307	132	1,439	1	0	0	-	1,438
2008/09	1,336	134	1,470	1	0	0	-	1,469
2009/10	1,367	136	1,503	1	0	0	-	1,502
2010/11	1,399	138	1,537	1	0	0	-	1,536
2011/12	1,430	0	1,430	1	0	0	-	1,429

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 data is not provided for these sales, as they were not previously included in the FRCC Forms. The 2001/02 data includes the forecasts of each of these sales.
* 2001/02 data is projected; actual data is not available at this time.

Table 10–7 (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] (%)
1992	3,555	-	3,555	-	118	3,673	55.0
1993	3,617	-	3,617	-	166	3,783	56.8
1994	4,003	-	4,003	-	141	4,144	58.5
1995	4,187	-	4,187	-	188	4,375	57.0
1996	4,297	-	4,297	-	174	4,471	52.7
1997	4,339	-	4,339	-	226	4,565	56.8
1998	4,734	-	4,734	-	175	4,909	56.7
1999	4,813	-	4,813	-	198	5,011	54.2
2000	5,032	-	5,032	-	259	5,291	57.0
2001	5,213		5,213		95	5,308	56.9
Forecast							
2002	5,411	-	5,411	841	255	6,507	51.1
2003	5,619	-	5,619	861	264	6,744	52.0
2004	5,758	-	5,758	819	268	6,845	53.5
2005	5,900	-	5,900	812	276	6,988	57.1
2006	6,049	-	6,049	819	282	7,150	57.7
2007	6,203	-	6,203	935	290	7,428	58.7
2008	6,346	-	6,346	955	298	7,599	58.8
2009	6,504	-	6,504	968	304	7,776	58.9
2010	6,665	-	6,665	980	310	7,955	58.9
2011	6,823	-	6,823	0	320	7,143	53.1

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 GWh sales to FMPA, KUA, SEC, and RCID. Historical data is not provided for these sales, as they were not previously included in the FRCC Forms.
4. Forecast load factor calculation considers all retail and wholesale peak demand and energy.

Table 10-8 (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 – 2001		2002 Forecast		2003 Forecast	
	Peak Demand[2] MW	NEL GWh	Peak Demand[2] MW	NEL GWh	Peak Demand[2] MW	NEL GWh
January	1,066	458	1,410	510	1,461	531
February	788	357	1,147	419	1,254	438
March	731	390	1,171	469	1,210	488
April	853	403	1,195	496	1,201	513
May	960	459	1,308	597	1,321	617
June	983	494	1,370	623	1,382	643
July	1,012	517	1,455	677	1,480	700
August	1,040	541	1,396	690	1,420	712
September	1,012	471	1,309	570	1,328	591
October	891	435	1,225	516	1,221	535
November	711	378	1,068	457	1,105	475
December	775	405	1,131	482	1,104	501

1. Includes OUC and City of St. Cloud peak demand and NEL for historical 2001 and forecast 2002 and 2003. Forecast 2002 and 2003 also includes OUC wholesale sales to FMPA, KUA, SEC, and RCID.
2. Includes Load Management, Conservation and Interruptible Load.

Table 10-9 (Schedule 5)
Fuel Requirements[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		Units	2001 Actual	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Nuclear		Trillion BTU	5	5	5	5	5	5	5	5	5	5	5
(2)	Coal		1000 Ton	2,122	2,156	2,156	1,846	1,983	2,006	2,042	2,050	1,999	2,054	2,007
(3)	Residual[2]	Total	1000 BBL	6	93	36	1	3	4	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	6	93	36	1	3	4	0	0	0	0	0
(7)	Distillate[3]	Total	1000 BBL	12	0	0	0	0	0	0	0	0	0	0
(8)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	1000 BBL	12	0	0	0	0	0	0	0	0	0	0
(11)	Natural Gas	Total	1000 MCF	617	361	3,095	15,274	13,524	14,303	16,373	17,236	19,803	19,920	14,492
(12)		Steam	1000 MCF	29	253	535	3	8	10	0	0	0	0	0
(13)		CC	1000 MCF	0	0	2,346	15,023	13,433	13,879	14,442	15,862	16,231	17,598	12,868
(14)		CT	1000 MCF	588	108	214	245	83	414	1,931	1,374	3,572	2,322	1,624
(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 10-10 (Schedule 6.1)
Energy Sources (GWH)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	2001 – Actual[1]	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Firm Inter-region Interchange		GWH	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWH	620	501	489	469	501	489	471	501	489	471	483
(3)	Residual	Total	GWH	0	588	228	8	19	24	0	0	0	0	0
(4)		Steam	GWH	0	588	228	8	19	24	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	0	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	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(12)	Natural Gas	Total	GWH	0	273	879	2,045	1,821	1,919	2,121	2,266	2,526	2,604	1,935
(12)		Steam	GWH	0	253	535	3	8	10	0	0	0	0	0
(13)		CC	GWH	0	0	316	2,019	1,804	1,872	1,952	2,148	2,219	2,406	1,798
(14)		CT	GWH	0	20	28	23	9	37	169	118	307	198	137
(15)	Coal	Steam	GWH	5,549	5,144	5,146	4,322	4,644	4,713	4,813	4,830	4,756	4,881	4,725
(16)	NUG		GWH	1,497	0	0	0	0	0	0	0	0	0	0
(17)	Hydro		GWH		0	0	0	0	0	0	0	0	0	0
(18)	Other	Purchases	GWH		1	3	1	2	4	22	0	5	0	0
		Sales	GWH	-1,770	0	0	0	0	0	0	0	0	0	0
		Total	GWH	-1,770	1	3	1	2	4	22	0	5	0	0
(19)	Net Energy for Load[2]		GWH	5,896	6,507	6,745	6,845	6.987	7,149	7,407	7,597	7,776	7,956	7,143

1. Actual 2001 data presents sales to the City of St. Cloud, economy sales, and all sales to FMPA, KUA, SEC, and RCID within "Other." For all years of forecast, the sales to the City of St. Cloud are included in the generation by fuel type.
2. Variation in Net Energy for Load between Schedule 3.3 and Schedule 6.1 can be attributed to rounding error.

Table 10-11 (Schedule 6.2)
Energy Sources (%)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	2001 – Actual[1]	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(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	10.52%	7.70%	7.25%	6.85%	7.17%	6.84%	6.36%	6.59%	6.29%	5.92%	6.76%
(3)	Residual	Total	GWH	0.00%	9.04%	3.38%	0.12%	0.27%	0.34%	0.00%	0.00%	0.00%	0.00%	0.00%
(4)		Steam	GWH	0.00%	9.04%	3.38%	0.12%	0.27%	0.34%	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	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(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	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(12)	Natural Gas	Total	GWH	0.00%	4.20%	13.03%	29.88%	26.06%	26.84%	28.64%	29.83%	32.48%	32.73%	27.09%
(12)		Steam	GWH	0.00%	3.89%	7.93%	0.04%	0.11%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
(13)		CC	GWH	0.00%	0.00%	4.68%	29.50%	25.82%	26.19%	26.35%	28.27%	28.54%	30.24%	25.17%
(14)		CT	GWH	0.00%	0.31%	0.42%	0.34%	0.13%	0.52%	2.28%	1.55%	3.95%	2.49%	1.92%
(15)	Coal	Steam	GWH	94.11%	79.05%	76.29%	63.14%	66.47%	65.93%	64.98%	63.58%	61.16%	61.35%	66.15%
(16)	NUG		GWH	25.39%	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%	0.02%	0.04%	0.01%	0.03%	0.06%	0.30%	0.00%	0.06%	0.00%	0.00%
		Sales	GWH	-30.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Total	GWH	-30.02%	0.02%	0.04%	0.01%	0.03%	0.06%	0.30%	0.00%	0.06%	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%

1. Actual 2001 data presents sales to the City of St. Cloud, economy sales, and all sales to FMPA, KUA, SEC, and RCID within "Other." For all years of forecast, the sales to the City of St. Cloud are included in the generation by fuel type.

Table 10-12 (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	%
2002	1,047	593	319	0	1,321	1,136	1	15.11%	0	1	15.11%
2003	1,047	623	303	0	1,367	1,177	0	15.00%	0	0	15.00%
2004	1,214	364	177	0	1,401	1,204	2	15.12%	0	2	15.12%
2005	1,214	448	164	0	1,498	1,233	64	19.72%	0	64	19.72%
2006	1,214	434	150	0	1,498	1,264	27	16.95%	0	27	16.95%
2007	1,354	324	150	0	1,528	1,294	19	16.34%	0	19	16.34%
2008	1,494	324	153	0	1,665	1,323	123	23.30%	0	123	23.30%
2009	1,494	284	155	0	1,623	1,352	47	18.11%	0	47	18.11%
2010	1,494	284	157	0	1,621	1,384	8	15.51%	0	8	15.51%
2011	1,494	284	0	0	1,738	1,416	112	22.88%	0	112	22.88%

1. Installed capacity includes the City of St. Cloud's generating units.
2. Firm capacity imports include capacity purchased from Reliant (Indian River units), a 30 MW unspecified purchase (in 2003 only), capacity purchased from KUA (from Stanton A), 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 10-13 (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	%
2002/03	1,092	593	300	0	1,385	1,161	37	17.93%	0	37	17.93%
2003/04	1,273	391	271	0	1,394	1,189	15	16.16%	0	15	16.16%
2004/05	1,273	475	144	0	1,605	1,216	193	29.70%	0	193	29.70%
2005/06	1,273	461	141	0	1,594	1,249	143	25.58%	0	143	25.58%
2006/07	1,448	351	151	0	1,649	1,279	161	26.41%	0	161	26.41%
2007/08	1,448	351	132	0	1,668	1,306	148	25.30%	0	148	25.30%
2008/09	1,623	311	134	0	1,801	1,335	248	31.85%	0	248	31.85%
2009/10	1,623	311	136	0	1,799	1,366	210	28.95%	0	210	28.95%
2010/11	1,623	271	138	0	1,757	1,398	130	23.49%	0	130	23.49%
2011/12	1,623	231	0	0	1,855	1,429	214	29.94%	0	214	29.94%

1. Installed capacity includes the City of St. Cloud's generating units.
2. Firm capacity imports include capacity purchased from Reliant (Indian River units), capacity purchased from KUA (from Stanton A), 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	A	Stanton Energy Center	CT	NG	DFO	PL	TK	10/2001	10/2003	UNK	173	188	167	181.	U
Stanton	UNK	Stanton Energy Center	GT	NG	DFO	PL	TK	10/2005	10/2006	UNK	148	184	140	175	P
Stanton	UNK	Stanton Energy Center	GT	NG	DFO	PL	TK	06/2007	06/2008	UNK	148	184	140	175	P

1. Capability ratings reflect OUC's ownership share of Stanton A.

Table 10-15 (Schedule 9)
Status Report and Specifications of Proposed Generation Facilities

(1)	Plant Name and Unit Number:	Stanton A	Combustion Turbine 1	Combustion Turbine 2
(2)	Capacity[1]			
	a. Summer:	167	140 MW	140 MW
	b. Winter:	181	175 MW	175 MW
(3)	Technology Type:	CT	GT	GT
(4)	Anticipated Construction Timing			
	a. Field construction start-date:	11/2001	10//2006	06//2207
	b. Commercial in-service date:	10/2003	10//2007	06//2008
(5)	Fuel			
	a. Primary fuel:	NG	NG	NG
	b. Alternate fuel:	DFO	DFO	DFO
(6)	Air Pollution Control Strategy	Low NO_x burners with SCR	Low NO_x burners	Low NO_x burners
(7)	Cooling Method	Cooling Tower	NA	NA
(8)	Total Site Area	3,280[2] acres	NA[3]	NA[3]
(9)	Construction Status	U	P	P
(10)	Certification Status	Certified	NA	NA
(11)	Status with Federal Agencies	Complete	Not begun	Not begun
(12)	Projected Unit Performance Data			
	Planned Outage Factor (POF):	CONFIDENTIAL	1.92	1.92
	Forced Outage Factor (FOF):	CONFIDENTIAL	1.96	1.96
	Equivalent Availability Factor (EAF):	CONFIDENTIAL	96.2	96.2
	Resulting Capacity Factor (%):	CONFIDENTIAL	3.6	4.3
	Average Net Operating Heat Rate (ANOHR):		11,500	11,393
(13)	Projected Unit Financial Data			
	Book Life (Years):	CONFIDENTIAL	20	20
	Total Installed Cost (In-Service Year $/kW):	CONFIDENTIAL	451	470
	Direct Construction Cost ($/kW):	CONFIDENTIAL	394	394
	AFUDC Amount ($/kW):	CONFIDENTIAL	7	8
	Escalation ($/kW):	CONFIDENTIAL	50	68
	Fixed O&M ($/kW-Yr)[4]:	CONFIDENTIAL	5.39	5.39
	Variable O&M ($/MWH)[4]:	CONFIDENTIAL	2.45	2.45
	K Factor:	CONFIDENTIAL	1.1061	1.1061

1. Capacity ratings for Stanton A represent OUC's 28 percent ownership share of the unit.
2. Represents total area of the Stanton Energy Center site.
3. Because no site has been finalized for Combustion Turbine 1 or 2, 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.
4. O&M projections are indicated in 2002 dollars.