OUC

The *Reliable* One

2001 Ten-Year Site Plan

Orlando Utilities Commission

April 2001

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1.0 Executive Summary

This report documents the 2001 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 Power 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, City of Lakeland (Lakeland), Kissimmee Utility Authority (KUA), and the Florida Municipal Power Agency (FMPA) All-Requirements Project. Power for OUC is supplied by the OUC jointly owned generation and power purchases. The total installed generating capacity based on OUC's ownership share is 1,092 MW winter and 1,047 MW summer as of January 1, 2001. The existing supply system has a broad range of generation technology and fuel diversity with coal providing the largest portion of OUC's energy requirement.

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 a 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 ranging from 2002 to 2004 depending upon the level of optional capacity purchased from Reliant.

OUC is currently seeking certification of Stanton A under the Florida Electrical Power Plant Siting Act. Stanton A is a 633 MW combined cycle unit to be built at Stanton Energy Center with a 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 with options to purchase all of Southern-Florida's capacity for an additional 20 years.

Four 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 cost programs to rank the expansion plans according to total cumulative present worth costs over a 20-year planning period. Several sensitivity analyses were performed to determine the impact on the least-cost alternatives as well.

Based on the detailed modeling of the OUC system, forecast of electrical demand and energy, forecast of fuel prices and availability, and environmental considerations, Table 1-1 presents the least-cost expansion plan.

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

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	162,239	162,239
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	171,252	320,806
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	182,007	476,848
2004	171 MW Joint Development with Southern - Florida (10/03)	220,059	651,537
2005	317 MW Southern - Florida Power Purchase (10/03)	221,751	814,531
2006	100 MW Indian River Power Purchase (10/03 - 09/04)	216,636	961,970
2007	100 MW Indian River Power Purchase (10/04 - 09/05)	230,334	1,107,119
2008	100 MW Indian River Power Purchase (10/05 - 09/06)	245,040	1,250,098
2009	156 MW GE 7FA Simple Cycle (06/07)	264,023	1,392,741
2010	156 MW GE 7FA Simple Cycle (06/08)	271,624	1,528,621

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

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 145,410 active services for 2000. Of these, 125,523 are residential services, 15,262 are general service non-demand services, and the remaining, 4,262 are general service demand services. St. Cloud's service area consisted of a year-end average of 17,995 active services for 2000.

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. OUC, KUA, FMPA and Southern-Florida are currently seeking certification of Stanton A under the supplemental provisions of the Florida Electrical Power Plant Siting Act. 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.

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.

2.2 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.

Table 2-1
Summary of OUC Generation Facilities

Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max Nameplate MW	Net Capability[1]	
				Pri	Alt	Pri	Alt				Summer MW	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.

- City of Lakeland 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 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 the City of Lakeland. McIntosh Unit 3 has supplementary oil and refuse fuel burning capability and also is capable of burning up to 20 percent petroleum coke. 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.

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, 1999, 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 gas and oil for fuel.

Table 2-2
Power Purchase Agreements

Company	Capacity	Duration
TECO PR	15 MW	Through 12/31/2012
Reliant	593 MW	10/01/1999 - 09/30/2001
Reliant	577.5 MW	10/01/2001 - 09/30/2003

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]Based on 633 MW rating of 70° F.	

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 and can be supplied by other OUC units if the capacity is available.

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 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 twelve 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 also 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:

- Upgrade the 69 kV line from KUA to the City of St. Cloud. Expected completion date is in 2003.
- Addition of the Grant to Robinson 115 kV transmission line. Expected completion date is in 2002.
- Addition of second bus tie transformer at the Southwood Substation. Expected completion date is in 2004.

Figure 2-1
Orlando Utilities Commission Service Territory

2.6 Service Area

OUC's service area encompasses approximately 394 square miles. This estimate includes the service OUC provides to the City of St. Cloud 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.

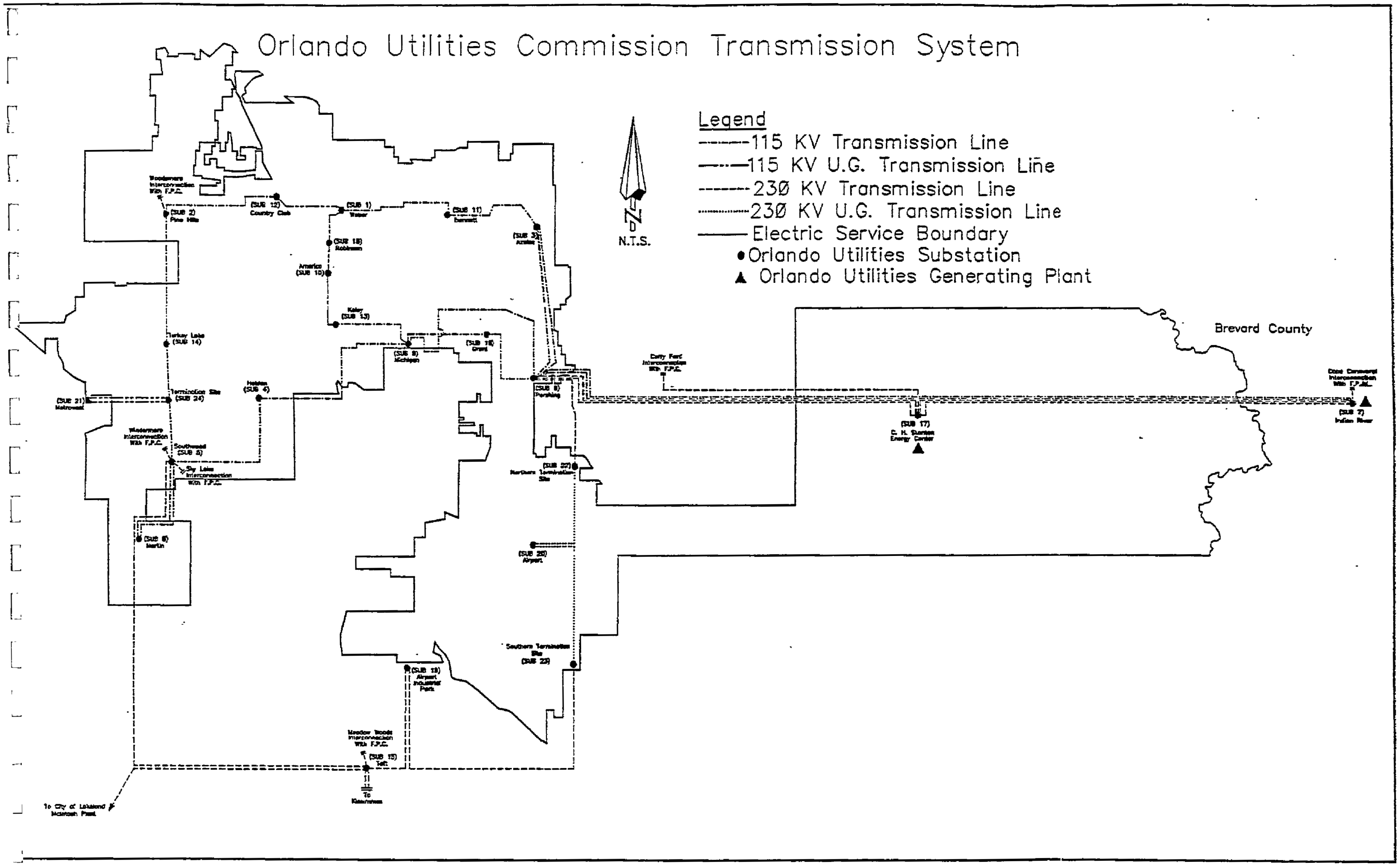
Orlando Utilities Commission Transmission System
Legend
115 KV Transmission Line
115 KV U.G. Transmission Line
230 KV Transmission Line
230 KV U.G. Transmission Line
Electric Service Boundary
Orlando Utilities Substation
Orlando Utilities Generating Plant
N.T.S.
Brevard County

Figure 2-1

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
- Transmission Business Unit
- Electric Distribution 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. 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 addition of new units.

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 the City of Lakeland'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)

Plant Name	Winter Capacity				Summer Capacity			
	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	759	65	247	1071	754	64	207	1025
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 cost of oil and 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 mix of RDF and coal. OUC's use of alternative or renewable fuels is further enhanced by burning a mix of petroleum coke in McIntosh Unit 3 along with coal and RDF. Petroleum coke is a waste by-product of the refining industry and besides the benefits of using a waste product, petroleum coke's lower prices results in significant savings over coal. Tests have been done, indicating 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 also allows the selection of either oil or gas.

3.1.2 Transmission Business Unit

Transmission Business Unit (TBU) also continues to generate new revenues by leasing space on OUC facilities for wireless personal communications systems and leasing dark fiber to other telecommunications companies. It is also marketing its expertise to other utilities and commercial customers.

TBU is also responsible for dispatching all generation for OUC and the Florida Municipal Power Pool (FMPP). The pool consists of OUC, Lakeland Electric, Kissimmee Utility Authority and the Florida Municipal Power Agency's All Requirements Project. TBU has operated the pool since its inception in 1988. Section 3.3 of this report provides additional details regarding FMPP and its strategic importance to OUC.

3.1.3 Electric Distribution Business Unit

OUC's Electric Distribution Business Unit (EDBU) is moving forward to use its superior record for reliability to develop new business and to prosper in a deregulated utility industry.

In 1997, EDBU restructured the business unit to take it to the next level of performance. It established a new Division of Costs and Control responsible for all of the business unit's financial operations. EDBU has also added a director of business development to market its expertise to other utilities and secure other revenue-making opportunities for OUC. EDBU is also going beyond the meter to offer customers expanded power quality services.

OUC's leadership in providing reliable electric distribution service is further demonstrated by its commitment to making initial investments in high quality material and equipment, implementing aggressive preventive maintenance programs, and placing more than 40 percent of its electric distribution lines underground which reduces the potential for accidental contacts with live wires and poles and also enhances the appearance of streets, and commercial and residential areas.

During 1999, OUC continued to experience the best reliability in the State of Florida for both the OUC and St. Cloud service area. In addition, OUC has an excellent record for the time it takes to restore outages, a measure of reliability required by the Florida Public Service Commission to be reported on a calendar year basis. That rate has been further improved from 64 minutes in 1998 to 62 minutes in 1999 to 59 minutes in 2000.

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 lesser competitive oil and gas steam units with more competitive combined cycle generation as well as the alternative of purchasing power when it is more economical for OUC customers.

3.3 Florida Municipal Power Pool

In 1988, OUC joined with the City of Lakeland and Florida Municipal Power Agency's All Requirements and 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 member's 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 the 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 power supply is also enhanced by twelve 230 kV interconnections with other Florida utilities, including five interconnections with Florida Power Corporation (FPC), three with Kissimmee Utility Authority (KUA), and one each with Florida Power and Light (FP&L), 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 unit as well as low heat rate.

Further demonstrating their environmental commitment to clean air, OUC has signed a contract to burn the methane gas collected from the Orange County landfill adjacent to Stanton Energy Center. Methane gas, when released into the atmosphere, is considered to be 20 times worse than carbon dioxide in terms of possible global warming effects. Both Stanton units have the capability of burning methane. In addition to their commitment to clean air, OUC is also equally committed to minimizing the environmental and esthetic 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 esthetic 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. 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. A proud and energetic bunch, 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 Power Demand and Energy Consumption

OUC has retained Regional Economic Research, Inc. (RER) to develop forecasts of power demand and energy consumption. The initial forecast scope was to develop a sales forecast for the OUC budgeting process and short-term financial planning. The scope was then extended to develop a long-term energy and demand forecast through 2020. 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.

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 1999. This provides 8 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:

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

Residential Customer Forecast. The number of customers is forecasted as a simple function of household projections for the Orlando 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 0.997 with an in-sample Mean Absolute percent Error (MAPE) of 0.2 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 0.71 with an in-sample MAPE of 4.2 percent. Given that St. Cloud is a relatively small part of OUC's service territory, the 4.2 percent average customer forecast error represents a relatively small number of total system customers. Combined, the average model error (the Mean Absolute Deviation) is 744 customers; this compares with an average number of customers over the estimation period of 123,100. The combined error is less than 1 percent. The model statistics are included in Appendix A. Figure 4-1 shows the residential customer forecast.

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:

$$Cooling_t = CoolIndex_t * CoolUse_t$$

$$Heating_t = HeatIndex_t * HeatUse_t$$

$$BaseUse_t = BaseIndex_t * OtherUse_t$$

End-Use Index Variables. The end-use index variables (*CoolIndex*, *HeatIndex*, and *BaseIndex*) are illustrated in Figure 4-2. These variables are designed to capture both increases in appliance saturation and changes in the relative efficiency of the stock.

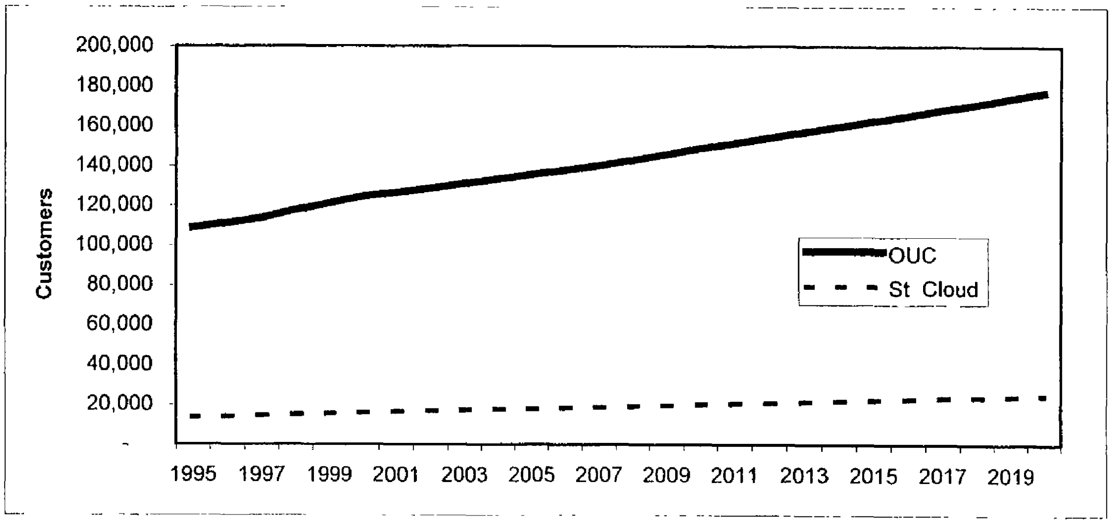

Figure 4-1
Residential Customer Forecast

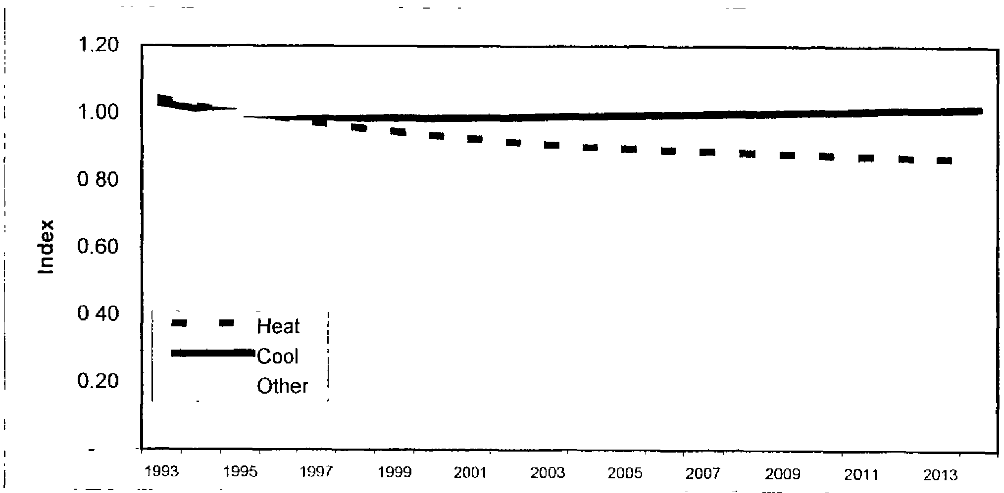

Figure 4-2
End-Use Trend Variables

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.

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).

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 52.43 kWh compared with residential monthly average usage of 1,033 kWh. All the model coefficients are highly significant (exhibiting P-values less than 0.05). The St. Cloud model explains slightly less of the variation in average use, with an adjusted R^2 of 0.91 and an in-sample MAPE of 5.6 percent. The model coefficients are highly significant.

Figure 4-3 shows projected average residential use on an annual basis and Figure 4-4 depicts projected residential sales.

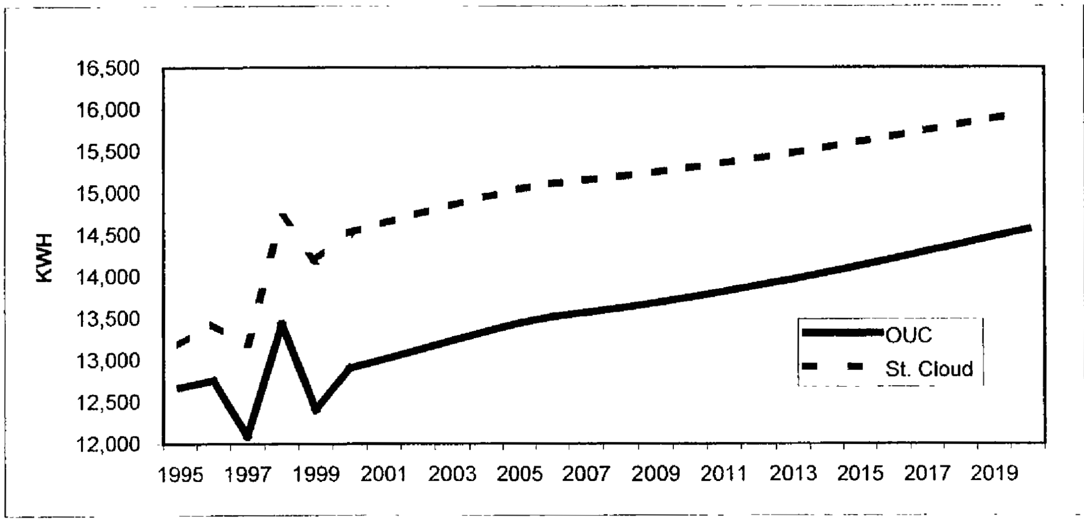

Figure 4-3
Residential Average Use Forecast (kWh)

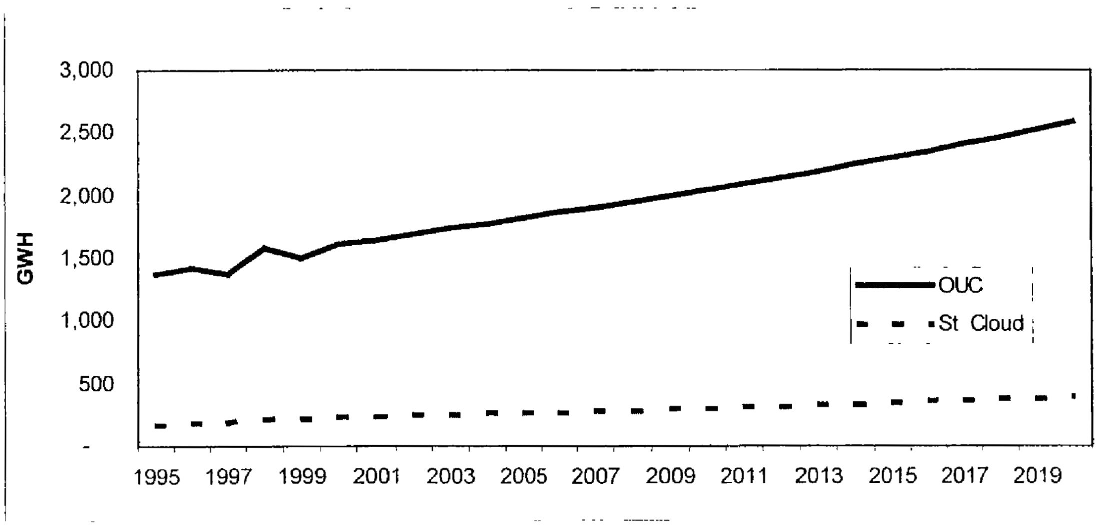

Figure 4-4
Residential Sales Forecast (GWh)

4.1.2 Non-residential 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.

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

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

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 1999. For OUC, the overall model adjusted R^2 is 0.996 with an in-sample MAPE of 0.20 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 0.73, with an in-sample MAPE of 3.45 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. Figure 4-5 shows the GSND customer forecasts.

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:

$$Cooling_t = CoolIndex_t * CoolUse_t$$

$$Heating_t = HeatIndex_t * HeatUse_t$$

$$BaseUse_t = BaseIndex_t * OtherUse_t$$

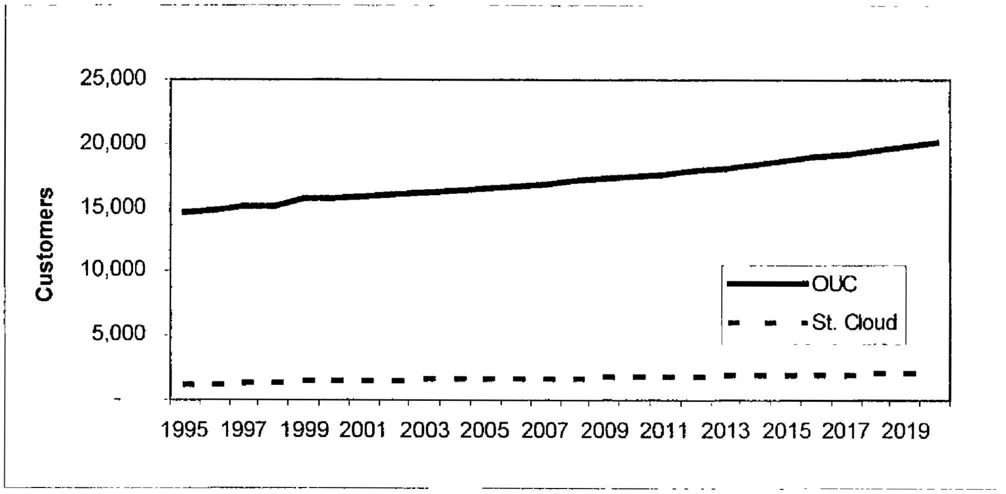

Figure 4-5
GSND Customer Forecast

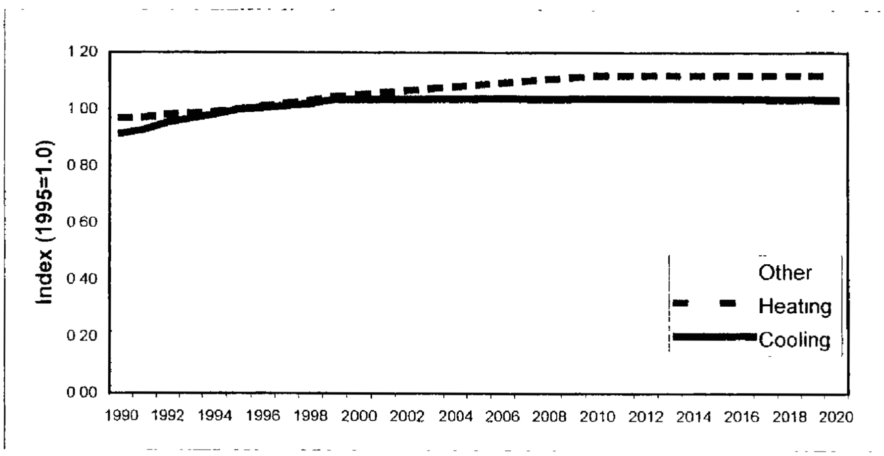

Figure 4-6
Commercial End-Use Index Projections (1995 = 1.0)

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 days of actual commercial heating (utilization of the heating stock) the heating index has relatively little impact on overall GSND average use. Figure 4-6 depicts the end-use trend variables.

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

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

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

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

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

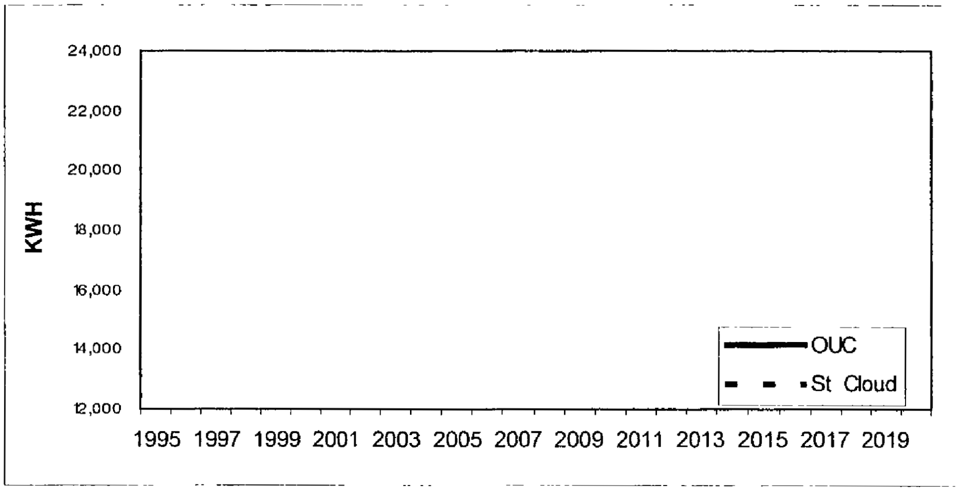

Figure 4-7
GSND Average Use Forecast (kWh)

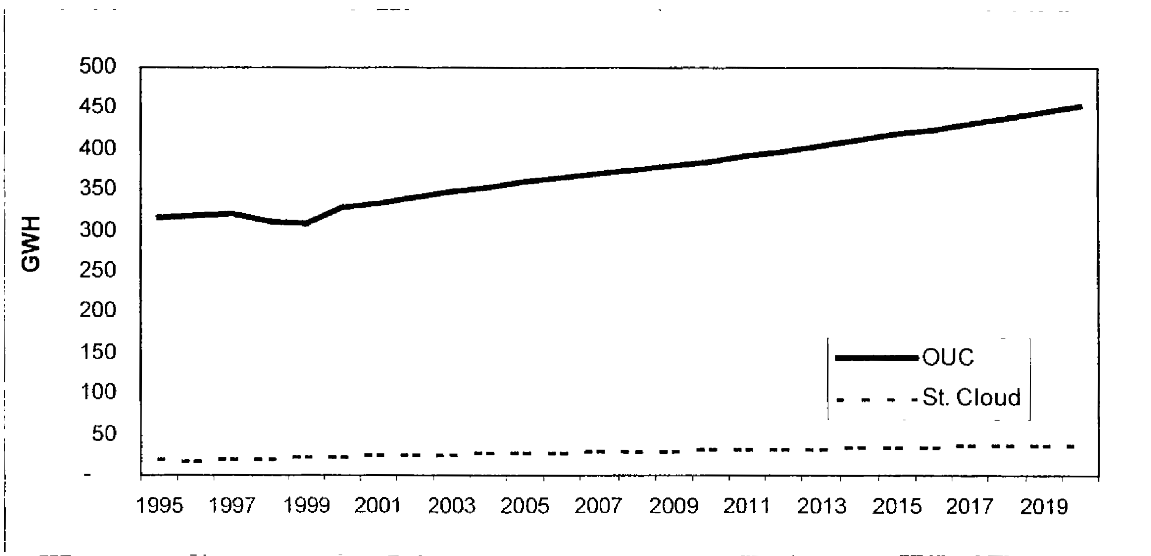

Figure 4-8
GSND Sales Forecast (GWh)

are highly significant. The adjusted R^2 for the OUC GSND average use model is 0.99 with an in-sample MAPE of 2.8 percent. For St. Cloud the GSND average use model has an adjusted R^2 of 0.86, with an in-sample MAPE of 4.1 percent. Figure 4-7 shows forecasted GSND average use on an annual basis. Total GSND sales are depicted in Figure 4-8. Model results are included in Appendix A.

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, an internet switching center, and the continued expansion at Universal Studios. Aggregate new-project load is shown in Figure 4-9.

Figure 4-10 shows total forecasted GSD loads for OUC and St. Cloud.

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 3.4 GWh a year through the forecast period. Figures 4-11 and 4-12 show forecasted street lighting sales.

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 1999. 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*

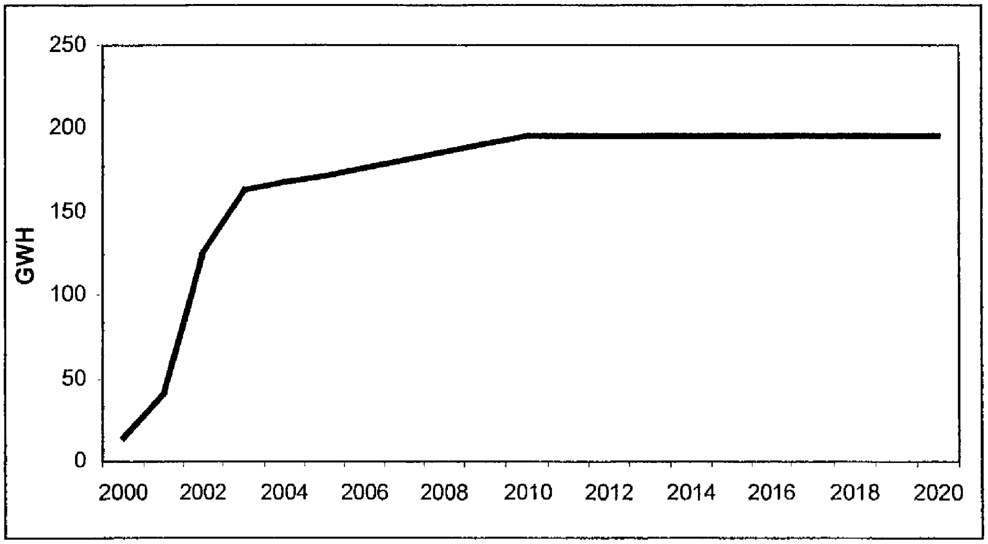

Figure 4-9
New GSD Load (GWh)

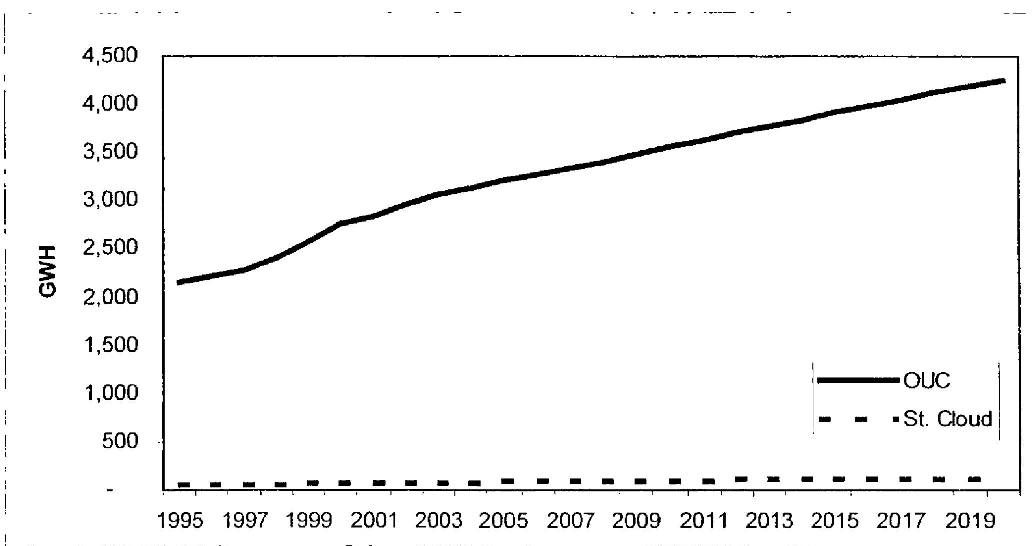

Figure 4-10
GSD Sales Forecast (GWh)

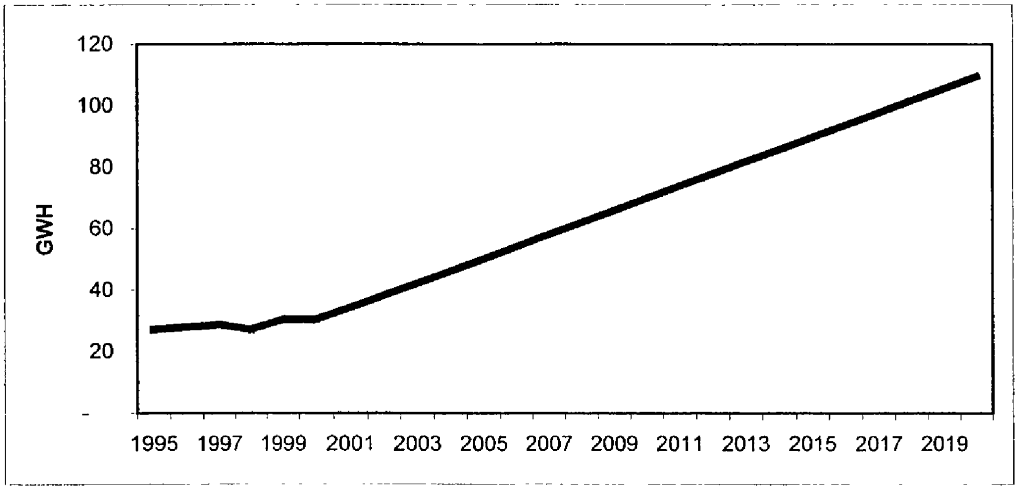

Figure 4-11
OUC Street Light Sales Forecast (GWh)

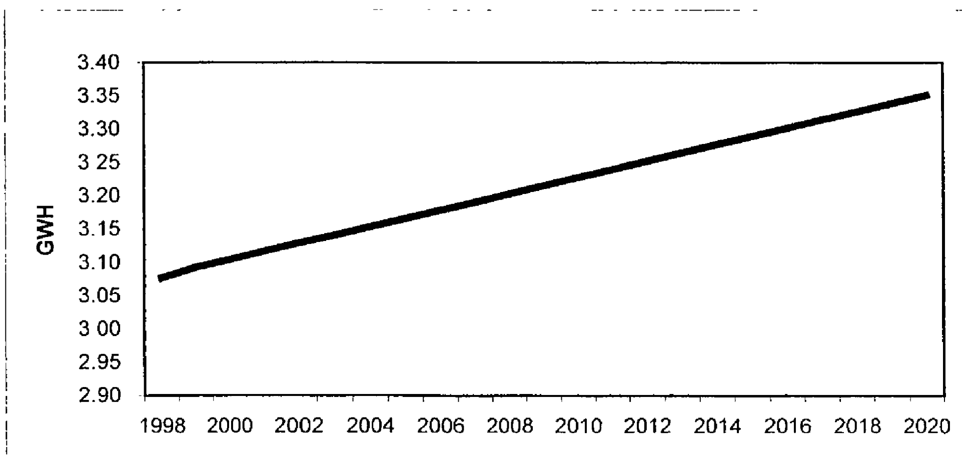

Figure 4-12
St. Cloud Street Light Sales Forecast (GWh)

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. In the on-peak hours (6:00 a.m. to 8:00 p.m.) adjusted R^2 varies from 0.65 to 0.81, with MAPEs that vary from 4.0 percent to 2.4 percent. The off-peak fractional models have adjusted R^2 values that vary from 0.65 to as low as 0.35. The low R^2 in the off-peak model is attributable to significant "noise" in the off-peak load data that can't be explained by weather or day-type variables. Still, even the models with low R^2 values have MAPEs of less than 4 percent.

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:

$$ResSaleTrend_m = 12\text{-month moving average (Residential Sales)}$$

$$NonResTrend_m = 12\text{-month moving average (Nonresidential Sales)}$$

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. The model adjusted R^2 is 0.95, with a MAPE of 2.6 percent. 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.

The resulting hourly load forecast for January and July of 2001 are depicted in Figures 4-13 and 4-14.

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. Figure 4-15 shows forecasted summer and winter system peak for the combined OUC and St. Cloud load requirements.

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 through 2005. Thereafter, adjustments were made to create a more conservative economic outlook.

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. Employment growth over this period is 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 2010), employment is assumed to continue to grow at the more conservative state growth rate forecasted by RFA. The slower growth is extrapolated beyond 2010 using an exponential smoothing model. The same process is used to develop a more conservative regional forecast of gross output. The resulting long-term employment and output growth (after

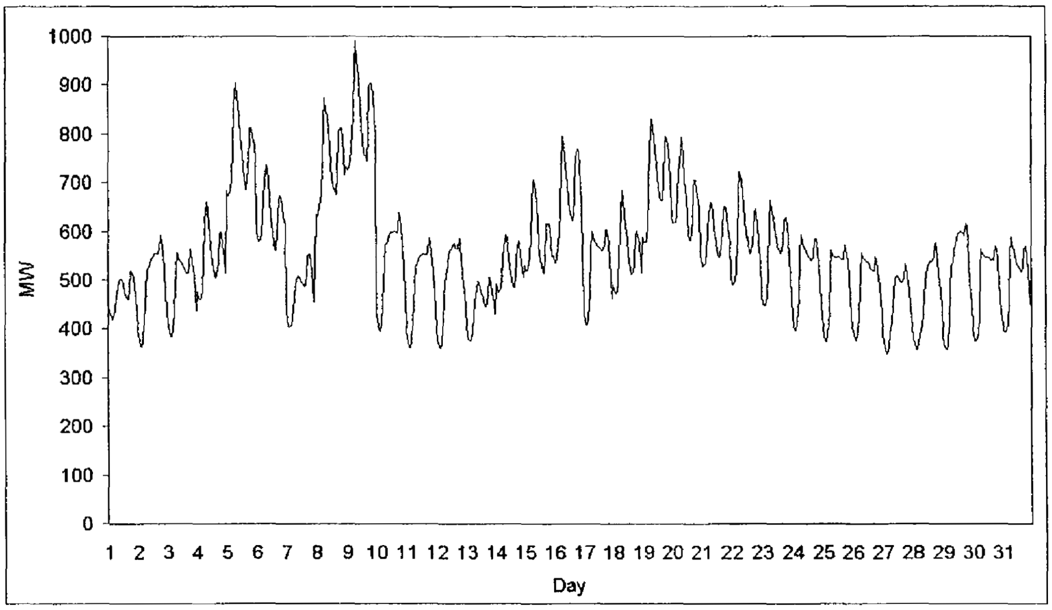

Figure 4-13
January OUC Hourly Load for 2001 (MW)

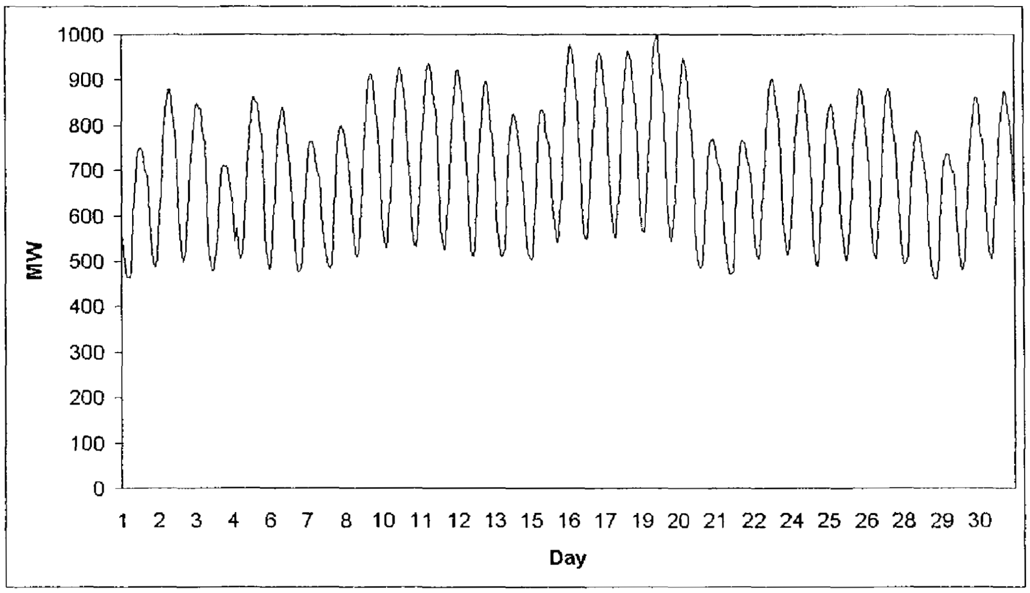

Figure 4-14
July OUC Hourly Load for 2001 (MW)

2010) is lower than RFA's outlook for Orlando and the state, and consistent with the University of Florida's long-term population forecast for the region. 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 2010 the number of households and real income are assumed to grow at the slower state rate. After 2010, population is assumed to grow at the rate projected by the University of Florida. Household projections are then calculated by dividing population projections by household size (number of household members) projections. An exponential smoothing model is used to extrapolate household size beyond 2010. Table 4-2 shows annual population, household, and real income forecast.

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. Historical and projected prices are depicted on Figure 4-16. The average annual price series is provided in Table 4-3.

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.

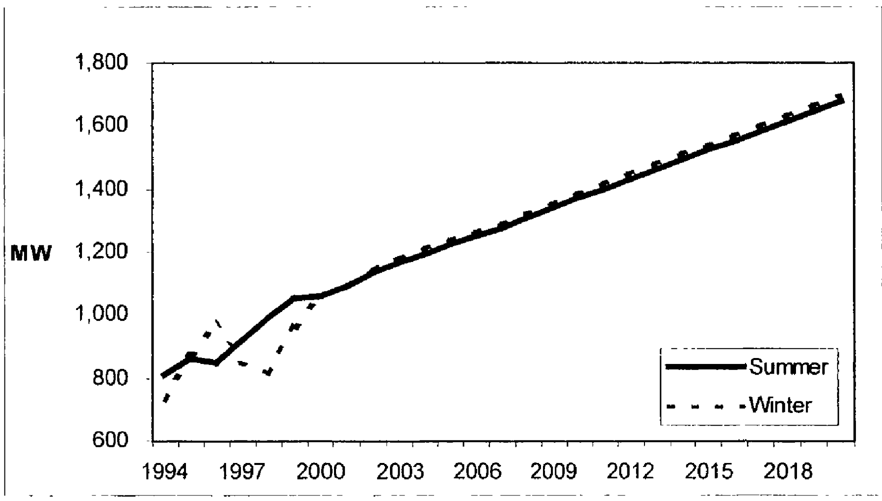

Figure 4-15
Summer and Winter System Peak Forecasts (OUC and St. Cloud Combined) (MW)

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	35.8
1996	146.7	41.3	304.4	44.5	81.6	37.8
1997	154.2	44.3	329.7	46.0	83.9	40.3
1998	158.7	46.2	354.7	49.3	86.9	43.1
1999	166.1	47.7	373.6	52.2	89.5	44.9
2000	171.2	49.4	391.1	54.4	91.9	46.8
2005	183.5	56.2	456.4	59.9	98.3	54.7
2010	197.7	63.5	540.9	66.5	105.2	64.9
2015	209.3	70.5	631.6	72.9	112.8	76.2
2020	220.6	77.5	722.1	79.1	120.3	87.4
Change	Percent	Percent	Percent	Percent	Percent	Percent
1996	5.3	7.0	5.6	5.5	2.5	5.6
1997	5.1	7.4	8.3	3.3	2.9	6.4
1998	3.0	4.3	7.6	7.2	3.5	7.0
1999	4.7	3.2	5.3	5.9	3.1	4.2
00-05	1.4	2.6	3.1	2.0	1.3	3.2
05-10	1.5	2.5	3.5	2.1	1.4	3.5
10-15	1.1	2.1	3.1	1.8	1.4	3.2
15-20	1.1	1.9	2.7	1.7	1.3	2.8

Table 4-2
Population, Household, and Income Projections

Year	Real Income per HH	Households (Thousands)	Population (Thousands)
1992	54,673	491	1,306
1993	56,031	499	1,337
1994	56,957	508	1,366
1995	57,724	520	1,393
1996	59,487	534	1,427
1997	61,079	551	1,468
1998	63,582	567	1,509
1999	64,343	582	1,545
2000	65,684	596	1,577
2005	70,545	655	1,723
2010	74,207	721	1,894
2015	78,478	791	2,079
2020	83,331	863	2,273
Change	Percent	Percent	Percent
1993	2.5	1.6	2.3
1994	1.7	1.8	2.1
1995	1.3	2.3	2.0
1996	3.1	2.8	2.4
1997	2.7	3.1	2.9
1998	4.1	3.0	2.8
1999	1.2	2.7	2.3
00-05	1.4	1.9	1.8
05-10	1.0	2.0	1.9
10-15	1.1	1.9	1.9
15-20	1.2	1.8	1.8

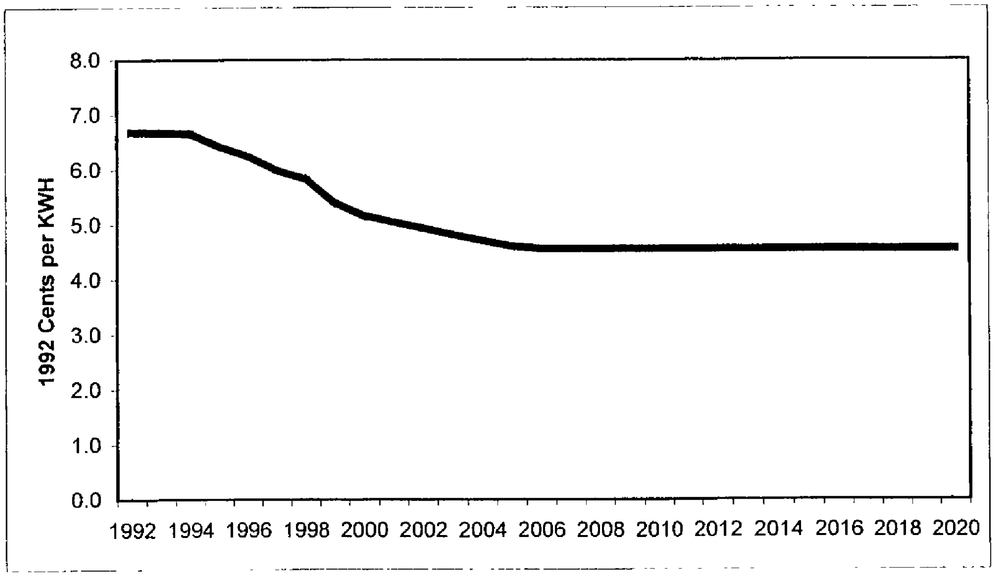

Figure 4-16
Historical and Forecasted Average Electricity Prices
(1992 Cents per kWh)

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	6.3
1997	6.0
1998	5.8
1999	5.4
2000	5.2
2005	4.6
2010	4.6
2015	4.6
2020	4.6
Change	**Percent**
1993	-0.1
1994	-0.4
1995	-3.4
1996	-2.7
1997	-4.1
1998	-2.7
1999	-7.3
00-05	-2.3
05-10	-0.2
10-15	0.0
15-20	0.0

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° if average daily temperature is less than 65°. 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:

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

Figure 4-17 shows historical and forecasted monthly CDD. The forecast begins in 2000.

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

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

HDD_d equals 65° minus the average daily temperature, if the average daily temperature is less than or equal to 65, and equals 0° if the daily temperature is greater than 65°. 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:

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

Figure 4-18 depicts the resulting HDD series. The forecast begins in 2000.

4.3 Base Case Load Forecast

A short-term monthly budget forecast was estimated through 2002, with a long-term annual forecast through 2020. 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.

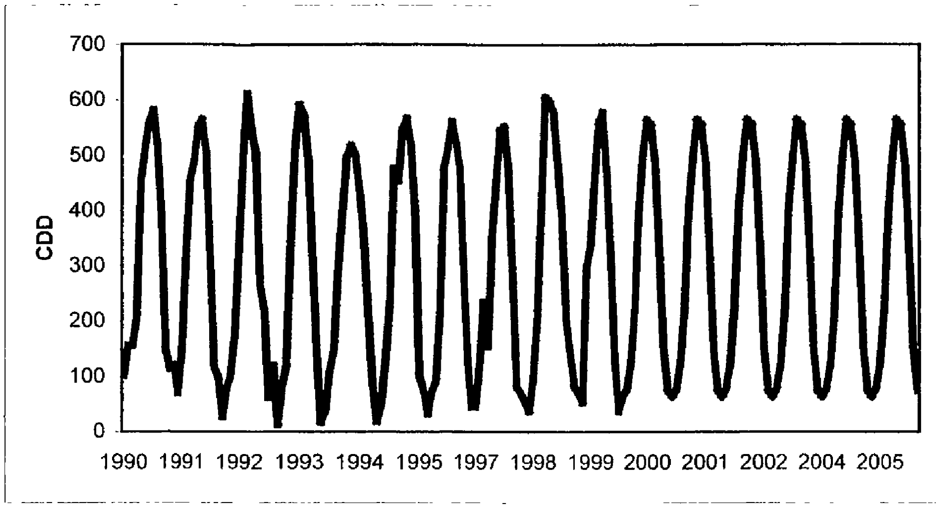

Figure 4-17
Monthly Cooling Degree Days

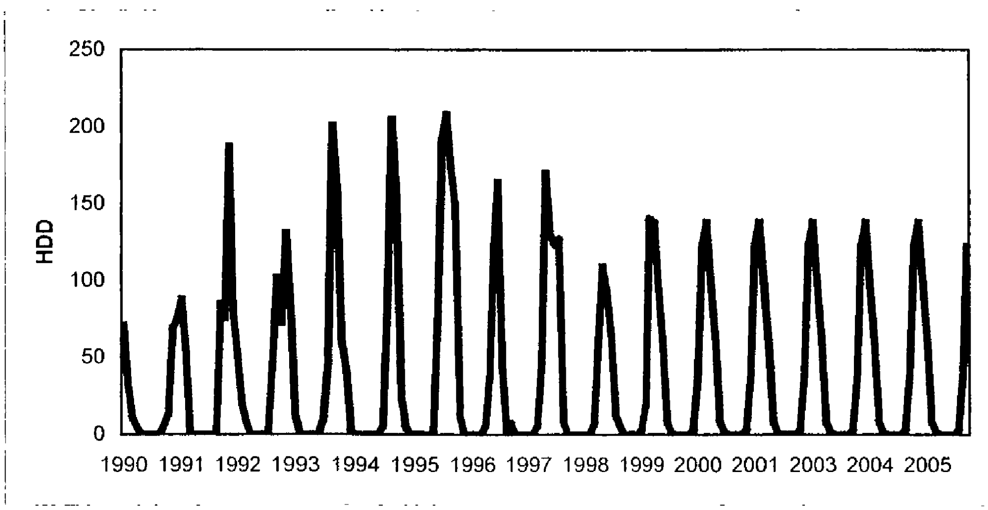

Figure 4-18
Heating Degree Days

Models are estimated using monthly sales data covering the period 1991 through 1999. 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 and Figure 4-19 summarize 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 1999, population has grown at an average annual rate of 2.6 percent and real gross output has grown at 5.8 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 1.6 percent and 3.9 percent, respectively. Orlando is expected to exceed overall state economic growth throughout the next 10 years. Figure 4-20 compares relative employment projections of Orlando and Florida. By indexing total employment to 1.0 in 1993, it is easier to compare the growth projected for Orlando and Florida.

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	1,062	1,051	5,363
2005	1,227	1,239	6,192
2010	1,372	1,386	6,925
2015	1,522	1,539	7,692
2020	1,679	1,697	8,492
Change	percent	percent	percent
95-99	4.1	2.0	2.7
00-05	2.9	3.3	2.9
05-10	2.3	2.3	2.3
10-15	2.1	2.1	2.1
15-20	2.0	2.0	2.0

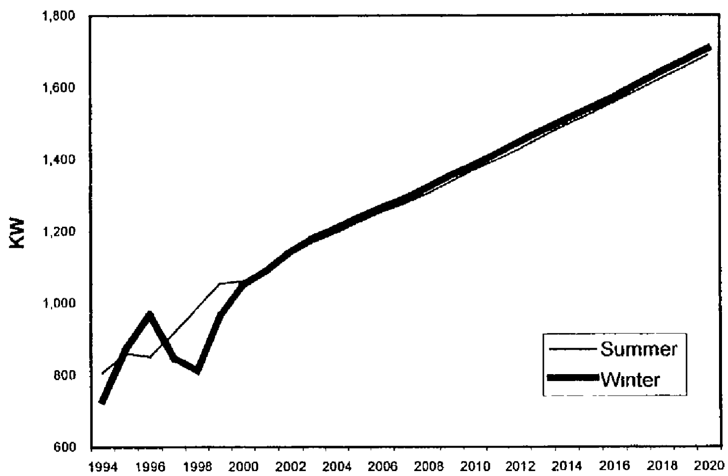

Figure 4-19
Summer and Winter System Peak Forecasts
(OUC and St. Cloud Combined) (MW)

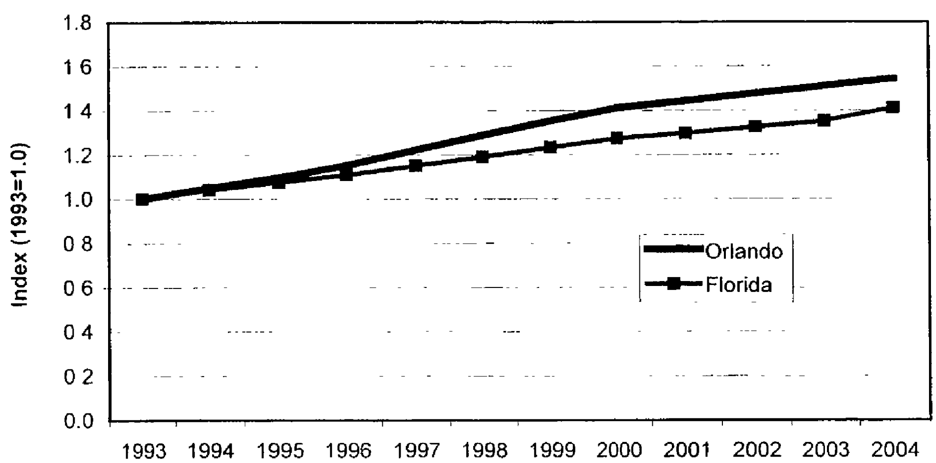

Figure 4-20
Relative Employment Performance (RFA) (1993=1.0)

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.

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, with the largest being the new Hard Rock Hotel and complex that will open this year. The new Orlando convention center is expected to open in 2002, further fueling regional convention and tourism activity. In addition, Lockheed Martin is planning to open a commercial flight-training and simulation center, which is expected to draw thousands of pilots seeking training and recertification. Top employers in the Orlando MSA are shown in Table 4-5.

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.

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 582,000 in 1999 to 863,000 by 2020, representing an average annual growth rate of 1.9 percent. Employment is projected to grow at 2.1 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.

Table 4-5
Largest Regional Employers

Employer	Number of Employees
Walt Disney World Company	55,000
Florida Hospital	11,210
Publix Super Markets, Inc.	<9,000
Winn-Dixie Stores, Inc.	8,978
Orlando Regional Healthcare System	8,200
Universal Studios Escape	7,000
Central Florida Investments, Inc.	5,000
Central Florida Healthcare System	4,500
Sun Trust Bank Central Florida	4,244
Darden Restaurants, Inc.	4,200
Lockheed Martin Electronics & Missiles	3,800
Sprint Communications Company	3,747
Source: RFA	

Table 4-6 summarizes economic projections for the Orlando MSA. 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. University of Florida's long-term population projections for the region are used to drive household growth after 2010.

4.3.2 Forecast Results

Based upon the previously discussed economic assumptions, total retail sales for OUC are expect to increase from 4,488 GWh in 1999 to 7,569 GWh by 2020. St. Cloud sales are projected to increase from 320.5 GWh to 573.6 GWh. Sales and customer projections are summarized in Tables 4-7 through 4-10.

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 0.8 percent and slow to 0.6 percent by the end of the forecast period. 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 1.8 percent rate for OUC and 2.2 percent rate for St. Cloud between 2000 and 2020. The OUC and St. Cloud residential sales forecasts are shown in Tables 4-11 and 4-12, respectively.

Small Commercial Sales Forecast. GSND sales are projected to grow at an average annual rate of 1.9 percent and 2.6 percent for OUC and St. Cloud respectively between 1999 and 2020. 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 the most of the GSND sales gains. The GSND customer forecast is driven by regional nonmanufacturing employment projections. The number of GSND customers is projected to grow at an average annual growth rate of 1.2 percent and 1.7 percent respectively for OUC and St. Cloud from 1999 to 2020. Tables 4-13 and 4-14 show annual GSND forecasts for OUC and St. Cloud.

Table 4-6
Orlando MSA Economic Projections

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57724	723	757	4.5	36
1996	534	59487	750	780	3.8	38
1997	551	61079	788	815	3.4	40
1998	567	63582	816	842	3.0	43
1999	582	64343	854	879	2.9	45
2000	596	65684	882	908	2.8	47
2005	655	70545	977	1013	3.5	55
2010	721	74207	1084	1122	3.4	65
2015	791	78478	1205	1248	3.4	76
2020	863	83331	1340	1387	3.4	87
Change	Percent	Percent	Percent	Percent	Percent	Percent
1996	2.8	3.1	3.8	3.0	-	5.6
1997	3.1	2.7	4.9	4.5	-	6.4
1998	3.0	4.1	3.7	3.2	-	7.0
1999	2.7	1.2	4.6	4.5	-	4.2
00-05	1.9	1.4	2.1	2.2	-	3.2
05-10	2.0	1.0	2.1	2.1	-	3.5
10-15	1.9	1.1	2.1	2.1	-	3.2
15-20	1.8	1.2	2.1	2.1	-	2.8

Table 4-7
OUC Long-Term Sales Forecast (GWH)

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St. Lts.	OUC Use	Total Retail
1995	1380	316	2154	27	-	55	3932
1996	1419	318	2211	28	-	61	4037
1997	1377	322	2274	29	-	56	4057
1998	1583	310	2405	27	-	78	4404
1999	1504	308	2570	30	-	76	4488
2000	1606	329	2756	31	-	78	4800
2005	1822	360	3207	33	17	100	5539
2010	2046	386	3561	36	34	122	6185
2015	2298	418	3913	39	51	145	6863
2020	2579	454	4259	42	67	167	7569
Change	percent	percent	percent	percent	percent	percent	percent
1996	2.8	0.5	2.7	3.1	-	11.7	2.7
1997	-3.0	1.2	2.8	2.3	-	-8.4	0.5
1998	15.0	-3.5	5.8	-5.4	-	39.9	8.5
1999	-5.0	-0.8	6.9	11.8	-	-3.1	1.9
00-05	2.5	1.8	3.1	1.8	-	5.2	2.9
05-10	2.3	1.4	2.1	1.7	14.9	4.1	2.2
10-15	2.3	1.6	1.9	1.6	8.4	3.4	2.1
15-20	2.3	1.7	1.7	1.5	5.9	2.9	2.0

Table 4-8
OUC Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	108845	14572	2970	126387
1996	111241	14855	3120	129216
1997	113808	15065	3445	132319
1998	117868	15168	3799	136836
1999	121173	15659	3871	140703
2000	124484	15779	4074	144337
2005	135530	16524	4560	156615
2010	148822	17474	5151	171448
2015	162621	18682	5753	187056
2020	177054	20107	6351	203512
Change	percent	percent	percent	percent
1996	2.2	1.9	5.0	2.2
1997	2.3	1.4	10.4	2.4
1998	3.6	0.7	10.3	3.4
1999	2.8	3.2	1.9	2.8
00-05	1.7	0.9	2.3	1.6
05-10	1.9	1.1	2.5	1.8
10-15	1.8	1.3	2.2	1.8
15-20	1.7	1.5	2.0	1.7

Table 4-9
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	74	3	320
2000	234	23	80	3	340
2005	271	27	94	3	396
2010	309	31	108	3	451
2015	351	34	123	3	511
2020	396	38	136	3	574
Change	percent	percent	percent	percent	percent
1996	5.5	-1.5	11.0	-	6.2
1997	0.8	1.1	9.4	-	3.0
1998	15.2	9.4	7.1	-	13.7
1999	0.2	8.5	2.4	0.5	1.3
00-05	3.0	3.1	3.4	0.4	3.1
05-10	2.7	2.6	2.8	0.4	2.7
10-15	2.6	2.2	2.5	0.4	2.5
15-20	2.5	1.9	2.1	0.4	2.3

Table 4-10
St. Cloud Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	13659	1293	116	15068
1996	14158	1311	132	15602
1997	14527	1359	140	16026
1998	15010	1427	150	16586
1999	15594	1522	152	17268
2000	16092	1553	163	17807
2005	18026	1714	182	19923
2010	20208	1886	203	22296
2015	22472	2037	219	24728
2020	24841	2188	236	27264
Change	percent	percent	percent	percent
1996	3.7	1.4	13.9	3.5
1997	2.6	3.6	6.1	2.7
1998	3.3	5.0	6.9	3.5
1999	3.9	6.6	1.6	4.1
00-05	2.3	2.0	2.3	2.3
05-10	2.3	1.9	2.1	2.3
10-15	2.1	1.6	1.6	2.1
15-20	2.0	1.4	1.5	2.0

Table 4-11
OUC Residential Sales Forecast Summary

Year	Retail Sales	Customers	Average Use (kWh)
1995	1380	108845	12679
1996	1419	111241	12765
1997	1377	113808	12096
1998	1583	117868	13430
1999	1504	121173	12411
2000	1606	124484	12905
2005	1822	135530	13443
2010	2046	148822	13749
2015	2298	162621	14128
2020	2579	177054	14565
Change	percent	percent	percent
1996	2.8	2.2	0.6
1997	-3.0	2.3	-5.2
1998	15.0	3.6	11.0
1999	-5.0	2.8	-7.6
00-05	2.5	1.7	0.8
05-10	2.3	1.9	0.5
10-15	2.3	1.8	0.5
15-20	2.3	1.7	0.6

Table 4-12
St. Cloud Residential Sales Forecast Summary

Year	Retail Sales (GWH)	Customers	Average Use (kWh)
1995	180	13659	13194
1996	190	14158	13431
1997	192	14527	13191
1998	221	15010	14713
1999	221	15594	14197
2000	234	16092	14522
2005	271	18026	15045
2010	309	20208	15298
2015	351	22472	15606
2020	396	24841	15956
Change	percent	percent	percent
1996	5.5	3.7	1.8
1997	0.8	2.6	-1.8
1998	15.2	3.3	11.5
1999	0.2	3.9	-3.5
00-05	3.0	2.3	0.7
05-10	2.7	2.3	0.3
10-15	2.6	2.1	0.4
15-20	2.5	2.0	0.4

Table 4-13
OUC General Service Nondemand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWh)
1995	316	14572	21713
1996	318	14855	21400
1997	322	15065	21353
1998	310	15168	20465
1999	308	15659	19657
2000	329	15779	20853
2005	360	16524	21764
2010	386	17474	22074
2015	418	18682	22382
2020	454	20107	22577
Change	Percent	Percent	Percent
1996	0.5	1.9	-1.4
1997	1.2	1.4	-0.2
1998	-3.5	0.7	-4.2
1999	-0.8	3.2	-3.9
00-05	1.8	0.9	0.9
05-10	1.4	1.1	0.3
10-15	1.6	1.3	0.3
15-20	1.7	1.5	0.2

Table 4-14
St. Cloud General Service Nondemand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWh)
1995	19	1293	14426
1996	18	1311	14004
1997	19	1359	13660
1998	20	1427	14229
1999	22	1522	14484
2000	23	1553	14967
2005	27	1714	15769
2010	31	1886	16316
2015	34	2037	16813
2020	38	2188	17197
Change	percent	percent	percent
1996	-1.5	1.4	-2.9
1997	1.1	3.6	-2.5
1998	9.4	5.0	4.2
1999	8.5	6.6	1.8
00-05	3.1	2.0	1.0
05-10	2.6	1.9	0.7
10-15	2.2	1.6	0.6
15-20	1.9	1.4	0.5

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 5.8 percent in 1998 and 6.9 percent in 1999. 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 the GSND to GSD. The GSD customer forecast is driven by total employment projections and total sales by projected regional gross output. Tables 4-15 and 4-16 summarize the GSD forecast.

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 4-17 and 4-18 show seasonal peak demands and net energy for load forecasts for OUC and St. Cloud.

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. The High and Low Case Scenarios were developed by modifying the Base Case economic assumptions. The primary drivers that were modified are regional population, labor force, employment, output, and income. Table 4-19 shows a comparison of the economic assumptions.

4.5.1 High Case Scenarios

The high scenario is based upon assumptions of continued strong economic growth. We assume that through 2005, area population growth does not slow, but continues to expand at a rate experienced over the last few years. After 2005, the number of households increases 0.5 percent to 0.4 percent faster than the base case. 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. Employment and regional output in the high case scenario are somewhat constrained by the relatively low unemployment rate already assumed in the base case. We assume that

Table 4-15
OUC Large General Service Demand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWh)
1995	2154	2970	725046
1996	2211	3120	708721
1997	2274	3445	660036
1998	2405	3799	632959
1999	2570	3871	663841
2000	2756	4074	676550
2005	3207	4560	703253
2010	3561	5151	691198
2015	3913	5753	680176
2020	4259	6351	670635
Change	percent	percent	percent
1996	2.7	5.0	-2.3
1997	2.8	10.4	-6.9
1998	5.8	10.3	-4.1
1999	6.9	1.9	4.9
00-05	3.1	2.3	0.8
05-10	2.1	2.5	-0.3
10-15	1.9	2.2	-0.3
15-20	1.7	2.0	-0.3

Table 4-16
St. Cloud Large General Service Demand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWh)
1995	56	116	479495
1996	62	132	467126
1997	67	140	481841
1998	72	150	482554
1999	74	152	486316
2000	80	163	488021
2005	94	182	516042
2010	108	203	534083
2015	123	219	559371
2020	136	236	578504
Change	percent	percent	percent
1996	11.0	13.9	-2.6
1997	9.4	6.1	3.2
1998	7.1	6.9	0.1
1999	2.4	1.6	0.8
00-05	3.4	2.3	1.1
05-10	2.8	2.1	0.7
10-15	2.5	1.6	0.9
15-20	2.1	1.5	0.7

Table 4-17
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	973	956	5006
2005	1123	1127	5777
2010	1253	1258	6451
2015	1389	1394	7156
2020	1529	1535	7890
Change	Percent	Percent	Percent
95-00	4.0	3.6	4.1
00-05	2.9	3.3	2.9
05-10	2.2	2.2	2.2
10-15	2.1	2.1	2.1
15-20	1.9	2.0	2.0

Table 4-18
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	89	95	357
2005	104	113	415
2010	118	128	474
2015	134	145	536
2020	150	162	602
Change	Percent	Percent	Percent
95-00	7.2	4.7	5.4
00-05	3.1	3.3	3.1
05-10	2.7	2.6	2.7
10-15	2.5	2.5	2.5
15-20	2.3	2.2	2.3

Table 4-19
Economic Assumptions

Economic Projections: Orlando MSA

High Scenario

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57,724	723	757	4.5	36
2000	596	65,684	882	908	2 8	47
2005	687	68,479	1,038	1,075	3.5	56
2010	779	70,938	1,188	1,229	3.3	67
2015	875	74,998	1,358	1,404	3 3	81
2020	978	80 575	1 554	1 606	3 3	96
95-00	2.8%	2 6%	4.1%	3 7%	-	5.5%
00-05	2.9%	0.8%	3.3%	3.4%	-	3 6%
05-10	2.5%	0 7%	2.7%	2 7%	-	3.7%
10-15	2 3%	1 1%	2 7%	2.7%	-	3.7%
15-20	2.3%	1 4%	2 7%	2 7%	-	3 5%

Base Scenario

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57,724	723	757	4 5	36
2000	596	65,684	882	908	2 8	47
2005	655	70,545	977	1,013	3 5	55
2010	721	74,207	1,084	1,122	3 4	65
2015	791	78,478	1,205	1,248	3 4	76
2020	863	83,331	1,340	1,387	3 4	87
95-00	2.8%	2 6%	4 1%	3 7%	-	5.5%
00-05	1 9%	1 4%	2 1%	2 2%	-	3.2%
05-10	2.0%	1 0%	2 1%	2 1%	-	3.5%
10-15	1 9%	1 1%	2 1%	2.1%	-	3 2%
15–20	1 8%	1 2%	2 1%	2 1%	-	2 8%

Low Scenario

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57,724	723	757	4 5	36
2000	596	65,684	882	908	2 8	47
2005	641	65,666	929	988	5 9	50
2010	679	66,812	974	1,047	7 0	55
2015	712	69,916	1,030	1,107	7.0	61
2020	743	74,118	1,085	1,166	7 0	66
95-00	2 8°/	2 6%	4.1%	3 7%	-	5 5%
00-05	1 5%	0 0%	1.0%	1 7%	-	1.3%
05-10	1 1%	0 3%	1.0%	1 2%	-	1 9%
10-15	0 9%	0 9%	1 1%	1 1%	-	2 0%
15-20	0.9%	1 2%	1 1%	1 1%	-	1 8%

there is only a slight improvement in the unemployment rate, as a relatively high labor force participation rate is already incorporated in RFA's base case forecast. Given that the number of households increases at a faster rate than the population during the first 10 years of the forecast (since household size declines during this period), income per household increases at a slightly lower rate than it does in the base case over the first 10 years. After 2010, household income grows at roughly the same rate as in the base case.

One other assumption was made for the high case: the Orlando area experiences stronger electricity demand due to an increase in computer-related loads. Implicit in the base case "other use" index is that computer loads increase at roughly 3 percent per year over the forecast horizon. This is based on Energy Information Administration (EIA) assumptions that have been incorporated into the EPRI COMMEND forecast model. Recently, there has been some debate as to the contribution of increased "computerization" to electric loads. In the high case scenario, we assume that computer loads increase at 6 percent annually. This results in the "other use" index (which is basically flat in the base case) increasing at a faster rate in the high case. Figure 4-21 shows a comparison of the resulting change in the commercial "other use" index.

4.5.2 Low Case Scenario

In the low case scenario, we assume that there is a significant slowdown in regional population growth. We assume that the growth in the number of households slows to 1.5 percent during the first 5 years, and declines further to a long-term growth rate of 0.9 percent. Moreover, we assume the unemployment rate averages 6.0 percent over the 20 year forecast horizon; this is not beyond the realm of possibility, given that Orlando's unemployment rate approached 8 percent during the summer of 1992. The higher unemployment rate translates into lower employment and economic output growth. Orlando's economic output is projected to increase less than 2 percent through forecast horizon. By way of comparison, growth in Orlando's gross product never dipped below 2.7 percent during the 1990s. Similarly, household income growth slows, with average household income growth remaining unchanged (in real terms) through the first 5 years, and not reaching the base case growth rate until after 2015.

4.5.3 High and Low Forecast Scenario Results

Table 4-20 summarizes the forecast scenario results, Table 4-21 summarizes the total system peak forecast, and both provide a comparison with the base case. Through 2005, high case assumptions result in an overall sales growth rate of 3.6 percent, compared with the base case growth of 2.9 percent. The growth rates narrow somewhat over the longer term, with energy requirements increasing at a 2.8 percent pace in the high case, compared with a 2.1 percent average in the base case.

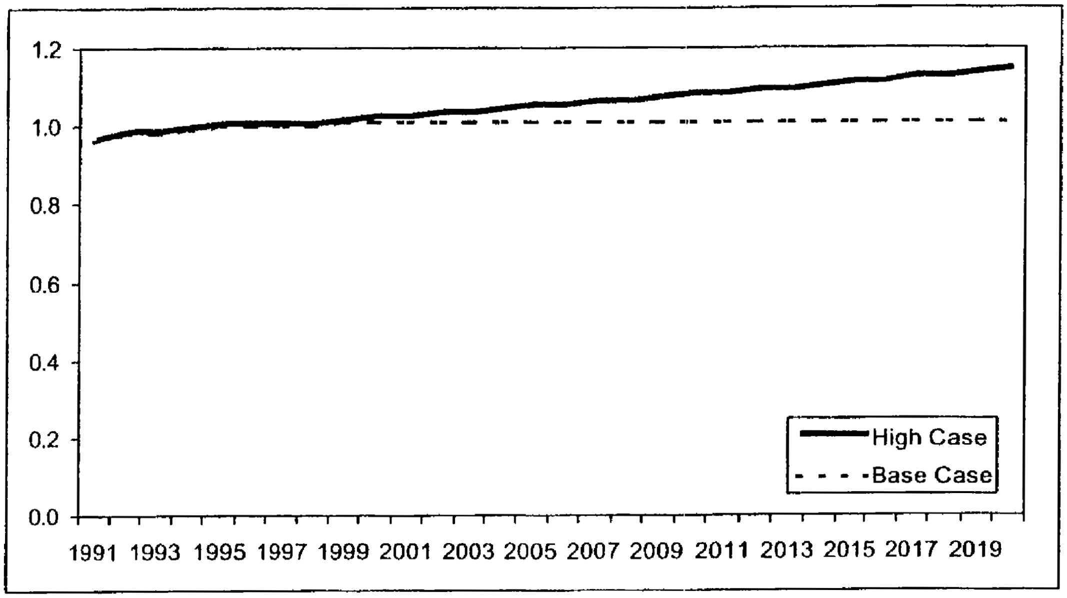

Figure 4-21
Comparison of Commercial "Other Use" Index

Table 4-20
Scenario Energy Forecast

Orlando Utilities Commission & St. Cloud

High Scenario* - G*WH

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St Lts.	OUC Use	Total Retail
1995	1,560	335	2,209	27	-	55	4,186
2000	1,840	352	2,836	34	-	78	5,139
2005	2,186	399	3,400	36	17	100	6,139
2010	2,523	444	3,878	39	34	122	7,040
2015	2,905	497	4,429	42	51	145	8,070
2020	3,348	559	5,070	45	67	167	9,258
95-00	3.4%	1.0%	5.1%	4.3%	-	7.2%	4.2%
00-05	3.5%	2.5%	3.7%	1.6%	-	5.2%	3.6%
05-10	2.9%	2.2%	2.7%	1 6%	14.9%	4.1%	2 8%
10-15	2.9%	2 3%	2.7%	1.5%	8 4%	3.4%	2 8%
15-20	2.9%	2 4%	2.7%	1.4%	5 9%	2.9%	2.8%

Base Scenario - GWH

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St Lts	OUC Use	Total Retail
1995	1,560	335	2,209	27	-	55	4,186
2000	1,840	352	2,836	34	-	78	5,139
2005	2,093	387	3,301	36	17	100	5,934
2010	2,355	417	3,669	39	34	122	6,636
2015	2,648	452	4,035	42	51	145	7,374
2020	2.975	492	4,396	45	67	167	8,143
95-00	3.4%	1 0%	5 1%	4 3%	-	7.2%	4 2%
00-05	2.5%	1.8%	3 1%	1 8%	-	5 2%	2 9%
05-10	2.3%	1 4%	2.1%	1 7%	14 9%	4.1%	2 2%
10-15	2.3%	1 6%	1.9%	1 6%	8 4%	3 4%	2 1%
15-20	2.3%	1 7%	1 7%	1 5%	5 9%	2.9%	2 0%

Low Scenario - G*WH*

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St Lts	OUC Use	Total Retail
1995	1,560	335	2,209	27	-	55	4,186
2000	1,840	352	2,836	34	-	78	5,139
2005	2,026	361	3,262	36	17	100	5,802
2010	2,177	360	3,535	39	34	122	6,268
2015	2,338	359	3,771	42	51	145	6,705
2020	2,510	360	4,004	45	67	167	7,153
95-00	3 4%	1.0%	5.1%	4 3%	-	7 2%	4 2%
00-05	1.9%	0 5%	2 9%	1 8%	-	5.2%	2 5%
05-10	1.4%	0 0%	1 6%	1 7%	14 9%	4 1%	1 6%
10-15	1 4%	-0 1%	1.3%	1 6%	8 4%	3 4%	1.3%
15-20	1 4%	0 0%	1 2%	1 5%	5 9%	2.9%	1 3%

Table 4-21
Scenario Peak Forecast

Total System Peak Forecast

High Case Scenario

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1995	861	876	4,377
2000	1,062	1,051	5,363
2005	1,265	1,273	6,384
2010	1,453	1,465	7,333
2015	1,662	1,673	8,392
2020	1,903	1,915	9,623
Average chg	Percent	Percent	Percent
95-00	4.3%	3.7%	4.1 %
00-05	3.6%	3.9%	3.5%
05-10	2.8%	2.8%	2.8%
10-15	2.7%	2.7%	2.7%
15-20	2.8%	2.7%	2.8%

Base Case Scenario

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1995	861	876	4,377
2000	1,062	1,051	5,363
2005	1,227	1,239	6,192
2010	1,372	1,386	6,925
2015	1,522	1,539	7,692
2020	1,679	1,697	8,492
chg			
95-00	4.3%	3.7%	4.1%
00-05	2.9%	3.3%	2.9%
05-10	2.3%	2.3%	2.3%
10-15	2.1%	2.1%	2 1%
15-20	2.0%	2.0%	2.0%

Low Case Scenario

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1995	861	876	4,377
2000	1,062	1,051	5,363
2005	1,177	1,193	5,940
2010	1,259	1,279	6,359
2015	1,338	1,358	6,763
2020	1,419	1,440	7,178
chg			
95-00	4.3%	3.7%	4.1%
00-05	2 1%	2.6%	2.1%
05-10	1.4%	1.4%	1 4%
10-15	1.2%	1.2%	1.2%
15-20	1.2%	1.2%	1.2%

In the low case, sales slow to a 2.5 percent pace through 2005. Energy requirements further decline as a result of weak population and employment growth to a 1.6 percent growth between 2005 and 2010 and to a 1.3 percent pace after 2010.

Over the 20 year forecast horizon, the average growth rates in total electricity retail sales for the OUC and St. Cloud service territories are: 1.7 percent in the low case, 2.3 percent in the base case, and 3.0 percent in the high case.

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. Economic conditions have also changed significantly; for example, the cost of power plants and interest rates have decreased drastically. 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 will soon be available in an interactive CD format. Beginning in the first quarter of 2001, an Internet interactive home energy audit complete with previous billing information on the customer will be available.

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), $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 the 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, as well as OUC's joint ownership share of Crystal River 3, McIntosh 3, and St. Lucie 2 operated by FPC, Lakeland Electric, and FP&L, respectively as well as St. Cloud's diesels.

6.1.2 Power Purchase Agreements.

As described in more detail in Section 2.3, OUC has a power purchase agreement in place with Reliant and schedules St. Cloud's purchase power from TECO. . Additionally, OUC is planning to purchase power from KUA.

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 through out 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 additional capacity will be needed by the winter of 2002. Furthermore, Table 6-2 shows that additional capacity will be necessary to satisfy forecast demand requirements for the summer of 2002. The majority of the capacity required in 2002 and 2003 can be satisfied by exercising the additional 10 percent option on the Reliant contract, which represents 52.5 MW. Regardless, OUC will need a substantial amount of capacity beginning with the expiration of the Reliant agreement on October 1, 2003.

6.3.2 Generator Capabilities and Requirements Forecast (with Committed Units).

As discussed in Section 2.2, 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 the Stanton Energy Center with a planned commercial operation date of October 1, 2003. The owners are currently seeking certification of Stanton A under the supplemental provisions of the Florida Electrical Power Plant Siting Act. OUC's ownership portion of Stanton A amounts to over 170 MW plus OUC has the option to purchase 80 percent of Southern-Florida's capacity under an executed Power Purchase Agreement for the next ten years with options for an additional ten years.

The current delivery schedule for combustion turbines combined with licensing and construction schedules precludes the addition of any other generating units other than Stanton A until 2005. As such, OUC will have to rely on purchase power to meet capacity requirements. For purposes of the TYSP, it is assumed that OUC will exercise its options from the Reliant PPA for 52.5 MW for fiscal years 2002 and 2003 and for 100 MW for fiscal year 2004. Tables 6-3 (Winter) and 6-4 (Summer) present OUC's capacity requirements including consideration of the above purchase power and Stanton A. Table 6-4 indicates that additional capacity is required by the summer of 2005.

6.3.3 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.

Table 6-1
OUC Winter Reserve Requirements

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2001	1,090	341	1,431	1,092	608	1,700	268	176	93
2002	1,144	323	1,467	1,092	540	1,632	165	184	(19)
2003	1,182	312	1,494	1,092	540	1,632	138	192	(54)
2004	1,210	263	1,473	1,092	15	1,107	-366	198	(564)
2005	1,239	172	1,411	1,071	15	1,086	-325	203	(528)
2006	1,267	139	1,406	1,071	15	1,086	-320	205	(525)
2007	1,292	139	1,431	1,071	15	1,086	-345	212	(558)
2008	1,323	142	1,465	1,071	15	1,086	-379	218	(597)
2009	1,356	144	1,500	1,071	15	1,086	-414	223	(637)
2010	1,386	146	1,532	1,071	15	1,086	-446	228	(673)

1. Includes St. Cloud.

Table 6-2
OUC Summer Reserve Requirements

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2001	1,092	341	1,433	1,047	608	1,653	222	176	46
2002	1,136	323	1,459	1,047	540	1,585	128	183	(55)
2003	1,170	312	1,482	1,047	540	1,585	105	190	(85)
2004	1,197	263	1,460	1,047	15	1,060	-398	196	(593)
2005	1,227	172	1,399	1,025	15	1,039	-359	201	(560)
2006	1,254	139	1,393	1,025	15	1,039	-353	203	(557)
2007	1,278	139	1,417	1,025	15	1,039	-377	210	(587)
2008	1,306	142	1,448	1,025	15	1,039	-408	215	(623)
2009	1,339	144	1,483	1,025	15	1,039	-443	220	(663)
2010	1,372	146	1,518	1,025	15	1,039	-478	225	(703)

1. Includes St. Cloud.

Table 6-3
OUC Winter Capacity Balance (With Committed Units)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2001	1090	341	1431	1092	608	1700	268	176	93
2002	1144	323	1467	1092	593	1684	218	184	33
2003	1182	312	1494	1092	593	1684	190	192	(1)
2004	1210	263	1473	1273	492	1765	293	198	95
2005	1239	172	1411	1252	376	1629	217	203	3
2006	1267	139	1406	1252	361	1614	208	205	3
2007	1292	139	1431	1252	351	1604	173	212	(39)
2008	1323	142	1465	1252	351	1604	139	218	(79)
2009	1356	144	1500	1252	351	1604	104	223	(119)
2010	1386	146	1532	1252	351	1604	72	228	(156)

Table 6-4
OUC Summer Capacity Balance (With Committed Units)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2001	1092	341	1433	1047	608	1655	222	176	46
2002	1136	323	1459	1047	593	1639	180	183	(3)
2003	1170	312	1482	1047	593	1639	157	190	(33)
2004	1197	263	1460	1213	465	1679	219	196	23
2005	1227	172	1399	1192	349	1541	142	201	(59)
2006	1254	139	1393	1192	334	1526	133	203	(70)
2007	1278	139	1417	1192	324	1516	99	210	(111)
2008	1306	142	1448	1192	324	1516	68	215	(147)
2009	1339	144	1483	1192	324	1516	33	220	(187)
2010	1372	146	1518	1192	324	1516	-2	225	(227)

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 69-230 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.

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.

7.0 Development of Supply-Side Alternatives

This section provides the description of supply-side generating unit alternatives considered by OUC. All generating unit alternatives would be located at the existing Stanton Energy Center site. 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 (PC).
- Circulating Fluidized Bed (CFB).
- Combined Cycle.
- Simple Cycle.

Table 7-1 exhibits the supply-side alternatives considered by OUC for further capacity addition planning purposes.

Table 7-1 Generation Expansion Candidates	
Simple Cycle	General Electric 7FA (156 MW)
Combined Cycle	Siemens-Westinghouse 501F 2x1 (514 MW) Siemens-Westinghouse 501F 2x1 (610 MW)
Solid Fuel	Circulating Fluidized Bed (267 MW) Pulverized Coal (446 MW)
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 in not intended to limit the alternatives to those manufacturers. Several manufacturers providing similar equipment could be utilized. The first year that the units are considered available for commercial operation is 2005.

7.1 Performance Estimates

Performance estimates have been compiled for each of the conventional capacity 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 site conditions, 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 for summer (97° F ambient), annual average (70° to 72° F ambient), and winter (30° F ambient).

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 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 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 simple and combined cycle units. Performance for solid fuel units was developed incorporating degradation.

Table 7-2
Degradation Factors

Unit	Net Output (%)	Heat Rate (%)
GE 7FA Simple Cycle	-4.04	2.87
WH 501F 2 x1 F 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 to incorporate future pulverized coal unit additions.

7.2.1 Pulverized Coal Capital Cost Estimates. Interest during construction (IDC) is not included in these estimates. Capital costs were developed based on escalating the actual Stanton 2 costs. The estimated capital cost is presented in Table 7-3

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 provided are based on Stanton 2 experience with modern facilities. Variable operations 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/maintenance of plant components based on the operating time of the plant, such as steam turbine inspection costs and catalyst replacement. The estimated O&M cost and performance are presented in Table 7-3.

Table 7-3
Generating Unit Characteristics
446 MW Pulverized Coal Unit

Total Capital Cost,[1] 2000 ($1000)	512,163
O&M Cost - Baseload Duty	
Fixed O&M Cost, 2000 ($/kW-yr)	14.17
Variable O&M Cost, 2000 ($/MWh)	3.73
Equivalent Forced Outage Rate (percent)	3.00
Planned Maintenance (days/year)	30
Construction Period (months)	42
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 site-specific costs as well as permitting and licensing.
Note: Capital cost does not include interest during construction.

7.3 Circulating Fluidized Bed

Typical atmospheric circulating fluidized bed units consist of a large boiler burning a variety of solid fuels including coal, petroleum coke, or biomass. Typically, the fuel and limestone are fluidized in a bed in the boiler with air. The fuel burns and turns water into steam. Like the PC unit, the steam created is run through a steam turbine connected to a generator to produce power. A 267 MW CFB unit with a dry scrubber and selective noncatalytic reduction (SNCR) burning petroleum coke or coal was selected as a solid fuel alternative. Petroleum coke was selected as the primary fuel based on its low market price. The CFB is assumed to be located at Stanton Energy Center and take advantage of existing infrastructure.

7.3.1 Circulating Fluidized Bed Capital Cost Estimates. The capital cost estimate was based on a recent bid to a Florida municipal utility for a unit at an existing site and is presented in Table 7-4.

7.3.2 Circulating Fluidized Bed O&M Costs and Performance Estimates. O&M and performance estimates for the petroleum coke fueled CFB were based on the following assumptions.

Fixed O&M costs include operating staff salary costs, basic plant supplies, and administrative costs. Fixed maintenance costs contain the maintenance staff salary costs and the costs of supplies associated with periodic maintenance. Staffing estimates provided are based on recent utility experience with modern facilities.

Variable operations costs include an assumed lime cost for flue gas desulfurization (FGD), waste disposal, and ammonia. Variable maintenance costs are the costs associated with the inspection/maintenance of plant components based on the operating time of the plant, such as steam turbine inspection costs. The estimated O&M cost and performance are presented in Table 7-4

Table 7-4
Generating Unit Characteristics
267 MW Circulating Fluidized Bed Unit

Total Capital Cost, 2000 ($1000)	366,076	
O&M Cost - Baseload Duty		
Fixed O&M Cost, 2000 ($/kW-yr)	23.55	
Variable O&M Cost, 2000 ($/MWh)	5.53	
Equivalent Forced Outage Rate (percent)	3.00	
Planned Maintenance (days/year)	28	
Construction Period (months)	36	
kW Output / Net Plant Heat Rate (NPHR), HHV (Btu/kWh)	Petroleum Coke	Coal
	267,000/9,831	10,087
	200,250/10,050	10,308
	133,500/10,885	11,163
	93,450/12,184	12,495

Note: Capital cost does not include interest during construction.

7.4 Combined Cycle Units

The two combined cycle units selected by OUC as generating unit alternatives are as follows:

- 2 x 1 Siemens-Westinghouse 501F – Standard size.
- 2 x 1 Siemens-Westinghouse 501F – Oversized.

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 application 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 natural gas fuel and baseload operation. The combined cycles 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 cycles include bypass stacks and dampers to allow simple cycle operation. The combined cycles also include fuel oil and demineralized water storage tanks.

7.4.1 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.

7.4.1.1 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.
- Spread footing is assumed for all foundations except major equipment and structures, which has an allowance for piling.
- 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 to be provided by the utility.
- 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.

7.4.1.2 Direct Cost Assumptions.

- Combustion turbine assumption include:
    - Dry low NO_x combustion system.
    - Fire detection and protection system.
    - Exhaust system with HRSG bypass damper and stack.
    - 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 assumption 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.

7.4.1.3 Indirect Cost Assumptions.

- General indirects include:
  - Relay checkouts and testing.
  - Instrumentation and control equipment calibration and testing.
  - Systems and plant start-up.
  - Operating crew during test and initial operation period.
  - Operating crew training.
  - Electricity and water and fuel used during construction.
- Insurance costs include:
  - General liability.
  - Builder's risk.
  - Liquidated damages.
- Engineering and related services include:
  - A/E services.
  - Outside consultants and other related costs incurred in the permitting and licensing process.
- Field construction management services include:
  - Field management staff including supporting staff personnel.
  - Field contract administration.
  - Field inspection and quality insurance.
  - Project control.

- Technical direction.
- Management of start-up and testing.
- Cleanup expense for the portion not included in the direct cost construction contracts.
- Safety and medical services.
- Insurance premiums.
- Other required labor insurance.
- Telephone and other utility bills associated with temporary services.

7.4.2 Siemens Westinghouse 2 x 1 501F Combined Cycle O&M Costs and Performance Estimates.

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 2 x 1 501F combined cycle units are presented in Table 7-5.

Table 7-5
Generating Unit Characteristics
Siemens-Westinghouse 501F Combined Cycle Units

	Standard Turbine	Oversized Turbine
Total Capital Cost ($1000)[1]	278,356	288,211
O&M Cost – Baseload Duty		
Fixed O&M Cost, 2003 ($/kW-yr)	6.32	5.32
Variable O&M Cost, 2003 ($/MWh)	3.68	3.68
Equivalent Forced Outage Rate (percent)	4.00	4.00
Planned Maintenance (days/year)	14	14
Construction Period (months)	24	24
kW Output / Net Plant Heat Rate (NPHR), at 70° F, 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. Reflects capital cost to achieve an October 1, 2003 commercial operation date.

7.5 Simple Cycle Combustion Turbine Generator

Simple cycle combustion turbine generators are supplied with fuel where it 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.

Cost estimates were based on standard plant arrangements for similar units and include adjustments for site-specific costs. Cost estimates include capital costs and O&M costs.

7.5.1 General Electric 7FA Combustion Turbine Generator 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. The capital cost estimate was developed on the basis of the current costs observed in the competitive generation market.

7.5.1.1 General Assumptions.

The plant will contain:

- One dual fueled combustion turbine.

- No consideration was given to possible future expansion.
- Spread footing assumed for all foundations except the combustion turbine, which has an allowance for piling included. Stabilization of existing subgrade is not anticipated.
- The combustion turbines will be capable of firing natural gas or No. 2 fuel oil.
- Fuel gas with adequate pressure, quantity, and suitable temperature to be provided at the site boundary.
- 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.
- A sanitary sewer treatment connection is assumed to be provided.
- Construction power is assumed to be provided.

- Natural gas available at the site boundary at the required pressure.
- Transmission hookup costs are included.
- Permitting and licensing costs are included.

7.5.1.2 Direct Cost Assumptions.

- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' service.
- Direct costs are based upon an overnight commercial operation date.
- Construction costs are based upon an engineer, procure, and construct (EPC) contracting philosophy and are based on utilizing union labor.
- Direct costs include sitework, concrete, architectural, metals, piping, insulation, mechanical equipment, electrical, and controls as identified in the detail listings.
- Direct costs include necessary substation modifications.
- Direct costs for the simple cycle alternatives include dry low NO_x burners.
- Direct costs for natural gas alternatives include a 3 day supply fuel oil storage tank for backup fuel.
- Direct costs include an allowance for startup spares.
- Buildings include:
    - General services building.
    - Maintenance shop.
    - Both are preengineered metal structures.
- Fire protection includes:
    - Standard CO_2 fire suppression system.
    - Water deluge of the transformers.
    - Hydrant protection of the cooling tower and site.

7.5.1.2 Indirect Cost Assumptions.

- General indirects include:
    - Relay checkouts and testing.
    - Instrumentation and control equipment calibration and testing.
    - Systems and plant startup.
    - Operating crew during test and initial operation period.
    - Operating crew training.
    - Electricity and water and fuel used during construction.
- Insurance costs include:
    - General liability.
    - Builder's risk

    - Liquidated damages.
- Engineering and related services include:
    - A/E services.
    - Outside consultants and other related costs incurred in the permit and licensing process.
- Field Construction Management services include:
    - Field management staff including supporting staff personnel.
    - Field contract administration.
    - Field inspection and quality assurance.
    - Project control.
    - Technical direction.
    - Management of startup and testing.
    - Cleanup expense for the portion not included in the direct cost construction contracts.
    - Safety and medical services.
    - Guards and other security services.
    - Insurance premiums.
    - Other required labor insurance.
    - Performance bond and liability insurance for equipment and tools.
    - Telephone and other utility bills associated with temporary services.
    - Shipping for equipment and materials.

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

For simple cycle units, O&M estimates are based on a maintenance cycle of 25 years. A capacity factor of 10 percent was assumed for simple cycle units.

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 disposal of combustion wastes and consumables such as scrubber additives, chemicals, lubricants, water, and maintenance repair parts.

O&M and performance estimates for the simple cycle units 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 generation (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 includes 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 the replacement and refurbishment costs.

The capital and O&M costs along with the performance estimates for the General Electric 7FA combustion turbine are presented in Table 7-6.

Table 7-6 Generating Unit Characteristics 156 MW General Electric 7FA Combustion Turbine	
Total Capital Cost, 2000 ($1000)	68,615
O&M Cost - Baseload Duty	
Fixed O&M Cost, 2000 ($/kW-yr)	5.13
Variable O&M Cost, 2000 ($/MWh)	2.33
Equivalent Forced Outage Rate (percent)	1.96
Planned Maintenance (days/year)	7
Construction Period (months)	12
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
Note: Capital cost does not include interest during construction.	

8.0 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 Black & Veatch's optimal generation expansion model POWROPT. 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 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 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, petroleum coke, natural gas, oil, and nuclear fuel. The base case forecasts are based on forecasts provided by Energy Ventures Analysis, Inc. (EVA) who were commissioned by OUC because of its fuel forecasting expertise and the belief that the EVA forecast would be the best available. EVA developed fuel forecasts for natural gas, coal, West Texas Intermediate (WTI) crude oil, and petroleum coke.

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 US fuel prices and the wide range of fluctuations and responses to market conditions. Because of the difficulty of forecasting in this environment, several sensitivity scenarios have been developed. These sensitivity scenarios include a high and low forecast based on the forecast developed from the EVA forecast, a scenario where OUC's actual 2000 fuel prices remain constant throughout the evaluation period in real terms, the 2001 Annual Energy Outlook (AEO) projections developed by the United States Department of Energy (DOE), and, finally, a scenario in which OUC's actual 2000 fuel prices escalate based on the 2001 AEO escalation rates for the various fuels.

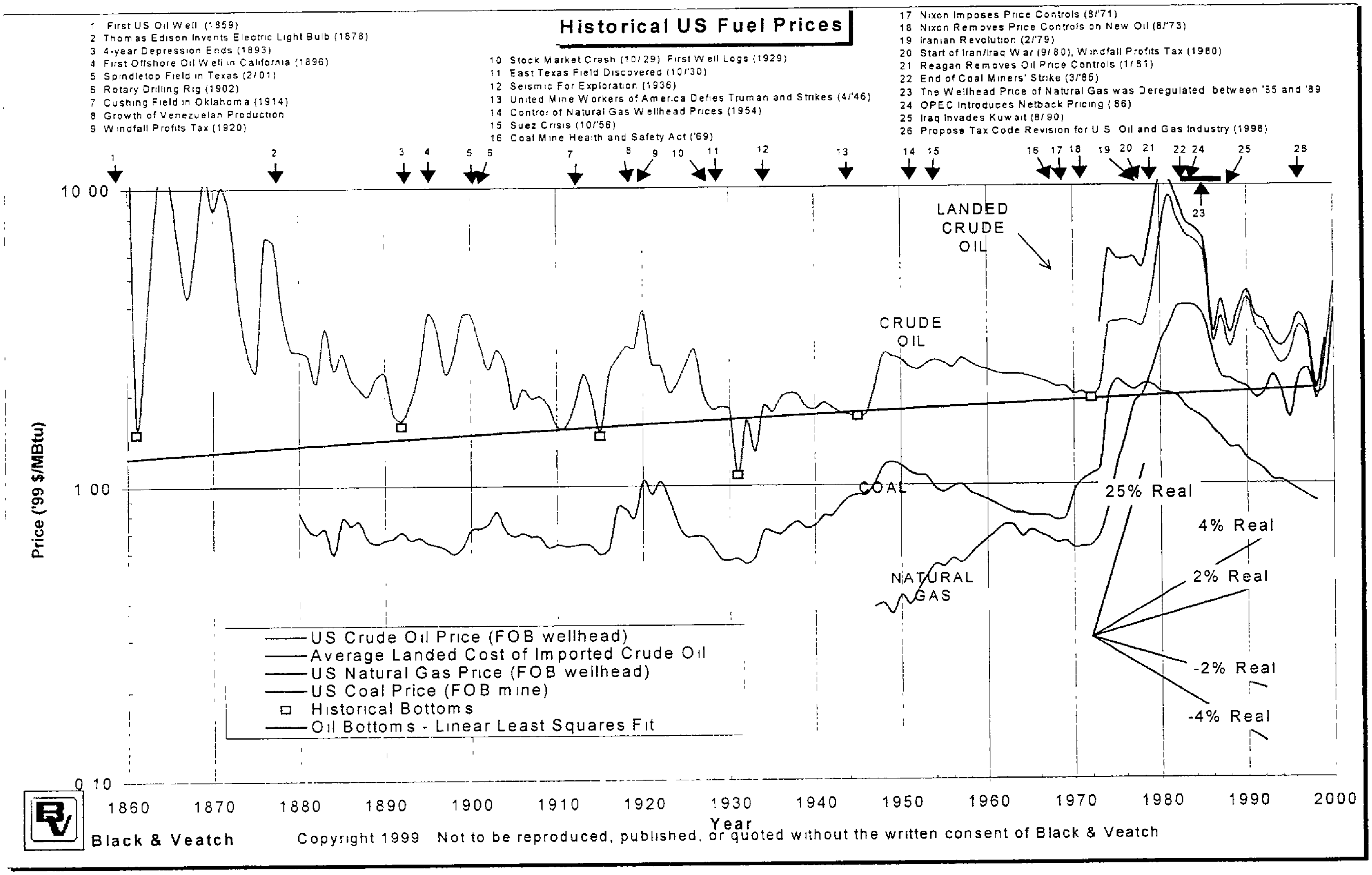
Historical US Fuel Prices
1 First US Oil Well (1859)
2 Thomas Edison Invents Electric Light Bulb (1878)
3 4-year Depression Ends (1893)
4 First Offshore Oil Well in California (1896)
5 Spindletop Field in Texas (2/01)
6 Rotary Drilling Rig (1902)
7 Cushing Field in Oklahoma (1914)
8 Growth of Venezuelan 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)
Price ('99 $/MBtu)
10 00
1 00
0 10
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
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 EVA Fuel Price Projections.

EVA developed projections for natural gas, coal, WTI crude oil, and petroleum coke on a real price basis.

8.2.1.1 Natural Gas. The natural gas price projections are for Henry Hub. The greatest concern with the forecast is in the years 2003 and 2004. The industry has entered a new era in which short-term supply increases cannot keep pace with short-term demand increases. This imbalance has resulted in very high gas prices. Despite record levels of drilling in both the United States and Canada, it appears this era will last for at least 3 years and could last up to 5 years. The big variable in the length of this era is the severity of winter weather in each of the forthcoming years 2002 through 2004, as the difference between a mild and cold winter can represent between 1.5 and 2.0 BCFD per year in additional demand. The projection does not assume any carbon taxes or other such major pieces of legislation that could significantly impact supply and demand. The Henry Hub natural gas projection in constant 2001 dollars is presented in Table 8-1.

8.2.1.2 Coal. The long-term coal price projection is based on low sulfur (1.8-2.5 lb SO_2/MBtu with a 12,500 Btu/lb heating value) Appalachian coal delivered to Orlando in railcars. The projection by mine and rail costs in constant 2001 dollars is presented in Table 8-2.

8.2.1.3 WTI Crude Oil. Crude oil prices are expected to decline. The projected WTI crude oil prices in constant 2000 dollars are presented in Table 8-3

8.2.1.4 Petroleum Coke. The petroleum coke forecast is a delivered price where the initial delivery is via barge from the Gulf Coast refineries and then offloaded to railcars. Crude oil prices, which are the largest cost component, are expected to decline as indicated in Table 8-3. Larger coke volumes are projected to be produced as crude oil becomes heavier. Refinery upgrades are producing a larger gasoline fraction from residue, which increases coke production, which has risen 36 percent in the last 3 years. Higher value markets for petroleum coke are limited including calcined coke for aluminum production and needle grade for steel refineries. Fuel grade (green coke) is the lowest value use for petroleum coke, but also is the only remaining expansion market. Petroleum coke is a thinly traded commodity and is at risk of rapid price escalation with large increases in demand. However, the cap is set by alternative coal prices ($1.80/MBtu) in the US market and alternative fuels in Europe. Fuel use, however, has discounted value because of the high metals content, high sulfur content, and low volatile content. Market potential for petroleum coke could grow and the price increase if more flue gas desulfurization (FGD) systems are retrofitted on existing plants. The projected power demand and projected price of petroleum coke delivered to Stanton Energy Center in constant 2001 dollars are presented in Table 8-4.

Table 8-1
EVA Forecast Natural Gas Prices At Henry Hub ($2001)

Year	[$/MBtu]
2001	5.64
2002	4.24
2003	3.27
2004	2.75
2005	2.65
2006	2.59
2007	2.63
2008	2.67
2009	2.71
2010	2.75

Table 8-2 EVA Forecast Long-Term Coal Prices ($2001)				
Year	Mine $/ton	Rail $/ton	Delivered $/ton	Delivered $/MBtu
2001	28.97	19.50	48.47	1.94
2002	25.85	19.07	44.92	1.80
2003	24.99	18.77	43.76	1.75
2004	24.89	18.50	43.39	1.74
2005	24.65	18.42	43.07	1.72
2006	24.45	18.29	42.74	1.71
2007	24.31	18.15	42.45	1.70
2008	24.17	18.01	42.18	1.69
2009	24.10	17.88	41.98	1.68
2010	24.03	17.75	41.78	1.67

Note: Long-term delivered cost to Stanton Energy Center based on Appalachian low-sulfur coal with 12,500 Btu/lb heating value and 1.8 to 2.5 lb SO_2/MBtu.

Table 8-3
EVA Forecast WTI Crude Oil Price ($2000)

Year	WTI Crude Oil [$/BBL]
2001	27.36
2002	24.14
2003	21.00
2004	19.50
2005	18.50
2006	18.25
2007	18.25
2008	18.25
2009	18.25
2010	18.50

Table 8-4
EVA Forecast Petroleum Coke Demand and Delivered Prices ($2001)

Year	Power Demand 1,000 tons	Most Probable $/MBtu	Low $/MBtu	High $/MBtu
2001	3,686	1.28	0.75	1.64
2002	3,686	1.20	0.74	1.64
2003	3,761	1.14	0.73	1.63
2004	3,987	1.12	0.73	1.63
2005	4,101	1.11	0.72	1.63
2006	4,214	1.09	0.72	1.63
2007	4,341	1.09	0.71	1.62
2008	4,471	1.08	0.70	1.62
2009	4,605	1.08	0.70	1.62
2010	4,743	1.09	0.69	1.61

8.2.2 Base Case Fuel Price Projections.

The coal price projections are assumed to apply to McIntosh 3 as well as units at Stanton Energy Center.

The annual general inflation rate of 2.5 percent is added to EVA's constant dollar fuel price forecasts to obtain nominal fuel price projections for evaluation purposes which are presented in Table 1A.5-5.

For natural gas, transportation charges must be added to obtain a delivered fuel cost. 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. In general, it is expected that FTS-2 tariff rates will lower somewhat as additional expansions are added. Also impacting the natural gas transportation situation is the proposed Gulfstream pipeline. In general, 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. For the purposes of this evaluation, OUC has assumed that natural gas transportation costs will be approximately $0.75/MBtu over the evaluation period. The $0.75/MBtu natural gas transportation cost is assumed to remain constant over the forecast period and is included in the natural gas price forecast in Table 8-5.

EVA did not provide forecasts for No. 2 and No. 6 oil. Delivered projections of No. 2 and No. 6 oil were developed by comparing OUC's actual delivered cost for No. 2 and No. 6 oil in 2000 to EVA's projected 2000 WTI crude oil price and applying the percentage difference in cost to EVA's WTI crude oil price.

Projections for nuclear fuel prices are based on OUC's actual 2000 nuclear fuel cost escalating at the general inflation rate.

8.2.3 High and Low Case Fuel Price Projections.

High and low case fuel price projections for all fuels except petroleum coke are developed by applying a 2 percent higher annual escalation rate to the base case fuel price projections for the high case and a 2 percent lower annual escalation rate to the base case projections for the low case except for the petroleum coke projections which apply the 2.5 percent general inflation rate to the EVA high and low projections. The high and low petroleum coke forecasts were provided directly by EVA. The high and low case fuel price projections are presented in Tables 8-6 and 8-7, respectively.

Table 8-5
Base Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2001	1.94	6.39	5.27	4.02	0.53	1.28
2002	1.85	5.10	4.76	3.64	0.55	1.23
2003	1.84	4.19	4.25	3.24	0.56	1.20
2004	1.87	3.71	4.04	3.09	0.57	1.21
2005	1.90	3.56	3.93	3.00	0.59	1.23
2006	1.93	3.68	3.98	3.04	0.60	1.23
2007	1.97	3.80	4.08	3.11	0.62	1.26
2008	2.01	3.92	4.18	3.19	0.63	1.28
2009	2.05	4.05	4.28	3.27	0.65	1.32
2010	2.09	4.18	4.45	3.40	0.67	1.36

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

Table 8-6
High Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2001	1.97	6.47	5.38	4.11	0.54	1.64
2002	1.92	5.26	4.98	3.80	0.57	1.68
2003	1.95	4.40	4.54	3.46	0.59	1.71
2004	2.02	3.98	4.41	3.37	0.62	1.76
2005	2.09	3.88	4.38	3.34	0.65	1.80
2006	2.17	4.08	4.51	3.44	0.68	1.84
2007	2.26	4.28	4.72	3.60	0.71	1.88
2008	2.35	4.50	4.93	3.76	0.74	1.93
2009	2.44	4.72	5.15	3.93	0.77	1.97
2010	2.53	4.96	5.45	4.16	0.81	2.01

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

Table 8-7
Low Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2001	1.91	6.31	5.15	3.93	0.52	0.75
2002	1.77	4.91	4.56	3.48	0.53	0.76
2003	1.73	3.94	3.97	3.03	0.53	0.77
2004	1.73	3.46	3.70	2.83	0.53	0.79
2005	1.72	3.26	3.53	2.69	0.53	0.79
2006	1.72	3.32	3.49	2.67	0.54	0.81
2007	1.72	3.37	3.51	2.68	0.54	0.82
2008	1.71	3.43	3.53	2.69	0.54	0.83
2009	1.71	3.48	3.55	2.71	0.54	0.85
2010	1.71	3.54	3.61	2.76	0.55	0.86

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

8.2.4 Constant 2000 Fuel Price Projections.

The constant 2000 fuel price projection assumes that the actual OUC 2000 fuel costs remain constant in real terms over the forecast period. The constant 2000 fuel price projection thus applies the 2.5 percent general inflation rate to OUC's actual 2000 fuel costs for all fuels except petroleum coke. The constant 2000 projection for petroleum coke was developed by applying the 2.5 percent general inflation rate to the base case forecast provided by EVA. Figure 8-1 indicates that it would be unprecedented for high fuel prices such as those occurring in 2000 to continue in real terms for an entire 20 year period. Nevertheless, the constant 2000 fuel price projection offers the opportunity to evaluate the possibility of continued high fuel prices. The constant 2000 fuel price projection is presented in Table 8-8. For purposes of this evaluation, the delivered gas price projection assumes the commodity portion of the price escalates at the 2.5 percent general inflation rate and the $0.75/MBtu transportation cost remains constant over the forecast period. This results in the delivered cost of natural gas escalating at slightly less than the general inflation rate of 2.5 percent.

8.2.5 2001 Annual Energy Outlook Fuel Price Projections.

The final two fuel price projections used in the sensitivity evaluations are based on the Annual Energy Outlook (AEO) fuel price data published by the Energy Information Administration (EIA), which is an independent agency of the Department of Energy (DOE). The AEO 2001 energy data is a comprehensive and reliable source of domestic and international energy supply, consumption, and price information.

AEO provides energy forecasts through the year 2020 and takes into account a number of important factors, some of which include:

- Restructuring of the US electricity markets
- Current regulations and legislation affecting the energy markets
- Current energy issues:
  - Appliance, gasoline, and diesel fuel, and renewable portfolio standards.
  - Expansion of natural gas industry
  - Carbon emissions
  - Competitive energy pricing

AEO 2001 energy information is objective and nonpartisan. It is used widely by both government and private sectors to assist in decision-making processes and in analyzing important policy issues.

Table 8-8
Constant 2000 Fuel Price Forecast ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2001	1.71	5.14	5.94	4.53	0.53	1.29
2002	1.75	5.25	6.09	4.64	0.55	1.32
2003	1.80	5.36	6.24	4.76	0.56	1.36
2004	1.84	5.47	6.39	4.88	0.57	1.39
2005	1.89	5.59	6.55	5.00	0.59	1.43
2006	1.94	5.71	6.72	5.13	0.60	1.46
2007	1.99	5.84	6.88	5.25	0.62	1.50
2008	2.03	5.96	7.06	5.39	0.63	1.54
2009	2.09	6.10	7.23	5.52	0.65	1.57
2010	2.14	6.23	7.41	5.66	0.67	1.61

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

AEO 2001 publishes 1999, 2005, 2010, 2015, and 2020 fuel price projections, which are presented in Table 8-9. From these projections, real compound annual escalation rates (CAERs) can be calculated for 1999 through 2005, 2005 through 2010, 2010 through 2015, and 2015 through 2020 periods. These real CAERs are used to develop annual fuel price projections to which the 2.5 percent general inflation rate is applied. The AEO 2001 fuel price projections are presented in Table 8-10. The delivered price of natural gas adds a constant $0.75/MBtu transportation cost to the AEO 2001 commodity projection. AEO does not project nuclear or petroleum coke prices. The nuclear and petroleum coke projections are those presented in the base case in Table 8-5. The AEO 2001 fuel price projections for 2000 are much lower than the actual 2000 OUC fuel prices shown in Table 8-8. Furthermore, the AEO projections are on a national average basis, which is heavily weighted by low cost western coal and do not reflect the relatively higher coal transportation costs to Florida. As a result, the AEO projections understate coal costs for Florida.

The second fuel price projection based on the AEO 2001 fuel price projections applies the AEO 2001 real escalation rates along with the 2.5 percent annual general inflation rate to the actual 2000 OUC fuel prices. These fuel price projections are presented in Table 8-11. The nuclear and petroleum coke projections are those presented in the base case in Table 8-5. This projection initially matches the actual 2000 OUC fuel prices and continues to escalate them into the future. High fuel prices continuing to escalate for a 20 year period would be unprecedented compared to historical prices presented in Figure 8-1.

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.

Table 8-9
2001 Annual Energy Outlook Real Fuel Price Projections and CAERs

	1999	2005	2010	2015	2020
No. 2 Oil,* $/MBtu	4.05	4.65	4.84	5.10	5.28
Residual Oil,* $/MBtu	2.42	3.52	3.88	4.00	4.07
Coal,* $/MBtu	1.21	1.13	1.05	1.01	0.98
Natural Gas,** $/MBtu	2.08	2.49	2.69	2.83	3.13
	1999-2005	2005-2010	2010-2015	2015-2020	1999-2020
No. 2 Oil* Real CAERs, percent	2.33	0.80	1.05	0.70	1.27
Residual Oil* Real CAERs, percent	6.49	1.97	0.61	0.35	2.51
Coal* Real CAERs, percent	-1.13	-1.46	-0.77	-0.60	-1.00
Natural Gas** Real CAERs, percent	3.04	1.56	1.02	2.04	1.97

*Delivered price.

**Well head price.

Source: DOE Energy Information Administration web site

Table 8-10
AEO 2001 Fuel Price Forecast ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2001	1.25	3.07	4.46	2.88	0.53	1.28
2002	1.26	3.20	4.68	3.14	0.55	1.23
2003	1.28	3.34	4.90	3.43	0.56	1.20
2004	1.30	3.48	5.14	3.74	0.57	2.21
2005	1.31	3.64	5.40	4.08	0.59	2.23
2006	1.33	3.76	5.57	4.27	0.60	1.23
2007	1.34	3.88	5.76	4.46	0.62	1.26
2008	1.35	4.01	5.95	4.66	0.63	1.28
2009	1.37	4.14	6.15	4.87	0.65	1.32
2010	1.38	4.28	6.35	5.09	0.67	1.36

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

Table 8-11
AEO 2001 Escalation Applied to 2000 OUC Fuel Prices ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2001	1.69	5.27	6.08	4.82	0.53	1.28
2002	1.71	5.52	6.37	5.26	0.55	1.23
2003	1.74	5.79	6.68	5.74	0.56	1.20
2004	1.76	6.08	7.01	6.26	0.57	2.21
2005	1.78	6.38	7.35	6.83	0.59	2.23
2006	1.80	6.61	7.60	7.14	0.60	1.23
2007	1.82	6.85	7.85	7.46	0.62	1.26
2008	1.84	7.10	8.11	7.80	0.63	1.28
2009	1.86	7.36	8.38	8.15	0.65	1.32
2010	1.88	7.63	8.66	8.52	0.67	1.36

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

8.3.2 Florida Gas Transmission Company.

FGT is an open access interstate pipeline company transporting natural gas for third parties through its 5,000 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 1.4 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.

FGT filed for FERC approvals of the Phase IV expansion project December 2, 1998. The filing consists of expanding services to southwest Florida with 139 miles of underground pipelines. The $268 million Phase IV project will add more than 38,000 horsepower of compression, and associated facilities and will provide approximately 197 million cubic feet per day (MMcf/d) of incremental firm transportation service on an average annual basis. FGT announced in May of 2000 that construction related to the Phase IV had begun and is scheduled for service by the May 2001 target.

FGT's Phase V expansion project, filed with the 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 $466 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 still requires final environmental approval.

FGT recently concluded an open season for Phase VI. FGT received what it defined as 'a positive response' to the open season. The intent of the project is to provide incremental firm transportation service to Florida. The new pipeline is proposed to extend from Savannah, Georgia, to Jacksonville, Florida, with access to Southern LNG Company's liquefied natural gas. Phase VI is scheduled for an in-service date of Spring 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.

There is currently one transportation company serving Peninsular Florida: FGT. Two additional pipelines, Buccaneer and Gulfstream, received preliminary approval from the Federal Energy Regulatory Commission (FERC) in April of last year. In September of last year, 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 is 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 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. The pipeline is discussed below. At this time, it is uncertain as to what effect the purchase will have on the pipeline configuration.

FGT, El Paso Merchant, and Gulfstream have all made competitive proposals to provide gas transportation to Stanton A.

8.3.5.1 Gulfstream Pipeline. The Gulfstream pipeline is a 744 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. Final environmental and routing approvals by FERC are expected in March of 2001. Construction for the Gulfstream pipeline is scheduled to begin in June of 2001, with 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, Coastal Corporation will lease up to 190 acres of vacant land at Port Manatee 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 evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program and has been used in several other Need for Power proceedings before the FPSC. The program 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 20 year period from 2000 through 2019.

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. OUC's and St. Cloud's systems were combined for purposes of expansion planning.

8.4.2 Expansion Candidates.

The expansion candidates for the POWROPT evaluation are presented in Section 7.0 Additionally, the option of extended the Reliant PPAs from 2004 through 2007 has been included in 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 described in detail in Section 7.0 and summarized in Table 7-1. 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 8-12 represents the least cost capacity addition plan for OUC under the base case scenario.

Table 8-12
OUC Least-Cost Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	162,239	162,239
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	171,252	320,806
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	182,007	476,848
2004	171 MW Joint Development with Southern – Florida (10/03)	220,059	651,537
	317 MW Southern – Florida Power Purchase (10/03)		
	100 MW Indian River Power Purchase (10/03 - 09/04)		
2005	100 MW Indian River Power Purchase (10/04 - 09/05)	221,751	814,531
2006	100 MW Indian River Power Purchase (10/05 – 09/06)	216,636	961,970
2007	156 MW GE 7FA Simple Cycle (06/07)	230,334	1,107,119
2008	156 MW GE 7FA Simple Cycle (06/08)	245,040	1,250,098
2009		264,023	1,392,741
2010		271,624	1,528,621

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

8.5 Sensitivity Analysis

OUC performed several sensitivity analyses to measure the impact of key assumptions. The sensitivity analyses include low and high fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

8.5.1 High Fuel Price Escalation.

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 8-6. Table 8-13 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity case.

8.5.2 Low Fuel Price Escalation.

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 8-7. Table 8-14 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity case.

8.5.3 AEO Fuel Price Projections.

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 8-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 8-15.

8.5.4 OUC 2000 Fuel Costs with 2001 AEO Escalation.

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 8-11. Table 8-16 presents the results of the economic evaluation for the least cost expansion plan.

8.5.5 Constant 2000 Fuel Price Projections.

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 8-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 8-1.

8.5.6 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. 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 8-18 and 8-19 indicate the summer and winter need for capacity based upon the high load and energy forecast.

As indicated in Table 8-18, the high load and energy growth scenario results in a 59 MW capacity shortfall in the summer of 2002. Since the only option available to OUC for the summer of 2002 and 2003 is the additional 52.5 MW purchase from the Reliant Agreement, it has been assumed that OUC will purchase power on the spot market to make up the resultant deficit.

As indicated in Table 8-19, the high load and energy growth scenario results in a capacity shortfall in the winter of 2002. The additional 52.5 MW purchase from the Reliant Agreement will satisfy OUC's needs for the winter of 2002 as well as for the winter of 2003.

Table 8-20 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity.

8.5.7 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 8-21 and 8-22 indicate the summer and winter need for capacity based upon the low load and energy forecast.

Capacity is required beginning in the summer of 2002 and the winter of 2004 for the low load and energy forecast. The extension of the 52.5 MW Reliant Agreement option will satisfy OUC's capacity requirements in the summer of 2002 and 2003 for the low load and energy growth scenario.

Table 8-23 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity.

Table 8-13
OUC High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	164,296	164,296
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	177,126	328,302
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	190,849	491,924
2004	171 MW Joint Development with Southern-Florida (10/03)	231,489	675,688
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	236,101	849,229
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	233,753	1,008,317
2007	156 MW GE 7FA Simple Cycle (06/07)	251,687	1,166,923
2008	156 MW GE 7FA Simple Cycle (06/08)	270,915	1,324,999
2009		295,247	1,484,512
2010		307,799	1,638,488

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

Table 8-14
OUC Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,192	160,192
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	164,871	312,851
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	173,094	461,251
2004	171 MW Joint Development with Southern–Florida (10/03)	208,994	627,157
	317 MW Southern-Florida Power Purchase (10/03)		
2005	100 MW Reliant Power Purchase (10/03 - 09/04)		
2006	100 MW Reliant Power Purchase (10/04 - 09/05)	207,750	779,860
2007	100 MW Reliant Power Purchase (10/05 - 09/06)	200,626	916,402
2008	156 MW GE 7FA Simple Cycle (06/07)	210,874	1,049,289
2009	156 MW GE 7FA Simple Cycle (06/08)	221,690	1,178,643
2010		236,622	1,306,482
		240,421	1,426,753

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

Table 8-15
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	122,380	122,380
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	130,892	243,577
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	148,674	371,040
2004	171 MW Joint Development with Southern–Florida (10/03)	190,039	521,900
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 – 09/05)	193,703	664,277
2006	100 MW Reliant Power Purchase (10/05 – 09/06)	188,233	792,385
2007	156 MW GE 7FA Simple Cycle (06/07)	199,987	918,411
2008	156 MW GE 7FA Simple Cycle (06/08)	213,237	1,042,833
2009		233,123	1,168,782
2010		238,759	1,288,221

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

Table 8-16
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,466	151,466
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	180,039	318,169
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	203,058	492,258
2004	171 MW Joint Development with Southern–Florida (10/03)	253,620	693,590
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 – 09/05)	258,420	883,536
2006	100 MW Reliant Power Purchase (10/05 – 09/06)	250,414	1,053,964
2007	446 MW Pulverized Coal (06/07)	269,942	1,224,073
2008		288,247	1,392,263
2009		303,651	1,556,316
2010		310,518	1,711,652

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

Table 8-17
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,191	151,191
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	175,598	313,782
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	197,052	482,722
2004	171 MW Joint Development with Southern–Florida (10/03)	247,056	678,844
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	251,529	863,725
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	244,615	1,030,206
2007	156 MW GE 7FA Simple Cycle (06/07)	260,608	1,194,433
2008	156 MW GE 7FA Simple Cycle (06/08)	276,878	1,355,989
2009		303,257	1,519,829
2010		311,701	1,675,757

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

Table 8-18
OUC Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2001	1100	341	1441	1047	608	1655	214	177	37
2002	1139	323	1462	1047	540	1587	125	184	(59)
2003	1180	312	1492	1047	540	1587	95	191	(96)
2004	1222	263	1485	1047	15	1062	-423	199	(622)
2005	1265	172	1437	1025	15	1040	-397	207	(604)
2006	1301	139	1440	1025	15	1040	-400	210	(610)
2007	1337	139	1476	1025	15	1040	-436	219	(655)
2008	1375	142	1517	1025	15	1040	-477	225	(702)
2009	1413	144	1557	1025	15	1040	-517	231	(749)
2010	1453	146	1599	1025	15	1040	-559	238	(797)

Table 8-19
OUC Winter Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2001	1092	341	1433	1092	608	1700	267	176	91
2002	1135	323	1458	1092	540	1632	174	183	(9)
2003	1179	312	1491	1092	540	1632	141	191	(51)
2004	1225	263	1488	1092	15	1107	-381	200	(581)
2005	1273	172	1445	1071	15	1086	-359	208	(567)
2006	1309	139	1448	1071	15	1086	-362	212	(574)
2007	1347	139	1486	1071	15	1086	-400	221	(621)
2008	1386	142	1528	1071	15	1086	-442	227	(668)
2009	1425	144	1569	1071	15	1086	-483	233	(716)
2010	1466	146	1612	1071	15	1086	-526	240	(766)

Table 8-20
OUC High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	163,316	163,316
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	173,482	323,947
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	186,448	483,796
2004	171 MW Joint Development with Southern-Florida (10/03)	229,304	665,825
	317 MW Southern-Florida Power Purchase (10/03)		
	200 MW Reliant Power Purchase (10/03 - 09/04)		
2005	200 MW Reliant Power Purchase (10/04 - 09/05)	232,466	836,695
2006	200 MW Reliant Power Purchase (10/05 - 09/06)	229,273	992,734
2007	200 MW Reliant Power Purchase (10/06 - 09/07)	246,638	1,148,158
2008	610 MW WH 501F 2x1 Combined Cycle (06/08)	259,828	1,299,765
2009		288,881	1,455,838
2010		299,302	1,605,564

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

Table 8-21
OUC Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2001	1084	341	1425	1047	608	1655	230	175	55
2002	1106	323	1429	1047	540	1587	158	179	(21)
2003	1129	312	1441	1047	540	1587	146	184	(38)
2004	1152	263	1415	1047	15	1062	-353	189	(542)
2005	1176	172	1348	1025	15	1040	-308	194	(502)
2006	1192	139	1331	1025	15	1040	-291	194	(485)
2007	1209	139	1348	1025	15	1040	-308	200	(508)
2008	1226	142	1368	1025	15	1040	-328	203	(531)
2009	1243	144	1387	1025	15	1040	-347	206	(552)
2010	1260	146	1406	1025	15	1040	-366	209	(575)

Table 8-22
OUC Winter Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2001	1078	341	1419	1092	608	1700	281	174	107
2002	1106	323	1429	1092	540	1632	203	179	24
2003	1134	312	1446	1092	540	1632	186	184	1
2004	1163	263	1426	1092	15	1107	-319	191	(510)
2005	1193	172	1365	1071	15	1086	-279	196	(475)
2006	1210	139	1349	1071	15	1086	-263	197	(459)
2007	1227	139	1366	1071	15	1086	-280	203	(482)
2008	1244	142	1386	1071	15	1086	-300	206	(506)
2009	1261	144	1405	1071	15	1086	-319	209	(528)
2010	1279	146	1425	1071	15	1086	-339	212	(551)
								1	

Table 8-23
OUC Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,822	160,822
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	167,665	316,068
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	172,724	464,151
2004	171 MW Joint Development with Southern--Florida (10/03)	214,166	634,162
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant River Power Purchase (10/04 - 09/05)	213,366	790,992
2006		203,692	929,621
2007	156 MW GE 7FA SC (06/07)	216,845	1,066,271
2008		225,042	1,197,580
2009		237,138	1,325,699
2010		241,196	1,446,357

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

9.0 Environmental and Land Use Information

The proposed generating units will be installed at the existing Stanton Energy Center site. Stanton Energy Center currently contains two 440 MW pulverized coal units, which went into service in 1987 and 1996. The site was originally certified for 2000 MW. 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 sake of brevity have not been reproduced. The following information focuses on Stanton A to be installed for commercial operation on October 1, 2003.

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 Florida Electrical Power Plant Siting Act (Act). The Need for Power Application for Stanton A was filed on January 29, 2001. The Need for Power hearing is scheduled for April 23 and 24, 2001. The Supplemental Site Certification Application for Stanton A was filed on January 22, 2001 and was ruled complete on February 5, 2001. The Stanton A certification hearing is scheduled for June 26,2001 and final action before the Siting Board is scheduled for August 28, 2001.

9.2 Land and Environmental Features

The Stanton Energy Center site is located in Orange County, Florida, with approximately 3,280 acres. The Econlockhatchee River is about three-fourths miles 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 the unit 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 site. The pipeline is planned to be routed in the existing transmission and railroad spur line right-of-way. Other pipelines may be considered if competing pipelines are successful in getting constructed 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.

9.2 Air Emissions

The 2x1 501 F combined cycle unit is planned to utilize low NO_x combustors as well as SCR to reduce NO_x emissions. The expected NO_x emissions are 3.5 ppm. The HRSG is planned to be designed with a spool piece for a CO catalyst, but installation of the CO catalyst is not planned. No. 2 fuel oil is used as an alternate fuel and SO_2 emissions will be controlled by limiting the sulfur content of the oil.

9.3 Water and Wastewater

The use of combined cycle technology reduces the amount of water required compared to convention steam generation. The 2x1 501 F combined cycle is expected to obtain water in the same manner as the existing Stanton units. Ground water will be used for steam cycle makeup, water injection and evaporative cooler makeup. Treated sewage effluent from The Orange County Easterly Subregional Wastewater Treatment Plant is planned to be used for the 2x1 501 F combined cycle as it is for Stanton 1 and 2.

The Stanton site is designed to reuse wastewater to the extent possible. When wastewater cannot be reused, it is evaporated with a brine concentrator. Thus the Stanton site is truly a zero discharge site. The planned 2x1 501 F combined cycle 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.

Table 10-1 (Schedule 1)
Existing Generating Facilities as of December 31, 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)
				Primary Fuel		Alternate Fuel		Alt Fuel			Gross Capability[1]		Net Capability[1]	
Plant Name	Unit No	Location	Unit Type	Fuel Type	Transport Method	Fuel Type	Transport Method	Storage (Days Burn)	Commercial In-Service MM/YY	Expected Retirement MM/YY	Summer MW	Winter MW	Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	PL	DFO	TK	0.2	06/89	Unknown	18 30	23.50	18 00	23 30
Indian River	B	Brevard	GT	NG	PL	DFO	TK	0.2	07/89	Unknown	18.30	23.50	18.00	23.30
Indian River	C	Brevard	GT	NG	PL	DFO	TK	0.2	08/92	Unknown	86 10	101 10	85 30	100 30
Indian River	D	Brevard	GT	NG	PL	DFO	TK	0 2	10/92	Unknown	86.10	101 10	85 30	100 30
Stanton Energy Center	1	Orange	ST	BIT	RR	NA	UN	UN	07/87	Unknown	320 13	322 19	301.62	303 68
Stanton Energy Center	2	Orange	ST	BIT	RR	NA	UN	UN	06/96	Unknown	335.76	335 76	319.29	319.29
McIntosh	3	Polk	ST	BIT	REF	NA	UN	UN	09/82	Unknown	146.00	146.00	136.80	136.80
Crystal River	3	Citrus	ST	NUC	TK	NA	UN	UN	03/77	Unknown	14.03	14 27	13.36	13.64
St. Lucie [2]	2	St. Lucie	ST	NUC	TK	NA	UN	UN	08/83	Unknown	54 20	54.20	51.09	51.94

[1]: OUC ownership share

[2]. Reliability exchange divides 50% power from Unit 1 and 50% power from Unit 2.

Table 10-2 (Schedule 2.1)
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(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
1991	262,590	2 57	1,201	102,134	11,759	320	13,758	23,259
1992	267,500	2 58	1,216	103,495	11,749	308	13,891	22,173
1993	271,500	2.58	1,256	104,978	11,964	310	14,091	22,000
1994	275,300	2.58	1,286	106,462	12,079	316	14,318	22,070
1995	278,500	2.56	1,380	108,805	12,683	316	14,590	21,659
1996	284,000	2.56	1,419	110,949	12,790	318	14,858	21,403
1997	290,600	2.55	1,377	113,977	12,081	322	14,994	21,475
1998	300,400	2.55	1,583	117,814	13,436	311	15,170	20,501
1999	310,500	2.55	1,504	121,767	12,351	308	15,547	19,811
2000	320,100	2.55	1,583	125,523	12,611	293	15,626	18,751
2001	332,523	2.55	1,646	126,480	13,011	334	15,899	21,027
2002	328,180	2 55	1,689	128,698	13,121	341	16,049	21,237
2003	334,176	2.55	1,734	131,049	13,234	347	16,201	21,449
2004	339,986	2 55	1,779	133,328	13,340	354	16,358	21,624
2005	345,602	2.55	1,822	135,530	13,443	360	16,524	21,764
2006	351,408	2.55	1,863	137,807	13,520	365	16,694	21,857
2007	357,465	2.55	1,902	140,182	13,571	370	16,869	21,910
2008	364,280	2.55	1,946	142,855	13,624	375	17,060	21,959
2009	371,967	2.55	1,996	145,869	13,683	380	17,267	22,014
2010	379,497	2.55	2,046	148,822	13,749	386	17,474	22,074

Table 10-3 (Schedule 2.2)
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(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				
1991	1,981	2,461	804,957	0	22	4	3,528
1992	2,004	2,542	788,356	0	23	4	3,555
1993	2,024	2,646	764,928	0	23	4	3,617
1994	2,131	2,749	775,191	0	22	5	3,760
1995	2,207	2,946	749,151	0	22	5	3,930
1996	2,259	3,116	724,968	0	23	5	4,024
1997	2,331	3,452	675,261	0	23	5	4,058
1998	2,497	3,806	656,069	0	22	5	4,418
1999	2,650	3,928	676,020	0	26	5	4,493
2000	2,785	4,262	653,526	0	25	6	4,692
Forecast							
2001	2,911	4,171	697,922	0	28	6	4,925
2002	3,056	4,269	715,839	0	32	6	5,124
2003	3,159	4,362	724,165	0	36	6	5,283
2004	3,230	4,458	724,436	0	40	6	5,408
2005	3,302	4,560	724,092	0	44	6	5,534
2006	3,373	4,666	722,812	0	48	6	5,655
2007	3,441	4,773	720,817	0	52	6	5,771
2008	3,515	4,892	718,473	0	56	6	5,898
2009	3,596	5,023	715,819	0	60	6	6,038
2010	3,678	5,151	713,998	0	64	6	6,180

Table 10-4 (Schedule 2.3)
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1) Year	(2) Sales for Resale GWh	(3) Utility Use & Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers (Average No.)	(6) Total No. of Customers
1991	0	129	3,657	0	118,353
1992	0	118	3,673	0	119,928
1993	0	166	3,783	0	121,715
1994	0	137	3,897	0	123,529
1995	0	171	4,101	0	126,341
1996	0	162	4,186	0	128,923
1997	0	213	4,271	0	132,423
1998	0	160	4,578	0	136,790
1999	0	181	4,674	0	141,234
2000	0	230	4,922	0	145,410
Forecast					
2001	0	217	5,142	0	146,550
2002	0	226	5,350	0	149,017
2003	0	232	5,516	0	151,613
2004	0	238	5,646	0	154,144
2005	0	243	5,777	0	156,615
2006	0	248	5,903	0	159,167
2007	0	253	6,024	0	161,825
2008	0	259	6,156	0	164,807
2009	0	265	6,302	0	168,159
2010	0	271	6,451	0	171,448

Table 10–5 (Schedule 3.1)
History and Forecast of Summer Peak Demand Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Residential	Commercial/Industrial		
Year	Total[1]	Wholesale	Retail	Interruptible	Load Management	Load Management	Conservation	Net Firm Demand
1991	714	0	714	0	0	0	-	714
1992	763	0	763	0	0	0	-	763
1993	760	0	760	0	0	0	-	760
1994	749	0	749	0	0	0	-	749
1995	799	0	799	0	0	0	-	798
1996	788	0	788	0	0	0	-	788
1997	846	0	846	0	0	0	-	846
1998	907	0	907	1	0	0	-	906
1999	969	0	969	0	0	0	-	969
2000	942	0	942	1	0	0	-	941
Forecast								
2001	1,000	0	1,000	1	0	0	-	999
2002	1,042	0	1,042	1	0	0	-	1,041
2003	1,073	0	1,073	1	0	0	-	1,072
2004	1,097	0	1,097	1	0	0	-	1,096
2005	1,124	0	1,124	1	0	0	-	1,123
2006	1,149	0	1,149	1	0	0	-	1,148
2007	1,170	0	1,170	1	0	0	-	1,169
2008	1,195	0	1,195	1	0	0	-	1,194
2009	1,225	0	1,225	1	0	0	-	1,224
2010	1,254	0	1,254	1	0	0	-	1,253

[1]. Includes conservation.

Table 10-6 (Schedule 3.2)
History and Forecast of Winter Peak Demand Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Residential	Commercial/Industrial		
Year	Total[1]	Wholesale	Retail	Interruptible	Load Management	Load Management	Conservation	Net Firm Demand
1991/92	673	0	673	0	0	0	-	673
1992/93	721	0	721	0	0	0	-	721
1993/94	674	0	674	0	0	0	-	674
1994/95	800	0	800	0	0	0	-	800
1995/96	885	0	885	0	0	0	-	885
1996/97	775	0	775	0	0	0	-	775
1997/98	746	0	746	1	0	0	-	745
1998/99	938	0	938	1	0	0	-	937
1999/00	971	0	971	1	0	0	-	970
2000/01	993	0	993	1	0	0	-	992
Forecast								
2001/02	1,041	0	1,041	1	0	0	-	1,040
2002/03	1,077	0	1,077	1	0	0	-	1,066
2003/04	1,102	0	1,102	1	0	0	-	1,101
2004/05	1,128	0	1,128	1	0	0	-	1,127
2005/06	1,152	0	1,152	1	0	0	-	1,151
2006/07	1,175	0	1,175	1	0	0	-	1,174
2007/08	1,202	0	1,202	1	0	0	-	1,201
2008/09	1,232	0	1,232	1	0	0	-	1,231
2009/10	1,259	0	1,259	1	0	0	-	1,258
2010/11	1,286	0	1,286	1	0	0	-	1,285

[1]. Includes conservation

Table 10–7 (Schedule 3.3)
History and Forecast of Annual Net Energy for Load – GWH
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	Total[1]	Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1991	3,528	-	3,528	-	129	3,657	58.5
1992	3,555	-	3,555	-	118	3,673	55.0
1993	3,617	-	3,617	-	166	3,783	56.8
1994	3,760	-	3,760	-	137	3,897	59 4
1995	3,930	-	3,930	-	171	4,101	58.7
1996	4,024	-	4,024	-	162	4,186	60.6
1997	4,058	-	4,058	-	213	4,271	57.6
1998	4,418	-	4,418	-	160	4,578	57.6
1999	4,493	-	4,493	-	181	4,674	55.1
2000	4,692	-	4,692	-	230	4,922	59 7
Forecast							
2001	4,925	-	4,925	-	217	5,142	58.8
2002	5,124	-	5,124	-	226	5,350	58.7
2003	5,283	-	5,283	-	232	5,516	58.7
2004	5,408	-	5,408	-	238	5,646	58.8
2005	5,534	-	5,534	-	243	5,777	58.7
2006	5,655	-	5,655	-	248	5,903	58.7
2007	5,771	-	5,771	-	253	6,024	58 8
2008	5,898	-	5,898	-	259	6,156	58.9
2009	6,038	-	6,038	-	265	6,302	58.8
2010	6,180	-	6,180	-	271	6,451	58.8

[1] Includes conservation.

Table 10-8 (Schedule 4)
Previous Year and Two Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Month	Actual – 2000		2001 Forecast		2002 Forecast	
	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh
January	882	371	993	417	1,041	434
February	680	338	869	347	842	359
March	695	357	836	379	866	390
April	686	356	789	383	844	399
May	888	446	855	437	882	453
June	897	462	970	485	1,010	503
July	941	487	1000	520	1,042	542
August	904	493	953	512	997	532
September	890	463	887	467	954	489
October	825	391	882	438	922	457
November	709	356	739	372	730	388
December	913	402	750	385	784	404

[1] Includes Load Management, Conservation and Interruptible Load.

Table 10-9 (Schedule 5)
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		Units	2000 Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Nuclear		Trillion BTU	6	5	5	5	5	5	5	5	5	5	5
(2)	Coal		1000 Ton	2,136	2,204	2,218	2,215	1,923	2,051	2,017	2,041	2,051	1,959	2,000
(3)	Residual[1]	Total	1000 BBL	8	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	8	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	0	0	0	0	0	0	0	0	0	0	0
(7)	Distillate[2]	Total	1000 BBL	3	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	3	0	0	0	0	0	0	0	0	0	0
(11)	Natural Gas	Total	1000 MCF	1,505	1,075	1,129	3,160	15,334	14,567	13,209	14,391	15,094	18,090	18,320
(12)		Steam	1000 MCF	61	0	0	0	0	0	0	0	0	0	0
(13)		CC	1000 MCF	0	0	0	2,106	15,002	14,399	12,830	12,747	13,996	15,550	17,135
(14)		CT	1000 MCF	1,444	1,075	1,129	1,054	332	168	379	1,644	1,098	2,539	1,185
(15)	Other		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0

[1] Residual includes #4, #5 and #6 oil.
[2] 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	2000 - Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Annual Firm Inter-region Interchange		GWH	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWH	539	471	501	489	471	501	489	471	501	489	471
(3)	Residual	Total	GWH	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)	Distillate	Total	GWH	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	111	13	10	122	732	690	630	740	751	955	911
(12)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0
(13)		CC	GWH	0	0	0	100	710	680	602	599	659	738	812
(14)		CT	GWH	111	13	10	12	22	10	28	141	92	217	99
(15)	Coal	Steam	GWH	5,488	5,239	5,272	5,267	4,525	4,825	4,734	4,797	4,820	4,622	4,710
(16)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0
(17)	Hydro		GWH	0	0	0	0	0	0	0	0	0	0	0
(18)	Other	Purchases	GWH	929	923	1,002	1,062	1,381	1,304	1,151	1,112	1,223	1,370	1,509
		Sales	GWH	(1,067)	(866)	(838)	(830)	(775)	(703)	(733)	(703)	(714)	(724)	(728)
		Total	GWH	(138)	57	164	232	606	601	418	409	509	646	781
(19)	Net Energy for Load		GWH	6,001	5,779	5,948	6,101	6,336	6,615	6,272	6,417	6,582	6,712	6,872

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	2000 - Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Annual Firm Inter-region Interchange		%	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		%	9	8	8	8	7	8	8	7	8	7	7
(3)	Residual	Total	%	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	%	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	%	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	%	0	0	0	0	0	0	0	0	0	0	0
(7)	Distillate	Total	%	0	0	0	0	0	0	0	0	0	0	0
(8)		Steam	%	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	%	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	%	0	0	0	0	0	0	0	0	0	0	0
(12)	Natural Gas	Total	%	2	0	0	2	11	10	10	11	11	14	13
(12)		Steam	%	0	0	0	0	0	0	0	0	0	0	0
(13)		CC	%	0	0	0	2	11	10	10	9	10	11	12
(14)		CT	%	2	0	0	0	0	0	0	2	1	3	1
(15)	Coal	Steam	%	91	91	89	86	71	73	75	75	73	69	69
(16)	NUG		%	0	0	0	0	0	0	0	0	0	0	0
(17)	Hydro		%	0	0	0	0	0	0	0	0	0	0	0
(18)	Other	Purchases	%	15	16	17	17	22	20	18	17	19	20	22
		Sales	%	(18)	(15)	(14)	(14)	(12)	(11)	(12)	(11)	(11)	(11)	(11)
		Total	%	(3)	1	3	3	10	9	6	6	8	9	11
(19)	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100

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	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2001	1025	593	341	0	1277	999	278	27.83	0	278	27.83
2002	1025	578	323	0	1280	1041	239	22.96	0	239	22 96
2003	1025	578	312	0	1291	1072	219	20.43	0	219	20.43
2004	1192	450	263	0	1379	1096	283	25.82	0	283	25.82
2005	1192	434	172	0	1454	1123	331	29.47	0	331	29.47
2006	1192	419	139	0	1472	1148	324	28.22	0	324	28 22
2007	1332	309	139	0	1502	1169	333	28.49	0	333	28.49
2008	1472	309	142	0	1639	1194	445	37 27	0	445	37 27
2009	1472	309	144	0	1637	1224	413	33.74	0	413	33.74
2010	1472	309	146	0	1635	1253	382	30 49	0	382	30.49

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	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2001	1071	593	341	0	1323	1040	283	27.21	0	283	27.21
2002	1071	578	323	0	1326	1076	250	23.23	0	250	23.23
2003	1071	578	312	0	1337	1101	236	21.44	0	236	21.44
2004	1252	477	263	0	1466	1127	339	30.08	0	339	30.08
2005	1252	461	172	0	1541	1151	390	33.88	0	390	33.88
2006	1252	446	139	0	1559	1174	385	32.79	0	385	32.79
2007	1427	336	139	0	1624	1201	423	35.22	0	423	35.22
2008	1602	336	142	0	1796	1231	565	45.90	0	565	45.90
2009	1602	336	144	0	1794	1258	536	42.61	0	536	42.61
2010	1602	336	146	0	1792	1285	507	39.46	0	507	39.46

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(1)	Unit No.	Location	Unit Type(2)	Fuel (3)		Fuel Transport		Const 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	
GE 7FA 2x1 CC	A	Stanton Energy Center	CT	NG	DFO	PL	TK	10/2001	10/2003	10/2033	170.70	185 23	166 51	181.18	L
GE 7FA SC		Stanton Energy Center	CT	NG	DFO	PL	TK	06/2006	06/2007	10/2037	147.60	184.30	140.08	174 91	OT
GE 7FA SC		Stanton Energy Center	CT	NG	DFO	PL	TK	06/2007	06/2008	10/2038	147 60	184.30	140 08	174.91	OT

[1] OUC Ownership Share