ORIGINAL

BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114

Tel: (913) 458-2000

Black & Veatch Corporation

April 14, 2005

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

Ms. Bayo,

Enclosed please find fifteen copies of the 2005 Orlando Utilities Commission (OUC) Ten-Year Site Plan (TYSP). The 2005 OUC TYSP was prepared for and submitted by Black & Veatch on behalf of OUC.

Should you require additional copies of the 2005 OUC TYSP, or have any other questions regarding the Plan, please do not hesitate to contact me at (913) 458-7432.

Very truly yours,

Myron Rollins

Myron Rollins

Enclosure[s]

Cc: Michael Haff (FPSC)

CMP ____
COM ____
CTR ____
ECR ____
GCL ____
OPC ____
MMS ____
RCA ____
SCR ____
SEC 1
OTH 2 Kim P.

The *Reliable* One®

2005 Ten-Year Site Plan

Orlando Utilities Commission

April 2005

OUC

The Reliable One®

2005 Ten-Year Site Plan
Orlando Utilities Commission

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140548.0040

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1.0 Executive Summary

This report documents the 2005 Orlando Utilities Commission (OUC) Ten-Year Site Plan pursuant to Section 186.801 Florida Statutes and Section 25-22.070 of Florida Administrative Code. The Ten-Year Site Plan provides information required by this rule, and consists of the following additional sections:

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

This Plan also integrates the power sales, purchases, and loads for the City of St. Cloud into the OUC Plan. Load forecasts for OUC and the City of St. Cloud have been integrated into one forecast, and details of the aggregated load forecast are provided in Section 4.0. A banded forecast is provided with base case growth, high growth, and low growth scenarios. This analysis, considering the forecasted growth, existing units, retiring units, purchase power contracts, and reserve margin requirements, indicates an initial need for additional capacity beginning in the summer of 2010 under the base case load forecast.

OUC is a member of the Florida Municipal Power Pool (FMPP) which consists of OUC, Lakeland Electric (Lakeland), and the Florida Municipal Power Agency (FMPA) All-Requirements Project. Power for OUC is supplied by OUC jointly owned generation and power purchases. OUC's total installed generating capacity, including units in which it has joint ownership as well as the diesel generation owned by the City of St. Cloud, is 1,220 MW (summer) and 1,278 MW (winter), as of January 1, 2005. The existing supply system has a broad range of generation technology and fuel diversity, with coal providing the largest portion (approximately 63 percent) of OUC's wholly or jointly owned summer generating capacity (approximately 60 percent winter).

In 1999, OUC sold the Indian River Steam Units to Reliant. As part of the agreement with Reliant and described in Section 2.0, OUC received a power purchase agreement (PPA) through September 30, 2003, with an extension option for up to four additional years. OUC has extended the agreement through fiscal year 2005. The agreement will terminate after fiscal year 2005.

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

The original Stanton A purchase power agreement (PPA) was for an initial term of 10 years and required OUC, KUA, and FMPA to purchase all of Southern-Florida's 65 percent capacity share of Stanton A for ten years, although the utilities retained the right to reduce the capacity purchased from Southern-Florida by 50 MW each year, beginning in the sixth year of the PPA, as long as the total reduction in capacity purchased did not exceed 200 MW. Beyond the initial term of the PPA, the utilities had options to extend the term of the PPA. However, subsequent amendments to the original PPA dictate that OUC shall continue its capacity purchase until the 16th year of the PPA. Beginning with the 16th contract year and ending with the 20th contract year, OUC maintains the irrevocable right to reduce the amount of capacity purchased by either 20 MW or 40 MW per year, as long as the total reduction in purchased capacity does not exceed 160 MW. Additionally, OUC has the option of terminating the PPA on September 30, 2023.

Four alternative power plant technologies including combustion turbines, combined cycles, pulverized coal, and circulating fluidized bed units were considered for capacity additions. The alternatives were modeled in Black & Veatch's POWROPT and POWRPRO optimal generation expansion and chronological production costing programs to identify the least-cost capacity expansion plan according to total cumulative present worth costs over a twenty-year (2005 through 2024) planning period. To remain consistent with the 10-year planning period required for the Ten-Year Site Plan, discussion included in the following sections is related to the 2005 through 2014 planning period only.

OUC's expansion plan for the 2005 through 2014 period consists of a natural gas combined cycle plant with an optional IGCC based on the Department of Energy (DOE)'s Clean Coal Power Initiative (CCPI) Integrated Gasification Combined Cycle (IGCC) project proposed by Southern Company Services, Inc. (Southern Company) and OUC with a commercial operation date of January 1, 2011. The natural gas combined cycle project will be placed in service by June 1, 2010. In October, 2004, the DOE selected OUC and Southern Company to build an advanced coal gasification facility as part of the DOE's Clean Coal Power Initiative. The unit was proposed to be built at Stanton Energy

Center, and the DOE indicated it would contribute $235 million to the cost of developing, constructing, and demonstrating the project. Information related to the CCPI is confidential and as such the amount of detail provided within this Ten-Year Site Plan related to the proposed project is somewhat limited.

2.0 Utility System Description

2.1 OUC Structure

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

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

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

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

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

OUC's electric system consisted of a year-end average of 160,159 active services for 2004. Of these, 138,239 were residential services, 16,659 were general service non-demand services, and the remaining 5,261 were general service demand services. St. Cloud's service area consisted of a year-end average of 22,885 active services for 2004 (20,496 residential, 2,156 general service non-demand, and 233 general service demand customers).

2.2 Generation System

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

- Indian River Plant Combustion Turbine Units A, B, C, and D.
- Stanton Energy Center Units 1 and 2, and Stanton A.
- Progress Energy Florida (formerly Florida Power Corporation) Crystal River Unit 3 Nuclear Generating Facility.
- Lakeland Electric McIntosh Unit 3.
- Florida Power and Light Company St. Lucie Unit 2 Nuclear Generating Facility.

The Stanton Energy Center is located 12 miles southeast of Orlando, Florida. The 3,280 acre site contains Units 1 and 2, as well as Stanton A, and the necessary supporting facilities. Stanton 1 was placed in commercial operation on July 1, 1987, followed by Stanton 2, which was placed in commercial operation on June 1, 1996. Both units are fueled by pulverized coal and operate at emission levels that are within the Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FDEP) requirement standards for SO_2, NO_x, and particulates. Stanton 1 is a 444 MW net coal-fired facility, of which OUC has a 68.6 percent ownership share providing 302 MW of capacity to the OUC system. Stanton 2 is a 446 MW net coal-fired generating facility, of which OUC maintains a 71.6 percent (319 MW) ownership share.

Table 2-1
Summary of OUC Generation Facilities

Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Net Capability[1]	
				Pri	Alt	Pri	Alt			Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	FO2	PL	TK	06/89	Unknown	18	23.4
Indian River	B	Brevard	GT	NG	FO2	PL	TK	07/89	Unknown	18	23.4
Indian River	C	Brevard	GT	NG	FO2	PL	TK	08/92	Unknown	85.3	100.3
Indian River	D	Brevard	GT	NG	FO2	PL	TK	10/92	Unknown	85.3	100.3
Stanton Energy Center	1	Orange	ST	BIT	---	RR	---	07/87	Unknown	301.6	303.7
Stanton Energy Center	2	Orange	ST	BIT	---	RR	---	06/96	Unknown	319.3	319.3
Stanton Energy Center	A	Orange	CC	NG	FO2	PL	TK	10/03	Unknown	173.6	184.8
McIntosh	3	Polk	ST	BIT	---	RR	---	09/82	Unknown	133	136
Crystal River	3	Citrus	NP	UR	---	TK	---	03/77	Unknown	13	13
St. Lucie[2]	2	St. Lucie	NP	UR	---	TK	---	06/83	Unknown	51	52
St. Cloud[3]	1	Osceola	IC	NG	FO2	PL	TK	07/82	10/06	2	1.825
	2		IC	NG	FO2	PL	TK	12/74	10/06	5	5
	3		IC	NG	FO2	PL	TK	09/82	10/06	2	2
	4		IC	NG	FO2	PL	TK	08/61	10/06	3	3
	6		IC	NG	FO2	PL	TK	03/67	10/06	3	3
	7		IC	NG	FO2	PL	TK	09/82	10/06	6	6
	8		IC			PL	TK	04/77	10/06	6	6

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

OUC has entered into an agreement with KUA, FMPA, and Southern-Florida governing the ownership of Stanton A, a combined cycle unit at the Stanton Energy Center which began commercial operation on October 1, 2003. OUC, KUA, FMPA, and Southern-Florida are joint owners of Stanton A with OUC maintaining a 28 percent ownership share, KUA and FMPA each maintaining 3.5 percent ownership shares, and Southern-Florida maintaining the remaining 65 percent of Stanton A's capacity.

Stanton A is a 2x1 combined cycle utilizing General Electric combustion turbines. Stanton A is dual fueled with natural gas as the primary fuel and No. 2 oil as the backup fuel. Stanton A uses evaporative coolers, duct burning, and power augmentation for additional output during peak periods and uses treated sewage effluent for cooling water. OUC maintains a 28 percent equity share of SEC A, while purchasing 52 percent as described further in Section 2.3.

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

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

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

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

As part of the Interlocal Agreement with St. Cloud, OUC has operating control of St. Cloud's seven internal combustion generating units, which have a total summer rating of 27 MW. One of the seven St. Cloud internal combustion generating units (Unit 8) is not operated and instead is kept in standby, so the resulting net summer generating capacity from St. Cloud's internal combustion units is 21 MW. All of the St. Cloud units are scheduled to retire in October, 2006.

2.3 Purchase Power Resources

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

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

The original Stanton A PPA was for an initial term of 10 years and required OUC, KUA, and FMPA to purchase all of Southern-Florida's 65 percent capacity share of Stanton A for ten years, although the utilities retained the right to reduce the capacity purchased from Southern-Florida by 50 MW each year, beginning in the sixth year of the PPA, as long as the total reduction in capacity purchased did not exceed 200 MW. Beyond the initial term of the PPA, the utilities had options to extend the term of the PPA. However, subsequent amendments to the original PPA dictate that OUC shall continue its capacity purchase until the 16th year of the PPA. Beginning with the 16th contract year and ending with the 20th contract year, OUC maintains the irrevocable right to reduce the amount of capacity purchased by either 20 MW or 40 MW per year, as long as the total reduction in purchased capacity does not exceed 160 MW. Additionally, OUC has the option of terminating the PPA on September 30, 2023.

St. Cloud has a Partial Requirements (PR) contract with Tampa Electric Company (TECO) for 15 MW, which expires December 31, 2012. As a result of the Interlocal Agreement with St. Cloud, OUC schedules the TECO PR purchase.

2.4 Power Sales Contracts

OUC is contractually obligated to supply power to two different purchasers – FMPA and Reedy Creek Improvement District (RCID) - for various durations of time. These power sales contracts are classified as either unit power sales or system power sales, and details of each of these contracts are summarized below.

2.4.1 FMPA Unit Power Sale

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

2.4.2 RCID System Power Sale

OUC has been involved in a partial requirements power sales contract with Reedy Creek Improvement District since January 1, 1999. The RCID partial requirements contract expires December 31, 2005. OUC will provide 115 MW to RCID during 2005.

2.5 Transmission System

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

The addition of a distribution transformer to the existing Kelly Substation (No. 13) was completed in November, 2004, and the new Lake Nona 230/15 kV substation was placed into in service in March, 2005. The addition of the new 230/25 kV St. Cloud South Substation and bus tie transformer and the 230/69 kV and associated 69 kV lines to the Central Substation are planned for completion in the fall of 2005. The upgrade of the 69 kV tie line to KUA has been delayed due to a road widening project along its path.

Table 2-2
OUC Transmission Interconnections

Utility	kV	Number of Interconnections
FPL (2 circuits)	230	1
PEF	230	8
KUA	230	2
KUA/FMPA	230	2
Lakeland	230	1
TECO	230	2
TECO/RCID	230	2
PEF	69	1
STC	69	1

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

Table 2-3
STC Transmission Interconnections

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

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

To increase reliability and relieve increased fault current levels due to the closing of the Stanton 230 kV bus, oil circuits breakers at two substations (No. 10 and No. 12) were upgraded to gas insulated and two distribution transformers and switchgears at substation No. 9 were replaced with new units.

To maintain reliable and economic service, OUC has developed the following schedule of transmission system upgrades.

- Relocating the bus tie transformer from the Stanton East bus to the Magnolia Ranch 69 kV substation.
- Addition of 230 kV lines between Stanton & Lake Nona via the Magnolia Ranch substation.
- Addition of a 69 kV line from Magnolia Ranch to SR 15, in Orange County, Florida.

3.0 Strategic Issues

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

3.1 Strategic Business Units

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

3.1.1 Power Resources Business Unit

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

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

Coal represents approximately 60 percent of the winter generating capacity (approximately 63 percent summer) either wholly or jointly owned by OUC. This strategy ensures against interruptions in supply and increases in the cost of oil and natural gas. Additional details of OUC's generating facilities are presented in Schedule 1 of Section 11.

Table 3-1
Generation Capacity (MW) Owned by OUC by Fuel Type (as of January 1, 2004)

Plant Name	Winter Capacity				Summer Capacity			
	Coal	Nuclear	Gas/Oil	Total	Coal	Nuclear	Gas/Oil	Total
Stanton	623		185	808	621		174	795
Indian River			248	248			207	207
Crystal River		13		13		13		13
C.D. McIntosh Jr.	136			136	133			133
St. Lucie		52		52		51		51
Total (MW)	759	65	433	1,257	754	64	381	1,199
Total (percent)	60.4	5.2	34.4	100.0	62.9	5.3	31.8	100.0

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

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

OUC's diversified mix of generating units provides protection against disruption of supply while simultaneously providing economic opportunities to reduce cost to customers. The ability to burn a variety of fuels is enhanced through the Indian River purchase power agreement, which utilizes a specified proportion of natural gas and oil which can be adjusted annually. Further, the DOE IGCC project now being investigated will be capable of burning either gasified coal (syngas) as well as natural gas.

3.1.2 Energy Delivery Business Unit

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

OUC's leadership in providing reliable electric distribution service is demonstrated by its commitment to making initial investments in high quality material and equipment. Additionally, nearly 50 percent of OUC's distribution system is underground, protecting it from trees and high winds. OUC's dependability is also attributable to its proactive maintenance programs to identify and correct potential problems, proactive replacement of old equipment, and a tree trimming program that minimizes tree-related service disruptions. OUC's reliability is demonstrated by the fact that during 2004, the average annual customer interruption for the combined Orlando-St. Cloud service area was well below that of OUC's competition. For the fourth consecutive year, OUC ranked at the top in the State for reliability of electric service. OUC finished well ahead of Florida's investor-owned utilities in both L-Bar (the average number of minutes a customer is out of power during an outage) and system average interruption duration indices (SAIDI, a measure of average amount of time a customer is without power during the course of a year).

3.2 Reposition of Assets

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

3.3 Florida Municipal Power Pool

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

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

3.4 Security of Power Supply

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

3.5 Environmental Performance

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

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

Further demonstrating its environmental commitment to clean air, OUC has signed a contract to burn the methane gas collected from the Orange County landfill adjacent to Stanton Energy Center. Methane gas, when released into the atmosphere, is considered to be 20 times worse than carbon dioxide in terms of possible global warming effects. Stanton 1 and Stanton 2 both have the capability of burning methane.

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

3.6 Community Relations

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

In Orange, Osceola, and Brevard Counties, where OUC serves customers and/or has generating units, OUC gives its wholehearted support to education, diversity, the arts, and social-service agencies. An active Chamber of Commerce participant in all three counties, OUC also supports area Hispanic Chambers and the Metropolitan Orlando Urban League. As a United Arts trustee, OUC has allowed its historic Lake Ivanhoe Power Plant to be turned into a performing arts center. OUC is also a corporate donor for WMFE public television and a co-sponsor of the "Power Station" exhibit at the Orlando Science Center.

4.0 Forecast of Peak Demand and Energy Consumption

OUC has retained Itron, formerly Regional Economic Research, Inc. (RER), to develop forecasts of peak demand and energy consumption. The forecast scope was to develop a sales forecast for OUC budgeting and financial planning process. The objective was thus to develop a forecast model that could be used successfully for forecasting both short and long-term energy and peak demand.

4.1 Forecast Methodology

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

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

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

4.1.1 Residential Sector Model

The residential model consists of both an average use per household model and a customer forecast model. Monthly average use models are estimated over the period encompassing 1994 through 2004. This provides seven years of historical data, with more than enough observations to estimate strong regression models. Once models are estimated, the residential energy requirements in month T is calculated as the product of the customer and average use forecast:

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

4.1.1.1 Residential Customer Forecast. The number of customers is forecasted as a simple function of household projections for the Orlando Metropolitan Statistical Area (MSA). Models were estimated using MSA-level data, as county level economic data is only available on an annual basis. Not surprisingly, the historical relationship between OUC customers and households in the Orlando MSA is extremely strong. The OUC customer forecast model has an adjusted R^2 of 0.999 with an in-sample Mean Absolute Percent Error (MAPE) of 0.18 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 0.89 with an in-sample MAPE of 3.5 percent. Given that St. Cloud is a relatively small part of OUC's service territory, the 3.5 percent average customer forecast error represents a relatively small number of total system customers.

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

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

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

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

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

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

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

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

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

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

- Weather conditions (as captured by heating and cooling degree days).
- Electricity prices.

- Household income.
- Household size.

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

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

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

4.1.1.5 Estimate Models. To estimate the forecast models, monthly average residential usage is regressed on *Cooling*, *Heating*, and *BaseUse*. Lagged *Use* variables are also included in the specification because the *Use* variables are constructed with calendar-month weather data, but the dependent variable (residential average use) is based on revenue-month sales. July residential sales, for example, reflect usage in both calendar months June and July. The end-use variables proved to work extremely well in the regression models. For OUC, the residential adjusted R^2 is 0.93 with an in-sample MAPE of about 4 percent. The standard error of the regression model is 43.2 kWh compared with residential monthly average usage of 1,070 kWh. All the model coefficients are highly significant (exhibiting P-values less than 0.09). The St. Cloud model explains slightly less of the variation in average use, with an adjusted R^2 of 0.91 and an in-sample MAPE of less than 5.0 percent. The model coefficients are highly significant.

4.1.2 Nonresidential Sector Models

The nonresidential sector is segmented into two revenue classes:

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

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

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

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

GSND Customers. GSND customers are forecasted using a simple regression model that relates GSND customers to Orlando MSA nonmanufacturing employment projections. An AR1 correction term was added to the specification to correct for serial correlation. The OUC customer model was estimated using monthly customer counts for the period January, 1994, through October, 2004. For OUC, the overall model adjusted R^2 is 0.99 with an in-sample MAPE of 0.26 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 0.92, with an in-sample MAPE of 4.01 percent. An AR1 correction was added to the St. Cloud model to help account for month-to-month swings in customer counts. The model coefficients in both the OUC and St. Cloud models are all highly significant.

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

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

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

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

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

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

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

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 increase in price causes a 0.2 percent decrease in the use variables. Similarly the productivity elasticity is set at 0.2 percent; a 1 percent increase in productivity leads to a 0.2 percent increase in the end-use utilization.

The *Use* variables are multiplied by the *Index* variables to generate *Cooling*, *Heating*, and *BaseUse*. Since 1992, GSND average use for OUC has actually been declining. This is largely because GSND customers tend to be larger (when compared with St. Cloud), and they are typically migrated to the GSD classification as soon as customers exceed the GSND usage limit. To account for the downward trend, a trend variable interactive with the *BaseUse* is incorporated into the average use specification; the variable has a negative sign and is highly significant. All the GSND model variables are highly significant. The adjusted R^2 for the OUC GSND average use model is 0.98 with an in-sample MAPE of 4.0 percent. For St. Cloud the GSND average use model has an adjusted R^2 of 0.85, with an in-sample MAPE of 7.1 percent.

4.1.2.2 GSD Models. The general service demand class represents the largest nonresidential customer class. Over the last five years, OUC has seen the strongest sales gains in the GSD customer class, with GSD sales growth averaging 3.9 percent for the combined OUC and St. Cloud service territories. While overall sales growth will slow significantly over the forecast period, GSD sales are expected to continue to show relatively strong sales growth through the forecast horizon.

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

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

Where:

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

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

In the OUC model, the end-use variables are all highly significant (except for the lagged heating variable). The adjusted R^2 is 0.95 with an in-sample MAPE of 2.7 percent. In the St. Cloud model, all the variables except the heating end-use variables are highly significant. The adjusted R^2 is 0.94 with a MAPE of 3.1 percent. The low t-statistics on the heating variables indicate that there is relatively little electric space heating in the GSD class.

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

Street Lighting Sales. Street lighting sales are forecasted using a simple trend model. It is assumed that street lighting sales will continue to increase at the rate experienced over the last seven years. The forecast also includes sales from the *OUC Convenient Lighting Program*, which targets outdoor lighting use. It is assumed that the *Convenient Lighting Program* will grow by about 2.0 GWh a year through the forecast period.

4.1.3 Hourly Load and Peak Forecast

The system hourly load forecast is based on a set of hourly load models using load data covering the period January, 1996, to December, 2004. To forecast hourly loads, historical hourly loads are expressed as a percentage of the total daily energy:

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

Where:

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

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

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

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

$$Load_h = Fraction_h * DailyEnergyForecast_d$$

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

$$DaykWh_d = System\ Energy_d/SalesTrend_m$$

$$SalesTrend_m = ResTrend_m + NonResTrend_m$$

Where:

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

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

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

$$DailyEnergyForecast_T = KWperKWh_T * SalesTrend_T$$

Where:

SalesTrend$_T$ *is calculated from retail monthly sales forecast*

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

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

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

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

4.2 Forecast Assumptions

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

4.2.1 Economics

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

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

Table 4-1
Employment and Gross Regional Output Projections - Orlando MSA

Year	Total Employment (thousands)	Non-Manufacturing Employment (thousands)	Gross Product (Billion $)
1990	610.7	520.6	33.9
1995	714.3	631.9	41.5
1996	749.7	660.1	44.5
1997	794.6	699.1	47.9
1998	837.7	736.4	51.8
1999	876.4	771.6	55.4
2000	909.6	803.6	56.6
2005	992.7	882.5	63.7
2010	1,144.0	1,029.2	79.0
2014	1,296.0	1,171.3	93.8
Change	Percent	Percent	Percent
90-95	3.2%	4.0%	4.1%
95-00	5.0%	4.9%	6.4%
00-05	1.8%	1.9%	2.4%
05-14	3.0%	3.2%	4.4%

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 as shown in Table 4-2. Economy.com's projections for the Orlando MSA were used.

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.

Table 4-2
Population, Household, and Income Projections – Orlando MSA

Year	Real Income per Household	Households (thousands)	Population (thousands)
1990	$59,818	501.0	1,240.6
1995	$60,505	542.7	1,428.3
1996	$ 61,934	558.5	1,469.6
1997	$63,467	577.7	1,520.0
1998	$66,815	595.9	1,567.8
1999	$ 69,076	611.2	1,607.9
2000	$71,064	629.7	1,656.3
2005	$71,650	718.0	1,879.5
2010	$74,532	813.1	2,097.8
2014	$77,100	913.4	2,320.5
Change	Percent	Percent	Percent
90-95	0.2%	1.6%	2.9%
95-00	3.3%	3.0%	3.0%
00-05	0.2%	2.7%	2.6%
05-14	0.8%	2.7%	2.4%

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. 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.

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

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

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

Year	Real Price (cents/kWh)
1992	6.7
1993	6.7
1994	6.7
1995	6.4
1996	6.2
1997	6.0
1998	5.8
1999	5.4
2000	5.3
2005	5.4
2010	5.3
2014	5.1
Change	**Percent**
1993	0.0
1994	0.0
1995	-4.5
1996	-3.1
1997	-3.2
1998	-3.3
1999	-6.9
00-05	0.4
05-14	-0.6

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

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

For each month, a normal CDD estimate is calculated using a 10-year average of the monthly values calculated from 1995 through 2004:

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

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

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

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

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

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

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

4.3 Base Case Load Forecast

A short-term monthly budget forecast was estimated through 2004, with a long-term annual forecast through 2014. As outlined in the methodology section, the sales forecast is developed from a set of structured regression models that can be used for both forecasting monthly sales and customers for the OUC budget period and over the longer term, 10-year forecast horizon. Forecast models are estimated for each of the major rate classifications including:

- Residential.
- General Service Non-Demand (Small Commercial Customers).

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

Models are estimated using monthly sales data covering the period 1994 through 2004. A separate set of forecast models are estimated for the OUC and St. Cloud service territories.

To support production-costing modeling, an 8,760 hourly load forecast is derived for each of the forecast years. The hourly load forecasts are based on a set of hourly and daily energy statistical models. The models are estimated from hourly system load data over the period January, 1996, to December, 2004. A separate set of models is estimated for OUC and St. Cloud. Seasonal peak demand forecasts are derived as the maximum hourly demand forecast occurring in the summer and winter months. Table 4-4 summarizes the annual sales and peak forecast for the combined OUC and St. Cloud service territories.

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

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	808	731	4,174
1995	861	876	4,377
1996	852	969	4,471
1997	917	849	4,566
1998	988	814	4,909
1999	1,055	965	5,011
2000	1,025	971	5,290
2005	1,166	1,168	6,059
2014	1,531	1,535	7,933
Change	Percent	Percent	Percent
95-00	3.5	2.1	3.9
00-05	2.6	3.8	2.8
05-14	3.1	3.1	3.0

4.3.1 Base Case Economic Outlook

Between 1995 and 2005, population has grown at an average annual rate of 3.2 percent and gross output has grown at 4.7 percent. Orlando's economic growth has consistently exceeded economic growth in both the state and nation. Orlando is expected to exceed overall state economic growth throughout the next ten years.

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

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

To accommodate growing convention, tourism, and regional business activity, the Orlando International Airport (OIA) is an anticipating a major expansion program that will ultimately double the capacity of the airport. In 2001, OIA served 28 million passengers. The airport had seen a decrease in the number of passengers since September 11, 2001. In 2003, OIA served 27.3 million passengers, which was a 2.5 percent increase over the prior year and almost equal to pre-September, 2001, levels. In fact, 2004 was expected to exceed the 2001 levels. Moving forward the OIA expects strong growth of over 3 percent a year over the next decade.

4.3.1.1 Economic Projections. While the economy is projected to slow from the torrid pace experienced over the last few years, relatively inexpensive labor and housing costs and strong in-migration from both other states and other nations will continue to fuel the regional economic expansion long into the future. The number of households in the Orlando MSA is projected to increase from 627,000 in 2000 to 952,000 by 2014, representing an average annual growth rate of 3.0 percent. Employment is projected to grow at 2.9 percent over the long-term.

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

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

4.3.2 Forecast Results

Based upon the previously discussed economic assumptions, total retail sales for OUC are expect to increase from 4,696 GWh in 2000 to 6,962 GWh by 2014. St. Cloud sales are projected to increase from 343 GWh to 699 GWh over this same period. Sales and customer projections are summarized in Tables 4-5 through 4-8.

4.3.2.1 Residential Forecast. With high electric end-use saturation, coupled with projected appliance efficiency-gains, residential average use is projected to increase relatively slowly over the forecast period. For OUC, average use per customer is forecasted to grow at 0.4 percent. Residential sales growth will be driven largely by the addition of new customers. With relatively strong population projections for the region, residential customers are expected to increase at a 2.5 percent rate for OUC and 4.4 percent rate for St. Cloud between 2000 and 2014. The OUC and St. Cloud residential sales forecasts are shown in Tables 4-5 through 4-8, respectively.

4.3.2.2 Small Commercial Sales Forecast. GSND sales are projected to grow at an average annual rate of 0.2 percent and 4.7 percent for OUC and St. Cloud, respectively, between 2000 and 2014. Projected GSND sales are driven by regional nonmanufacturing employment and output growth. Average use is projected to be relatively flat (particularly for OUC). Average use growth is partly constrained by size limitation; as customers exceed the 50 kW rate-class cut-off, they are migrated to the appropriate GSD rate. For OUC, average GSND use has actually trended downward over the last few years. Small commercial customer growth accounts for most of the GSND sales gains. The GSND customer forecast is driven by regional nonmanufacturing employment projections. The number of GSND customers is projected to grow at an average annual growth rate of 1.5 percent and 4.5 percent, respectively, for OUC and St. Cloud from 2000 to 2014. Tables 4-5 through 4-8 show annual GSND forecasts for OUC and St. Cloud.

4.3.2.3 Large Nonresidential Sales Forecast. General Service Demand (GSD) represents the largest commercial and industrial customers. Over the last couple of years, OUC has experienced phenomenal growth from this sector with GSD sales up 7.1 percent from 1998 to 1999 and 4.8 percent from 1999 to 2000. While sales are projected to slow significantly from this pace (for example, the average annual growth rate between 2000 and 2004 decreased to 2.8 percent), sales are projected to continue to show relatively strong gains as a result of new major developments coming on line and overall strong regional output growth. Average use actually declines somewhat over the forecast period as smaller customers migrate from GSND to GSD. The GSD customer forecast is driven by total employment projections and total sales by projected regional gross output. Tables 4-5 through 4-8 summarize the GSD forecast.

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

Year	Residential	GS Non-Demand	GS Demand	St. Lighting	Conv. St. Lts.	OUC Use	Total Retail
1995	1,380	316	2,157	27	--	55	3,935
1996	1,419	318	2,211	28	--	53	4,030
1997	1,377	322	2,280	29	--	56	4,063
1998	1,583	311	2,410	27	--	93	4,423
1999	1,504	308	2,581	30	--	76	4,498
2000	1,583	293	2,705	31	--	84	4,696
2005	1,820	271	3,112	38	9	121	5,371
2014	2,413	300	4,013	46	31	159	6,962
Change	Percent	Percent	Percent	Percent	Percent	Percent	Percent
1996	2.8	0.5	2.5	3.1	--	-3.6	2.4
1997	-3.0	1.2	3.1	2.3	--	5.7	0.8
1998	15.0	-3.5	5.7	-5.4	-	66.1	8.9
1999	-5.0	-0.9	7.1	11.8	--	-18.3	1.7
00-05	2.8	-1.5	2.8	4.2	-	7.6	2.7
05-14	3.2	1.1	2.9	2.1	14.7	3.1	2.9

Table 4-6
OUC Average Number of Customers Forecast

Year	Residential	GS Non-Demand	GS Demand	Total Retail
1995	108,702	14,572	2,965	126,239
1996	111,241	14,855	3,120	129,216
1997	113,669	15,065	3,438	132,172
1998	117,868	15,168	3,793	136,829
1999	121,173	15,659	3,865	140,697
2000	125,891	15,506	4,412	145,809
2005	141,788	16,959	5,360	163,107
2014	180,098	18,731	6,752	205,581
Change	Percent	Percent	Percent	Percent
1996	2.3	1.9	5.2	2.4
1997	2.2	1.4	10.2	2.3
1998	3.7	0.7	10.3	3.5
1999	2.8	3.2	1.8	2.8
00-05	2.4	1.8	4.0	2.4
05-14	2.7	1.1	2.6	2.5

Table 4-7
St. Cloud Sales Forecast (GWH)

Year	Residential	GS Non-Demand	GS Demand	St. Lighting	Total Retail
1995	180	19	56	-	254
1996	190	18	62	-	270
1997	192	19	67	1	278
1998	221	20	72	3	316
1999	221	22	73	3	318
2000	238	26	76	3	343
2005	328	31	101	4	464
2014	482	48	134	5	669
Change	Percent	Percent	Percent	Percent	Percent
1996	5.5	-1.5	11.0		6.2
1997	0.8	1.1	9.4	200.0	3.0
1998	15.2	9.4	7.1		13.7
1999	0.2	6.9	0.7		0.6
00-05	6.6	3.6	5.9	5.9	6.2
05-14	4.4	5.0	3.2	2.5	4.1

Table 4-8
St. Cloud Average Number of Customers Forecast

Year	Residential	GS Non-Demand	GS Demand	Total Retail
1995	13,659	1,293	120	15,072
1996	14,158	1,311	138	15,607
1997	14,527	1,359	142	16,028
1998	15,010	1,427	150	16,586
1999	15,550	1,511	152	17,212
2000	16,470	1,610	163	18,242
2005	21,646	2,214	229	24,089
2014	28,846	2,844	313	32,023
Change	Percent	Percent	Percent	Percent
1996	3.7	1.4	15.1	3.6
1997	2.6	3.6	3.0	2.7
1998	3.3	5.0	5.3	3.5
1999	3.6	6.6	1.4	3.8
00-05	5.6	6.6	7.0	5.7
05-14	3.1	2.8	3.5	3.2

4.4 Net Peak Demand and Net Energy for Load

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

4.5 High and Low Load Scenarios

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

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

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	749	674	3,926
1995	798	800	4,103
1996	788	885	4,186
1997	846	773	4,271
1998	907	746	4,578
1999	969	873	4,674
2000	941	882	4,922
2005	1,051	1,049	5,568
2014	1,357	1,355	7,189
Change	Percent	Percent	Percent
95-00	3.3	2.0	3.7
00-05	2.2	3.5	2.5
05-14	2.9	2.9	2.9

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

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	59	57	249
1995	63	76	274
1996	64	84	285
1997	71	76	295
1998	81	68	331
1999	86	92	337
2000	84	89	369
2005	115	119	491
2014	174	180	743
Change	Percent	Percent	Percent
95-00	6.0	3.2	6.1
00-05	6.5	6.0	5.9
05-14	4.7	4.7	4.7

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

High Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,213	1,215	6,301
2014	1,607	1,610	8,350
95-00	3.6%	2.1%	3.9 %
00-05	3.4%	4.6%	3.6%
05-14	3.2%	3.2%	3.2%
Base Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,166	1,168	6,059
2014	1,531	1,535	7,933
95-00	3.5%	2.1%	3.9%
00-05	2.6%	3.8%	2.8%
05-14	3.1%	3.1%	3.0%
Low Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,120	1,121	5,817
2014	1,284	1,285	6,668
95-00	3.5%	2.1%	3.9%
00-05	1.8%	2.9%	1.9%
05-14	1.5%	1.5%	1.5%

4.5.1 High Load Scenario

The high load scenario is based upon assumptions of continued strong economic growth. It has been assumed that through 2014, area population growth does not slow, but continues to expand at a rate experienced over the last few years. The University of Florida's high and low population projections were used to help bound the population growth assumptions. Stronger population growth allows for continued expansion of the labor force; this in turn translates into stronger employment and total output growth.

4.5.2 Low Load Scenario

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

5.0 Demand-Side Management

Throughout its history, OUC has demonstrated a strong commitment to serve its customers' conservation needs. OUC has undertaken many conservation programs to meet customer needs and expectations. OUC's demand-side management (DSM) goals were approved by the FPSC on March 23, 2000, by Order No. PSC-00-0587-FOF-EG. The evaluations for this docket indicated that there were no cost-effective conservation measures available for OUC. As a result, the FPSC approved zero goals for OUC for the residential and commercial/industrial sectors as presented in Table 5-1. Nevertheless, OUC proposed to continue existing programs feeling that they were in the overall best interest of OUC's customers. The FPSC goals for OUC and the programs implemented to meet these goals are presented briefly in this section and in greater detail in OUC's 2000 Demand-Side Management Plan filed in Docket No. 990722-EG. In addition, OUC's 2005 Demand-Side Management Plan was approved by the FPSC on September 1, 2004, and similarly established zero residential, commercial, and industrial DSM and conservation goals for OUC (Docket No. 040035-EG).

Table 5-1
Total Conservation Goals Approved by the FPSC

Year	Residential			Commercial / Industrial		
	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

The demand-side management programs voluntarily continued and offered by OUC to its customers during 2004 included programs which result in energy and/or demand reductions that are quantifiable, as well as programs that are not quantifiable but aid OUC's customers in reliability, energy conservation, and education. Table 5-2 presents a listing of the programs which were offered by OUC in 2004, and the remainder of this section provides a description of each of these programs.

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

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

5.1 Quantifiable Conservation Programs

5.1.1 Residential Energy Survey Program

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

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

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

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

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

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

5.1.2 Residential Energy Efficiency Rebate Program

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

5.1.3 Residential Low-Income Home Energy Fix-Up Program

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

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

- Attic insulation.
- Exterior and interior caulking.
- Weather-stripping doors and windows.
- Minor air conditioning / heating supply and return air duct repairs.
- Water heater and hot water pipe insulation.
- Minor water leakage repair.
- Installation of water flow restrictors.
- Minor electrical repairs.

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

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

5.1.4 Residential Insulation Billed Solutions Program

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

5.1.5 Residential Efficient Electric Heat Pump Program

This program provides rebates to qualifying customers who install heat pumps having a seasonal energy efficiency ratio (SEER) of 11.0 (or greater). Customers will be able to obtain rebates ranging from $100 to $300, depending upon the SEER rating of the heat pump selected. Customers will benefit from the increased energy conservation in their home, which will decrease their electric bills. One of the main benefits of this program is the duct work and insulation level improvements made by contractors when installing the energy efficient heat pumps. Changes to building code regulations will likely increase the minimum SEER value to 13.0 in order to qualify for this program beginning in 2006.

5.1.6 Residential Gold Ring Program

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

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

Gold Ring Homes can use 20 to 30 percent less energy than other homes. Gold Ring homeowners benefit from lower energy bills and qualification for all FHA, VA, and Energy Efficient Mortgage Programs. This allows the homeowner to increase their income to debt ratio by two percent and makes it easier to qualify for a mortgage.

5.1.7 Commercial Energy Survey Program

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

5.1.8 Commercial Indoor Lighting Retrofit Program

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

5.2 Additional Conservation Programs.

The following programs were offered by OUC to its customers in 2004, resulting in energy savings and increased reliability. Although the programs are neither directly nor easily quantifiable, each program is a valuable service provided by OUC to its customers.

5.2.1 Residential Night Security Lighting Program

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

5.2.2 Residential Energy Conservation Rate

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

5.2.3 Commercial OUConsumption Online Program

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

5.2.4 Commercial OUConvenient Lighting Program

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

During 2004, OUConvenient Lighting projects included the Rosen Hotels & Resorts, Baldwin Park Development Co., and the Orange County Convention Center, among many others. In St. Cloud, OUConvenient Lighting worked with developers to provide lighting solutions to the Stevens Plantation project, which is planned to include 800 single-family homes, up to 250,000 square feet of neighborhood retail, and a 100-acre business park with up to one million square feet of office and light manufacturing space.

OUConvenient Lighting also experienced participation outside of OUC's service territory during 2004. The program provided services to the Reunion Resort & Club (Reunion), located in Osceola County near Walt Disney World. As part of OUConvenient Lighting's work with Reunion, streetlights were provided for stretches of several major highways as well as all the major roadways between Reunion neighborhoods.

5.2.5 Commercial Power Quality Analysis Program

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

5.2.6 Commercial Infrared Inspections Program

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

5.2.7 OUCooling

OUCooling was originally formed in 1997 as partnership between OUC and Trigen-Cinergy Solutions which helps to lower air conditioning-related electric charges and reduce capital and operating costs. During 2004, OUC bought Trigen-Cinergy's rights and is now the sole owner of OUCooling. OUCooling will fund, install, and maintain a central chiller plant for each business district participating in the program. The main benefits to the businesses are lower energy consumption, increased reliability, and no environmental risks associated with the handling of chemicals. Other benefits for the businesses include avoided initial capital cost, maintenance costs, a smaller mechanical room (therefore more rental space), no insurance requirements, improved property resale value, and relief of maintenance personnel for other duties.

During 2004, OUCooling added four customers totaling 2,000 tons of chilled water in downtown Orlando. The customers added consist of the Florida A&M College of Law, the Sanctuary luxury condominiums, the CNL II Tower, and the Metropolitan at Lake Eola Condominiums. Also during 2004, OUC constructed its North Central water chiller plant. The North Central plant began operating in November, 2004, and has greater capacity than the original plant. Looking ahead to 2005, OUCooling has already signed two additional projects – the Plaza development and the Jackson condos – and will be actively working to secure additional agreements both downtown and elsewhere.

OUC's first chiller plant was installed at Lockheed Martin Corp. The plant was built in 1999 and serves eight customers. OUC next began operation of a chilled water system serving downtown Orlando. In 1999, the downtown project won three awards. In 2000, the Downtown Orlando Partnership gave its Award of Excellence to OUC based on the chilled water plant. The downtown Orlando "district cooling" division now provides air conditioning service to more than a dozen large commercial customers with a combined two million square feet of space.

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

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

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

5.2.8 Green Power Initiative

OUC offers its customers an opportunity to participate in its *Green Power Initiative* – a program developed to increase the role of renewable energy among OUC's customers. Participation in this program helps add renewable energy to OUC's generation portfolio, improves regional air and water quality, and assists OUC in developing additional renewable energy resources. Program participants pay an additional five dollars on their monthly utility bills and in return add 200 kWh of renewable energy to the power mix every month. Participation helps OUC develop cleaner alternative energy resources such as solar, wind, and biomass. Annual participation, per customer, of 2,400 kWh of renewable energy is equivalent to the environmental benefit of planting three acres of forest, taking three cars off the road, preventing the use of 27 barrels of oil, or bicycling over 30,575 miles instead of driving.

5.2.9 Photovoltaic Generation Pilot Program

OUC has initiated its *Photovoltaic Generation Pilot Program* to customers on Standby Service in which on-site generation consists of photovoltaic (PV) capacity. A PV system is a solar electric generating system which contains solar PV panels, batteries (optional), a static power converter, wiring, fuses, wiring devices, conduit, circuit breakers, transfer or disconnect switches, etc., for making the physical connections required to install the PV system and connect it to the normal wiring system. The program is available to the first 150 kW of residential PV generation and 350 kW of General Service PV generation located in either the OUC or City of St. Cloud service territories.

Participating customers will be reimbursed for any export power supplied by the PV system at a rate equal to the applicable per kWh Standby Base and Fuel Energy Charges in the event that the PV system is grid-integrated. If the customer qualifies for buyback credits, OUC shall furnish and install such metering facilities as OUC determines to be appropriate to measure the electricity delivered by the customer to OUC's delivery system. The customer will receive both a monthly per kW credit as well as a flat monthly credit for the ownership and use of the PV system.

6.0 Forecast of Facilities Requirements

6.1 Existing Capacity Resources and Requirements

6.1.1 Existing Generating Capacity

As shown in Tables 6-1 and 6-2 which are presented at the end of this section, OUC and St. Cloud together have an existing generating capability of 1,220 MW in the summer and 1,278 MW of winter generating capability. The existing generating capability consists of OUC's joint ownership share of Stanton Energy Center (Units 1 and 2, as well as Stanton A) and the Indian River combustion turbines operated by OUC, OUC's joint ownership share of Crystal River 3, McIntosh 3, and St. Lucie 2 operated by Progress Energy Florida, Lakeland Electric, and FPL, respectively, as well as St. Cloud's diesels (which are scheduled to retire in October, 2006).

6.1.2 Power Purchase Agreements

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

Corresponding with the construction of Stanton A, OUC entered into a PPA with Southern-Florida to purchase capacity from Southern-Florida's 65 percent ownership share of Stanton A. The original Stanton A PPA was for an initial term of 10 years and required OUC, KUA, and FMPA to purchase all of Southern-Florida's 65 percent capacity share of Stanton A for ten years, although the utilities retained the right to reduce the capacity purchased from Southern-Florida by 50 MW each year, beginning in the sixth year of the PPA, as long as the total reduction in capacity purchased did not exceed 200 MW. Beyond the initial term of the PPA, the utilities had options to extend the term of the PPA. However, subsequent amendments to the original PPA dictate that OUC shall continue its capacity purchase until the 16th year of the PPA. Beginning with the 16th contract year and ending with the 20th contract year, OUC maintains the irrevocable right to reduce the amount of capacity purchased by either 20 MW or 40 MW per year, as long as the total reduction in purchased capacity does not exceed 160 MW. Additionally, OUC has the option of terminating the PPA on September 30, 2023.

6.1.3 Power Sales Agreements

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

6.1.4 Modifications and Retirements of Generating Facilities

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

By the end of the Ten-Year Site Plan planning period, McIntosh 3 will be 32 years old and, therefore, increasing consideration should be given to life extension costs or its possible retirement.

An additional factor affecting potential unit modifications and/or retirements is the finalization of the Environmental Protection Agency (EPA)'s Clean Air Interstate Rule (CAIR). The CAIR mandates a NO_x reduction cap in the State of Florida, among other states, of 0.58 million tons by 2009 and 0.48 million tons by 2015. The affect that CAIR will have on OUC's generating assets will be influenced by the ultimate CAIR state implementation plan (SIP). The implementation of CAIR could have a further impact on considerations regarding retirement of aging capacity such as McIntosh 3.

6.2 Reserve Margin Criteria

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

6.3 Future Resource Needs

6.3.1 Generator Capabilities and Requirements Forecast

Since OUC has elected to use a 15 percent reserve margin criterion, OUC applies it to St. Cloud's load as well as partial requirements (PR) purchases and sales. Tables 6-1 and 6-2 (presented at the end of this section) display the forecast reserve margins for the combined OUC and St. Cloud systems for the winter and summer seasons, respectively. The capacity associated with the natural gas combined cycle and optional DOE CCPI project is included in the "installed capacity" column of Tables 6-1 and 6-2. The increase in capacity between 2010 and 2011 is a result of the optional conversion of the natural gas combined cycle to operation on gasified coal (syngas).

Table 6-1 and Table 6-2 indicate that no additional capacity is required during the 2005 through 2014 planning period. The combined cycle operating on natural gas with commercial operation planned for June 1, 2010 (and possible addition of the DOE IGCC project January 1, 2011) satisfies both forecast summer and winter capacity requirements through the term of this Ten-Year Site Plan.

6.3.2 Transmission Capability and Requirements Forecast

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

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

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

Table 6-1
OUC and St. Cloud (STC) Forecast Winter Reserve Requirements – Base Case

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)		Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[4] (MW)
	OUC	STC	RCID P.R.	FMPA I.R.		Installed[1]	SEC A PPA	Reliant PPA	TECO P.R.	Total	Required[2]	Available[3]	
2005/06	1,079	124	0	22	1,225	1,278	343	0	15	1,636	180	413	233
2006/07	1,110	130	0	0	1,240	1,257	343	0	15	1,615	186	377	191
2007/08	1,143	137	0	0	1,280	1,257	343	0	15	1,615	192	337	145
2008/09	1,175	143	0	0	1,318	1,257	343	0	15	1,615	198	299	102
2009/10	1,211	151	0	0	1,362	1,257	343	0	15	1,615	204	255	51
2010/11	1,248	158	0	0	1,406	1,568	343	0	15	1,926	211	523	312
2011/12	1,282	165	0	0	1,447	1,568	343	0	15	1,926	217	482	265
2012/13	1,317	172	0	0	1,489	1,568	343	0	0	1,911	223	422	199
2013/14	1,355	180	0	0	1,535	1,568	343	0	0	1,911	230	376	146
2014/15	1,391	187	0	0	1,578	1,568	343	0	0	1,911	237	333	97

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

Table 6-2
OUC and St. Cloud (STC) Forecast Summer Reserve Requirements – Base Case

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)		Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin[4] (MW)
	OUC	STC	RCID P.R.	FMPA I.R.		Installed[1]	SEC A PPA	Reliant PPA	TECO P.R.	Total	Required[2]	Available[3]	
2005	1,051	115	115	43	1,324	1,220	322	300	15	1,857	192	535	343
2006	1,081	120	0	22	1,223	1,220	322	0	15	1,557	180	336	156
2007	1,112	126	0	0	1,238	1,199	322	0	15	1,536	186	300	115
2008	1,145	133	0	0	1,278	1,199	322	0	15	1,536	192	260	69
2009	1,177	139	0	0	1,316	1,199	322	0	15	1,536	197	222	25
2010	1,213	146	0	0	1,359	1,489	322	0	15	1,826	204	469	265
2011	1,250	153	0	0	1,403	1,510	322	0	15	1,847	210	447	236
2012	1,285	160	0	0	1,445	1,510	322	0	15	1,847	217	405	188
2013	1,320	167	0	0	1,487	1,510	322	0	0	1,832	223	345	122
2014	1,357	174	0	0	1,531	1,510	322	0	0	1,832	230	301	72

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

7.0 Supply-Side Alternatives

In order to perform the economic analysis described in Section 8.0, Black & Veatch developed capital cost, performance, and O&M cost estimates for four different generating technologies including simple cycle, combined cycle, pulverized coal, and circulating fluidized bed. The estimates were used in OUC's 20-year evaluation; however, as described in Section 6.0, no capacity additions are required during the 2005 through 2014 planning period beyond the addition of the DOE IGCC project. Therefore, detailed descriptions of the supply-side alternatives have not been included in the Ten-Year Site Plan.

8.0 Analysis and Results

8.1 Analysis Methodology

8.1.1 Methodology

The economic evaluation used to determine OUC's capacity expansion plan over the 2005 through 2024 planning period is based on the cumulative present worth of annual costs for capital costs, non-fuel O&M costs, fuel costs, and purchase power demand and energy costs. Capital costs are included for new unit additions only, as capital costs for existing units represent sunk costs and are the same for every plan. Annual capital costs for new unit additions are determined by applying a levelized fixed charge rate to the capital costs for each unit beginning in the first year of commercial operation. Non-fuel O&M costs include fixed and variable O&M costs; however fixed O&M costs are not included for existing units since these costs are the same for every plan.

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

8.1.2 Economic Parameters

The following economic parameters were assumed for the determination of OUC's 20-year capacity expansion plan.

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

8.1.2.2 Municipal Bond Rate. The 30-year municipal bond rate is assumed to be 5.0 percent.

8.1.2.3 Present Worth Discount Rate. OUC's present worth discount rate is assumed to be equal to the municipal bond rate of 5.0 percent.

8.1.2.4 Interest During Construction Interest Rate. The interest during construction rate is assumed to be 5.0 percent.

8.1.2.5 Levelized Fixed Charge Rate. The fixed charge rate, or FCR, represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year fixed charge rate. Based on the municipal bond rate of 5.0 percent, a 1.0 percent annual insurance cost, a 2.0 percent bond issuance fee, and a six month debt reserve fund earning the bond interest rate of 5.0 percent, the levelized fixed charge rate for a 30-year capital recovery period is 7.69 percent.

8.2 Fuel Price Projections

This section presents the fuel price projections for coal, natural gas, No. 2 fuel oil, No. 6 fuel oil, and nuclear fuel. OUC provided its most recent fuel forecasts for natural gas and coal. The forecasts for No. 6 and No. 2 fuel oils were developed by Black & Veatch based on the differential costs between the forecast prices for each fuel versus natural gas presented in the 2004 OUC Ten-Year Site Plan.

Fuel prices are highly volatile and are dependent not only on supply and demand, but also political stability and interdependent markets. Even the best forecasters face a tough job of forecasting in such a volatile market. Due to the difficulty of forecasting in this environment, a high fuel price scenario and a low fuel price scenario were also developed for use in the Ten-Year Site Plan.

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

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

8.2.1 Coal

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

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

Year	Coal	Natural Gas	No. 6 Oil	No. 2 Oil	Nuclear
2005	2.12	7.38	6.04	7.79	0.42
2006	2.41	6.83	5.51	7.09	0.43
2007	2.48	6.65	5.36	6.91	0.44
2008	2.49	6.47	5.27	6.78	0.45
2009	2.54	6.31	5.19	6.67	0.46
2010	2.60	6.14	5.11	6.60	0.48
2011	2.66	5.99	5.03	6.50	0.49
2012	2.87	5.84	4.95	6.43	0.50
2013	2.99	5.86	4.81	6.25	0.51
2014	3.06	5.89	4.67	6.08	0.52

8.2.2 Natural Gas

The base case forecast for delivered natural gas is presented in Table 8-1. OUC has natural gas transportation capability from Florida Gas Transmission Company (FGT) under FTS-1 and FTS-2 tariffs. The FTS-2 tariff is expected to change as additional expansions are conducted on the FGT system (described in Section 8.3.2). In general, it is expected that the FTS-2 tariff rates will decrease as additional system expansions are added. Also impacting the natural gas transportation situation is the Gulfstream pipeline project (described in Section 8.3.3). Increased competition would be expected to increase pressure to lower transportation costs. The impacts of transportation capacity being bought and sold on the secondary market will also influence the average natural gas transportation costs. Further, the potential of introducing liquefied natural gas (described in Section 8.3.4) into the gas supply in the State of Florida will also affect natural gas prices in the future.

8.2.3 No. 6 Fuel Oil

The forecast for No. 6 fuel oil used in OUC's 20-year evaluation was developed by Black & Veatch. The methodology used in doing so was to calculate the percent difference for each year's No. 6 fuel oil forecast compared to the corresponding year's forecast natural gas price as presented in the 2004 OUC Ten-Year Site Plan. This percent difference was then applied to the annual natural gas forecast developed by OUC for use in their 20-year evaluation.

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

8.2.4 No. 2 Fuel Oil

The methodology used to develop the forecast for No. 2 fuel oil was identical to that described above for No. 6 fuel oil, with percent differences calculated based on the forecasts for natural gas and No. 2 fuel oil presented in the 2004 OUC Ten-Year Site Plan. The resulting forecast for No. 2 fuel oil was used in the analysis of the simple cycle combustion turbines utilized in OUC's 20-year evaluation in order to reflect the fact that the addition of a combustion turbine may require more natural gas than OUC has available under existing FGT contracts. Because the forecast for No. 2 fuel oil is higher per MBtu than the forecast for natural gas, such an analysis reflects a "worse case" scenario. That is, if the addition of combustion turbines prove economical when firing No. 2 fuel oil, it will be even more cost-effective firing the lower cost natural gas.

8.2.5 Nuclear Fuel

The forecast for nuclear fuel remains unchanged from that used for the 2004 OUC Ten-Year Site Plan for the years 2005 through 2013. The forecast for 2014 and beyond was developed by extrapolating the 2013 forecast at the general inflation rate of 2.5 percent. The nuclear fuel price forecast is presented in Table 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 upon both domestic and offshore production and imports. Natural gas reserves are mostly dependent on domestic production. Increasing demand for natural gas as a fuel for both home heating and power production is contributing to the volatility of its price, which in turn has provided incentives for increased production. A somewhat cyclic effect is expected, where short-term demand and price volatility will drive increased production and future price stability.

8.3.1 Service to Proposed Plant Site

FGT's 26-inch pipeline is located approximately 2.5 miles south of the Stanton Energy Center site, the location of the DOE IGCC project.

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 wholly owned by Citrus Corporation which, in turn, is jointly owned by CCE Holdings, LLC, and Southern Natural Gas, an El Paso Energy Corporation affiliate and one of the largest independent producers of natural gas in the United States. CCE Holdings LLC is a Southern Union and GE Commercial Finances Energy Financial Services subsidiary.

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 mainline delivery capacity of 2.1 billion cubic feet per day.

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.

FGT has completed system expansions over the last few years including the following projects:

- The Phase IV expansion project was completed in 2001. This project consisted of expanding services to southwest Florida with 139 miles of underground pipelines and more than 38,000 horsepower of compression, and associated facilities. Approximately 197 million cubic feet per day (MMcf/d) of incremental firm transportation service was added on an average annual basis.

- The Phase V expansion project was completed in 2002. This project consisted of approximately 167 miles of new pipeline and 132,615 horsepower of compression to the existing system. Approximately 428 MMcf/d of incremental mainline capacity to Florida was added.
- The Phase VI expansion project was completed in 2003. This expansion added 120 MMcf/d of incremental firm transportation service to Florida.
- In their new open season, FGT has recently announced plans for pipeline expansion. The new pipeline will extend from Savannah, Georgia, to Jacksonville, Florida, with access to Southern LNG Company's liquefied natural gas project at Elba Island.

8.3.3 Alternative Natural Gas Supply Pipelines to Peninsular Florida

The Gulfstream pipeline is a 581 mile pipeline owned jointly by Williams Company and Duke Energy. The pipeline originates from the Mobile Bay region in East Louisiana and Mississippi, and crosses the Gulf of Mexico to a landfall in Manatee County (south Tampa Bay). The pipeline supplies Florida with 1.1 billion cubic feet of gas per day serving existing and prospective electric generation and industrial projects in southern Florida. The pipeline was placed in service in May, 2002.

Gulfstream has completed construction of a 110 mile, 30 inch natural gas pipeline expansion project that began service during the spring of 2005. The expansion will provide new transportation service to Polk, Hardee, Highlands, Okeechobee, and Martin counties.

8.3.4 Liquified Natural Gas (LNG) Supply to Peninsular Florida

LNG is natural gas that has been cooled to approximately -256° F for purposes of shipping and storing, as the volume of liquefied natural gas is reduced by a factor of approximately 600, allowing considerably more natural gas to be shipped and stored in liquid form than in gaseous form. The LNG is stored in double-walled tanks at atmospheric pressure and shipped aboard specially designed tankers. Upon arrival at an LNG receiving terminal, LNG in its liquid state, is stored in permanent double-walled tanks. The LNG is then heated, vaporized, and regulated for temperature and pressure, for distribution as natural gas. LNG can be a viable alternative supply source to supplement the overall natural gas supply reliability within the Florida market.

Three LNG projects have been proposed for the State of Florida, each of which would originate in the Bahamas and would deliver natural gas to Florida via subsea pipelines. The three companies that originally proposed such projects were the AES

Corporation (AES), Tractebel North America, Inc. (Tractabel), and El Paso Corporation (El Paso).

All three companies submitted bids to the Bahamas Energy, Scientific, and Technology (BEST) Commission to construct LNG terminals in the Bahamas. The terminals would consist of LNG receiving, storage tanks and regasification facilities constructed in the Bahamas, with the natural gas being delivered to Florida via subsea pipeline. The following discussion addresses each of the three originally proposed LNG projects.

AES has proposed development of LNG facilities through its AES Ocean LNG, Ltd. subsidiary. The proposed project would be constructed, owned, and operated by AES and would include approximately 54 miles of under water pipeline between Ocean Cay, Bimini, and Broward County, Florida. The pipeline would connect with, and receive gas transported by another 40 mile pipeline within the Bahamian-jurisdiction (owned by an AES affiliate). The project is designed to deliver 842 million cubic feet (MMcf) per day. The BEST Commission completed its review of AES's Environmental Impact Assessment (EIA) in December, 2003. The Federal Energy Regulatory Commission (FERC) approved the corresponding pipeline Final Environmental Impact Statement (FEIS) in January, 2004, and the State of Florida submerged land leases and environmental resource permits were issued in April ,2004.

Tractebel, operating as Tractebel Bahamas LNG, Limited, proposed an LNG facility including a pipeline spanning approximately 96 miles divided into a US and Bohemian portion from the Grand Bahamas to Port Everglades, Florida. The project is called the Calypso project. The State of Florida issued Tractebel an Environmental Resource Permit (ERP) in April, 2004, to operate the natural gas pipeline in Florida. The proposed pipeline would interconnect with FGT's system adjacent to Florida Power & Light's Lauderdale Plant and would be capable of supplying 865 MMcf per day of natural gas to Florida. The BEST commission's review of Tractebel's EIA for its proposed LNG project was concluded in June, 2004.

El Paso also had proposed an LNG project to deliver natural gas from South Riaing Point on Grand Bahama Island to Riviera Beach, Florida, via its proposed 126 mile Seafarer Pipeline. El Paso has submitted applications to FERC and the State of Florida and submitted its EIA to the BEST Commission in November, 2003. FPL Group Resources, LLC., a subsidiary of FPL Group, has purchased options from El Paso to develop the associated LNG terminal in the Bahamas and has obtained a 50 percent interest in the Seafarer Pipeline. If built, the El Paso/FPL Group Resources project would be capable of providing 1,100 MMcf per day of natural gas to Florida.

Recently, FPL Group Resources, Tractebel, and El Paso have announced plans to combine efforts to develop a single LNG terminal in the Bahamas. A newly combined pipeline development group and terminal development group will work to obtain permitting so that either proposed pipeline (Calypso or Seafarer) can be completed, thus best enabling one, optimal project to be constructed. Under the agreement, Tractebel and El Paso would be equity owners of both the Seafarer and Calypso pipeline projects and will plan to build one pipeline from an LNG terminal in the Bahamas to Florida.

8.4 Results for Capacity Expansion Plans

8.4.1 Methodology

The supply-side evaluation of generating unit alternatives was performed for the 2005 through 2024 planning period using POWROPT, an optimal generation expansion model developed by Black & Veatch. Developed as an alternative to and benchmarked against other optimization programs, POWROPT has proven to be an effective modeling program. POWROPT has been used in several Need for Power proceedings before the Florida Public Service Commission.

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

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 costs for each year of the expansion plan, from which the cumulative present worth cost is developed. For purposes of expansion planning, POWROPT and POWRPRO consider the combined systems of OUC and St. Cloud.

8.4.2 Results of the Economic Analysis

As discussed previously, OUC performed a 20-year analysis to determine its capacity expansion plan for the 2005 through 2014 planning period. However, as demonstrated in Section 6.0, OUC does not forecast any capacity requirements beyond the addition of a natural gas combined cycle with an optional DOE IGCC over the term of this Ten-Year Site Plan.

8.5 Sensitivity Analysis

As part of its capacity planning process, OUC considers a number of sensitivity analyses to measure the impact of variations to critical assumptions. Among the sensitivity analyses considered are high and low fuel price projections, high and low load and energy growth projections, increased present worth discount rate, and high and low capital cost sensitivities. However, none of the sensitivity analyses listed above, with the exception of the high load and energy growth projections, would change the schedule of unit additions, as no capacity additions beyond the addition of a natural gas combined cycle and optional DOE IGCC are required during the 2005 through 2014 planning period. In the high load and energy growth scenario, additional capacity would be required in 2014.

9.0 Environmental and Land Use Information

The Stanton Energy Center, originally certified for 2,000 MW, currently consists of two pulverized coal units, which went into service in 1987 and 1996, and a 2x1 combined cycle unit (Stanton A) which began commercial operation in 2003. Extensive environmental and land use information was filed with the Site Certification Application for Stanton 1 and additional information was filed with the Supplemental Site Certification Applications for Stanton 2 and Stanton A. The original and supplemental Site Certification Applications were submitted to all the agencies and for the sake of brevity have not been reproduced for inclusion in this Ten-Year Site Plan. The natural gas combined cycle plant with an optional DOE IGCC would be located at Stanton Energy Center, utilizing the site's existing infrastructure.

9.1 Status of Site Certification

Ultimate certification for 2,000 MW was obtained with the Site Certification for Stanton 1. Stanton 2 and Stanton A were certified under the Supplemental Site Certification provisions of the Florida Electrical Power Plant Siting Act (Act). The natural gas combined cycle plant with an optional DOE IGCC will require that OUC file a supplemental site certification application, similar to the process for Stanton 2 and Stanton A.

9.2 Land and Environmental Features

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

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

The Stanton Site is served by an approximately 18 mile rail spur from the CSX railroad.

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

9.3 Air Emissions

The optional DOE IGCC project will utilize state-of-the-art emissions controls, demonstrating the cleanest, most efficient coal-fired power technology in the world. Emissions of SO_2 and NO_x from the project will be significantly lower than other clean coal technologies, and the mercury capture rate will be greater. Air emissions were quantified in the OUC and Southern DOE CCPI application, but are being treated as confidential at this time.

9.4 Water and Wastewater

The amount of water required for operation of the optional DOE IGCC project has not yet been determined. However, treated sewage effluent will be used for cooling. In December, 2003, the *Water Conservation Feasibility Study* was developed for the Stanton site, which will assist OUC in developing further strategies for water conservation.

The Stanton site is designed to reuse wastewater to the extent possible. When wastewater cannot be reused, it is evaporated with a brine concentrator/crystallizer; thus, the Stanton site is truly a zero discharge site. The wastewater generated by the IGCC project will be disposed using the existing wastewater treatment facilities.

10.0 Conclusions

As discussed throughout this Ten-Year Site Plan, OUC and Southern were selected by the Department of Energy to build an advanced coal gasification facility as part of the DOE's Clean Coal Power Initiative. The natural gas combined cycle plant is currently assumed to be operational by June 1, 2010, with operation on gasified coal (syngas) by January 1, 2011, if the optional DOE IGCC project is performed The addition of this unit satisfies forecast capacity requirements through the end of the Ten-Year Site Plan planning period (2005 through 2014). Therefore, no capacity additions are required nor presented in this Ten-Year Site Plan. It should be noted that details of the DOE IGCC project are confidential, and OUC and Southern are currently in negotiations related to the project.

11.0 Ten-Year Site Plan Schedules

This section presents the schedules required by the Ten-Year Site Plan rules for the Florida Public Service Commission (FPSC). For each table the FPSC Schedule number is included in parenthesis. The information contained within the FPSC Schedules is representative of the combined OUC and City of St. Cloud systems, consistent with all Sections of the 2005 OUC Ten-Year Site Plan.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)
				Primary Fuel		Alternate Fuel		Alt Fuel	Commercial. In-	Expected	Gross Capability[1]		Net Capability[1]	
Plant Name	Unit No.	Location	Unit Type	Fuel Type	Transport Method	Fuel Type	Transport Method	Storage (Days Burn)	Service MM/YYYY	Retirement MM/YYYY	Summer MW	Winter MW	Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	PL	DFO	TK	0.2	06/1989	Unknown	18.30	23.50	18.00	23.30
Indian River	B	Brevard	GT	NG	PL	DFO	TK	0.2	07/1989	Unknown	18.30	23.50	18.00	23.30
Indian River	C	Brevard	GT	NG	PL	DFO	TK	0.2	08/1992	Unknown	86.10	101.10	85.30	100.30
Indian River	D	Brevard	GT	NG	PL	DFO	TK	0.2	10/1992	Unknown	86.10	101.10	85.30	100.30
Stanton Energy Center	1	Orange	ST	BIT	RR	NA	UN	UN	07/1987	Unknown	320.13	322.19	301.62	303.68
Stanton Energy Center	2	Orange	ST	BIT	RR	NA	UN	UN	06/1996	Unknown	335.76	335.76	319.29	319.29
Stanton Energy Center	A	Orange	CC	NG	PL	DFO	TK	3	10/2001	Unknown	180.60	198.00	173.60	184.80
McIntosh	3	Polk	ST	BIT	REF	NA	UN	UN	09/1982	Unknown	146.00	146.00	136.80	136.80
Crystal River	3	Citrus	ST	NUC	TK	NA	UN	UN	03/1977	Unknown	14.03	14.27	13.36	13.64
St. Lucie[2]	2	St. Lucie	ST	NUC	TK	NA	UN	UN	08/1983	Unknown	54.20	54.20	51.09	51.94
St. Cloud	1	Osceola	IC	NG	PL	DFO	TK	5	07/1982	10/2006	2.000	2.000	2.000	2.000
St. Cloud	2	Osceola	IC	NG	PL	DFO	TK	5	12/1974	10/2006	5.000	5.000	5.000	5.000
St. Cloud	3	Osceola	IC	NG	PL	DFO	TK	5	09/1982	10/2006	2.000	2.000	2.000	2.000
St. Cloud	4	Osceola	IC	NG	PL	DFO	TK	5	08/1961	10/2006	3.000	3.000	3.000	3.000
St. Cloud	6	Osceola	IC	NG	PL	DFO	TK	5	03/1967	10/2006	3.000	3.000	3.000	3.000
St. Cloud	7	Osceola	IC	NG	PL	DFO	TK	5	09/1982	10/2006	6.000	6.000	6.000	6.000
St. Cloud[3]	8	Osceola	IC	NG	PL	DFO	TK	5	04/1977	10/2006	6.000	6.000	6.000	6.000

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					General Service Non-Demand		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
1995	315,900	2.56	1,560	123,351	12,647	335	15,953	20,999
1996	321,600	2.56	1,609	125,617	12,809	336	16,221	20,714
1997	330,000	2.55	1,568	129,433	12,114	341	16,416	20,772
1998	341,000	2.55	1,804	133,732	13,490	331	16,597	19,943
1999	351,400	2.55	1,725	137,815	12,517	330	17,066	19,337
2000	362,000	2.56	1,821	141,546	12,865	318	17,172	18,519
2001	372,200	2.55	1,893	145,762	12,987	316	17,281	18,286
2002	383,200	2.55	1,973	150,365	13,121	314	17,681	17,759
2003	391,500	2.54	2,033	153,841	13,215	297	17,993	16,506
2004	403,900	2.54	2,079	158,735	13,097	299	18,815	15.892
Forecast								
2005	415,800	2.54	2,148	163,434	13,143	302	19,173	15,751
2006	426,900	2.54	2,218	167,798	13,218	308	19,437	15,846
2007	437,000	2.54	2,284	171,749	13,298	313	19,679	15,905
2008	447,300	2.54	2,353	175,848	13,381	318	19,932	15,954
2009	459,200	2.54	2,430	180,548	13,459	323	20,192	15,996
2010	471,900	2.54	2,513	185,585	13,541	328	20,453	16,037
2011	485,300	2.54	2,598	190,869	13,611	333	20,719	16,072
2012	499,400	2.54	2,689	196,373	13,693	337	20,992	16,054
2013	514,600	2.54	2,787	202,393	13,770	342	21,277	16,074
2014	531,200	2.54	2,895	208,944	13,855	348	21,575	16,130

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	General Service Demand						
Year	GWh	Average No. of Customers	Average kWh Consumption per Customer	Railroads and Railways	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
1995	2,263	3,072	736,654	0	24	5	4,187
1996	2,321	3,245	715,254	0	26	5	4,297
1997	2,399	3,597	666,945	0	26	5	4,339
1998	2,569	3,956	649,393	0	25	5	4,734
1999	2,725	4,078	668,220	0	28	5	4,813
2000	2,859	4,418	647,199	0	28	6	5,032
2001	2,967	4,774	621,557	0	31	6	5,213
2002	3,031	4,981	608,512	0	40	6	5,364
2003	3,136	5,413	579,346	0	37	6	5,509
2004	3,221	5,494	586,276	0	41	6	5,646
Forecast							
2005	3,329	5,589	595,634	0	45	6	5,830
2006	3,424	5,751	595,375	0	48	6	6,004
2007	3,535	5,884	600,782	0	52	6	6,190
2008	3,649	6,030	605,141	0	55	6	6,381
2009	3,751	6,186	606,369	0	60	6	6,570
2010	3,868	6,342	609,902	0	63	6	6,778
2011	3,990	6,506	613,280	0	66	6	6,993
2012	4,095	6,678	613,208	0	69	6	7,196
2013	4,195	6,863	611,249	0	73	6	7,403
2014	4,301	7.065	608.776	0	76	6	7,626

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

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

(1) Year	(2) Sales for Resale[2] GWh	(3) Utility Use & Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers (Average No.)	(6) Total No. of Customers[3]
1995	0	188	4,375	0	142,376
1996	0	174	4,471	0	145,083
1997	0	226	4,565	0	149,446
1998	0	175	4,909	0	154,285
1999	0	198	5,011	0	158,959
2000	0	259	5,291	0	163,135
2001	969	191	6,373	0	167,817
2002	821	211	6,396	0	173,027
2003	920	253	6,682	0	177,247
2004	715	238	6,599	0	183,044
Forecast					
2005	676	229	6,735	0	188,196
2006	21	235	6,260	0	192,986
2007	0	241	6,431	0	197,312
2008	0	253	6,634	0	201,810
2009	0	260	6,830	0	206,926
2010	0	272	7,050	0	212,380
2011	0	283	7,276	0	218,094
2012	0	292	7,488	0	224,043
2013	0	299	7,702	0	230,533
2014	0	306	7,932	0	237,584

1. Historical and forecast data includes both OUC and the City of St. Cloud.
2. To maintain consistency with the FRCC Forms, the "Sales for Resale" forecast includes OUC's forecast GWh sales to FMPA, KUA, SEC, and RCID. Historical "Sales for Resale" includes GWh sales to FMPA, KUA, SEC, and RCID for 2001, 2002, 2003, and 2004, as in the FRCC forms.
3. Total No. of Customers includes aggregate of Rural & Residential, General Service Non-Demand, and General Service Demand.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Residential	Commercial/Industrial		
Year	Total[2]	Wholesale[3]	Retail	Interruptible	Load Management	Load Management	Conservation	Net Firm Demand
1995	862	0	862	0	0	0	0	862
1996	852	0	852	0	0	0	0	852
1997	917	0	917	0	0	0	0	917
1998	988	0	988	1	0	0	0	987
1999	1,055	0	1,055	0	0	0	0	1,055
2000	1,026	0	1,026	1	0	0	0	1,025
2001	1,382	341	1,041	1	0	0	0	1,381
2002	1,408	319	1,089	1	0	0	0	1,407
2003	1,381	303	1,078	1	0	0	0	1,380
2004	1,311	231	1,080	1	0	0	0	1,310
Forecast								
2005	1,311	144	1,167	1	0	0	0	1,310
2006	1,224	22	1,202	1	0	0	0	1,223
2007	1,239	0	1,239	1	0	0	0	1,238
2008	1,279	0	1,279	1	0	0	0	1,278
2009	1,317	0	1,317	1	0	0	0	1,316
2010	1,360	0	1,360	1	0	0	0	1,359
2011	1,404	0	1,404	1	0	0	0	1,403
2012	1,446	0	1,446	1	0	0	0	1,445
2013	1,488	0	1,488	1	0	0	0	1,487
2014	1,532	0	1,532	1	0	0	0	1,531

1. Historical data includes ' oth OUC and the City of St. Cloud for 1994 and beyond. Forecast data includes both OUC and the City of St. Cloud.
2. Includes conservation.
3. To maintain consistency with the FRCC Forms, the "Wholesale" forecast includes OUC's forecast MW sales to FMPA, KUA, SEC, and RCID. Historical "Wholesale" includes MW sales to FMPA, KUA, SEC, and RCID for 2001, 2002, 2003, and 2004, as in the FRCC forms.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Residential	Commercial/Industrial		
Year	Total[2]	Wholesale[3]	Retail	Interruptible	Load Management	Load Management	Conservation	Net Firm Demand
1994/95	876	0	876	0	0	0	0	876
1995/96	969	0	969	0	0	0	0	969
1996/97	851	0	851	0	0	0	0	851
1997/98	814	0	814	1	0	0	0	813
1998/99	1,030	0	1,030	1	0	0	0	1,029
1999/00	1,060	0	1,060	1	0	0	0	1,059
2000/01	1,066	0	1,066	1	0	0	0	1,065
2001/02	1,345	302	1,044	1	0	0	0	1,345
2002/03	1,414	277	1,137	1	0	0	0	1,413
2003/04	1,420	241	1,178	1	0	0	0	1,419
2004/05[4]	1,288	119	1,169	1	0	0	0	1,287
Forecast								
2005/06	1,226	22	1,204	1	0	0	0	1,225
2006/07	1,241	0	1,241	1	0	0	0	1,240
2007/08	1,281	0	1,281	1	0	0	0	1,280
2008/09	1,319	0	1,319	1	0	0	0	1,318
2009/10	1,363	0	1,363	1	0	0	0	1,362
2010/11	1,407	0	1,407	1	0	0	0	1,406
2011/12	1,448	0	1,448	1	0	0	0	1,447
2012/13	1,490	0	1,490	1	0	0	0	1,489
2013/14	1,536	0	1,536	1	0	0	0	1,535
2014/15	1,579	0	1,579	1	0	0	0	1,578

4. 2004/05 is a forecast as actual information was not available at time of publication.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	Total[2]	Conservation	Retail	Wholesale[3]	Utility Use & Losses	Net Energy for Load	Load Factor[4] (%)
1995	4,375	0	4,187	0	188	4,375	57.9
1996	4,471	0	4,297	0	174	4,471	59.9
1997	4,565	0	4,339	0	226	4,565	56.8
1998	4,909	0	4,734	0	175	4,909	56.8
1999	5,011	0	4,813	0	198	5,011	54.2
2000	5,291	0	5,032	0	259	5,291	58.9
2001	6,373	0	5,213	969	191	6,373	52.7
2002	6,396	0	5,364	821	211	6,396	58.5
2003	6,682	0	5,509	920	253	6,682	55.2
2004	6,599	0	5,884	715	0	6,599	57.5
Forecast							
2005	6,735	0	6,059	676	0	6,735	58.7
2006	6,260	0	6,239	21	0	6,260	58.4
2007	6,431	0	6,431	0	0	6,431	59.3
2008	6,634	0	6,634	0	0	6,634	59.3
2009	6,830	0	6,830	0	0	6,830	59.2
2010	7,050	0	7,050	0	0	7,050	59.2
2011	7,276	0	7,276	0	0	7,276	59.2
2012	7,488	0	7,488	0	0	7,488	59.2
2013	7,702	0	7,702	0	0	7,702	59.1
2014	7,932	0	7,932	0	0	7,932	59.1

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

Table 11-8 (Schedule 4)
OUC and St. Cloud Previous Year and Two Year Forecast of Retail Peak Demand and Net Energy for Load by Month[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual – 2004[2]		2005 Forecast		2006 Forecast	
Month	Peak Demand[3] MW	NEL GWh	Peak Demand[2] MW	NEL GWh	Peak Demand[2] MW	NEL GWh
January	1,132	496	1,287	513	1,225	481
February	1,104	450	1,023	453	929	411
March	1,012	490	1,038	510	944	462
April	1,124	495	1,066	507	987	468
May	1,305	589	1,205	594	1,124	552
June	1,292	639	1,295	626	1,210	583
July	1,286	667	1,310	675	1,223	628
August	1,283	646	1,306	676	1,219	630
September	1,270	591	1,245	617	1,165	580
October	1,159	562	1,162	566	1,086	530
November	1,066	480	1,020	484	951	454
December	1,095	493	1,080	513	1,012	481

1. Includes OUC and City of St. Cloud peak demand and NEL as well as wholesale sales to FMPA, KUA, SEC, and RCID (MW and NEL) for historical 2004 and forecast 2005 and 2006. Forecast 2005 and 2006 also includes OUC wholesale sales to FMPA, KUA, SEC, and RCID.
2. Actual 2004 Peak Demand may not correspond to Schedule 3.1 due to coincidence issues between OUC native load, City of St. Cloud native load, and wholesale power sales.
3. Includes Load Management, Conservation and Interruptible Load.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		Units	Actual 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	Nuclear		Trillion BTU	6	5	5	5	5	5	5	5	5	5	5
(2)	Coal		1000 Ton	1,897	1,927	1,719	1,790	1,784	1,770	1,810	2,452	2,375	2,627	2,639
(3)	Residual[2]	Total	1000 BBL	10	2	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	10	2	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[3]	Total	1000 BBL	30	0	0	0	0	0	0	0	0	0	0
(8)		Steam	1000 BBL	3	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	0	0	0	0	0	0	0	0	0	0	0
(11)	Natural Gas	Total	1000 MCF	15,585	13,007	14,415	14,277	15,717	17,021	18,057	7,099	10,397	6,612	8,004
(12)		Steam	1000 MCF	58	6	1	2	1	3	2	1	1	0	0
(13)		CC	1000 MCF	15,464	12,953	14,060	13,540	15,280	15,980	17,734	6,909	10,089	6,103	7,319
(14)		CT	1000 MCF	63	48	354	735	436	1,038	321	189	307	509	685
(15)	Other		Trillion BTU	1	0	0	0	0	0	0	0	0	0	0

1. Includes fuel required for OUC and the City of St. Cloud.
2. Residual includes No. 4, No. 5 and No. 6 oil.
3. Distillate includes No. 1, No. 2 oil, kerosene, jet fuel and amounts used at coal burning plants for flame stabilization and on start up.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	Annual Firm Inter-region Interchange		GWH	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWH	508	501	476	459	489	484	466	482	480	490	501
(3)	Residual	Total	GWH	0	13	0	0	0	0	0	0	0	0	0
(4)		Steam	GWH	0	13	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	23	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	22	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	1	0	0	0	0	0	0	0	0	0	0
(12)	Natural Gas	Total	GWH	2,200	1,735	1,884	1,850	2,059	2,226	2,400	930	1,363	873	1,060
(12)		Steam	GWH	0	6	1	2	1	3	2	1	1	0	0
(13)		CC	GWH	2,195	1,725	1,853	1,785	2,020	2,134	2,369	912	1,334	827	997
(14)		CT	GWH	5	4	30	63	38	89	29	17	28	46	63
(15)	Coal	Steam	GWH	4,908	4,484	3,897	4,094	4,067	4,098	4,180	5,860	5,643	6,334	6,355
(16)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0
(17)	Hydro		GWH	0	0	0	0	0	0	0	0	0	0	0
(18)	Other	Purchases	GWH	0	2	3	28	19	22			2	5	16
		Sales	GWH	440	0	0	0	0	0			0	0	0
		Total	GWH	0	2	3	28	19	22	4		2	5	16
(19)	Net Energy for Load[1]		GWH	7,639	6,735	6,260	6,431	6,634	6,830	7,050	7,276	7,488	7,702	7,932

1. Variation in Net Energy for Load between Schedule 3. and Schedule 6.1 can be attributed to rounding error.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	Annual Firm Inter-region Interchange		GWH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(2)	Nuclear		GWH	6.65	7.44	7.60	7.14	7.37	7.09	6.61	6.62	6.41	6.36	6.32
(3)	Residual	Total	GWH	0.00	0.1[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(4)		Steam	GWH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(5)		CC	GWH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(6)		CT	GWH	0.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(7)	Distillate	Total	GWH	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(8)		Steam	GWH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(9)		CC	GWH	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(10)		CT	GWH	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(12)	Natural Gas	Total	GWH	28.80	25.76	30.10	28.77	31.04	32.59	34.04	12.78	18.20	11.33	13.36
(12)		Steam	GWH	0.00	0.09	0.02	0.03	0.02	0.04	0.03	0.01	0.01	0.00	0.00
(13)		CC	GWH	28.73	25.61	29.60	27.76	30.45	31.24	33.60	12.53	17.82	10.74	12.57
(14)		CT	GWH	0.07	0.06	0.48	0.98	0.57	1.30	0.41	0.23	0.37	0.60	0.79
(15)	Coal	Steam	GWH	64.25	66.58	62.25	63.66	61.31	60.00	59.29	80.54	75.36	82.24	80.12
(16)	NUG		GWH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(17)	Hydro		GWH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(18)	Other	Purchases	GWH	0.00	0.03	0.05	0.44	0.29	0.32	0.06	0.05	0.03	0.06	0.20
		Sales	GWH	5.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Total	GWH	5.76	0.03	0.05	0.44	0.29	0.32	0.06	0.05	0.03	0.06	0.20
(19)	Net Energy for Load		GWH	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity[1]	Firm Capacity Import[2]	Firm Capacity Export[3]	QF	Total Capacity Available	System Firm Peak Demand[4]	Reserve Margin Before Maintenance[5,6]		Scheduled Maintenance	Reserve Margin After Maintenance[5,6]	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2005	1,220	637	158	0	1,699	1,166	533	41.78%	0	533	41.78%
2006	1,220	337	22	0	1,535	1,201	334	28.00%	0	334	28.00%
2007	1,199	337	0	0	1,536	1,238	298	24.25%	0	298	24.25%
2008	1,199	337	0	0	1,536	1,278	258	20.36%	0	258	20.36%
2009	1,199	337	0	0	1,536	1,316	220	16.89%	0	220	16.89%
2010	1,489	337	0	0	1,826	1,359	467	34.53%	0	467	34.53%
2011	1,510	337	0	0	1,847	1,403	444	31.84%	0	444	31.84%
2012	1,510	337	0	0	1,847	1,445	402	28.00%	0	402	28.00%
2013	1,510	322	0	0	1,832	1,487	345	23.23%	0	345	23.23%
2014	1,510	322	0	0	1,832	1,531	301	19.69%	0	301	19.69%

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

Table 11-13 (Schedule 7.2)
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity[1]	Firm Capacity Import[2]	Firm Capacity Export[3]	QF	Total Capacity Available	System Firm Peak Demand[4]	Reserve Margin Before Maintenance[5,6]		Scheduled Maintenance	Reserve Margin After Maintenance[5,6]	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2005/06	1,278	358	22	0	1,614	1,203	411	34.35%	0	411	34.35%
2006/07	1,257	358	0	0	1,615	1,240	375	30.42%	0	375	30.42%
2007/08	1,257	358	0	0	1,615	1,280	335	26.35%	0	335	26.35%
2008/09	1,257	358	0	0	1,615	1,318	297	22.70%	0	297	22.70%
2009/10	1,257	358	0	0	1,615	1,362	253	18.74%	0	253	18.74%
2010/11	1,568	358	0	0	1,926	1,406	520	37.17%	0	520	37.17%
2011/12	1,568	358	0	0	1,926	1,447	479	33.29%	0	479	33.29%
2012/13	1,568	343	0	0	1,911	1,489	422	28.37%	0	422	28.37%
2013/14	1,568	343	0	0	1,911	1,535	376	24.52%	0	376	24.52%
2014/15	1,568	343	0	0	1,911	1,578	333	21.13%	0	333	21.13%

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

Table 11-14 (Schedule 8)
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel		Fuel Transport		Construction Start	Commercial In-Service	Expected Retirement	Gross Capability[1]		Net Capability[1]		Status
				Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	Sum MW	Win MW	Sum MW	Win MW	
SEC	IGCC	Orange	CC	BIT	NG	RR	PL	01/08	06/10				311	311	P

SEC IGCC is part of Department of Energy's Clean Coal Power Initiative grant awarded to OUC and Southern Company. Details of the unit are confidential. However, the unit will be located at Stanton Energy Center and is assumed to have a commercial operation date of January 1, 2011, with the combined cycle portion (operating on natural gas) operational by June 1, 2010. Details of the proposal are confidential.

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

(1)	**Plant Name and Unit Number:**	SEC IGCC[1]
(2)	**Capacity**	
	a. Summer:	311
	b. Winter:	311
(3)	**Technology Type:**	CC
(4)	**Anticipated Construction Timing**	
	a. Field construction start-date:	01/2008
	b. Commercial in-service date:	06/2010
(5)	**Fuel**	
	a. Primary fuel:	BIT
	b. Alternate fuel:	NG
(6)	**Air Pollution Control Strategy**	N/A
(7)	**Cooling Method**	N/A
(8)	**Total Site Area**	
(9)	**Construction Status**	Not started
(10)	**Certification Status**	Underway
(11)	**Status with Federal Agencies**	Underway
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF):	N/A
	Forced Outage Factor (FOF):	N/A
	Equivalent Availability Factor (EAF):	N/A
	Resulting Capacity Factor (%):	N/A
	Average Net Operating Heat Rate (ANOHR):	N/A
(13)	**Projected Unit Financial Data**	
	Book Life (Years):	N/A
	Total Installed Cost (In-Service Year $/kW):	N/A
	Direct Construction Cost ($/kW):	N/A
	AFUDC Amount ($/kW):	N/A
	Escalation ($/kW):	N/A
	Fixed O&M ($/kW-Yr)[2]:	N/A
	Variable O&M ($/MWH)[3]:	N/A
	K Factor:	N/A

1. SEC IGCC is part of Department of Energy's Clean Coal Power Initiative grant awarded to OUC and Southern Company. Details of the unit are confidential. However, the unit will be located at Stanton Energy Center and is assumed to have a commercial operation date of January 1, 2011, with the combined cycle portion (operating on natural gas) operational by June 1, 2010. Details of the proposal are confidential, and have been indicated by "N/A" in Table 11-15.