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

Ms. Bayo,

Enclosed please find 25 copies of the 2006 Orlando Utilities Commission (OUC) Ten-Year Site Plan (TYSP). The 2006 OUC TYSP was prepared for and submitted by Black & Veatch on behalf of OUC.

Should you require additional copies of the 2006 OUC TYSP, or have any other questions regarding the TYSP, please do not hesitate to contact me at (913) 458-7134.

Very truly yours,

Bradley Kushner

Enclosure[s]

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OUC

The *Reliable* One®

2006 Ten-Year Site Plan
Orlando Utilities Commission

April 2006

BLACK & VEATCH
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B&V Project 143935

ENERGY WATER INFORMATION GOVERNMENT

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1.0 Executive Summary

This report documents the 2006 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)
- Supply-Side Alternatives (Section 7.0)
- Economic Evaluation Criteria and Methodology (Section 8.0)
- Analysis and Results (Section 9.0)
- Environmental and Land Use Information (Section 10.0)
- Conclusions (Section 11.0)
- Ten-Year Site Plan Schedules (Section 12.0)

This Plan also integrates the power sales, purchases, and loads for the City of St. Cloud into the OUC Plan, as OUC and St. Cloud have entered into an Interlocal Agreement under which OUC has assumed responsibility for supplying all of St. Cloud's loads through 2032. 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.

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

OUC is currently seeking certification of Stanton Energy Center Unit B (Stanton B) under the Florida Electrical Power Plant Siting Act. In February 2006, OUC filed the Stanton B Need for Power Application with the Florida Public Service Commission (Docket No. 060155-EM). The proposed Stanton B project is the result of the proposal submitted by Southern Company Services (SCS) on behalf of its partners

Southern Power Company (SPC), OUC, and Kellogg Brown & Root, Inc. (KBR) for funding of an air blown Transport Gasification combined cycle demonstration project to be located at OUC's Stanton Energy Center. The proposal was submitted June 15, 2004 in response to the Clean Coal Power Initiative (CCPI) of the US Department of Energy (DOE). Stanton B is planned as a 1x1 combined cycle unit that will be capable of firing coal derived syngas or natural gas, and is planned or commercial operation on June 1, 2010. For purposes of the analysis presented in this Ten-Year Site Plan, it has been assumed that Stanton B will receive approval by the Florida Public Service Commission and all other necessary regulatory approvals and is therefore considered to be a capacity resource for OUC beginning in the summer of 2010.

Four alternative power plant technologies including combustion turbines, combined cycle, pulverized coal, and circulating fluidized bed units were considered for capacity additions in the Stanton B Need for Power Application. However, as illustrated in Section 6.0 of this report, OUC is not forecast to require any additional capacity during the 2006 through 2015 timeframe with Stanton B considered a committed unit with commercial operation planned for June 1, 2010. Therefore, OUC's capacity expansion plan for the 2006 through 2015 period includes no capacity additions beyond installation of Stanton B. It should be noted that various aspects of Stanton B are confidential, and as such the amount of detail provided within this Ten-Year Site Plan for Stanton B is somewhat limited.

2.1 Existing Generation System

Presently, OUC has ownership interests in five electric generating plants, which are described further in this section. Table 2-1 summarizes OUC's generating facilities which include:

- Stanton Energy Center Units 1 and 2, and Stanton A.
- Indian River Plant Combustion Turbine Units A, B, C, and D.
- Progress Energy Florida (formerly Florida Power Corporation) Crystal River Unit 3 Nuclear Generating Facility.
- Lakeland Electric McIntosh Unit 3.
- Florida Power & Light Company (FPL) 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 Unit 1 was placed in commercial operation on July 1, 1987, followed by Stanton Unit 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 sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulates. Stanton Unit 1 is a 444 MW net coal fired facility. OUC has a 68.6 percent ownership share of this unit, which provides 302 MW of capacity to the OUC system. Stanton Unit 2 is a 446 MW net coal fired generating facility. OUC and St. Cloud's share of this unit is 334.5 MW.

OUC has entered into an agreement with Kissimmee Utility Authority (KUA), Florida Municipal Power Agency (FMPA), and Southern Company - Florida LLC (SCF) governing the ownership of Stanton A, a combined cycle unit at the Stanton Energy Center that began commercial operation on October 1, 2003. OUC, KUA, FMPA, and SCF 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 SCF 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. OUC maintains a 28 percent equity share of SEC A, while purchasing 52 percent as described further in Section 2.2.

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	334.5	334.5
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)Reflects net capability to serve OUC and St. Cloud.
(2)OUC owns approximately 6.1 percent of 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.

The Indian River Plant is located 4 miles south of Titusville on US Highway 1. The 160 acre Indian River Plant site contains three steam electric generating units (No. 1, 2, and 3) and four combustion turbine units (A, B, C, and D). The three steam turbine units were sold to Reliant in 1999. 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 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 analyses performed in this Application, it was assumed that McIntosh Unit 3 would burn coal priced identically to that used for Stanton Units 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 853 MW net nuclear generating facility operated by FPL. 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 by St. Lucie Unit 1 and half 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, but is kept in standby, so that the resulting net summer generating capacity from St. Cloud's internal combustion units is 21 MW. All of the St. Cloud internal combustion units are currently assumed to retire in October 2006.

2.2 Purchase Power Resources

OUC has a purchase power agreement (PPA) with SCF for 80 percent of SCF's ownership share of Stanton A. Under the original Stanton A PPA OUC, KUA, and FMPA agreed to purchase all of SCF's 65 percent capacity share of Stanton A for 10 years, although the utilities retained the right to reduce the capacity purchased from SCF 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. The utilities originally had options to extend the PPA beyond its initial term. OUC, KUA, and FMPA have unilateral options to purchase all of Stanton A's capacity for the estimated 30 year useful life of the unit. Subsequent amendments to the original PPA continue OUC's capacity purchase through the 20th year of the PPA. Beginning with the 16th contract year and ending with the 20th contract year, OUC will maintain 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 after the 20th contract year, which ends September 30, 2023. Rather than terminating the PPA, OUC may elect to continue the PPA for an additional 5 years under the *Extended Term* option beginning October 1, 2023, and ending September 30, 2028. OUC may subsequently continue the PPA for an additional 5 years under the *Further Extension* option beginning October 1, 2028, and ending September 30, 2033.

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 may schedule the TECO PR purchase.

2.3 Power Sales Contracts

OUC has had a number of power sales contracts with various entities over the past several years. However, OUC is currently contractually obligated to supply power to only FMPA through a unit power sales contract, which has been in place with FMPA since May 1, 1986. The contract expires December 31, 2006; OUC will provide FMPA with 22 MW during 2006.

2.4 Transmission System

OUC's existing transmission system consists of 28 substations interconnected through approximately 326 miles of 230 kV, 115 kV, and 69 kV lines and cables. OUC is fully integrated into the state transmission grid through its twenty-three 230 kV, one 115 kV, and two 69 kV metered 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 four substations, as well as approximately 51 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 on Figure 2-1.

Table 2-2
OUC Transmission Interconnections

Utility	kV	Number of Interconnections
FPL	230	2
Progress Energy Florida (PEF)	230	8
KUA	230	2
KUA/FMPA	230	2
Lakeland Electric	230	1
TECO	230	2
TECO/Reedy Creek Improvement District	230	2
PEF	69	1
St. Cloud	69	1
Southern Company	230	1
Reliant Energy	230	2
Reliant Energy	115	1

Table 2-3
St. Cloud Transmission Interconnections

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

The addition of a distribution transformer to the existing Kaley substation (No. 13) was completed in December 2004, and the new Lake Nona 230/15 kV substation was placed into 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 were planned for completion in February 2006. The upgrade of the 69 kV tie line to KUA has been delayed because of a road widening project along its path.

To increase reliability and relieve higher fault current levels resulting from the closing of the Stanton 230 kV bus, oil circuit breakers at three substations (No. 10, No. 11, and No. 12) were upgraded to gas insulated models, 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 and Lake Nona via the Magnolia Ranch substation.
- Addition of a 69 kV line from Magnolia Ranch to State Road (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 12.

Table 3-1
Generation Capacity (MW) Owned by OUC by Fuel Type (as of January 1, 2006)

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. OUC's fuel diversity will be further enhanced through the addition of Stanton B, which will be capable of burning either coal derived syngas or natural gas once it becomes commercial (assumed to be June 1, 2010).

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 2005, 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 sale of the Indian River steam units allowed OUC to take positions in Stanton A and B and to update and diversify its generation portfolio. The sale offered OUC the ability to replace the less competitive oil and gas steam units with more competitive combined cycle generation.

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 1 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 metered 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, two with Florida Power & Light, and one each with Lakeland Electric and the City of St. Cloud. In addition to enhancing reliability, these interconnections also facilitate the marketing of electric energy by OUC to and from other electric utilities in Florida.

3.5 Environmental Performance

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

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 Divisions 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.

During 2005, events sponsored by OUC included the second annual OUC Downtown Orlando Triathlon, and the OUC Half Marathon & 5K. OUC also participated in the OUC Junior Achievement Bowl-A-Thon. Employees from OUC participated in these events and numerous others throughout the year. OUC also partnered with the Florida Interactive Entertainment Academy at the University of Central Florida (UCF), continuing the long-standing partnership between OUC and UCF.

Overall, OUC and its employees contributed more than $213,000 to various charities and community endeavors in 2005, including more than $46,000 to the Hurricane Katrina Relief Funds. Since 1993, OUC employees have donated more than 55,000 hours to 180 community organizations.

4.0 Forecast of Peak Demand and Energy Consumption

OUC retained Itron, formerly Regional Economic Research, Inc. (RER), to assist in the development of forecasts of peak demand and energy consumption. The project scope was to develop a set of sales, energy, and demand forecast models that could support OUC's budgeting and financial planning process as well as long-term planning requirements. OUC utilized its internal knowledge of the service area with the expertise of Itron in the development of the forecast models.

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 these 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. Furthermore, since there is virtually no retail natural gas in the OUC service territory, end-use modeling would provide little information on 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 SAE model, entails specifying end-use variables (heating, cooling, and other use) and utilizing these variables in sales regression models. While the SAE approach loses some end-use detail, it adequately forecasts short-term energy requirements, and it provides a reasonable structure for forecasting long-term energy requirements.

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 were estimated over the period encompassing 1996 to 2005. This provides 10 years of historical data, with more than enough observations to estimate strong regression models. Once models were estimated, the residential energy requirement in month T was calculated as the product of the customer and average use forecast:

$$\text{Residential Sales}_T = \text{Average User Per Household}_T \times \text{Number of Customers}_T$$

4.1.1.1 Residential Customer Forecast. The number of customers was forecasted as a simple function of household projections for the Orlando MSA. Models were estimated using MSA-level data, since 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 had an adjusted R^2 of 0.99, with an in-sample Mean Absolute Percent Error (MAPE) of 0.2 percent. For St. Cloud, the model performance was not as strong, given the "noise" in the historical monthly billing data. The adjusted R^2 was 0.91, with an in-sample MAPE of 3.5 percent. Since 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. The SAE modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$), depicted as follows:

$$\text{Use}_{y,m} = \text{Heat}_{y,m} + \text{Cool}_{y,m} + \text{Other}_{y,m}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for end-use elements provides the following econometric equation:

$$\text{Use}_m = a + b_1 \times \text{XHeat}_m + b_2 \times \text{XCool}_m + b_3 \times \text{XOther}_m + \varepsilon_m$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. The estimated model can then be thought of as an SAE model, where the estimated slopes are the adjustment factors.

XHeat captures the factors that affect residential space heating. These variables include the following:

- Heating degree-days.
- Heating equipment saturation levels.
- Heating equipment operating efficiencies.
- Average number of days in the billing cycle for each month.
- Thermal integrity and footage of homes.
- Average household size, household income, and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier as follows:

$$\mathbf{XHeat_{y,m} = HeatIndex_{y} \times HeatUse_{y,m}}$$

where:

$XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m).
$HeatIndex_y$ is the annual index of heating equipment.
$HeatUse_{y,m}$ is the monthly usage multiplier.

The heat index is defined as a weighted average energy intensity measured in kWh. Given a set of starting end-use energy intensities (EI), the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), and building structural index (*StructuralIndex*). Formally, the heating equipment index is defined as follows:

$$\mathbf{HeatIndex_y = StructuralIndex_y \times \sum_{Type} EI^{Type} \times \frac{\left(Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left(Sat_{98}^{Type} \middle/ Eff_{98}^{Type} \right)}}$$

StructuralIndex is based on EIA square footage projections and thermal shell efficiency for the southeast census region. EIA's current projections show average square footage increasing slightly faster than thermal shell integrity improvements.

Electric heating saturation in the OUC service area is relatively high with approximately 85 percent of the homes using electric space heat. Heat pumps account for nearly half the existing stock and are projected to increase as a share of heating equipment over time. Given that heat pumps are significantly more efficient than resistance heat, efficiency gains are expected to outstrip increasing heat saturation, which in turn slows expected residential heating sales growth.

Heating sales are also driven by the factors that impact utilization of the appliance stock. Heating use depends on weather conditions, household size, household income, and prices. The heat use variable is constructed as follows:

$$\mathbf{HeatUse}_{y,m} = \left(\frac{\mathbf{HDD}_{y,m}}{\mathbf{HDD}_{98}}\right) \times \left(\frac{\mathbf{HHSize}_{y}}{\mathbf{HHSize}_{98}}\right)^{0.20} \times \left(\frac{\mathbf{Income}_{y}}{\mathbf{Income}_{98}}\right)^{0.20} \times \left(\frac{\mathbf{Price}_{y,m}}{\mathbf{Price}_{98}}\right)^{-0.15}$$

where:

HDD is the number of heating degree days in year (y) and month (m).
HHSize is the average household size in a year (y).
Income is the average real income per household in a year (y).
Price is the average real price of electricity in month (m) and year (y).

By construction, $HeatUse_{y,m}$ has an annual sum that is close to 1.0 in the base year (1998). The index changes over time with changes in HDD, HHSize, Income, and Price. In this form, the coefficients represent end-use elasticity estimates. The elasticity estimates are based on short-term estimates embedded in the EPRI end-use forecasting model REEPS (Residential End-Use Planning System) and elasticities used by EIA in their long-term energy forecast model. The elasticities are also validated by evaluating out-of-sample model fit statistics using different elasticity estimates.

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree-days.
- Cooling equipment saturation levels.
- Cooling equipment operating efficiencies.

- Thermal integrity and footage of homes.
- Average household size, household income, and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier as follows:

$$\mathbf{XCool}_{y,m} = \mathbf{CoolIndex}_{y} \times \mathbf{CoolUse}_{y,m}$$

where:

$XCool_{y,m}$ is the estimated cooling energy use in year (y) and month (m).
$CoolIndex_y$ is the cooling equipment index.
$CoolUse_{y,m}$ is the monthly usage multiplier.

The cooling equipment index is calculated as follows:

$$\mathbf{CoolIndex}_y = \mathbf{StructuralIndex}_y \times \sum_{Type} \mathbf{EI}^{Type} \times \frac{\left(\mathbf{Sat}_y^{Type} \Big/ \mathbf{Eff}_y^{Type} \right)}{\left(\mathbf{Sat}_{98}^{Type} \Big/ \mathbf{Eff}_{98}^{Type} \right)}$$

As air conditioning saturation increases, the index increases. As efficiency increases, the index decreases. Again, because of the high current saturation of air conditioning, the index is largely driven by increasing overall air conditioning efficiency. A slight increase in the structural index (as a result of increasing square footage) results in a small increase in the cooling equipment index over time.

The cooling utilization variable is constructed similar to that of the heating use variable. CoolUse is defined as follows:

$$\mathbf{CoolUse}_{y,m} = \left(\frac{\mathbf{CDD}_{y,m}}{\mathbf{CDD}_{98}} \right) \times \left(\frac{\mathbf{HHSize}_y}{\mathbf{HHSize}_{98}} \right)^{0.20} \times \left(\frac{\mathbf{Income}_y}{\mathbf{Income}_{98}} \right)^{0.20} \times \left(\frac{\mathbf{Price}_{y,m}}{\mathbf{Price}_{98}} \right)^{-0.15}$$

where:

CDD is the number of cooling degree days in year (y) and month (m).

Monthly estimates of nonweather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by the following:

- Appliance and equipment saturation levels.
- Appliance efficiency levels.
- Average household size, real income, and real prices.

The explanatory variable for other uses is defined as follows:

$$\mathbf{XOther}_{y,m} = \mathbf{OtherEqpIndex}_{y,m} \times \mathbf{OtherUse}_{y,m}$$

The first term on the right hand side of this expression ($OtherEqpIndex_{y,m}$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term ($OtherUse$) captures the impact of changes in price, income, and household size on appliance utilization. The appliance index is defined as follows:

$$\mathbf{OtherIndex}_{y,m} = \mathbf{EI}^{\mathbf{Type}} \times \frac{\left(\mathbf{Sat}_y^{\mathbf{Type}} \Big/ \frac{\mathbf{1}}{\mathbf{Eff}_y^{\mathbf{Type}}} \right)}{\left(\mathbf{Sat}_{98}^{\mathbf{Type}} \Big/ \frac{\mathbf{1}}{\mathbf{Eff}_{98}^{\mathbf{Type}}} \right)} \times \mathbf{MoMult}_m^{\mathbf{Type}}$$

where:

EI is the energy intensity for each appliance (annual kWh).
Sat represents the fraction of households who own an appliance type.
$MoMult_m$ is a monthly multiplier for the appliance type in month (m).
Eff is the average operating efficiency for water heaters.

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration. Saturation and efficiency trends are based on EIA projections for the southeast census region.

Economic activity is captured through the OtherUse variable, where OtherUse is defined as follows:

$$OtherUse_{y,m} = \left(\frac{HHSize_y}{HHSize_{98}}\right)^{0.20} \times \left(\frac{Income_y}{Income_{98}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{98}}\right)^{-0.15}$$

Increase in household income translates into an increase in XOther, while increases in electricity prices result in a decrease in XOther. Decreasing household size (number per household) translates into a decrease in XOther.

4.1.1.3 Estimate Models. To estimate the forecast models, monthly average residential usage is regressed on XCool, XHeat, and XOther. Lagged *Use* values of XCool and Xheat are also included in the specification since these 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 worked extremely well in the regression models. For OUC, the residential adjusted R^2 is 0.94 with an in-sample MAPE of approximately 3.8 percent. The mean absolute deviation (MAD) is 40.2 kWh compared to a residential monthly average usage of 1,084 kWh. All the model coefficients are highly significant (exhibited by t-statistics greater than 2.0). The St. Cloud model also explains average usage well with an R^2 of 0.94. 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.

The SAE approach is also used to develop models to forecast electricity sales for commercial nondemand and demand classes. The commercial SAE model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$) as follows:

$$\mathbf{Sales}_{y,m} = \mathbf{Heat}_{y,m} + \mathbf{Cool}_{y,m} + \mathbf{Other}_{y,m}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation:

$$\mathbf{Sales}_m = a + b_1 \times \mathbf{XHeat}_m + b_2 \times \mathbf{XCool}_m + b_3 \times \mathbf{XOther}_m + \varepsilon_m$$

The model parameters are then estimated using linear regression.

The constructed variables XHeat, XCool, and XOther capture structural as well as market condition changes. The end-use variables include the following:

- Heating and cooling degree-days.
- End-use saturation and efficiency trends.
- Real regional output.
- Price.

The end-use variables are represented as the product of an annual equipment index (Index) and a monthly usage multiplier (Use). The variables are defined as follows:

$$\mathbf{XHeat}_{y,m} = \mathbf{HeatIndex}_y \times \mathbf{HeatUse}_{y,m}$$

$$\mathbf{XCool}_{y,m} = \mathbf{HeatIndex}_y \times \mathbf{HeatUse}_{y,m}$$

$$\mathbf{XOther}_{y,m} = \mathbf{OtherIndex}_{y,m} \times \mathbf{OtherUse}_{y,m}$$

The heating equipment index captures change in end-use saturation and efficiency. The heating index is defined as follows:

$$\mathbf{HeatIndex}_y = \mathbf{HeatSales}_{98} \times \frac{\left(\mathbf{HeatShare}_y / \mathbf{Eff}_y\right)}{\left(\mathbf{HeatShare}_{98} / \mathbf{Eff}_{98}\right)}$$

In this expression, 1998 is defined as the base year. The ratio on the right is equal to 1.0 in 1998. As end-use saturation increases, the index increases; as efficiency increases, the index decreases. The starting heating sales estimate (HeatSales98) is derived from the EIA end-use forecast database for the southeast census region.

Similarly, projections of saturation and efficiency changes are based on EIA's long-term outlook for the southeast region.

The heating variable XHeat is constructed by interacting the index variable (HeatIndex) with a variable that captures short-term stock utilization (HeatUse). Temperature data, prices, and regional output are incorporated into the HeatUse variable. The calculated heat utilization variable is computed as: follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{98}}\right) \times \left(\frac{Output_{y}}{Output_{98}}\right)^{0.30} \times \left(\frac{Price_{y,m}}{Price_{98}}\right)^{-0.20}$$

where:

HDD is the number of heating degree days in year (y) and month (m).

Output is real gross regional product in year (y) and month (m).

Price is the average real price of electricity in year (y) and month (m).

As constructed, HeatUse is also an index value with a value of 1.0 in 1998. Furthermore, in this functional form, the coefficients of 0.3 and -0.2 can be interpreted as elasticities. A 1.0 percent change in output will translate into a 0.3 percent increase in the HeatUse index. A 1.0 percent increase in real price will translate into a -0.2 percent change in HeatUse.

The cooling variable (XCool) is constructed in a similar manner. Cooling requirements are driven by the following:

- Cooling degree-days.
- Cooling equipment saturation levels.
- Cooling equipment operating efficiencies.
- Business activity (as captured by regional output).
- Price.

The following cooling variable is the product of an equipment-based index and monthly usage multiplier:

$$\mathbf{CoolIndex_y} = \mathbf{CoolSales_{98}} \times \frac{\left(\mathbf{CoolShare_y} / \mathbf{Eff_y}\right)}{\left(\mathbf{CoolShare_{98}} / \mathbf{Eff_{98}}\right)}$$

where:

CoolIndex$_y$ is an index of the cooling equipment.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Saturation and efficiency trends are derived from the EIA end-use database for the southeast census region. Given the nearly 100 percent saturation in air conditioning, the index is driven downwards by improving air conditioning efficiency.

The CoolUse variable is constructed similar to the HeatUse variable. CoolUse captures the interaction of temperature (*CDD*), regional output (*Output*), and price. The output and price elasticity are estimated be 0.3 and -0.2, respectively. The constructed use variable is defined as follows:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{98}}\right) \times \left(\frac{Output_y}{Output_{98}}\right)^{0.30} \times \left(\frac{Price_{y,m}}{Price_{98}}\right)^{-0.20}$$

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (1998). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will vary to reflect changes in commercial output and prices.

Monthly estimates of nonweather sensitive sales can be derived in a similar fashion as space heating and cooling. Based on end-use concepts, other sales are driven by the following:

- Equipment saturation levels.
- Equipment efficiency levels.
- Average number of days in the billing cycle for each month.
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m}$$

The first term embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$\text{OtherIndex}_{y,m} = \sum_{\text{Type}} \text{OtherSales}_{98}^{\text{Type}} \times \left(\frac{\text{Share}_{y}^{\text{Type}} \big/ \text{Eff}_{y}^{\text{Type}}}{\text{Share}_{98}^{\text{Type}} \big/ \text{Eff}_{98}^{\text{Type}}} \right)$$

where:

OtherSales represents starting base year non-HVAC sales.

Share represents saturation of other office equipment.

Eff is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the primary commercial non-HVAC end-uses. End-uses embedded in OtherIndex include lighting, water heating, cooking, refrigeration, office equipment, and miscellaneous equipment. The equipment categories are based on EIA categorizations. Economic drivers interact with the OtherIndex through the utilization variable OtherUse. OtherUse is defined as follows:

$$OtherUse_{y,m} = \left(\frac{Output_y}{Output_{98}} \right)^{0.30} \times \left(\frac{Price_{y,m}}{Price_{98}} \right)^{-0.20}$$

4.1.2.1 GSND Sales Forecast. The GSND sales forecast is derived from a total sales forecast model where sales are specified as a function of regional output, (real) price, heating and cooling degree-days, and end-use indices to account for changes in commercial sector end-use saturation and efficiency.

4.1.2.2 GSND Sales Models. GSND sales models are estimated for OUC and St. Cloud. Both models explain historical monthly sales variations. The adjusted R^2 for the OUC GSND sales model is 0.98 and the adjusted R^2 for St. Cloud is 0.82. The estimated end-use variable coefficients are statistically significant at the 5 percent level of confidence in both models.

4.1.2.3 GSD Models. The GSD class represents the largest nonresidential customer class. Over the last 5 years, OUC has seen its strongest sales gains in this customer class, with GSD sales growth averaging 2.5 percent annually 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 a relatively strong sales growth through the forecast horizon.

The GSD models include XCool and XOther. Low t-statistics on the heating variables indicate that there is relatively little electric space heating in the GSD class. In the OUC model, XCool and XOther are highly significant with t-statistics over 2.0. The adjusted R^2 is 0.94 with an in-sample MAPE of 2.9 percent. The St. Cloud end-use variables are also statistically significant with t-statistics over 2.0. The St. Cloud model has an adjusted R^2 of 0.94 with a MAPE of 3.6 percent.

The eight largest OUC customers (GSLD) are backed out of OUC GSD sales data and forecasted separately. The companies include a defense contractor, the Orlando International Airport (OIA), two regional medical centers, a sewage treatment facility, the convention center, and two theme parks. Forecasts are based on discussions with customer support staff. For all customers, except the airport and the convention center, the sales forecasts are held constant at the 2004 level. The OIA and convention center forecasts are based on airport and convention center expansion plans. The GSLD forecast is combined with the other GSD forecast to develop a total GSD forecast.

OUC's own electric use (OUC Use) is also forecasted separately. The forecast is primarily driven by expected demand for OUC's chilled water cooling plants in the metropolitan Orlando area. OUC chiller-related electricity requirements are backed out of the GSD sales forecast since chilled water sales are expected to directly displace GSD air conditioning load.

4.1.2.3.1 Street Lighting Sales. Street lighting sales are forecasted using a simple trend model. 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 2.5 GWh a year through the forecast period.

4.1.3 Hourly Load and Peak Forecast

In order to capture the load diversity across the two retail companies, separate system hourly load forecasts are estimated for OUC and St. Cloud. The hourly load forecasts are then combined to generate a total system hourly load forecast. Summer and winter peak demands are then calculated from the combined utility system hourly load forecast.

The system load profiles are based on a set of hourly load models using load data covering the January 1996 to December 2005 period. Historical hourly loads are first expressed as a percentage of the total daily energy as follows:

$$\mathbf{Fraction}_{dh} = \mathbf{Load}_{hd} \div \mathbf{Energy}_{d}$$

where:

$Load_{hd}$ = the system load in hour (h) and day (d).

$Energy_d$ = the system energy in day (d).

Hourly fraction models are then estimated using the Ordinary Least Squares (OLS) regression where the hourly models are specified as a function of daily weather conditions, months, day of the week, and holidays. A second model is estimated for daily energy ($Energy_d$) where daily energy is specified as a function of daily temperatures, day of the week, holidays, seasons, and a trend variable to account for underlying growth over the estimation period.

The hourly fraction and daily energy models are used to simulate hourly fractions and daily energy for normal daily weather conditions. Normal daily temperatures are calculated by first ranking each year from the hottest to coldest day. 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.

Given weather normal hourly fractions (*WNFraction*) and weather normal daily energy (*WNDailyEnergy*), it is possible to calculate weather normal load for hour (h) in day (d) as follows:

$$\mathbf{WNLoad}_{dh} = \mathbf{WNFraction}_{dh} \times \mathbf{WNDailyEnergyt}_{dh}$$

The system 8,760 hourly load forecast is generated by combining the weather normal system load shape with the energy forecast using *MetrixLT*. The energy forecast is allocated to each hour based on the weather normal hourly profile. Separate hourly load forecasts are derived for OUC and St. Cloud.

Under normal daily weather conditions OUC is just as likely to experience a winter peak as it is a summer peak. OUC experiences a "needle-like" peak in the winter months on the 1 or 2 days where the low temperature falls below freezing. The needle peak is largely driven by backup resistant heat built into the residential heat pumps.

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 forecasts are aggregated to yield total system hourly load requirements. Forecasted seasonal peaks are then derived by finding the maximum hourly demand in January (for the winter peak) and July (for the summer peak).

4.2 Forecast Assumptions

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

4.2.1 Economics

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

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

4.2.1.2 Population, Households, and Income. The primary economic drivers in the residential forecast model are population, the number of households, and real personal income. Economy.com's projections for the Orlando MSA were used, and the projections are presented in Table 4-2.

4.2.2 Price Assumption

An aggregate retail price series was used as a proxy for effective prices in each of the model specifications. Since retail rates (across rate schedules) have generally moved in the same direction, an average retail price variable captures price movement across all the customer classes. The average annual price series is provided in Table 4-3.

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

Year	Total Employment (thousands)	Nonmanufacturing Employment (thousands)	Gross Product (billion $)
1990	610.2	520.1	34.9
1995	714.9	631.4	43.8
2000	909.2	803.4	60.2
2005	1,015.2	897.7	73.1
2010	1,212.4	1,055.3	94.0
2015	1,424.8	1,250.4	114.2
2020	1,658.1	1,464.5	138.3
2025	1,875.9	1,665.0	166.7
Average Annual Increase			
90-95	3.2%	4.0%	4.6%
95-00	4.9%	4.9%	6.6%
00-05	2.2%	2.2%	4.0%
05-10	3.6%	3.3%	5.2%
10-15	3.3%	3.5%	4.0%
15-20	3.1%	3.2%	3.9%
20-25	2.5%	2.6%	3.8%

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

Year	Real Income per Household	Households (thousands)	Population (thousands)
1990	$59,822	471.2	1,240.6
1995	$60,512	542.7	1,428.3
2000	$71,067	629.7	1,656.3
2005	$74,167	727.3	1,906.0
2010	$75,833	836.4	2,161.0
2015	$77,778	978.2	2,481.9
2020	$79,357	1,142.2	2,865.2
2025	$83,427	1,279.5	3,206.2
Average Annual Increase			
90-95	0.2%	2.9%	2.9%
95-00	3.3%	3.0%	3.0%
00-05	0.9%	2.9%	2.8%
05-10	0.4%	2.8%	2.5%
10-15	0.5%	3.2%	2.8%
15-20	0.4%	3.1%	2.9%
20-25	1.0%	2.3%	2.3%

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

Year	Real Price (cents/kWh)
2000	5.3
2005	5.6
2010	5.7
2015	5.8
2020	6.0
2025	6.1
Annual Increase	
00-05	1.1%
05-10	0.4%
10-15	0.4%
15-20	0.7%
20-25	0.3%

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 2005 Demand-Side Management (DSM) Plan was approved by the Florida Public Service Commission (FPSC) on September 1, 2004 (Docket No. 040035-EG). The FPSC determined that there were no cost-effective conservation measures available for use by OUC, and therefore established zero DSM and conservation goals for OUC's residential, commercial, and industrial sectors through 2014. Although OUC's FPSC-approved DSM and conservation goals are zero, OUC recognizes the importance of energy efficiency and conservation in today's market. Therefore, OUC has voluntarily maintained and continued to offer those programs that have shown high customer demand and participation. The FPSC goals for OUC and the programs currently offered by OUC are presented briefly in this section and in greater detail in OUC's 2005 Demand-Side Management Plan.

Table 5-1
Total Conservation Goals Approved by the FPSC

	Residential			Commercial / Industrial		
Year	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction
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
2010	0	0	0	0	0	0
2011	0	0	0	0	0	0
2012	0	0	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0

The demand-side management programs voluntarily continued and offered by OUC to its customers during 2005 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. The quantifiable

DSM and conservation programs voluntarily continued and offered to OUC's customers in 2005 included the following:

- Residential Energy Survey Program (Walk-Through, Video or DVD, 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.

In addition, OUC continues additional programs that are not quantifiable, but aid OUC's customers in reliability, energy conservation, and education. The programs that are not quantifiable which were offered by OUC to its customers in 2005 include the following:

- Residential Energy Conservation Rate.
- Commercial OUConsumption Online Program.
- Commercial OUConvenient Lighting Program.
- Commercial Power Quality Analysis Program.
- Commercial Infrared Inspections Program.
- Commercial OUC Backup Generation Service.
- OUCooling.
- Green Pricing Initiative Program.
- Photovoltaic Generation Pilot Program.

In general, many things have changed over the last few years leading to a decrease in customer participation and decreased cost-effectiveness of DSM and conservation programs. As each program continues, participation tends to gradually decrease because the market for the program becomes saturated. Most of the customers that want to and are willing to participate will have done so early in the program.

The decrease in cost-effectiveness of DSM and conservation programs is a result of numerous factors. 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 near 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 and conservation programs to be cost-effective and to achieve high levels of customer participation.

The remainder of this section describes each of the quantifiable and non-quantifiable DSM and conservation programs voluntarily continued and offered by OUC to its customers during 2005.

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 DVD, 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 residential customers. The participant is given a choice to receive either a low-flow showerhead or a compact fluorescent bulb. OUC Conservation Specialists 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 is now available to OUC customers in an interactive DVD format. The video (or DVD) is free and is distributed either in the English or Spanish version to OUC customers by request. The measure was developed to further assist OUC customers in surveying their homes for potential energy saving opportunities. The video walks the customer through a complete visual assessment of energy and water efficiency in his or her 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. The interactive On-Line Energy Survey is available on OUC's Web site, www.OUC.com.

One of the primary benefits of the Residential Energy Survey Program is the education it provides to customers on energy conservation measures and ways their lifestyle can directly affect their energy use. Customers participating in the Energy Survey Program are informed about conservation measures that 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 10 years and interest in both the Energy Survey Video and DVD, 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 homes. 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 or R-30.

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. Each customer must request a free Residential Energy Survey. Ordinarily, Energy Survey recommendations require a customer to spend money replacing or adding energy conservation measures, which low-income customers may not have the discretionary income to implement. To be eligible for this program, the customer must be equipped with all electric appliances.

OUC pays 85 percent of the total cost for home weatherization for the following measures:

- Attic insulation.
- Exterior and interior caulking.
- Weather-stripping of 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.

Under this program, OUC will arrange for a licensed, approved contractor to perform the necessary repairs and will pay 85 percent of the bill. The remaining 15 percent can be paid on the participant's monthly electric bill over a period of time and interest free. 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 that this program 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 a minimum R-19 level to pay for the insulation on their monthly utility bill for up to 2 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. The maximum that can be funded is $600. Feedback from customers that have taken advantage of the program has been very positive.

5.1.5 Residential Efficient Electric Heat Pump Program

This program provides rebates to qualifying customers who install heat pumps having a seasonal energy efficiency ratio (SEER) of 11.0 (or greater) in 2005. In 2006, the minimum required efficiency ratio (SEER) will increase to 14.0. Customers will be able to obtain rebates ranging from $100 to $300, depending on the SEER rating of the heat pump selected. A qualified, licensed, and insured air conditioner contractor must perform the work. Customers will benefit from the increased energy conservation in their homes, which will decrease their electric bills. One of the main benefits of this program is the ductwork and insulation level improvements made by contractors when installing energy efficient heat pumps.

5.1.6 Residential Gold Ring Program

The Residential Gold Ring Program is closely aligned with Energy Star Ratings. In developing the program, OUC partnered with local home builders to construct new homes according to Energy Star standards. Features may include high efficiency heat pumps, heat recovery water heaters, R-30 attic insulation, interior air ducts, double pane windows, window shading, etc.

The contractor is required to qualify its homes to Energy Star standards by having the homes rated by a certified rater. In return for each Energy Star home certification, the builder receives a rebate of $200 or $100 for townhomes. In addition, OUC will help support the builder's efforts through additional advertising and other promotional strategies.

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 his or her income-to-debt ratio by 2 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 who has a Commercial Energy Survey receives a report at the time of the survey and the book *Business Energy Efficiency Guide* which 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 energy conservation, which decreases their electric and water 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. Upfront 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 completely paid, the participating customer's annual energy bill will decrease by the approximate amount of projected energy cost savings.

5.2 Additional Conservation Programs.

The following programs were offered by OUC to its customers in 2005, resulting in energy savings and increased reliability. Although the programs are neither directly nor easily quantifiable, each program provides a valuable service to OUC's customers.

5.2.1 Residential Energy Conservation Rate

Beginning in October 2002, OUC modified its residential rate structure to a two-tiered block structure to encourage energy conservation. Residential customers using more than 1,000 kWh per month 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.

5.2.2 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.

5.2.3 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 upfront 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 as well as providing preventive and corrective maintenance.

Recent OUConvenient Lighting projects include 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 1 million square feet of office and light manufacturing space.

5.2.4 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 overvoltage, undervoltage, outages, electric noise, and harmonic distortion. Under the Power Quality Analysis program, trained and experienced service personnel 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 ongoing follow-up services to monitor results.

5.2.5 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.

5.2.6 OUCooling

OUCooling was originally formed in 1997 as a partnership between OUC and Trigen-Cinergy Solutions, and 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, lower maintenance costs, a smaller mechanical room (therefore more rental space), no insurance requirements, improved property resale value, and availability of maintenance personnel for other duties.

OUCooling operates two chilled water plants that serve customers in downtown Orlando as well as in Parramore. Underground "loops" run from each facility to buildings partnered with OUCooling. In Parramore and downtown Orlando alone, about 10 miles of underground pipes have the capacity to deliver 15,000 tons of chilled water to businesses – enough chilled water to cool about 6,000 residential homes. The 17.6 million gallon chilled water storage tank at the Orange County Convention Center is the largest in the world. The tank works in tandem with 20 water chillers and feeds a cooling loop that can handle more than 33,000 gallons of 37° F water per minute.

OUC's first chiller plant was installed at Lockheed Martin Corp. The plant was built in 1999 and serves eight customers. After that project, OUC 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 2 million square feet of space.

In 2002, the International District Energy Association (IDEA) presented OUCooling a first-place award for signing up more customer square footage for its chilled-water business than any other company in 2001. OUCooling signed up 9 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 included 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.

5.2.7 Green Pricing Initiative

OUC offers its customers an opportunity to participate in its Green Pricing Initiative, a pilot 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 $5.00 on their monthly utility bills in return for 200 kWh to support funding to add additional renewable energy to OUC's portfolio. Participation will help OUC develop cleaner alternative energy resources, such as solar, wind, and biomass. The annual per customer participation of 2,400 kWh is equivalent to the environmental benefit of planting 3 acres of forest, taking three cars off the road, preventing the use of 27 barrels of oil, or bicycling more than 30,575 miles instead of driving.

5.2.8 Photovoltaic Generation Pilot Program

OUC has initiated its Photovoltaic Generation Pilot Program to customers on standby service in which onsite generation consists of PV capacity. A PV system is a solar electric generating system that 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 will 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 and Planned Generating Capacity

Tables 6-1 and 6-2, which are presented at the end of this section, indicate that OUC and St. Cloud currently have a combined installed generating capability of 1,293 MW in the winter and 1,235 MW in the summer. OUC's existing generating capability (described in more detail in Section 2.0) consists of the following:

- A joint ownership share in the Stanton Energy Center (Units 1, 2, and Stanton A).
- Joint ownership shares of the Indian River combustion turbine units.
- Joint ownership shares of Crystal River Unit 3, McIntosh Unit 3, and St. Lucie Unit 2.

Additionally, the capacity from St. Cloud's generating units is included as generating capability, consistent with the Interlocal Agreement described in Section 2.0.

As discussed throughout this Ten-Year Site Plan, it has been assumed that Stanton B will receive all necessary regulatory approvals and will begin commercial operation June 1, 2010. Stanton B is expected to provide 283 MW of winter capacity and 256 MW of summer capacity. Including the capacity from Stanton B will increase the combined OUC and St. Cloud installed generating capability to1,555 MW in the winter and 1,470 MW in the summer (after accounting for the assumed retirement of St. Cloud's internal combustion units in October 2006).

6.1.2 Power Purchase Agreements

As described in Section 2.2, OUC schedules St. Cloud's power purchase from TECO. Corresponding with the construction of Stanton A, OUC entered into a PPA with SCF to purchase capacity from SCF's 65 percent ownership share of Stanton A. The original Stanton A PPA was for a term of 10 years and allowed OUC, KUA, and FMPA to purchase all of SCF's 65 percent capacity share of Stanton A for 10 years. The utilities retained the right to reduce the capacity purchased from SCF 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. The utilities originally had options to extend the PPA beyond its initial term. OUC, KUA, and FMPA have unilateral options to purchase all of Stanton A's capacity for the estimated 30 year useful life of the unit. Subsequent amendments to the original PPA continue OUC's capacity purchase until the 16th year of the PPA. Beginning with the 16th contract year and ending with the 20th contract year, OUC will maintain 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. OUC has the option of terminating the PPA on September 30, 2023, or extending the PPA up to an additional 10 years through two separate 5 year extensions.

6.1.3 Power Sales Agreements

As described in Section 2.3, OUC will continue its unit power sale to FMPA in 2006, providing FMPA with 22 MW. The contract expires December 31, 2006.

6.1.4 Retirements of Generating Facilities

OUC has not scheduled any unit retirements over the planning horizon, but will continue to evaluate options on an ongoing basis. However, the internal combustion units owned by St. Cloud are scheduled to be retired in October 2006.

By the end of the Ten-Year Site Plan planning period, McIntosh 3 will be 33 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 US Environmental Protection Agency (EPA)'s Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). OUC has not made final decisions on its compliance strategy for the regulatory requirements under CAIR and CAMR but continues to actively evaluate its options as part of its planning process.

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

OUC has applied a minimum 15 percent reserve margin criterion to its own load and to St. Cloud's load, as well as the TECO partial requirements purchase. 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 Stanton B is included in Tables 6-1 and 6-2 beginning in the summer of 2010.

Table 6-1 and Table 6-2 indicate that no additional capacity is required during the 2006 through 2015 planning period. The addition of Stanton B in June 2010 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 its customers. OUC has adopted the North American Electric Reliability Council (NERC) Planning Standards as the basis for electric power transmission system planning for its needs and those of the City of St. Cloud. For the purposes of planning studies, OUC utilizes certain criteria that pertain to voltage and line and transformer loading. Criteria of 95 percent and 105 percent of nominal system voltage establish 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 uses the following planning criteria to review the need and options for increasing the capability of the transmission system. During the course of a planning study, the OUC and St. Cloud transmission systems are subjected to a single contingency analysis that involves an outage of 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 also included. If a violation of the voltage or loading criteria occurs, a permanent solution may be an upgrade or new construction. The revised system containing the improvement is then subjected to the same analysis as the original to ensure that no voltage or loading violations remain. OUC has recently changed its planning philosophy in situations where voltage or loading criteria are exceeded. Instead of using an operational procedure as the first step to correcting the problem, OUC will investigate permanent solutions such as new construction. As a short-term solution, operational remedies will continue to be used until new facilities can be put into service.

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	FMPA I.R.		Installed[1]	SEC A PPA	SEC B	TECO P.R.	Total	Required[2]	Available[3]	
2006/07	1,116	138	0	1,254	1,272	343		15	1,631	188	378	190
2007/08	1,151	143	0	1,294	1,272	343		15	1,631	194	338	144
2008/09	1,187	148	0	1,335	1,272	343		15	1,631	200	297	97
2009/10	1,220	154	0	1,374	1,272	343		15	1,631	206	258	52
2010/11	1,252	160	0	1,412	1,272	343	283	15	1,913	212	503	291
2011/12	1,285	167	0	1,452	1,272	343	283	15	1,913	218	463	245
2012/13	1,318	173	0	1,491	1,272	343	283	0	1,898	224	407	183
2013/14	1,352	180	0	1,532	1,272	343	283	0	1,898	230	366	136
2014/15	1,388	187	0	1,575	1,272	343	283	0	1,898	236	323	87
2015/16	1,424	195	0	1,619	1,272	343	283	0	1,898	243	279	36

(1) Includes existing net capability to serve OUC and St. Cloud.
(2) "Required Reserves" include 15% reserve margin on OUC retail peak demand, and STC retail peak demand.
(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)		Available Capacity (MW)
	OUC	STC	FMPA I.R.		Installed[1]	SEC A PPA	SEC B	TECO P.R.	Total	Required[2]	Available[3]	
2006	1,081	131	22	1,234	1,235	322	0	15	1,572	182	340	159
2007	1,108	135	0	1,243	1,214	322	0	15	1,551	186	310	124
2008	1,141	140	0	1,281	1,214	322	0	15	1,551	192	272	80
2009	1,173	146	0	1,319	1,214	322	0	15	1,551	198	234	37
2010	1,202	151	0	1,353	1,214	322	256	15	1,765	203	414	212
2011	1,231	157	0	1,388	1,214	322	256	15	1,807	208	421	213
2012	1,261	163	0	1,424	1,214	322	256	15	1,807	214	385	172
2013	1,292	169	0	1,461	1,214	322	256	0	1,792	219	331	112
2014	1,324	176	0	1,500	1,214	322	256	0	1,792	225	292	67
2015	1,357	183	0	1,540	1,214	322	256	0	1,792	231	252	21

[1] Includes existing net capability to serve OUC and St. Cloud. St. Cloud's internal combustion units assumed to retire in October 2006.
[2] "Required Reserves" include 15% reserve margin on OUC retail peak demand, and STC retail peak demand.
[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 identifying Stanton B as part of OUC's least-cost capacity expansion plan in the Stanton B Need for Power Application (Docket No. 060155-EM), 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 25-year evaluation presented in the Stanton B Need for Power Application. However, as described previously in this Ten-Year Site Plan, no capacity additions are required during the 2006 through 2015 planning period beyond the addition of Stanton B in June 2010. Therefore, detailed descriptions of the supply-side alternatives have not been included in the Ten-Year Site Plan.

8.0 Economic Evaluation Criteria and Methodology

This section summarizes the economic evaluation criteria and methodology presented in the Stanton B Need for Power Application (Docket No. 060155-EM). The criteria and methodology were utilized in determining that Stanton B represents OUC's most cost-effective capacity addition to satisfy forecast capacity requirements beginning in the summer of 2010.

8.1 Economic Parameters

8.1.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed operation and maintenance (O&M) escalation rate, and nonfuel variable O&M escalation rate are each assumed to be 2.5 percent.

8.1.2 Cost of Capital

OUC uses a weighted average cost of capital for economic evaluations. The weighted average cost of capital is based on the debt/equity ratio (approximately 65/35), the embedded rate for new debt (projected to be 5.25 percent), and the return on equity (approximately 10.3 percent). OUC's weighted average cost of capital is approximately 7.0 percent.

8.1.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to OUC's weighted average cost of capital of 7.0 percent.

8.1.4 Interest During Construction Rate

The interest during construction (IDC) rate is assumed to be equal to the embedded debt rate of 5.25 percent.

8.1.5 Levelized Fixed Charge Rate

The fixed charge rate (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 FCR. The FCR calculation includes 0.10 percent for property insurance. Bond issuance fees and insurance costs are not included in the calculation of the levelized FCR, since these are already considered in OUC's embedded debt rate. Assuming a 30 year financing term, the resulting levelized FCR is 8.159 percent.

8.2 Fuel Price Forecast Methodology

Fuel price projections for coal, natural gas, and No. 2 fuel oil were developed for OUC by Energy Ventures Analysis, Inc. (EVA). The fuel price projections were provided for fuels currently being used by OUC, as well as for fuels that might be used by future units considered in the economic analysis performed as part of the Stanton B Need for Power Application

Black & Veatch has reviewed the forecasts developed in this section and believes that they are reasonable and appropriate. However, developing meaningful long-range estimates can be difficult when dealing with volatile energy markets, such as those recently experienced. The fuel price forecasts in this section represent the base case forecasts; however, it should be recognized that actual fuel prices will differ from those outlined herein. This uncertainty was addressed in part by the fuel price sensitivities considered and presented in the Stanton B Need for Power Application.

8.2.1 Coal Price Forecast Methodology

EVA provided forecast prices for a variety of coals and coal types, including coals from every major commercial region in the United States plus imported coals. Forecasts were developed for Central Appalachian coals (ranging from very low sulfur to mid sulfur content), Northern Appalachian coals (including low, mid, and high sulfur content), PRB coals (very low sulfur content with both higher and lower heating values), and very low sulfur coals imported from Colombia and Venezuela. For each of the coal sources, EVA identified likely transportation modes and routes. In developing forecast transportation rates, EVA considered OUC's long-term rail contract, which specifies rates from most origins.

EVA's forecast of coal prices considered recent price increases compared to historical levels. These price increases were due to a number of factors. The price of eastern US coal rose because of the increased export of eastern US coal in response to rising international coal prices, a steady decline in eastern coal production capacity in response to previously low market prices, barriers to entry in the eastern US coal mining industry, and increased mining costs.

PRB coal prices also rose in 2005 because of various factors. Rail transportation disruptions reduced deliveries, causing a decrease in customer stocks and an increase in demand for 2006 delivery. Additionally, utilities in the eastern US switched to PRB coal in response to high costs for SO_2 emission allowances and higher prices for eastern US coals (as described previously). Overall, excess PRB capacity decreased because of previous capacity reductions and increased demand.

Prior to these events, EVA had forecasted rising coal prices. EVA further increased its price forecast to reflect rising production costs. However, the coal price forecasts provided by EVA assume that the current capacity shortage will be overcome by increased supply and prices will fall from their current elevated levels.

8.2.2 Natural Gas Price Forecast Methodology

The natural gas price forecast provided by EVA was based on an analysis of the supply and demand fundamentals for natural gas. The natural gas market in the United States is currently in a supply limited environment, with natural gas prices set by the marginal customer rather than the cost of supply. EVA's current position is that this supply limited environment and the associated high natural gas prices will continue into 2007. Beyond 2007, supply is expected to fill the supply and demand differential from various emerging resource areas, resulting in a decline in natural gas prices. The resource that is expected to have the greatest intermediate-term impact on natural gas prices is liquefied natural gas (LNG.). Imports of LNG are expected to increase because of a combination of scheduled first- and second-phase capacity expansions at existing US LNG terminals and a series of new LNG terminals in the United States.

Over the forecast period, the power sector will account for about 62 percent of the projected increased demand for natural gas. The expected increase in the power sector is the net result of two factors: projected economic growth (which drives electricity demand growth rates) and the recent dominance of natural gas fired units for capacity additions. Mitigating these factors will be the increased usage of coal fired, nuclear, and renewable capacity additions. Natural gas demand growth in other sectors is expected to be modest, primarily as a result of conservation in response to high fuel prices. Natural gas prices in Florida, with the exception of the transportation component, are affected by the same factors that impact natural gas prices throughout the United States.

8.2.3 Fuel Oil Forecast Methodology

EVA believes that world oil supplies will increase approximately 11.5 million barrels per day (MMBD) between now and the end of this decade. This projected increase, which should outpace increases in demand over the same period, is based on announced development projects. EVA's assessment is somewhat conservative, because other analysts believe the increase in supplies may be 5 MMBD higher. The increase in supplies forecast by EVA should enable the world oil market to restore spare capacity levels to the more acceptable 3 MMBD level.

Price-induced conservation has caused worldwide demand growth rates to decline from the record 3.2 percent, or 2.5 MMBD, realized in 2004. For the forecast period, demand is expected to grow at an average annual rate of 1.7 MMBD. Worthwhile to note is that China, India, and the United States will account for about 44 percent of the projected growth.

After 2015, the world will likely be 100 percent dependent on the Organization of Petroleum Exporting Countries (OPEC) for the incremental barrel, since non-OPEC production will begin to decline. In addition, all but six countries (Saudi Arabia, Iran, Iraq, Venezuela, the UAE, and Canada) will be at or past their peak production levels based on the current understanding of the world's reserve potential and industry technology. At such time, seven countries will account for 50 percent of the world's oil production, whereas the current 11 OPEC members account for 41 percent of worldwide oil production. Given such a scenario and based on the oil market's reaction to recent tight supply conditions, a significant (i.e., $15 to $20 per barrel) scarcity premium will likely reemerge in the later years of this forecast.

8.3 Fuel Price Forecasts

The following subsections present the annual price projections for coal, natural gas, and No. 2 fuel oil provided by EVA.

8.3.1 Coal

Low sulfur (1.8 lb SO_2/MBtu) Central Appalachian coal fuels the existing Stanton Units 1 and 2 and was assumed to be the fuel for the pulverized coal alternative considered as a supply-side candidate in the analyses performed for the Stanton B Need for Power Application. High sulfur (4.0 lb SO_2/MBtu) Northern Appalachian coal was used for the CFB alternative, while Stanton B will use PRB coal. The price forecasts (in real 2005 dollars) provided by EVA for these coals are presented in Table 8-1 and represent the delivered cost of coal, excluding railcars. OUC currently owns railcars for Stanton Units 1 and 2. The costs for railcars were accounted for separately in the capital cost estimates of the coal fired alternatives considered, including Stanton B.

Table 8-1
Coal Price Forecasts (Delivered, Real 2005 $/MBtu)

Calendar Year	Low Sulfur Central Appalachian (1.8 lb SO_2/MBtu, 12,500 Btu/lb)	High Sulfur Northern Appalachian (4.0 lb SO_2/MBtu, 13,000 Btu/lb)	High Btu Gillette PRB (0.8 lb SO_2/MBtu, 8,800 Btu/lb)
2006	2.77	2.38	2.50
2007	2.52	2.27	2.38
2008	2.53	2.37	2.43
2009	2.50	2.33	2.42
2010	2.49	2.32	2.44
2011	2.50	2.32	2.44
2012	2.52	2.32	2.43
2013	2.54	2.34	2.45
2014	2.55	2.35	2.45
2015	2.57	2.37	2.47

8.3.2 Natural Gas

Natural gas is the primary fuel for Stanton A and OUC's Indian River combustion turbines, and was also considered as the primary fuel for the 1x1 7FA combined cycle alternative considered in the Need for Power Application. The price forecast (in real 2005 dollars) provided by EVA for natural gas is presented in Table 8-2 and considers the Florida Gas Transmission (FGT) Zone 3 basis adder for Henry Hub, as well as fuel loss and usage charges. The forecast does not include the natural gas transportation charges for delivery to the Stanton Energy Center that would be required for new natural gas fired capacity.

8.3.3 No. 2 Fuel Oil

No. 2 fuel oil is the secondary fuel for Stanton A as well as for OUC's Indian River combustion turbines, and will also be used as the primary fuel for the simple cycle combustion turbines considered in the Stanton B Need for Power Application. Forecasts for low sulfur No. 2 fuel oil (0.05 percent sulfur) provided by EVA (in real 2005 cents per gallon) are presented in Table 8-3.

Table 8-2
Natural Gas Price Forecast
(Real 2005 $/MBtu)

Calendar Year	Natural Gas[1] ($/MBtu)
2006	10.33
2007	7.33
2008	5.78
2009	5.73
2010	5.73
2011	5.74
2012	5.81
2013	5.87
2014	5.90
2015	5.97

[1]Including FGT Zone 3 basis adder, fuel losses, and usage charges.

Table 8-3
No. 2 Fuel Price Forecast
(0.05 Percent Sulfur, Real 2005 Cents/Gallon)

Calendar Year	No. 2 Fuel Oil (cents/gallon)
2006	169.0
2007	140.3
2008	134.4
2009	134.4
2010	134.3
2011	135.7
2012	138.5
2013	141.3
2014	144.1
2015	146.9

8.4 Economic Evaluation Methodology

This section discusses the methodology applied by Black & Veatch to the fuel forecasts provided by EVA to develop the fuel costs used in the economic analyses performed in the Stanton B Need for Power Application. Table 8-4, presented at the end of this section, presents the resulting fuel price projections used in the economic analyses of Stanton B.

8.4.1 Coal

EVA provided forecasts for low sulfur (1.8 lb SO_2/MBtu) Central Appalachian, high sulfur Northern Appalachian (4.0 lb SO_2/MBtu), and PRB coal. The Central Appalachian coal forecast was used for Stanton Units 1 and 2 as well as McIntosh Unit 3, and it has been assumed that this coal would be burned by the pulverized coal alternative. The Northern Appalachian coal was assumed to be burned by the CFB alternative. Stanton B will use the PRB coal. The nominal forecasts for these coal types are presented in Table 8-4 and were developed by applying the 2.5 percent annual inflation rate to the real delivered price projections provided by EVA.

8.4.2 Natural Gas

Black & Veatch used the natural gas price forecast provided by EVA, which did not include delivery charges to the Stanton Energy Center. This is appropriate because OUC has already contracted for firm natural gas delivery for Stanton A and the Indian River combustion turbines through FGT. For the 1x1 7FA combined cycle considered in the analysis presented in the Stanton B Need for Power Application, the FGT firm transportation service charges were considered as a fixed cost rather than included in the cost per MBtu of natural gas. The natural gas forecast presented in Table 8-4 was developed by applying the 2.5 percent annual inflation rate to the real natural gas price projections provided by EVA.

8.4.3 No. 2 Fuel Oil

EVA provided price projections for low sulfur No. 2 fuel oil (0.05 percent sulfur) on a cent per gallon basis, exclusive of delivery charges to the Stanton Energy Center. Based on recent historical information provided by OUC, a basis adder for delivery of fuel oil to Stanton Energy Center was developed. This adder was estimated to be $0.28 per barrel, or approximately 0.67 cents per gallon (assuming 42 gallons per barrel).

Low sulfur fuel oil would not likely meet the air permitting requirements of any new combustion turbine constructed by OUC. Ultra-low sulfur diesel (ULSD) will be required for vehicle use as early as June 2006, and power plants have recently been permitted on ULSD. Based on this information, it was determined that ULSD, with a sulfur content of 0.0015 percent, would be more appropriate for use in the analysis. Black & Veatch developed an incremental cost for ULSD that was added to the EVA projections of low sulfur No. 2 fuel oil. Data from the US Department of Energy's Energy Information Administration (EIA) was used to develop an incremental cost of approximately 6.1 cents/gallon.

After adjusting the EVA forecast to include the delivery adder and the incremental cost for ULSD, Black & Veatch converted the forecast prices (provided in cents/gallon) to $/MBtu by assuming a heat content of 140,000 Btu/gallon. The resulting annual forecasts were then converted from real 2005 dollars to nominal dollars, assuming the 2.5 percent annual inflation rate. The resulting fuel price forecasts are shown in Table 8-4.

8.4.4 Nuclear

EVA did not provide projections for nuclear fuel, which are required for OUC's ownership shares of St. Lucie Units 1 and 2 and Crystal River Unit 3. OUC provided historical prices for nuclear fuel, which Black & Veatch used as the basis for developing the forecasts presented in Table 8-4.

Table 8-4
Fuel Price Forecasts (Nominal $/MBtu)

Calendar Year	Low Sulfur Central Appalachian (1.8 lb SO_2/MBtu, 12,500 Btu/lb) - Delivered	High Sulfur Northern Appalachian (4.0 lb SO_2/MBtu, 13,000 Btu/lb) - Delivered	High Btu Gillette PRB (0.8 lb SO_2/MBtu, 8,800 Btu/lb) - Delivered	Natural Gas (Including FGT Zone 3 Basis Adder, Fuel Losses, and Usage Charges)	Ultra-Low Sulfur Diesel (0.0015% sulfur) - Delivered	Nuclear - Delivered
2006	2.84	2.44	2.57	10.58	15.60	0.50
2007	2.65	2.38	2.50	7.70	13.84	0.51
2008	2.72	2.55	2.61	6.23	13.73	0.523
2009	2.76	2.57	2.67	6.33	14.07	0.54
2010	2.82	2.62	2.76	6.48	14.42	0.55
2011	2.90	2.69	2.83	6.66	14.89	0.57
2012	2.99	2.76	2.89	6.90	15.50	0.58
2013	3.09	2.85	2.99	7.16	16.13	0.59
2014	3.18	2.93	3.06	7.37	16.79	0.61
2015	3.30	3.03	3.16	7.64	17.46	0.62

9.0 Analysis and Results

A detailed economic analysis was performed in the Stanton B Need for Power Application (Docket No. 060155-EM) to evaluate the cost-effectiveness of Stanton B and to determine the least-cost capacity expansion plan to meet OUC's forecast capacity requirements. This section presents the methodology used in the economic analysis of Stanton B; however, as stated previously the addition of Stanton B in June 2010 satisfies both forecast summer and winter capacity requirements through the term of this Ten-Year Site Plan.

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model Black & Veatch developed as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program. POWROPT and its detailed chronological production costing module, POWRPRO, have both been used in numerous Need for Power Applications filed with the Florida Public Service Commission, including FMPA's Treasure Coast Energy Center Unit 1 Need for Power Application filed in April 2005 (Docket No. 050256-EM).

POWROPT operates on an hourly chronological basis and is used to determine a set of optimal capacity expansion plans to satisfy forecast 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 generating unit alternatives and purchase power options, in conjunction with existing capacity resources, while maintaining user-defined reliability criteria. All capacity expansion plans were analyzed over a 25 year period from 2006 through 2030.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's POWRPRO was used to obtain the annual production cost for the expansion plan. POWRPRO is a computer-based chronological production costing model developed for use in power supply systems planning. POWRPRO simulates the hour-by-hour operation of a power supply system over a specified planning period. Required inputs are carried forward from those used in POWROPT and include the performance characteristics of generating units, fuel costs, and the system hourly load profile for each year.

POWRPRO summarizes each unit's operating characteristics for every year of the planning horizon. These characteristics include, among others, each unit's annual generation, fuel consumption, fuel cost, average net operating heat rate, the number of hours the unit was on line, the capacity factor, variable O&M costs, and the number of starts and associated costs. Fixed O&M costs were included only for new unit additions, as the fixed O&M costs for existing units are generally considered sunk costs that will not vary from one expansion plan to another. The annual capacity charges for the Stanton A and the TECO Partial Requirements Purchase Power Agreements likewise were not included, as they also represent sunk costs. Similarly, fixed costs for firm natural gas transportation capacity from FGT for existing units are considered sunk costs and are not included. The operating costs of each unit are aggregated to determine annual operating costs for each year of the expansion plan. Capital costs, fixed O&M costs, and fixed costs for natural gas transportation (for combined cycle units additions) are then added for each capacity addition selected, at which point the cumulative present worth cost (CPWC) of each expansion plan can be calculated.

The CPWC calculation accounts for annual system costs (fuel and energy, fixed O&M for capacity additions, non-fuel variable O&M, startup costs, and levelized capital costs) for each year of the expansion planning period and discounts each back to 2006 at the present worth discount rate of 7.0 percent. These annual present worth costs are then summed over the 2006 through 2030 period to calculate the total CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various capacity expansion plans, and the plan with the lowest CPWC is considered the least-cost capacity expansion plan.

9.1 Results of the Economic Analysis

As discussed previously, the Stanton B Need for Power Application presented the results of a 25-year analysis performed in determining that Stanton B represented OUC's most cost-effective capacity addition to satisfy forecast capacity requirements beginning in the summer of 2010. However, as demonstrated in Section 6.0, OUC does not forecast any capacity requirements beyond the addition of Stanton B in June 2010 during the term of this Ten-Year Site Plan.

9.2 Sensitivity Analyses

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 numerous scenarios considered in the Stanton B Need for Power Application were high and low fuel price projections, high and low load and energy growth projections and high capital cost sensitivities. However, none of the sensitivity analyses listed above, with the exception of the high load and energy growth projection sensitivity, would change the schedule of unit additions, as no capacity additions beyond Stanton B are required during the 2006 through 2015 planning period under the base case load forecast. In the high load and energy growth scenario, additional capacity would be required in 2014.

10.0 Environmental and Land Use Information

The Stanton Energy Center, originally certified for 2,000 MW, currently consists of two pulverized coal units (Stanton Units 1 and 2), 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 as well as the recently filed Supplemental Site Certification Application for Stanton B. 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.

10.1 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. OUC is awaiting certification of Stanton B under Supplemental Site Certification.

10.2 Land and Environmental Features

The Stanton Energy Center is located in Orange County, Florida, and consists of 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, Stanton A, and Stanton B.

10.3 Air Emissions

Stanton B will be subject to Florida Department of Environmental Protection's Prevention of Significant Deterioration (PSD) permitting program, which requires Best Available Control Technology (BACT) for the emissions of various pollutants. The combined cycle unit will include post-combustion emissions controls. Moreover, selective catalytic reduction (SCR) will be demonstrated during the unit's 4-year demonstration phase to further reduce NO_x emissions. Taken together, these design features will make Stanton B one of the most efficient and lowest polluting coal fired power plants in the United States. The estimated emissions from Stanton B are presented in Table 10-1. The actual permitted emissions rates have not been established; however, such permitted rates shall not exceed the estimated average emission rates presented in Table 10-1.

Table 10-1
Stanton B Emissions Rates
(Full Load, Average Conceptual Design Conditions)

NO_x	
Syngas	0.07 lb/MBtu
Natural Gas	0.018 lb/MBtu
SO_2	
Syngas	0.04 lb/MBtu
Natural Gas	0.0006 lb/MBtu
Hg	
Syngas	1.7 lb/TBtu
Natural Gas	0.00 lb/TBtu

10.4 Water and Wastewater

Water for cooling tower makeup for Stanton B will be reclaimed water (treated wastewater). Reclaimed water will be supplied from the existing Eastern Water Reclamation Facility, Orange County wastewater treatment plant. A maximum of 2.6 million gallons per day (mgd) of makeup water is expected to be required for Stanton B. The majority of this water supply will be for cooling tower makeup, which will utilize treated effluent.

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.

There will be five major sources of wastewater from Stanton B: sanitary waste, HRSG blowdown, oil/water separator effluent, cooling tower blowdown, and other plant wastewaters from the combined cycle unit. Sanitary wastewaters will be directed to a new onsite septic system. HRSG blowdown will be routed to the cooling tower basin. Wastewaters with the potential for oil contamination will be routed to a new oil/water separator. Effluent from the oil/water separator and other combined cycle plant wastewaters will be combined and discharged to OUC's existing recycle basin. Cooling tower blowdown will be routed separately to the existing zero-discharge wastewater system.

Gasification wastewaters will consist of oil/water separator effluent, sanitary wastes, and rainwater runoff. Sanitary wastes will be directed to the combined cycle septic system. Rainwater runoff will be collected and sent to the existing Stanton Energy Center collection pond and then discharged to natural drainage courses. Oil/water separator effluent will be discharged to the combined cycle waste water system.

11.0 Conclusions

As discussed throughout this Ten-Year Site Plan, OUC filed the Need for Power Application for Stanton B with the Florida Public Service Commission on February 22, 2006 (Docket No. 060155-EM). The proposed Stanton B project is the result of the proposal submitted by Southern Company Services (SCS) on behalf of its partners Southern Power Company (SPC), OUC, and Kellogg Brown & Root, Inc. (KBR) for funding of an air blown Transport Gasification combined cycle demonstration project to be located at OUC's Stanton Energy Center. The proposal was submitted June 15, 2004 in response to the Clean Coal Power Initiative (CCPI) of the US Department of Energy (DOE). Stanton B is planned as a 1x1 F-class IGCC unit that will be capable of firing coal derived syngas or natural gas, and is planned for commercial operation on June 1, 2010. For purposes of the analyses presented in this Ten-Year Site Plan, it has been assumed that Stanton B will receive approval by the Florida Public Service Commission and all other necessary regulatory approvals and is therefore considered to be a capacity resource for OUC beginning in the summer of 2010.

The addition of Stanton B satisfies forecast capacity requirements through the end of the Ten-Year Site Plan planning period (2006 through 2015). Therefore, no capacity additions are required nor presented in this Ten-Year Site Plan. It should be noted that significant detail related to the Stanton B project is presented in the Stanton B Need for Power Application, and the information pertaining to Stanton B presented in this Ten-Year Site Plan is intended to be an overview for the sake of brevity.

12.0 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 2006 OUC Ten-Year Site Plan.

Table 12-1 (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	351.70	351.70	334.45	334.45
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)Reflects capability to serve OUC and St. Cloud.
(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 12-2 (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
1996	321,600	2.57	1,609	125,107	12,861	336	16,169	20,781
1997	330,000	2.57	1,569	128,504	12,210	341	16,353	20,852
1998	341,000	2.57	1,804	132,824	13,582	331	16,597	19,943
1999	351,400	2.56	1,725	137,317	12,562	330	17,058	19,346
2000	362,000	2.55	1,821	141,993	12,825	320	17,236	18,566
2001	372,200	2.55	1,893	145,838	12,980	316	17,184	18,389
2002	383,200	2.55	1,973	150,194	13,136	315	17,669	17,828
2003	391,500	2.55	2,033	153,708	13,226	299	18,011	16,601
2004	403,900	2.54	2,082	158,755	13,115	300	18,866	15,902
2005	421,100	2.54	2,198	165,545	13,277	320	19,672	16,267
Forecast								
2006	434,000	2.54	2,275	170,590	13,336	318	20,065	15,848
2007	445,800	2.54	2,332	175,260	13,306	324	20,412	15,873
2008	456,900	2.54	2,394	179,593	13,330	332	20,756	15,995
2009	469,400	2.54	2,459	184,489	13,329	340	21,121	16,098
2010	482,900	2.54	2,533	189,907	13,338	346	21,490	16,101
2011	497,300	2.54	2,608	195,562	13,336	352	21,866	16,098
2012	512,200	2.54	2,688	201,449	13,343	358	22,252	16,088
2013	528,500	2.54	2,770	207,828	13,328	362	22,650	15,982
2014	546,000	2.54	2,862	214,730	13,328	367	23,063	15,913
2015	564,500	2.54	2,959	222,010	13,328	372	23,481	15,843

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

Table 12-3 (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
1996	2,300	3,254	706,822	0	23	5	4,273
1997	2,391	3,594	665,275	0	24	5	4,330
1998	2,569	3,956	649,393	0	25	5	4,734
1999	2,723	4,071	668,877	0	29	5	4,812
2000	2,861	4,420	647,358	0	28	6	5,036
2001	2,967	4,763	622,992	0	31	6	5,213
2002	3,033	4,980	609,036	0	40	6	5,367
2003	3,138	5,417	579,287	0	37	6	5,513
2004	3,221	5,500	585,636	0	42	6	5,651
2005	3,283	5,561	590,361	0	45	6	5,852
Forecast							
2006	3,379	5,927	570,103	0	49	6	6,027
2007	3,485	6,239	558,583	0	52	6	6,199
2008	3,612	6,492	556,377	0	56	6	6,400
2009	3,723	6,761	550,658	0	59	6	6,587
2010	3,820	7,028	543,540	0	63	6	6,768
2011	3,917	7,305	536,208	0	66	6	6,949
2012	4,016	7,594	528,839	0	69	6	7,137
2013	4,113	7,905	520,304	0	73	6	7,324
2014	4,210	8,241	510,860	0	76	6	7,521
2015	4,308	8,587	501,689	0	80	6	7,725

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

Table 12-4 (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)]
1996	0	198	4,471	0	144,530
1997	0	236	4,566	0	148,451
1998	0	175	4,909	0	153,377
1999	0	199	5,011	0	158,446
2000	0	255	5,291	0	163,648
2001	969	191	6,373	0	167,785
2002	821	208	6,396	0	172,843
2003	920	249	6,682	0	177,136
2004	714	234	6,599	0	183,121
2005	704	219	6,775	0	190,778
Forecast					
2006	39	260	6,326	0	196,582
2007	0	268	6,467	0	201,911
2008	0	275	6,675	0	206,841
2009	0	285	6,872	0	212,371
2010	0	291	7,059	0	218,425
2011	0	300	7,249	0	224,733
2012	0	307	7,444	0	231,295
2013	0	316	7,640	0	238,383
2014	0	324	7,845	0	246,034
2015	0	334	8,059	0	254,078

[(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. Historical "Sales for Resale" includes GWh sales to FMPA, KUA, SEC, and RCID for 2001, 2002, 2003, 2004, and 2005, as in the FRCC forms.
[(3)]Total No. of Customers includes aggregate of Rural & Residential, General Service Non-Demand, and General Service Demand.

Table 12–5 (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
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	1055	0	1055	0	0	0	0	1055
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
2005	1,353	147	1,206	0	0	0	0	1,353
Forecast								
2006	1,234	22	1,212	0	0	0	0	1,234
2007	1,243	0	1,243	0	0	0	0	1,243
2008	1,281	0	1,281	0	0	0	0	1,281
2009	1,319	0	1,319	0	0	0	0	1,319
2010	1,353	0	1,353	0	0	0	0	1,353
2011	1,388	0	1,388	0	0	0	0	1,388
2012	1,424	0	1,424	0	0	0	0	1,424
2013	1,461	0	1,461	0	0	0	0	1,461
2014	1,500	0	1,500	0	0	0	0	1,500
2015	1,540	0	1,540	0	0	0	0	1,540

(1)Historical and 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. Historical "Wholesale" includes MW sales to FMPA, KUA, SEC, and RCID for 2001, 2002, 2003, 2004, and 2005, as in the FRCC forms.

Table 12–6 (Schedule 3.2).
OUC and St. Cloud History and Forecast of Winter Peak Demand (Base Case)(1)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total(2)	Wholesale(3)	Retail	Interruptible	Residential Load Management	Commercial/Industrial Load Management	Conservation	Net Firm Demand
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	1,196	241	955	1	0	0	0	1,419
2004/05	1,203	123	1,080	1	0	0	0	1,202
2005/06(4)	1,242	22	1,220	1	0	0	0	1,241
Forecast								
2006/07	1,254	0	1,254	0	0	0	0	1,254
2007/08	1,294	0	1,294	0	0	0	0	1,294
2008/09	1,335	0	1,335	0	0	0	0	1,335
2009/10	1,374	0	1,374	0	0	0	0	1,374
2010/11	1,412	0	1,412	0	0	0	0	1,412
2011/12	1,452	0	1,452	0	0	0	0	1,452
2012/13	1,491	0	1,491	0	0	0	0	1,491
2013/14	1,532	0	1,532	0	0	0	0	1,532
2014/15	1,575	0	1,575	0	0	0	0	1,575
2015/16	1,619	0	1,619	0	0	0	0	1,619

(1)Historical and 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. Historical "Wholesale" includes MW sales to FMPA, KUA, SEC, and RCID for 2001/02, 2002/03, 2003/04, 2004/05, and 2005/06, as in the FRCC forms.
(4)2005/06 is a forecast as actual information was not available at time of publication.

Table 12–7 (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) (%)
1996	4,471	0	4,273	0	198	4,471	52.7%
1997	4,566	0	4,330	0	236	4,566	56.8%
1998	4,909	0	4,734	0	175	4,909	56.8%
1999	5,011	0	4,812	0	199	5,011	54.2%
2000	5,291	0	5,036	0	255	5,291	57.0%
2001	6,373	0	5,213	969	191	6,373	52.7%
2002	6,396	0	5,367	821	208	6,396	51.9%
2003	6,682	0	5,513	920	249	6,682	54.0%
2004	6,599	0	5,651	714	234	6,599	53.1%
2005	6,775	0	5,852	704	219	6,775	57.2%
Forecast							
2006	6,326	0	6,027	39	260	6,326	58.5%
2007	6,467	0	6,199	0	268	6,467	58.9%
2008	6,675	0	6,400	0	275	6,675	58.9%
2009	6,872	0	6,587	0	285	6,872	58.8%
2010	7,059	0	6,768	0	291	7,059	58.6%
2011	7,249	0	6,949	0	300	7,249	58.6%
2012	7,444	0	7,137	0	307	7,444	58.5%
2013	7,640	0	7,324	0	316	7,640	58.5%
2014	7,845	0	7,521	0	324	7,845	58.5%
2015	8,059	0	7,725	0	334	8,059	58.4%

(1)Historical and 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. Historical "Wholesale" includes GWh sales to FMPA, KUA, SEC, and RCID for 2001, 2002, 2003, 2004, and 2005, as in the FRCC Forms.
(4)Forecast load factor calculation considers all retail and wholesale peak demand and energy. Calculated as ratio of annual NEL to the product of the annual peak demand times 8,760 hours.

Table 12-8 (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 – 2005[2]		2006 Forecast		2007 Forecast	
Month	Peak Demand[3] (MW)	NEL GWh	Peak Demand[3] (MW)	NEL GWh	Peak Demand[3] (MW)	NEL GWh
January	1,202	503	1,241	481	1,254	494
February	998	453	946	432	949	444
March	1,097	510	886	474	888	485
April	1,037	485	1,011	479	1,015	489
May	1,202	579	1,145	565	1,151	570
June	1,262	611	1,182	578	1,188	590
July	1,331	708	1,234	645	1,243	650
August	1,353	723	1,211	627	1,221	637
September	1,230	636	1,133	564	1,141	579
October	1,181	581	1,069	534	1,076	552
November	979	485	931	461	935	480
December	946	501	1,035	487	1,046	496

[1]Includes OUC and City of St. Cloud peak demand and NEL as well as wholesale sales to FMPA and RCID (MW and NEL) for historical 2005. Forecast 2006 includes OUC wholesale sales to FMPA.
[2]Actual 2005 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 12-9 (Schedule 5).
Fuel Requirements[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		Units	Actual 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	Nuclear		Trillion BTU	5	6	6	5	6	6	5	6	6	5	6
(2)	Coal		1000 Ton	2,198	1,947	1,957	1,968	2,003	2,299	2,448	2,448	2,577	2,625	2,713
(3)	Residual[2]	Total	1000 BBL	9	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	9	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(7)	Distillate[3]	Total	1000 BBL	5	0	0	0	0	0	0	0	0	0	0
(8)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	1000 BBL	2	0	0	0	0	0	0	0	0	0	0
(10)		CT	1000 BBL	3	0	0	0	0	0	0	0	0	0	0
(11)	Natural Gas	Total	1000 MCF	15,614	6,222	7,317	8,920	9,576	7,228	6,800	6,572	7,306	8,389	8,390
(12)		Steam	1000 MCF	34	0	0	0	0	0	0	0	0	0	0
(13)		CC	1000 MCF	15,406	4,819	6,076	7,515	7,829	5,722	5,902	5,793	6,429	7,304	7,220
(14)		CT	1000 MCF	174	1,403	1,240	1,404	1,747	1,507	898	779	877	1,085	1,171
(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. Forecast 2006 through 2015 represents results of production cost modeling to serve combined OUC and City of St. Cloud loads and contracted wholesale sales only.
[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 12-10 (Schedule 6.1)
Energy Sources (GWH)[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	Annual Firm Inter-region Interchange		GWH	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWH	471	512	518	484	518	518	477	517	537	489	518
(3)	Residual	Total	GWH	6	0	0	0	0	0	0	0	0	0	0
(4)		Steam	GWH	6	0	0	0	0	0	0	0	0	0	0
(5)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)	Distillate	Total	GWH	2	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	2	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(12)	Natural Gas	Total	GWH	2,234	793	895	1,105	1,178	879	856	828	920	1,060	1,052
(12)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0
(13)		CC	GWH	2,221	673	798	992	1036	757	787	770	854	976	961
(14)		CT	GWH	13	120	97	113	142	121	69	59	66	84	91
(15)	Coal	Steam	GWH	5,590	4,984	5,015	5,046	5,126	5,626	5,895	6,080	6,182	6,288	6,478
(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	36	39	38	49	37	21	19	2	9	11
		Sales	GWH	68	0	0	0	0	0	0	0	0	0	0
		Total	GWH	68	36	39	38	49	37	21	19	2	9	11
(19)	Net Energy for Load[2]		GWH	8,371	6,326	6,466	6,674	6,871	7,059	7,249	7,444	7,640	7,846	8,059

[1] Forecast 2006 through 2015 represents results of production cost modeling to serve combined OUC and City of St. Cloud loads and contracted wholesale sales only.
[2] Variation in Net Energy for Load between Schedule 3.3 and Schedule 6.1 can be attributed to rounding error.

Table 12-11 (Schedule 6.2)
Energy Sources (%)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(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	5.63%	8.10%	8.01%	7.26%	7.54%	7.33%	6.58%	6.95%	7.02%	6.23%	6.43%
(3)	Residual	Total	GWH	0.07%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(4)		Steam	GWH	0.07%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)	Distillate	Total	GWH	0.02%	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	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(12)	Natural Gas	Total	GWH	26.69%	12.54%	13.83%	16.56%	17.15%	12.45%	11.81%	11.13%	12.04%	13.51%	13.06%
(12)		Steam	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(13)		CC	GWH	26.53%	10.64%	12.34%	14.87%	15.08%	10.73%	10.86%	10.34%	11.18%	12.44%	11.92%
(14)		CT	GWH	0.16%	1.90%	1.50%	1.69%	2.07%	1.72%	0.95%	0.79%	0.86%	1.07%	1.13%
(15)	Coal	Steam	GWH	66.78%	78.79%	77.55%	75.60%	74.60%	79.70%	81.32%	81.67%	80.91%	80.15%	80.38%
(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%	0.58%	0.60%	0.58%	0.72%	0.53%	0.29%	0.25%	0.03%	0.11%	0.13%
		Sales	GWH	0.81%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Total	GWH	0.81%	0.58%	0.60%	0.58%	0.72%	0.53%	0.29%	0.25%	0.03%	0.11%	0.13%
(19)	Net Energy for Load		GWH	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 12-12 (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	%
2006	1,235	337	22	0	1,550	1,212	340	28.1%	0	340	28.1%
2007	1,214	337	0	0	1,551	1,243	310	25.0%	0	310	25.0%
2008	1,214	337	0	0	1,551	1,281	272	21.3%	0	272	21.3%
2009	1,214	337	0	0	1,551	1,319	234	17.8%	0	234	17.8%
2010	1,470	337	0	0	1,807	1,353	456	33.7%	0	456	33.7%
2011	1,470	337	0	0	1,807	1,388	421	30.4%	0	421	30.4%
2012	1,470	337	0	0	1,807	1,424	385	27.1%	0	385	27.1%
2013	1,470	322	0	0	1,792	1,461	331	22.7%	0	331	22.7%
2014	1,470	322	0	0	1,792	1,500	292	19.5%	0	292	19.5%
2015	1,470	322	0	0	1,792	1,540	252	16.4%	0	252	16.4%

(1)Installed capacity reflects assumed retirement of the City of St. Cloud's internal combustion units (in October 2006).
(2)Firm capacity imports include capacity purchased from TECO and capacity purchased from Southern Company-Florida, LLC (from Stanton A).
(3)Firm capacity export includes all forecast sales to FMPA.
(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.
(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 and St. Cloud peak demand.

Table 12-13 (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	%
2006/07	1,272	358	0	0	1,630	1,254	378	30.2%	0	378	30.2%
2007/08	1,272	358	0	0	1,630	1,294	338	26.2%	0	338	26.2%
2008/09	1,272	358	0	0	1,630	1,335	297	22.3%	0	297	22.3%
2009/10	1,272	358	0	0	1,630	1,374	258	18.8%	0	258	18.8%
2010/11	1,555	358	0	0	1,913	1,412	503	35.6%	0	503	35.6%
2011/12	1,555	358	0	0	1,913	1,452	463	31.9%	0	463	31.9%
2012/13	1,555	343	0	0	1,898	1,491	407	27.4%	0	407	27.4%
2013/14	1,555	343	0	0	1,898	1,532	366	23.9%	0	366	23.9%
2014/15	1,555	343	0	0	1,898	1,575	323	20.5%	0	323	20.5%
2015/16	1,555	343	0	0	1,898	1,619	279	17.2%	0	279	17.2%

(1)Installed capacity reflects assumed retirement of the City of St. Cloud's internal combustion units (in October 2006).
(2)Firm capacity imports include capacity purchased from TECO and capacity purchased from Southern Company-Florida, LLC (from Stanton A).
(3)OUC currently has no contracted firm capacity exports beyond calendar year 2006.
(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.
(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 and St. Cloud peak demand.

Table 12-14 (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[1]	B	Orange	CC	SUB	NG	RR	PL	01/08	06/10				256	283	P

[1] Need for Power Application for Stanton Energy Center B (SEC B) filed February 22, 2006 (Docket No. 060155-EM).

Table 12-15 (Schedule 9)
Status Report and Specifications of Proposed Generation Facilities

(1)	**Plant Name and Unit Number:**	Stanton Energy Center B[1]
(2)	**Capacity**	
	a. Summer:	256
	b. Winter:	283
(3)	**Technology Type:**	IGCC
(4)	**Anticipated Construction Timing**	
	a. Field construction start-date:	01/2008
	b. Commercial in-service date:	06/2010
(5)	**Fuel**	
	a. Primary fuel:	SUB
	b. Alternate fuel:	NG
(6)	**Air Pollution Control Strategy**	BACT compliant
(7)	**Cooling Method**	Mechanical draft
(8)	**Total Site Area**	Approximately 3,280 acres
(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] Need for Power Application for Stanton Energy Center B (SEC B) filed February 22, 2006 (Docket No. 060155-EM). Certain details of the unit are confidential as indicated by "N/A." However, the unit will be located at Stanton Energy Center and is assumed to have a commercial operation date of June 1, 2010.