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March 29, 2002

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

Michael,

Enclosed please find twenty (20) copies of the 2002 Kissimmee Utility Authority (KUA) Ten-Year Site Plan (TYSP). Per your request, the 2002 KUA TYSP has also been distributed directly to the following individuals:

Paul Darst
Department of Community Affairs

Buck Oven
Department of Environmental Protection

Doug Bailey
Fish and Wildlife Conservation Commission

Dr. David Block
Florida Solar Energy Center

Jim Golden
South Florida Water Management District

Brian Sodt
Central Florida Regional Planning Council

Anthony (Tony) Cotter
Orange County Government Florida

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

Very truly yours,

Myron Rollins

Myron Rollins

Enclosure[s]

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OTH

2002 10-Year Site Plan

KUA
KISSIMMEE
UTILITY
AUTHORITY

April 2002

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1.0 Executive Summary

This report documents the 2001 Kissimmee Utility Authority (KUA) Ten-Year Site Plan (TYSP) pursuant to Florida Administrative Codes (FAC) 25-22.070 through 25-22.072. The TYSP provides the information required by this rule. The TYSP is divided into five main sections: Description of Existing Facilities, Forecast of Electric Power Demand and Energy Consumption, Conservation and Demand-Side Management, Forecast of Facilities Requirements and Appendix. Schedules required by the FPSC have been included in Appendix A following Section 5.0.

1.1 Description of Existing Facilities

Section 2.0 of the TYSP details KUA's existing generating and transmission facilities. The section includes a historical overview of KUA's electric system, description and table of existing power generating facilities, existing power purchase information, and maps showing service area and transmission lines. KUA's existing generating facilities and purchases provide KUA approximately 308 MW (net) during winter and 365 MW (net) during summer.

1.2 Forecast of Demand and Energy Consumption

Section 3.0 of the TYSP presents the load forecast summary for KUA's system. KUA is projected to remain a summer peaking system. A 4.18 percent annual summer peak demand growth rate is projected for 2003 through 2012. This growth rate is slightly lower than KUA's historical annual growth rate of 4.85 percent during the last 10 years.

Net energy for load is projected to grow at an average annual rate of 4.18 percent over the next 10 years compared to 4.79 percent over the last 10 years. In addition to the base case load forecast, projections were developed for high and low load growth scenarios based on high and low population estimates published by the Bureau of Economic and Business Research (BEBR).

1.3 Demand-Side Programs

Section 4.0 provides descriptions of KUA's existing conservation and demand-side management (DSM) programs and additional programs that have been evaluated. With the exception of direct load control, none of the evaluated alternatives were determined to be cost-effective.

1.4 Forecast of Facilities Requirements

Section 5.0 integrates the electrical demand and energy forecast with the conservation and DSM forecast to determine the facilities requirements for a 20-year planning horizon (2002-2011).

Fuel price projections are provided with a description of the applied forecast methodology. Fuel price forecasts are provided for coal, natural gas, No. 2 oil, No. 6 oil, and nuclear.

PROSYM production costing software was used to develop annual fuel usage and total system production cost forecasts. The forecast of fuel usage is presented in the Appendix A and schedules.

2.0 Description of Existing Facilities

2.1 Historical Background

The first recorded mention of electric lights--in what was then called Kissimmee City--was made during a City Council meeting on December 17, 1891. An Electric Light Committee was formed and notified the Council that a plan had been prepared showing the location of proposed lights for the town. However, to implement the plan, requests for 300 lights would be required to secure the first electric light plant in the area.

During the ensuing years, electric light discussions persisted. On April 9, 1892, a proposal was made that a bond issue for $23,000 be implemented to provide for a public works department and electric lights. On April 18, 1893, a ballot was taken and this bonding request was approved by a vote of 41 to 5.

On December 4, 1900, Kissimmee City entered into a contract with W. C. Maynard, a citizen of the town, doing business as Kissimmee Light Co. The contract with Mr. Maynard gave him the exclusive right and franchise to erect and maintain an electric light plant in Kissimmee City for a period of 20 years.

Initially, Kissimmee Light Co. agreed to supply consumers with electricity at a cost of 3 cents per night for each sixteen candle power incandescent light and $7.50 per month for arc lights of standard power.

During a Council meeting on June 28, 1901, a resolution was passed and Kissimmee City purchased Kissimmee Light Co. from Maynard for $4,293.59. A Committee was then appointed by the City Council to manage the company.

2.1.1 History In The Making

The decades that span the 1900s to the 1980s were spent laying the operational groundwork and infrastructure that KUA heavily relies on today. The utility's initial purchase was a 15 kilowatt generator in 1901. In the twenties, three diesel engines were added to the system, providing electricity to approximately 200 customers. The thirties marked the pioneer connection between St. Cloud and Kissimmee, while during the forties and fifties, the utility worked diligently to increase the distribution capacity. The seventies were monumental in KUA's importance when Kissimmee and St. Cloud inter-tied with the rest of the continental United States through Florida Power Corporation at Lake Cecile.

From 1972 to 1982, the utility experienced multiple management changes, including five Utility Directors. In 1982, James C. Welsh, current President and General Manager, replaced Don Hornak as Utility Director. As KUA settled in with a new Director, many accomplishments were realized: KUA became an owner in the St. Lucie Nuclear Power Plant from Florida Power & Light; a 50 MW combined cycle unit was installed, marking KUA's first entry into gas turbine technology and a re-entry into the steam electric generation business after many years of sole dependence on diesel type units.

2.1.2 A New Beginning

The year 1983 marked the turning point in the making of what KUA is today. During 1983, the City Commission established an Ad-Hoc Committee to explore the concept of making the electric utility department of the City into a separate authority. The Committee also investigated the best way to manage the utility. The conclusion was that the authority would best be run by an independent board consisting of individuals with strong business backgrounds.

In 1984, the Ad-Hoc Committee presented its recommendation of making the electric utility department of the City into a separate authority. Subsequently, the City Commission reappointed the Ad-Hoc Committee members to a Charter Committee. This latter committee had the difficult task of developing a charter for the utility. In 1985, the City Commission approved the charter, subject to a vote of the people of the City of Kissimmee. A month later, voters accepted the Kissimmee Utility Authority Charter by a 2 to 1 margin.

2.1.3 KUA Today

Today, KUA is a municipal electric utility under the direction of a six member board of directors. In addition, KUA acts as a billing and customer service agent for the Water and Sewer and Refuse Departments of the City of Kissimmee. Its service area covers the City of Kissimmee and some unincorporated areas, totaling approximately 85 square miles.

The primary goal of KUA is to provide reliable electric service to its customers at the lowest possible cost in the best environmentally acceptable method. In order to accomplish this, KUA has diversified its power supply resources, which are based on KUA's own generation, offsite generation through joint participation projects, and through long- and short-term purchase power contracts.

2.2 Kissimmee Utility Authority

2.2.1 General

The Kissimmee Utility Authority (KUA) is a body politic organized and legally existing as part of the government of the City of Kissimmee. On October 1, 1985, the City of Kissimmee transferred ownership and operational control of the electric generation, transmission, and distribution system to KUA. KUA has all the powers and duties of the City of Kissimmee to construct, acquire, expand, and operate the system in an orderly and economic manner.

2.2.2 Load and Electrical Characteristics

KUA's load and electrical characteristics have many similarities to other Peninsular Florida utilities. Except during years with extreme winter weather conditions, KUA's system peak demand occurs during the summer months. KUA's system peak demand during 2001 was 252 MW.

KUA's historical and projected peak demands for the period 1991 through 2020 are presented in Table 2-1. Further details of KUA's load and electrical characteristics are contained in Section 3.0, Forecast of Electrical Power Demand and Energy Consumption.

KUA is a member of the Florida Municipal Power Pool (FMPP), along with Orlando Utilities Commission (OUC), the Florida Municipal Power Agency (FMPA), All Requirements Project, and the City of Lakeland. FMPP operates as an hourly energy pool. Commitment and dispatch services for FMPP are provided by OUC. Each member of the FMPP retains the responsibility of adequately planning its own system to meet native load and Florida Reliability Coordinating Council (FRCC) reserve requirements.

2.2.3 Generation Resources

KUA owns and operates or has ownership interest in generating units comprising several technologies, including nuclear, coal fired, diesel, simple cycle, and combined cycle. Table 2-2 provides a summary of KUA's existing generating resources. The following paragraphs describe KUA's generating assets and ownership interests in detail.

KUA owns and operates eight diesel generating units ranging in age from 17 to 41 years. Each of these diesel units is located at the Roy B. Hansel Generating Station in Kissimmee. Six of these diesel units are fueled by natural gas, while the remaining two burn No. 2 oil. The total nameplate capacity of the eight diesels is 18.35 MW. In addition, KUA owns and operates a natural gas fired (with No. 2 oil as backup) combined cycle plant, which is also located at the Hansel site. Hansel CC comprises a 35 MW (nameplate) combustion turbine and two 10 MW (nameplate) steam turbine generators powered by the CT's waste heat. The total nameplate generating capability at the Hansel site is approximately 73.35 MW.

KUA and FMPA are both 50 percent joint owners of Cane Island Units 1 and 2. Unit 1 is a simple cycle General Electric LM6000 aero-derivative combustion turbine with a nameplate rating of 42 MW. Unit 2 is a one-on-one General Electric Frame 7EA combined cycle with a nameplate rating of 120 MW. Cane Island Unit 3, a 1x1 General Electric 7F combined cycle, went into commercial operation on January 25, 2002, providing 243.7 MW in summer and 267 MW in winter. Cane Island Unit 3 is jointly

Table 2-1
Summary of Load Forecast

Year	Winter Peak Demand (MW)			Summer Peak Demand (MW)		
	Base	High	Low	Base	High	Low
Historical						
1990	200	--	--	151	--	--
1991	147	--	--	157	--	--
1992	158	--	--	169	--	--
1993	158	--	--	183	--	--
1994	173	--	--	180	--	--
1995	196	--	--	195	--	--
1996	218	--	--	206	--	--
1997	198	--	--	216	--	--
1998	180	--	--	233	--	--
1999	219	--	--	236	--	--
2000	221	--	--	250	--	--
2001	246	--	--	252	--	--
Forecast						
2002	262	266	258	272	277	269
2003	277	286	270	288	297	281
2004	291	304	279	303	316	290
2005	306	324	288	318	336	300
2006	320	342	295	333	356	307
2007	333	363	299	347	377	311
2008	346	385	303	360	400	315
2009	359	408	306	373	424	318
2010	372	433	309	387	450	322
2011	387	458	310	402	476	323
2012	401	483	310	417	502	322
2013	416	509	308	432	530	321
2014	431	537	307	448	558	320
2015	446	566	306	464	589	319
2016	461	596	304	479	620	316
2017	476	626	300	495	651	312
2018	492	658	296	512	685	308
2019	509	692	293	529	720	305
2020	526	728	289	547	757	301

Table 2-2
Kissimmee Utility Authority Existing Generating Facilities

Plant	Unit No.	Location	Type	Fuel Primary	Fuel Alternate	Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability Summer (MW)	Net Capability Winter (MW)	Fuel Transportation Primary	Fuel Transportation Alternate
Hansel	8	Osceola County 27,T255/R29E	IC	NG	FO2	02/59	Unknown	3.00	2.0	2.0	PL	TK
	14		IC	NG	FO2	02/72	Unknown	2.07	1.8	1.8	PL	TK
	15		IC	NG	FO2	02/72	Unknown	2.07	1.8	1.8	PL	TK
	16		IC	NG	FO2	02/72	Unknown	2.07	1.8	1.8	PL	TK
	17		IC	NG	FO2	02/72	Unknown	2.07	1.8	1.8	PL	TK
	18		IC	NG	FO2	02/72	Unknown	2.07	1.8	1.8	PL	TK
	19		IC	FO2	--	02/83	Unknown	2.50	2.5	2.5	TK	--
	20		IC	FO2	--	02/83	Unknown	2.50	2.5	2.5	TK	--
	21		CT	NG	FO2	02/83	Unknown	35.00	25.0	25.0	PL	TK
	22		ST	WH	--	02/83	Unknown	10.00	10.0	10.0	--	--
	23		ST	WH	--	02/83	Unknown	10.00	10.0	10.0	--	--
Plant Total								73.35	61.0	61.0		
Crystal River	3	Citrus County 33,T17S/R16E	N	UR	--	03/77	Unknown	890.46	5.6(1)	5.6(1)	TK	--
Plant Total								890.46	5.6	5.6		
Stanton Energy Center	1	Orange County 13,14,23,24/ R31E/T23S and 18,19/ T23S/R32E	ST	BIT	--	07/87	Unknown	464.58	21.0(2)	21.0(2)	RR	--
Plant Total								464.58	21.0	21.0		

Table 2-2 (Continued)
Kissimmee Utility Authority Existing Generating Facilities

Plant	Unit No.	Location	Type	Fuel		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability		Fuel Transportation	
				Primary	Alternate				Summer (MW)	Winter (MW)	Primary	Alternate
Indian River	A	Brevard County 12/T23S/R35E	CT	NG	FO2	07/89	Unknown	41.40	4.00[3]	4.0[3]	PL	TK
	B		CT	NG	FO2	07/89	Unknown	41.40	4.00[3]	4.0[3]	PL	TK
Plant Total								82.80	8.0	8.0		
Cane Island	1	Osceola County 29,32/R28E/ T25S	CT	NG	FO2	11/94	Unknown	42.00	15.2[4]	20.3[4]	PL	TK
	2		CT	NG	FO2	06/95	Unknown	80.00	34.4[4]	40.2[4]	PL	TK
	2		ST	WH	--	06/95	Unknown	40.00	20.0[4]	20.0[4]	--	--
Plant Total								162.00	69.6	80.5		
System Total as of January 1, 2001									165.2	176.1		

Notes:

(1) KUA's 0.6754 percent portion of joint ownership.

(2) KUA's 4.8193 percent ownership portion.

(3) KUA's 12.2 percent portion of joint ownership.

(4) KUA's 50 percent ownership portion.

owned by KUA and FMPA with KUA receiving half of the net plant output.

KUA owns a 0.6754 percent interest, or 6 MW (nameplate), in the Florida Power Corporation's (FPC) Crystal River Nuclear Unit 3, located in Citrus County, Florida. KUA also has a 4.8193 percent ownership interest, or 22,300 kW (nameplate), in the Orlando Utilities Commission's (OUC) Stanton Energy Center Unit 1 and a 12.2 percent, or 10 MW (nameplate), interested in OUC's Indian River Combustion Turbine Project Units A and B.

KUA, FMPA, OUC, and Southern-Florida are joint owners in Stanton A, a 2x1 General Electric 7FA combined cycle under construction at OUC's Stanton Energy Center. KUA owns a 3.5 percent interest and will also purchase a portion of Southern-Florida's ownership interest as purchase power as described in Section 2.2.4. Stanton A is scheduled for October 1, 2003 commercial operation.

2.2.4 Purchase Power Resources

KUA is a member of the Florida Municipal Power Agency (FMPA), a legal entity organized in 1978 and existing under the laws of Florida. During 1983, FMPA acquired an 8.8060 percent (73.9 MW) undivided ownership interest in St. Lucie Unit 2 on behalf of KUA and 15 other members of the FMPA. KUA's entitlement share of this unit, based on a power purchase contract and adjusted for transmission losses, is 6.9 MW. FMPA has also entered into a Reliability Exchange Agreement with FPL, under which half of KUA's entitlement share of capacity and energy will be supplied from St. Lucie Unit 1 and half from Unit 2.

In addition to the above resources, KUA purchases electric power and energy from other utilities. KUA has a contract to purchase 20 MW of firm capacity from OUC through December 2003. This contract also provides for supplemental purchases up to an additional 50 MW if the capacity is available from OUC. KUA has a 1.80725 percent (7.9 MW) entitlement share of Stanton 1 through the FMPA Stanton 1 Project and a 7.6628 percent (33.3 MW) share of Stanton 2 through the FMPA Stanton 2 Project. The Stanton 2 percentage includes recently acquired Homestead and Lake Worth shares totaling 3.8314 percent.

KUA has entered into a purchase power agreement with Southern-Florida to purchase 10 percent of Southern-Florida's 65 percent ownership share of Stanton A for a term of ten years with four additional five-year extensions. The purchase will commence with the commercial operation of Stanton A scheduled for October 1, 2003. During the first three years of the purchase power agreement, KUA will resell excess capacity available from the Southern-Florida power purchase agreement. KUA's purchase power resources are summarized in Table 2-3.

2.2.5 Transmission and Interconnections

KUA has direct transmission interconnections with: (i) FPC, delivered at 69 kV from the FPC Lake Bryan substation and at 230 kV at OUC's Taft substation; (ii) OUC (two lines and an auto-transformer), delivered at 230 kV at OUC's Taft substation; (iii) the City of St. Cloud, Florida, at KUA's 69 kV interconnection with St. Cloud's transmission facilities; and (iv) TECO, one 230 kV circuit through the interconnection with the Osceola and Lake Jewell circuits.

Electric power and energy supplied from KUA-owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines to eight distribution substations. KUA provides electric service to retail customers primarily by 13.2 kV feeder circuits from the distribution substations.

2.2.6 Service Area

KUA serves a total area of approximately 85 square miles, including the city's 10 square mile area near the center. As of December 2001, KUA served approximately 50,375 electric customers. Of these, 40,394 were residential, 8,194 were general service non-demand, and the remaining 744 were general service demand. KUA's electric service area, shown on Figure 2-1, is entirely located in Osceola County.

Table 2-3
Purchase Power Resources (1)

Calendar Year	Utility/Unit (MW)						Total MW
	St. Lucie 1 and 2	Stanton 1(2)	Stanton 2(3)	OUC D(4)	Southern PPA(5)	Future Purchase(6)	
2001	6.9	7.9	33.3	20.0	0.0	0.0	68.1
2002	6.9	7.9	33.3	20.0	0.0	0.0	68.1
2003	6.9	7.9	33.3	20.0	0.0	0.0	68.1
2004	6.9	7.9	33.3	0.0	14.2	0.0	50.4
2005	6.9	7.9	33.3	0.0	24.2	0.0	66.4
2006	6.9	7.9	33.3	0.0	34.2	0.0	81.4
2007	6.9	7.9	33.3	0.0	41.3	0.0	89.4
2008	6.9	7.9	33.3	0.0	41.3	0.0	96.4
2009	6.9	7.9	33.3	0.0	41.3	13.0	109.4
2010	6.9	7.9	33.3	0.0	41.3	28.0	121.4
2011	6.9	7.9	33.3	0.0	41.3	46.0	134.4
2012	6.9	7.9	33.3	0.0	41.3	63.0	147.4
2013	6.9	7.9	33.3	0.0	41.3	81.0	160.4
2014	6.9	7.9	33.3	0.0	41.3	99.0	174.4
2015	6.9	7.9	33.3	0.0	41.3	117.0	188.4
2016	6.9	7.9	33.3	0.0	41.3	135.0	202.4
2017	6.9	7.9	33.3	0.0	41.3	153.0	215.4
2018	6.9	7.9	33.3	0.0	41.3	172.0	229.4
2019	6.9	7.9	33.3	0.0	41.3	192.0	244.4
2020	6.9	7.9	33.3	0.0	41.3	212.0	258.4

Notes:

(1) No reserves are supplied by the selling utility. KUA provides for 15 percent reserves.
(2) KUA share of Stanton 1 through FMPA Stanton 1 Project is 1.80725 percent.
(3) KUA share of Stanton 2 through FMPA Stanton 2 Project is 7.6628 percent. Total percentage represents KUA's original purchase percentage plus the sum of recently acquired Homestead and Lake Worth purchase percentages, equal to 3.8314 percent.
(4) 20 MW Schedule D ending in December 2003.
(5) Stanton A Purchase beginning in 2004.
(6) Unspecified purchases to maintain 15 percent reserve requirement.

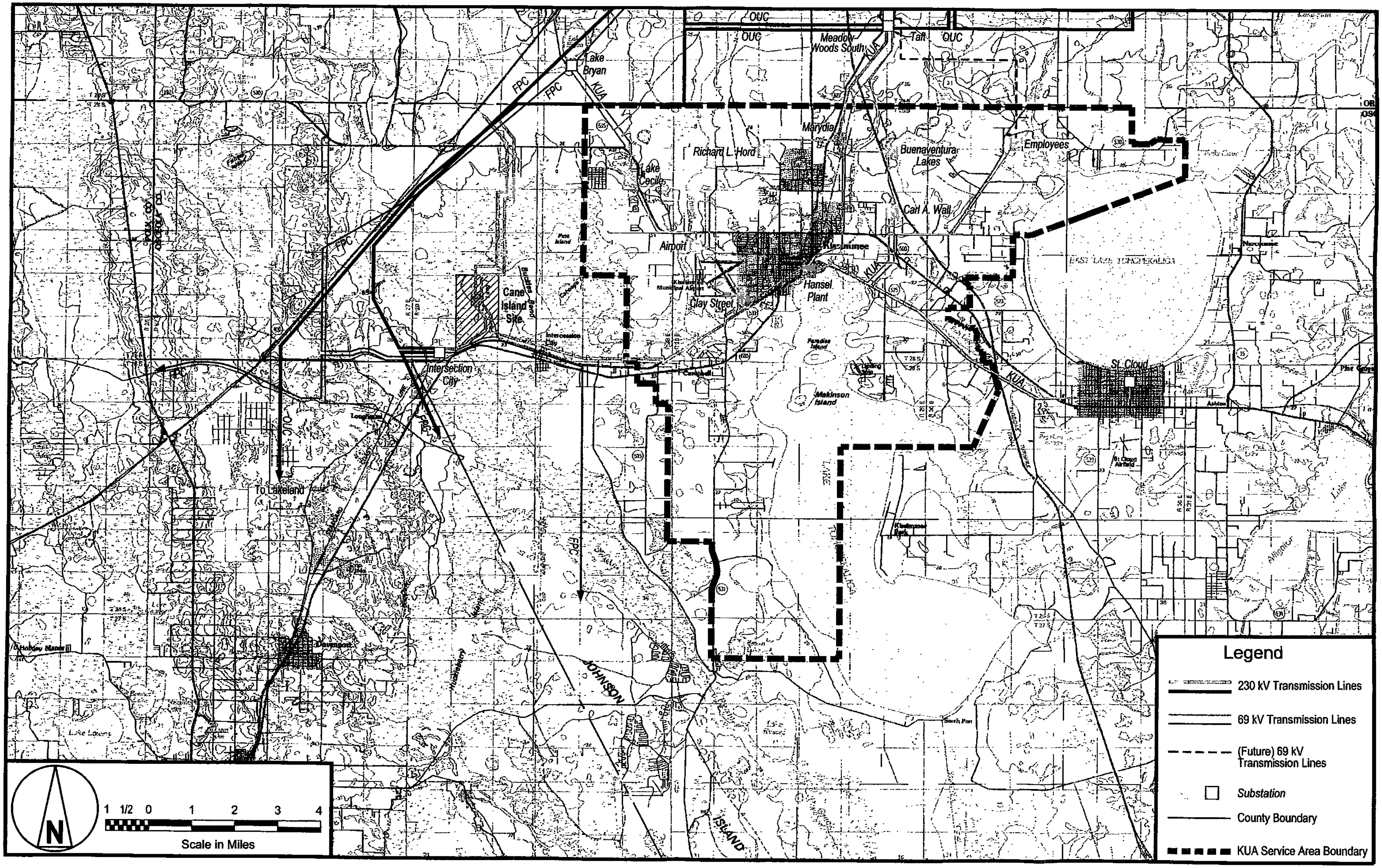

Figure 2-1
Service Area Map

3.0 Forecast of Demand and Energy Consumption

Annually, KUA prepares a detailed long-term electric load and energy forecast using econometric techniques. This detailed forecast is developed on a fiscal year basis (October through September) and serves as a primary driver in annual planning activities. The information presented has been summarized in calendar year format in accordance with FRCC guidelines. KUA's fiscal year forecast has been converted to a calendar year basis, except where specifically noted, and is aggregated as required by FRCC.

The following sections describe KUA's general forecasting approach. Each of the forecasting models is explained, and the summary results of the forecasts are presented.

3.1 Forecast Modeling Approach

Econometric forecast models have been used to project monthly sales by customer class. The econometric models and associated statistical relationships were developed to forecast annual changes in electricity consumption by rate classification as a function of demographic, weather, and economic factors such as income, temperature, and real price of electricity. The models were developed using statistical relationships between historical, economic, weather, and electric system data.

The statistical estimating technique used in the development of the models was ordinary least squares multiple regression. This method is used to determine the linear relationship between a dependent variable, such as energy usage, and multiple independent econometric variables based on changes in the values of the variables through time. Implicit in the model development is the assumption that customer class energy usage will be affected by the same key factors in the future as in the past. The following equation represents this linear relationship:

$$Y = a + \sum_{i1}^{n} [b_i * X_i] + e$$

where,

Y = dependent variable (predicted)

a = constant term

b_i = coefficient terms

X_i = independent variables

e = error term

The calculated equation minimizes the sum of the squared errors between the actual and predicted values of the dependent variable.

An important consideration in regression analysis is the selection of variables. Independent variables explain changes in the dependent variable. Therefore, sufficient historical data for both dependent and independent variables must be available to produce a reliable regression equation. Also, to forecast values of the dependent variable, the independent variables must have the potential to be projected into the future.

All regression equations were tested using five primary statistical measures. The first measure is the adjusted R^2, the coefficient of determination corrected for reduced degrees of freedom due to inclusion of additional independent variables in the regression equation. The coefficient of determination (perfect = 1.0) is the proportion of variability in the dependent variable that is explained by the independent variables. The second measure is the F statistic, which is a test of whether there is a significant linear relationship between the dependent variable and the entire set of independent variables. The F-test is performed by determining the calculated F statistic (F_{CALC}) and comparing this value with the corresponding value of the F distribution (F_{DIST}). The third measure is the T statistic, which is a test for multi-collinearity of the independent variables. This test is performed by determining the calculated T statistic (T_{CALC}) and comparing this value with the corresponding value of the T distribution (T_{DIST}). The fourth measure is the Durbin-Watson (DW) statistic, which is a test for serial correlation of adjacent error terms. The fifth, and final, measure is the Bayesian Information Criterion (BIC). The BIC serves as a guide to the selection of the number of terms in an equation by placing a penalty on additional coefficients.

3.2 Econometric Data and Projections

This section describes the data sources used in the development of the econometric variable projections for the forecast period. As in previous forecasts, economic and population forecasts from the Bureau of Economic and Business Research (BEBR) were included in the analysis as econometric variables.

3.2.1 Historical Data

A careful compilation of historical data was developed to formulate a reliable econometric model for forecasting electricity sales. Monthly historical sales data were compiled for each major customer classification for the period of January 1985 through September 2000. Additional data including temperature, population, employment, households, real personal income, and total housing starts was also compiled. The econometric data used was obtained from BEBR data applicable to the MSA in which Kissimmee is located.

MSAs are Metropolitan Statistical Areas defined by the Census Bureau for various regions within each state. Kissimmee is located within the Orlando MSA. The Orlando MSA also includes Lake, Orange, Osceola, and Seminole Counties. Although some variance in general MSA versus Kissimmee data can be expected, the homogeneous nature of the surrounding region provided well-aligned trend relationships between historical electricity use and the econometric variables selected for the forecast.

3.2.2 Econometric Projections

The Florida Economic Forecast was completed before the terrorist attack of September 11. Because the outlook of the forecast was long term in nature, it was not altered to reflect the possible short-term economic impacts that resulted. Additionally, the forecast this year reflects for the first time, results of the 2000 Census. The 2000 Census revealed a larger population than many demographers had projected. Florida's July 1, 2000 population is currently estimated at 16.087 million, about 744 thousand above that used in last year's long-term forecast. As a consequence, previous year's estimates of population have been revised and have resolved some questions raised regarding employment, labor force, and housing starts data. By 2010 Florida's population is estimated to grow to 91.0 Million, exceeding the 17.5 Million forecast last year.

Although Osceola County economic and population forecasts show slower growth, Osceola County's annual growth rate continues to exceed the surrounding counties. In contrast, the forecast growth rate of real per capita income, a measure of the average Floridian standard of living, accelerates from the previous 15 years.

3.3 Forecasting Assumptions

The first key assumption included in the load forecast analysis is related to regional weather patterns. Because predicting future weather patterns is not possible, normal weather conditions were assumed for the load forecast model. Monthly average temperatures for the last 10 years were used as a representation of normal weather. For weather projections, the weather for every month of the forecast period was set equal to that month's 10 year average of monthly temperatures for the historical period. The same methodology was applied uniformly to all other weather-related variables used in the analysis.

3.4 Sales Forecast

3.4.1 Residential Sales

To forecast residential electricity sales, annual forecasts of residential electricity use per customer, and number of customers were developed using ordinary least squares multiple regression models. The product of residential service customers and electricity use per customer forecasts yields total annual residential electricity sales.

3.4.1.1 Residential Customers. In the development of the 2002 econometric model for residential customers, Osceola County population (POPA), Average Household Size (AHS), Employment (EWS), Employment (E), Households (HH), and Cumulative Housing Starts (CTS) estimates were used as potential explanatory variables. Based on KUA's statistical evaluation, POPA and CTS were both statistically significant in representing monthly fluctuations in residential customers. Autoregressive (_AUTO[*]) terms were introduced to minimize the effects of serial correlation. In effect, the

_AUTO[*] variable incorporates the residual from previous observations into the regression model for the current observation. The resulting equation and statistics are shown in Table 3-1.

3.4.1.2 Residential Energy Use Per Customer. The 2002 econometric model for residential electricity use per customer evaluated the real price of electricity (PRICERES), Income Per Household (INCPERHH), Real Taxable Sales (RTS100), Real Income Per Capita (RYPC), Real Personal Income (RYTOT), and Billing Month Adjusted Heating and Cooling Degree Days (BM_HDD, BM_CDD) as potential explanatory variables. Based on KUA's statistical evaluation, PRICERES, INCPERHH, BM_CDD, and BM_HDD were statistically significant in representing monthly fluctuations in residential energy use per customer. An autoregressive (_AUTO[*]) term was introduced to minimize the effects of serial correlation. The resulting equation and statistics are shown in Table 3-1.

3.4.1.3 Weather Impacts. Temperature and billing data were adjusted to compensate for different reporting periods. The degree days were shifted from calendar month to billing month to more accurately reflect the relationship between temperature and energy consumption. An example of this shifting is described as follows:

> *A customer has his electric meter read on billing cycle 2. In February, billing cycle 2 corresponds with a meter reading date of February 2nd. Sales to this customer are billed in February, but primarily occur in January. If the remainder of February is bitterly cold, the corresponding degree days are not reflected in the customer's February bill. As a result, error is introduced.*
>
> *By aligning the sales and degree days, the model is more responsive to changes in temperature.*

Table 3-1
Sales Forecast Equations and Statistics

RSCUSTT = 0.224*RSCUTT[-12] +166.47*POPA + 0.4*_AUTO[-1] + 0.41*_AUTO[-2] + 0.18* _AUTO[-3] (3.15) (4.75) (5.47) (5.6) (2.47) RSCUSTT: Total Residential Customers POPA: Total Population in Osceola County _AUTO[-1]: First Order Autoregressive Term _AUTO[-2]: Second Order Autoregressive Term _AUTO[-3]: Third Order Autoregressive Term	Key Statistics: Adjusted R^2: 0.9984 Ljung-Box(p): 0.9789 Bayesian Information Criterion: 261.3
RSUPC = - 3.92*PRICERES – 4.67*PRICERES[-12] + 22.55*INCPERHH + 1.259*BM_CDD + 1.787*BM_HDD + 0.555*BM_CDD[-1] + 0.515*BM_HDD[-1] –0.115*RSUP[-2]+ 0.562*_AUTO[-12] (-4.64) (-5.53) (14.03) (14.62) (17.18) (5.75) (5.0) (-2.98) (9.28) RSUPC: Residential Use Per Customer PRICERES: Residential Real Price of Electricity INCPERHH: Real Personal Income Per Household BM_CDD: Billing Month Adjusted Cooling Degree Days BM_HDD: Billing Month Adjusted Heating Degree Days _AUTO[-12]: Autoregressive Term	Key Statistics: Adjusted R^2: 0.9462 Ljung-Box(P): 0.9174 Bayesian Information Criterion: 59.04
GSNCUSTT = 46.939*POPA + 0.767*_AUTO[-1] + 0.222*_AUTO[-2] (13.137) (11.012) (3.197) GSNCUSTT: Total General Service Non-Demand Customers POPA: Total Population in Osceola County _AUTO[-1]: First Order Autoregressive Term _AUTO[-2]: Second Order Autoregressive Term	Key Statistics: Adjusted R^2: 0.9977 Ljung-Box(P): 0.7654 Bayesian Information Criterion: 108.6

Table 3-1 (Continued)
Sales Forecast Equations and Statistics

GSNKWHT = - 56418.78*PRICEGSN-57464.465*PRICEGSN[-12]+ 301717.950*INCPERHH + (-5.27) (-6.06) (13.113) 5810.137BM)HDD+1023.088*BMC_TIME + 2414654.736*RATECHANGE + 0.416*_AUTO[- (4.88) (17.67) (7.858) (6.23) 1]+0.199*_AUTO[-12] (3.59) GSNKWHT: Total General Service Non-Demand Energy Sales PRICEGSN: General Service Non-Demand Real Price of Electricity INCOERHH: Osceola County Real Income per Household BM_HDD: Billing Month Heating Degree Days BMC_TIME: Increasing Saturation of Cooling-Related Load RATECHANGE: Change in Rate Classification in October 1990 _AUTO[-1]: First Order Autoregressive Term _AUTO[-12] Auto-Regressive Term	Key Statistics: Adjusted R^2: 0.9753 Ljung-Box(P): 0.9455 Bayesian Information Criterion: 7.2e+005
OLSKWHT = 15052.783*CTS-0.427*OLSKWHT[-12] + 0.975*_AUTO[-1] (7.789) (-6.338) (60.584) OLSKWHT: Outdoor Lighting Sales CTS: Cumulative Osceola Housing Starts _AUTO[-1] : First Order Auto regressive Term	Key Statistics: Adjusted R^2: 0.9814 Ljung-Box(P): 0.3564 Bayesian Information Criterion: 3.255e+004

3.4.2 General Service Non-Demand Forecast

The model for the general service non-demand rate classification comprises forecasts for customers and energy sales and includes temporary service and KUA rate classifications.

3.4.2.1 General Service Non-Demand Customers. In the development of the 2002 econometric model for general service non-demand customers, Osceola County Population (POPA), Average Household Size (AHS), Employment EWS), Employment (E), Households (HH), and Cumulative Housing Starts (CTS) estimates were used as potential explanatory variables. Based on KUA's statistical evaluation, only POPA was statistically significant in representing monthly fluctuations in general service non-demand customers. Autoregressive (_AUTO[*]) terms were introduced to minimize the effects of serial correlation. The resulting equation and statistics are shown in Table 3-1.

3.4.2.2 General Service Non-Demand Electricity Sales. The 2002 econometric model for general service non-demand energy sales evaluated the real price of electricity (PRICEGSN), Income Per Household (INCPERHH), Real Taxable Sales (RTS100), Real Income Per Capita (RYPC), Real Personal Income (RYTOT), and Billing Month Adjusted Heating and Cooling Degree Days (BM_HDD, BM_CDD) as potential explanatory variables. In addition, a variable to reflect the impact of a rate reclassification in October 1990 on sales (RATECHANGE) was considered.

Based on KUA's statistical evaluation, PRICEGSN, INCPERHH, BM_CDD, BM_HDD, and RATECHANGE were statistically significant in representing monthly fluctuations in general service non-demand energy sales. An autoregressive (_AUTO[*]) term was also introduced to minimize the effects of serial correlation. The resulting equation and statistics are shown in Table 3-1.

3.4.3 General Service Demand Forecast

Modeling the general service demand rate classification continues to be the Achilles' heel of the energy forecast. For the purposes of this load forecast, general service demand comprises GSD, GSDT, GSLD, Interruptible, and Contract Rate classifications. General service demand represents approximately 30 percent of total energy sales with 793 customers (September 2001). Because general service demand represents such a large percentage of total energy consumption, assumptions and models used to forecast have a significant impact on the overall energy forecast.

The number of customers in the general service demand rate classification (GSD) has remained unpredictable over the course of the last several years. The initial and most abrupt change occurred as a result of a shift in rate classification (October 1990) that encouraged the migration of smaller GSD customers to the non-demand classification (GSND). Since September 1992, the net change in customers is zero.

During the interim, the number of customers has been as low as 713 (March 1995) and as high as 829 (August, 2001). Econometric, exponential smoothing, and Box-Jenkins methods have been used to analyze the GS Demand customers. At this point in time, the best estimate for the future is the current level of customers, 825.

The forecast of no growth is reasonable given the unexplained variation in general service demand customers. The fluctuations in customers have been as great as 9 percent in 3 months. This size of drop in general service demand is certainly suspicious. Without understanding the reasons behind data volatility, it continues to be a challenge to forecast. Meetings with key personnel have brought no additional insight to this situation and, until it is better understood, forecasting no customer growth for general service demand customers is recommended.

Using OLS, a model was prepared for general service demand energy sales. The final model fit the historical data well, but when used to forecast, it produced unreasonable results. Because a model for general service demand customers had already been determined, the OLS model for general service demand energy sales was theoretically indicating that the use per customer would double over the forecast horizon. This conclusion is unreasonable.

Planners from the City of Kissimmee were subsequently consulted regarding future large customer expansions. Over the next 5 years, City plans include the addition of approximately 56 GWh of energy requirements. These energy requirements have been added in the general service demand forecast as spot loads.

In addition to the information provided by City Planners and KUA Staff, a review of the energy sales growth rates in general service demand shows the smallest increase in energy sales to be approximately 1 percent.

3.4.4 Outdoor Lighting Forecast

Street lighting, vapor lighting, and outdoor lighting were combined into one class for forecasting purposes. This year, outdoor lighting was forecast using exponential smoothing. When viewing the historical data after October 1992, outdoor lighting sales appear to be trended and unseasonable, the characteristics of a Holt model for exponential smoothing. The resulting equation and statistics are shown in Table 3-1.

3.5 Net Energy for Load and Peak Demand Forecast

KUA developed three load and energy growth scenarios consisting of a base case, a high case, and a low case. A description of the assumptions utilized in developing the base, high, and low cases considered by KUA is presented in Table 3-2.

3.5.1 Net Energy For Load

During the past several years, net energy for load (NEL) was projected by applying an efficiency factor of 95 percent to the projection of total sales. During 1997, an attempt was made to develop an econometric model for NEL using the relationship of NEL to total sales and certain monthly variables. After further review, it was decided that the econometric model did not provide significant accuracy to the projection of NEL and KUA returned to the 95 percent efficiency factor methodology. Tables 3-3, 3-4, and 3-5 present KUA's Base, High, and Low Case NEL forecasts. Net energy for load is projected to grow at an average annual rate of 4.8 percent from 2003 through 2012 compared to 4.79 percent from 1991 through 2001.

3.5.2 Peak Demand Forecast

The forecast of peak load was prepared using average winter and summer load factors of 52 percent and 50 percent, respectively. Our attempts to use econometrics to model peak load in the past have been unsuccessful due to a lack of data.

It is important to note that the latter methodology for estimating winter and summer peak demands only provides the seasonal peaks. For some of KUA's planning and financial models, monthly peaks are required. In order to accommodate this need, monthly peaks were estimated by shaping the seasonal peak estimates with a reference monthly load pattern. Because the load and energy forecast is a normal weather forecast and 1993 represents the closest to a normal weather year, the 1993 monthly peak load pattern was selected.

Table 3-2
Sensitivity Case Summary

Description	Base Case	High Case	Low Case
Residential Customers	Base Case Cumulative Total Housing Starts and Population Figures	High Case Cumulative Total Housing Starts and Population Figures	Low Case Cumulative Total Housing Starts and Population Figures
Residential Energy Sales	Base Case Income Per Household	High Case Income Per Household	Low Case Income Per Household
GS Non-Demand Customers	Base Case Population	High Case Population	Low Case Population
GS Non-Demand Energy Sales	Base Case Income Per Household	High Case Income Per Household	Low Case Income Per Household
GS Demand Customers	Hold Flat at 742	Hold Flat at 742	Hold Flat at 742
GS Demand Energy Sales	No Growth Until 2006, Then Grow at 1 Percent	No Growth Until 2006, Then Grow at 2 Percent	No Growth in Energy Sales
Spot Loads	Brought On Line Evenly Over 5 Years	Brought On Line Evenly Over 5 Years	Brought On Line Evenly Over 5 Years
Outdoor Lighting	Base Case Model	Upper Limit	Lower Limit

Table 3-3
2002 Base Case Load Forecast
Annual Summary of Historical and Projected Data

	Residential Service		GS Non-Demand		GS Demand						Total		
Calendar Year	Average Accounts	Sales (MWh)	Average Accounts	Sales (MWh)	Average Accounts	Base GSD Sales (MWh)	WEC Sales (MWh)	Spot Load Sales (MWh)	Total GSD Sales (MWh)	Outdoor Lighting Sales (MWh)	Average Accounts	Sales (MWh)	Net Energy for Load (MWh)
1986	19,857	215,331	2,279	30,337	609	182,789	0	0	182,789	838	22,745	429,295	455,520
1987	21,294	232,646	2,453	31,400	705	206,688	0	0	206,688	934	24,452	471,669	510,589
1988	22,588	251,281	2,963	39,023	769	235,618	0	0	235,618	2,508	26,320	528,431	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	0	0	255,167	1,925	29,696	594,997	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	0	0	277,828	1,696	32,956	658,333	698,045
1991	29,014	325,317	5,272	77,954	785	273,275	0	0	273,275	4,686	35,071	681,232	720,749
1992	30,128	341,341	5,912	92,306	744	270,110	0	0	270,110	4,962	36,784	708,720	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	0	0	283,911	5,046	38,553	760,022	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	0	0	295,446	5,546	40,418	803,676	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	0	0	299,255	6,237	42,051	857,503	915,228
1996	35,015	447,161	7,408	133,209	741	304,918	0	0	304,918	6,725	43,164	892,014	943,404
1997	35,603	448,281	7,738	141,416	747	323,844	0	0	323,844	7,212	44,088	920,752	970,415
1998	36,573	508,138	7,856	153,422	731	336,475	0	0	336,475	7,796	45,160	1,005,832	1,042,380
1999	38,095	505,037	7,920	151,443	740	342,815	0	0	342,815	8,366	46,755	1,007,662	1,049,523
2000	39,971	536,388	8,095	160,614	738	359,111	0	0	359,111	9,241	48,803	1,065,354	1,116,042
2001	41,306	559,177	8,276	165,036	793	368,781	0	2,777	371,558	9,683	50,375	1,105,454	1,151,053
2002	42,704	570,617	8,537	168,552	825	368,781	0	13,886	382,666	10,118	52,066	1,131,953	1,191,529
2003	44,004	616,924	8,873	178,720	825	368,781	0	24,994	393,775	10,514	53,702	1,199,933	1,263,087
2004	45,180	654,646	9,178	189,527	825	368,781	0	36,103	404,883	10,909	55,184	1,259,965	1,326,279
2005	46,309	694,723	9,471	201,192	825	368,781	0	47,211	415,992	11,305	56,605	1,323,212	1,392,854

Table 3-3 (Continued)
2002 Base Case Load Forecast
Annual Summary of Historical and Projected Data

	Residential Service		GS Non-Demand		GS Demand						Total		
Calendar Year	Average Accounts	Sales (MWh)	Average Accounts	Sales (MWh)	Average Accounts	Base GSD Sales (MWh)	WEC Sales (MWh)	Spot Load Sales (MWh)	Total GSD Sales (MWh)	Outdoor Lighting Sales (MWh)	Average Accounts	Sales (MWh)	Net Energy for Load (MWh)
2006	47,439	736,576	9,764	213,092	825	369,652	0	55,543	425,194	11,701	58,028	1,386,563	1,459,540
2007	48,560	777,194	10,050	224,254	825	373,348	0	55,543	428,891	12,096	59,435	1,442,435	1,518,352
2008	49,641	817,977	10,316	235,304	825	377,082	0	55,543	432,624	12,492	60,782	1,498,397	1,577,260
2009	50,673	857,735	10,559	245,955	825	380,852	0	55,543	436,395	12,888	62,057	1,552,973	1,634,708
2010	51,682	899,436	10,785	256,972	825	384,661	0	55,543	440,203	13,283	63,293	1,609,895	1,694,626
2011	52,689	946,974	10,997	269,408	825	388,508	0	55,543	444,050	13,679	64,511	1,674,111	1,762,222
2012	53,663	991,546	11,188	280,843	825	392,393	0	55,543	447,935	14,074	65,676	1,734,399	1,825,683
2013	54,602	1,040,088	11,362	293,264	825	396,317	0	55,543	451,859	14,470	66,789	1,799,682	1,894,402
2014	55,513	1,088,256	11,524	305,435	825	400,280	0	55,543	455,822	14,866	67,862	1,864,379	1,962,504
2015	56,398	1,136,436	11,675	317,455	825	404,283	0	55,543	459,825	15,261	68,898	1,928,978	2,030,503
2016	57,293	1,185,575	11,830	329,404	825	408,325	0	55,543	463,868	15,657	69,948	1,994,504	2,099,478
2017	58,203	1,235,923	11,991	341,304	825	412,409	0	55,543	467,951	16,052	71,019	2,061,231	2,169,717
2018	59,134	1,288,309	12,152	353,347	825	416,533	0	55,543	472,075	16,448	72,112	2,130,179	2,242,294
2019	60,086	1,342,825	12,315	365,538	825	420,698	0	55,543	476,241	16,844	73,226	2,201,447	2,317,313
2020	61,059	1,399,570	12,479	377,884	825	424,905	0	55,543	480,448	17,239	74,363	2,275,140	2,394,884

Note: Historical data is complete through calendar year 2001.

Table 3-4
2002 High Case Load Forecast
Annual Summary of Historical and Projected Data

	Residential Service		GS Non-Demand		GS Demand						Total		
Calendar Year	Average Accounts	Sales (MWh)	Average Accounts	Sales (MWh)	Average Accounts	Base GSD Sales (MWh)	WEC Sales (MWh)	Spot Load Sales (MWh)	Total GSD Sales (MWh)	Outdoor Lighting Sales (MWh)	Average Accounts	Sales (MWh)	Net Energy for Load (MWh)
1986	19,857	215,331	2,279	30,337	609	182,789	0	0	182,789	838	22,745	429,295	455,520
1987	21,294	232,646	2,453	31,400	705	206,688	0	0	206,688	934	24,452	471,669	510,589
1988	22,588	251,281	2,963	39,023	769	235,618	0	0	235,618	2,508	26,320	528,431	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	0	0	255,167	1,925	29,696	594,997	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	0	0	277,828	1,696	32,956	658,333	698,045
1991	29,014	325,317	5,272	77,954	785	273,275	0	0	273,275	4,686	35,071	681,232	720,749
1992	30,128	341,341	5,912	92,306	744	270,110	0	0	270,110	4,962	36,784	708,720	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	0	0	283,911	5,046	38,553	760,022	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	0	0	295,446	5,546	40,418	803,676	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	0	0	299,255	6,237	42,051	857,503	915,228
1996	35,015	447,161	7,408	133,209	741	304,918	0	0	304,918	6,725	43,164	892,014	943,404
1997	35,603	448,281	7,738	141,416	747	323,844	0	0	323,844	7,212	44,088	920,752	970,415
1998	36,573	508,138	7,856	153,422	731	336,475	0	0	336,475	7,796	45,160	1,005,832	1,042,380
1999	38,095	505,037	7,920	151,443	740	342,815	0	0	342,815	8,366	46,755	1,007,662	1,049,523
2000	39,971	536,388	8,095	160,614	738	359,111	0	0	361,914	9,241	48,803	1,068,157	1,132,999
2001	41,321	560,654	8,281	163,914	793	368,781	0	2,803	382,796	9,682	50,395	1,117,046	1,175,837
2002	43,045	583,234	8,637	164,806	825	368,781	0	14,015	394,007	10,179	52,507	1,152,226	1,212,870
2003	45,057	642,403	9,150	178,720	825	368,781	0	25,227	405,219	10,735	55,032	1,237,078	1,302,187
2004	47,219	699,414	9,683	189,527	825	368,781	0	36,438	416,431	11,370	57,728	1,316,742	1,386,044

Table 3-4 (Continued)
2002 High Case Load Forecast
Annual Summary of Historical and Projected Data

	Residential Service		GS Non-Demand		GS Demand						Total		
Calendar Year	Average Accounts	Sales (MWh)	Average Accounts	Sales (MWh)	Average Accounts	Base GSD Sales (MWh)	WEC Sales (MWh)	Spot Load Sales (MWh)	Total GSD Sales (MWh)	Outdoor Lighting Sales (MWh)	Average Accounts	Sales (MWh)	Net Energy for Load (MWh)
2005	49,508	762,007	10,238	201,192	825	368,781	0	47,650	424,840	12,070	60,571	1,400,109	1,473,798
2006	51,679	830,320	10,748	213,092	825	369,652	0	56,059	425,711	12,683	63,252	1,481,805	1,559,795
2007	53,692	903,661	11,217	224,254	825	373,348	0	56,059	429,407	13,274	65,734	1,570,596	1,653,259
2008	55,733	982,272	11,701	235,304	825	377,082	0	56,059	433,141	13,932	68,259	1,664,649	1,752,262
2009	57,847	1,067,246	12,200	245,955	825	380,852	0	56,059	436,911	14,619	70,872	1,764,732	1,857,613
2010	60,044	1,159,259	12,716	256,972	825	384,661	0	56,059	440,720	15,352	73,585	1,872,303	1,970,845
2011	61,933	1,252,029	13,137	269,408	825	388,508	0	56,059	444,567	16,126	75,895	1,982,129	2,086,451
2012	63,455	1,344,109	13,473	280,843	825	392,393	0	56,059	448,452	16,944	77,753	2,090,348	2,200,366
2013	64,924	1,440,594	13,814	293,264	825	396,317	0	56,059	452,376	17,805	79,563	2,204,038	2,320,040
2014	66,408	1,543,253	14,162	305,435	825	400,280	0	56,059	456,339	18,712	81,395	2,323,739	2,446,041
2015	67,926	1,652,875	14,516	317,455	825	404,283	0	56,059	460,342	19,667	83,267	2,450,338	2,579,303
2016	69,419	1,764,818	14,861	329,404	825	408,325	0	56,059	464,384	20,602	85,105	2,579,209	2,714,957
2017	70,883	1,879,404	15,196	341,304	825	412,409	0	56,059	468,468	21,551	86,905	2,710,727	2,853,397
2018	72,366	2,000,835	15,538	353,347	825	416,533	0	56,059	472,592	22,557	88,730	2,849,331	2,999,296
2019	73,880	2,129,846	15,887	365,538	825	420,698	0	56,059	476,757	23,605	90,592	2,995,746	3,153,417
2020	75,428	2,267,006	16,242	377,884	825	424,905	0	56,059	480,964	24,705	92,494	3,150,559	3,316,378

Note: Historical data is complete through calendar year 2001.

Table 3-5
2002 Low Case Load Forecast
Annual Summary of Historical and Projected Data

	Residential Service		GS Non-Demand		GS Demand					Outdoor	Total		Net
Calendar Year	Average Accounts	Sales (MWh)	Average Accounts	Sales (MWh)	Average Accounts	Base GSD Sales (MWh)	WEC Sales (MWh)	Spot Load Sales (MWh)	Total GSD Sales (MWh)	Lighting Sales (MWh)	Average Accounts	Sales (MWh)	Energy for Load (MWh)
1986	19,857	215,331	2,279	30,337	609	182,789	0	0	182,789	838	22,745	429,295	455,520
1987	21,294	232,646	2,453	31,400	705	206,688	0	0	206,688	934	24,452	471,669	510,589
1988	22,588	251,281	2,963	39,023	769	235,618	0	0	235,618	2,508	26,320	528,431	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	0	0	255,167	1,925	29,696	594,997	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	0	0	277,828	1,696	32,956	658,333	698,045
1991	29,014	325,317	5,272	77,954	785	273,275	0	0	273,275	4,686	35,071	681,232	720,749
1992	30,128	341,341	5,912	92,306	744	270,110	0	0	270,110	4,962	36,784	708,720	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	0	0	283,911	5,046	38,553	760,022	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	0	0	295,446	5,546	40,418	803,676	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	0	0	299,255	6,237	42,051	857,503	915,228
1996	35,015	447,161	7,408	133,209	741	304,918	0	0	304,918	6,725	43,164	892,014	943,404
1997	35,603	448,281	7,738	141,416	747	323,844	0	0	323,844	7,212	44,088	920,752	970,415
1998	36,573	508,138	7,856	153,422	731	336,475	0	0	336,475	7,796	45,160	1,005,832	1,042,380
1999	38,095	505,037	7,920	151,443	740	342,815	0	0	342,815	8,366	46,755	1,007,662	1,049,523
2000	39,971	536,388	8,095	160,614	738	359,111	0	0	359,111	9,241	48,803	1,065,354	1,116,042
2001	41,279	559,647	8,269	163,853	793	368,781	0	2,777	371,558	9,659	50,341	1,104,717	1,165,663
2002	42,220	562,292	8,407	163,395	825	368,781	0	13,886	382,666	9,739	51,452	1,118,093	1,176,940
2003	42,963	590,226	8,612	173,497	825	368,781	0	24,994	393,775	9,863	52,401	1,167,360	1,228,800

Table 3-5 (Continued)
2002 Low Case Load Forecast
Annual Summary of Historical and Projected Data

	Residential Service		GS Non-Demand		GS Demand					Outdoor Lighting Sales (MWh)	Total		Net Energy for Load (MWh)
Calendar Year	Average Accounts	Sales (MWh)	Average Accounts	Sales (MWh)	Average Accounts	Base GSD Sales (MWh)	WEC Sales (MWh)	Spot Load Sales (MWh)	Total GSD Sales (MWh)		Average Accounts	Sales (MWh)	
2004	43,674	610,940	8,816	180,720	825	368,781	0	36,103	404,883	10,016	53,316	1,206,560	1,270,063
2005	44,389	632,545	9,019	188,349	825	368,781	0	47,211	415,992	10,195	54,234	1,247,081	1,312,717
2006	44,856	648,286	9,148	195,206	825	368,781	0	55,543	424,323	10,246	54,829	1,278,062	1,345,328
2007	45,050	658,165	9,212	201,312	825	368,781	0	55,543	424,323	10,246	55,087	1,294,047	1,362,154
2008	45,185	667,225	9,273	207,384	825	368,781	0	55,543	424,323	10,280	55,283	1,309,213	1,378,119
2009	45,307	676,099	9,332	213,411	825	368,781	0	55,543	424,323	10,309	55,465	1,324,142	1,393,834
2010	45,428	684,918	9,389	219,390	825	368,781	0	55,543	424,323	10,347	55,642	1,338,979	1,409,452
2011	45,375	685,465	9,394	223,565	825	368,781	0	55,543	424,323	10,250	55,593	1,343,603	1,414,319
2012	45,134	678,868	9,355	226,223	825	368,781	0	55,543	424,323	10,100	55,315	1,339,515	1,410,016
2013	44,854	671,708	9,315	228,859	825	368,781	0	55,543	424,323	9,978	54,995	1,334,869	1,405,125
2014	44,567	664,469	9,274	231,475	825	368,781	0	55,543	424,323	9,848	54,666	1,330,115	1,400,121
2015	44,280	657,261	9,232	234,070	825	368,781	0	55,543	424,323	9,725	54,337	1,325,379	1,395,136
2016	43,896	645,021	9,160	235,466	825	368,781	0	55,543	424,323	9,512	53,881	1,314,322	1,383,497
2017	43,408	628,774	9,065	235,899	825	368,781	0	55,543	424,323	9,269	53,298	1,298,265	1,366,595
2018	42,902	612,695	8,970	236,392	825	368,781	0	55,543	424,323	9,048	52,697	1,282,458	1,349,955
2019	42,398	597,041	8,875	236,944	825	368,781	0	55,543	424,323	8,826	52,097	1,267,134	1,333,825
2020	41,898	581,858	8,780	237,553	825	368,781	0	55,543	424,323	8,612	51,503	1,252,345	1,318,258

Note: Historical data is complete through calendar year 2001.

Using the projected winter and summer peaks, the remaining monthly peaks are developed by applying the 1993 percent of annual peak factor to the year of concern's annual peak. This calculation is performed for each year of the forecast period.

The forecast of peak load was prepared using average winter and summer load factors of 52 percent and 50 percent, respectively. Previous attempts to model peak load have been unsuccessful due to a lack of data. The estimate of peak load conditions is very dependent on weather and customer equipment. Although relatively reliable temperature data are available, peak load is also sensitive to other variables such as cloud cover, humidity, and barometric pressure.

Table 3-6 presents KUA's winter and summer base-, high-, and low-case peak demand forecasts. A 4.44 percent annual summer peak demand growth rate is projected for 2002 through 2011. This growth rate is lower than KUA's historical annual growth rate of 5.40 percent during the last 10 years.

3.6 High and Low Sensitivities

The high and low sensitivities represent changes in the independent economic variables. The high and low load forecasts sensitivities are driven by the BEBR's high and low population forecasts. The economic forecast provided by BEBR is projected to 2015, and BEBR's long-term population forecast is projected to 2020. The BEBR economic forecast was used through 2015.

In order to develop economic data beyond 2010, the economic data have been adjusted by using their rate of change with respect to population in the Base Case, and maintaining that ratio in the High and Low Cases.

Table 3-6
2002 Load Forecast Annual Summary of Gross Peak Demand

Calendar Year	Winter Peak Base Case (MW)	Winter Peak High Case (MW)	Winter Peak Low Case (MW)	Summer Peak Base Case (MW)	Summer Peak High Case (MW)	Summer Peak Low Case (MW)
1986	128	---	---	101	---	---
1987	110	---	---	115	---	---
1988	131	---	---	121	---	---
1989	148	---	---	141	---	---
1990	200	---	---	151	---	---
1991	147	---	---	157	---	---
1992	158	---	---	169	---	---
1993	158	---	---	183	---	---
1994	173	---	---	180	---	---
1995	196	---	---	195	---	---
1996	218	---	---	206	---	---
1997	198	---	---	216	---	---
1998	180	---	---	233	---	---
1999	219	---	---	236	---	---
2000	221	---	---	250	---	---
2001	246	---	---	252	---	---
2002	262	266	258	272	277	269
2003	277	286	270	288	297	281
2004	291	304	279	303	316	290
2005	306	324	288	318	336	300
2006	320	342	295	333	356	307
2007	333	363	299	347	377	311
2008	346	385	303	360	400	315
2009	359	408	306	373	424	318
2010	372	433	309	387	450	322
2011	387	458	310	402	476	323

Table 3-6 (Continued)
2002 Load Forecast Annual Summary of Gross Peak Demand

Calendar Year	Winter Peak Base Case (MW)	Winter Peak High Case (MW)	Winter Peak Low Case (MW)	Summer Peak Base Case (MW)	Summer Peak High Case (MW)	Summer Peak Low Case (MW)
2012	401	483	310	417	502	322
2013	416	509	308	432	530	321
2014	431	537	307	448	558	320
2015	446	566	306	464	589	319
2016	461	596	304	479	620	316
2017	476	626	300	495	651	312
2018	492	658	296	512	685	308
2019	509	692	293	529	720	305
2020	526	728	289	547	757	301

Note: Historical data is complete through calendar year 2001.

It is important to understand that the BEBR high and low population forecasts do not represent a particular high and low economic scenario. Rather, the high and low forecasts represent a range in which two-thirds of the population estimates are likely to fall. This range is developed by an analysis of error in previous forecast years.

The economic variables affect the residential, general service, and lighting forecasts, but do not affect the general service demand (GSD) classification. The uncertainty of the future competitive environment drives the assumptions for the high and low scenarios of GSD.

In order to simulate the high scenario for GSD, the annual growth in energy sales is assumed to be 2 percent from 2006 onward. In this scenario, a strong economy results in greater growth and relatively little competition. For the low scenario, there is no annual energy sales growth other than spot loads. In this scenario, KUA continues to grow, but overall growth is offset by large consumers leaving KUA's system for a competitor.

4.0 Demand-Side Programs

Kissimmee Utility Authority (KUA) has tested potential demand-side management (DSM) measures for cost-effectiveness. Measures were evaluated using the FPSC approved Florida Integrated Resource Evaluator (FIRE) model. The FIRE model evaluates the economic impact of existing and proposed conservation measures by determining the relative cost-effectiveness of the measures versus an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation and is used by several utilities in Florida.

4.1 Existing Conservation Programs

KUA is committed to conservation and load management programs and will continue to evaluate both old and new DSM programs on a frequent and regular basis in an attempt to identify cost-effective programs for the electric system that add value for the customers. KUA's energy conservation specialist performs approximately 700 free audits annually, advising customers on the appropriate conservation programs to implement.

KUA's conservation programs were originally established for the City of Kissimmee under the Florida Energy Efficiency and Conservation Act (FEECA) program. KUA is no longer classified as a FEECA utility. The following is a list of conservation programs outlined in KUA's submission to the FPSC when KUA was subject to FEECA:

- Residential energy audit.
- Commercial and industrial energy analysis.
- Fixup program - KUA will assist or arrange to have installed in residences:
  - Electrical outlet gaskets.
  - Solar screen/reflective film.
  - Water heater jackets.
  - Water flow restrictors.
  - Weatherstripping.

  - Caulking.
  - Energy conserving lamps.
  - Duct tape.
  - Pool timers.
  - Clock thermostats.
  - Water heater thermostat set back.
  - Hot water pipe insulation.
  - Water heater timers.
  - Ceiling insulation.
- High-pressure sodium street lighting/private area lighting conversion (from mercury vapor and incandescent).
- Water heater conversion from resistance heating to:
  - Dedicated heat pump water heaters.
  - Natural gas.
  - Solar.
  - Air conditioning/heat pump.
- Elimination of electric strip heating.
- Public awareness programs.
- Natural gas.
- Cogeneration plans.

The following sections discuss the DSM programs KUA now has in place.

4.1.1 Residential Load Management (SAVE)

KUA currently offers a residential direct load control program that has been in place since 1992. This program is called Shifting Adds Value to Energy (SAVE). SAVE is designed to cycle residential air conditions, electric water heaters, and electric space heaters to reduce KUA's system peak demand. The SAVE program was administered to over 4,171 customers as of December 31, 2001. The program is voluntary for all residential customers. For participating in the program, customers receive a monthly credit on their bills. KUA installs load control receivers on eligible equipment, and transmits radio signals to cycle equipment for peak demand reduction. The SAVE program provides a utility controlled process that ensures a direct capacity value to KUA, while minimizing impacts to the customer's lifestyle.

There are no significant reductions in energy consumption from this program. Table 4-1 shows KUA's historical and forecasted estimate of peak demand reductions resulting from this load management program.

Table 4-1
KUA Load Management Impact

Fiscal Year	Average Active Customers	Low Case (MW)	Base Case (MW)	High Case (MW)
1993	1,382	---	3.16	---
1994	4,399	---	8.32	---
1995	6,799	---	11.90	---
1996	7,675	---	12.62	---
1997	7,025	---	11.98	---
1998	6,355	---	12.15	---
1999	5,705	---	12.00	---
2000	5,035	---	11.00	---
2001	4,171	-	10	---
Forecast				
2002	---	8.1	9.0	9.9
2003	---	7.1	8.0	8.9
2004	---	7.1	8.0	8.9
2005	---	7.1	8.0	8.9
2006	---	7.1	8.0	8.9
2007	---	7.1	8.0	8.9
2008	---	7.1	8.0	8.9
2009	---	7.1	8.0	8.9
2010	---	7.1	8.0	8.9

4.1.1.1 Delivery Strategy. The approach for delivering the program is based on two design components: (i) promoting the program to existing customers through bill inserts and general media; and (ii) granting bill credits for participants based on the number and type of appliances being controlled. A schedule reflecting bill credits is presented in Table 4-2.

Table 4-2
SAVE Program, Load Management Credits

Appliance	Control Period	Monthly Credit	With Water Heater Control
Water Heater	Year Round	$2.50	--
Central Air Conditioning (15 minutes per 1/2 hour)	April-October	$4.50	$7.00
Central heating (15 minutes per 1/2 hour)	November-March	$4.50	$7.00

4.1.1.2 Implementation Activities. Because KUA has operated the program since 1992, current implementation activities focus on ongoing installation and maintenance of load switches, and updating and maintaining tracking systems to monitor participation.

4.1.2 Residential Appliance Efficiency

The Residential Appliance Efficiency Program is designed to encourage the specification and installation of energy efficient appliances such as high efficiency central air conditioners, heat pumps, and pool pumps.

Promotion of these high efficiency residential appliances helps to reduce residential cooling loads, which contribute to KUA's system peak. Additionally, since the useful lifetime estimates of these appliances are relatively long (15 years or greater), this program serves to address "lost opportunities," particularly in the new construction market.

The program is targeted to residential homeowners in the replacement and new construction market. Customers include those who currently have standard air conditioners, heat pumps, and/or pool pumps. When applicable equipment requires replacement, customers become candidates for an upgrade to high efficiency systems.

4.1.3 Commercial Cooling

The Commercial Cooling Program is designed to use customer and trade ally information and education to encourage the specification and installation of energy efficient cooling systems in the commercial markets.

The promotion of these high efficiency commercial systems helps to reduce commercial cooling loads that contribute to KUA's system peak. Additionally, since the useful lifetime estimates of these systems are relatively long (15 years or greater), this program serves to address "lost opportunities," particularly in the new construction market.

Although difficult to estimate, KUA's energy and summer demand are reduced with this program.

4.1.4 Residential Fix Up

This program is designed to make residential dwellings more efficient, focusing on the thermal envelope. This includes the following measures for existing residential buildings:

- Ceiling insulation.
- Duct leak repair (also for new homes).
- Hot water saving measures.

Duct leak repair is recommended for new homes because inspections often reveal installation problems that cause significant inefficiencies. Although difficult to estimate, this program achieves energy savings and some peak reduction in both the summer and winter.

4.2 Analysis of Demand-Side Management Alternatives

KUA used the FIRE model to evaluate the most cost-effective DSM measures from FPL's 2000 Demand-Side Management Plan. For the residential sector, KUA is already implementing the following three DSM measures that were found to be the most cost-effective based on the Rate Impact Test in FPL's 2000 Demand-Side Management Plan:

- Residential Load Control--Existing Construction.
- Residential Load Control--New Construction.
- Ceiling Insulation R0 - R19--Existing Construction.

Therefore, KUA analyzed the next most cost-effective residential DSM measure in FPL's 2000 Demand-Side Management Plan that is the BuildSmart EPI less than 90 for new construction. The results of that analysis follow along with the analysis of the commercial off-peak battery charging measure.

4.2.1 FIRE Model Output Analysis

KUA requires all measures to pass the Rate Impact Test to be considered cost-effective. Of the potential DSM measures tested, none passed the Rate Impact Test. Thus, KUA has concluded that there are no cost-effective DSM measures available that would avoid or defer the need for Stanton A. Table 4-3 presents the FIRE model results of the DSM analysis.

Table 4-3
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
BuildSmart - EPI Less Than 90 - New Construction	0.44	0.71	0.07
Commercial			
Off-Peak Battery Charging	0.37	0.04	0.48

The results of the DSM analysis are not surprising due to the previously performed analyses for similarly situated utilities. The failing cost-effectiveness of DSM has been exhibited in the Need for Power Dockets for KUA and FMPA for Cane Island Unit 3 (Docket No. 980802) and Lakeland Electric's conversion of McIntosh Unit 5 (Docket No. 990023), and in recent Demand-Side Management Ten-Year Plans for OUC (Docket No. 990722-EG) and JEA (Docket No. 990720-EG).

The decrease in the cost-effectiveness of the DSM measures can be attributed to the decreased price of installing new generation, the higher efficiency of new generation, relatively low interest rates, and the general increase in the efficiency of appliances and dwellings.

5.0 Forecast of Facilities Requirements

5.1 Florida Municipal Power Pool

KUA is a member, along with the Orlando Utilities Commission (OUC), City of Lakeland, and the All-Requirements Project of the Florida Municipal Power Agency (FMPA), of the Florida Municipal Power Pool (FMPP). The four utilities operate as one large control area. All FMPP capacity resources, totaling approximately 2,579 MW, are committed and dispatched together from the OUC operations center.

The FMPP does not provide for the sharing of planning reserves among its members. Members are required to provide their own reserves. A member of the FMPP can withdraw from FMPP with 1 year's written notice. Therefore, KUA must ultimately plan on a stand-alone basis.

5.2 Need for Capacity

This section addresses the need for additional electric capacity to serve the needs of KUA's electric customers in the future. The need for capacity is based on KUA's load forecast, reserve margin requirements, existing generating and purchase power capacity, scheduled retirements of generating units, and expiration of purchase power contracts. Based on the results of the capacity balance analysis of KUA's existing resources, KUA is expected to experience a capacity deficit of approximately 13 MW in 2009, growing to approximately 18 MW in 2011. The estimated deficit is based on the base case summer peak demand forecast. Table 5-1 presents the results of the capacity balance analysis.

5.2.1 Load Forecast

KUA's 2002 load forecast, described in Section 3.0, was used to determine the need for capacity. A summary of the load forecast is shown in Table 5-2. The peak demands presented in Table 5-2 do not reflect the demand reductions achieved through KUA's load management program further described in Section 4.0.

Table 5-1
Capacity Balance

Year	Existing/ Committed Generation(1)	Existing/ Committed Purchases(2)	Summer Peak Demand (MW)			DSM Impacts (MW)			Reserve Margin		
			Base	High	Low	Base	High	Low	Base	High	Low
2002	287	68.1	272	276.9	268.7	9	9.9	8.1	35.02%	33.00%	36.26%
2003	287	68.1	288.4	297.3	280.5	8	8.9	7.1	26.64%	23.13%	29.88%
2004	308	50.4	302.8	316.4	290	8	8.9	7.1	21.57%	16.55%	26.69%
2005	308	66.4	318.0	336.5	299.7	8	8.9	7.1	20.77%	14.29%	27.96%
2006	308	81.4	333.2	356.1	307.2	8	8.9	7.1	19.74%	12.15%	29.76%
2007	308	89.4	346.7	377.5	311.0	8	8.9	7.1	17.33%	7.81%	30.77%
2008	308	89.4	360.1	400.1	314.6	8	8.9	7.1	12.87%	1.58%	29.24%
2009	321	89.4	373.2	424.1	318.2	8	8.9	7.1	12.38%	-1.16%	31.92%
2010	336	89.4	386.9	450.0	321.8	8	8.9	7.1	12.27%	-3.56%	35.18%
2011	354	89.4	402.3	476.4	322.9	8	8.9	7.1	12.45%	-5.16%	40.41%
2012	354	89.4	416.8	502.4	321.9	8	8.9	7.1	8.46%	-10.15%	40.85%
2013	354	89.4	432.5	529.7	320.8	8	8.9	7.1	4.45%	-14.86%	41.35%
2014	354	89.4	448.1	558.5	319.7	8	8.9	7.1	0.75%	-19.32%	41.84%
2015	354	89.4	463.6	588.9	318.5	8	8.9	7.1	-2.68%	-23.55%	42.39%
2016	354	89.4	479.3	619.9	315.9	8	8.9	7.1	-5.92%	-27.43%	43.59%
2017	354	89.4	495.4	651.5	312.0	8	8.9	7.1	-9.03%	-31.00%	45.42%
2018	354	89.4	511.9	684.8	308.2	8	8.9	7.1	-12.01%	-34.40%	47.26%
2019	354	89.4	529.1	720.0	304.5	8	8.9	7.1	-14.91%	-37.65%	49.09%
2020	354	89.4	546.8	757.2	301.0	8	8.9	7.1	-17.71%	-40.75%	50.87%
2021	354	89.4	563.8	794.7	295.8	8	8.9	7.1	-20.22%	-43.57%	53.59%

(1)Includes Cane Island Unit 3 and Stanton A.
(2)Includes OUC schedules D purchase ending 2003, Southern PPA beginning 2004.

Table 5-2
Summary of Gross Peak Demands

Year	Winter Peak Demand (MW)			Summer Peak Demand (MW)		
	Base	High	Low	Base	High	Low
2002	262	259	255	272	277	269
2003	277	281	265	288	297	281
2004	291	304	274	303	316	290
2005	306	325	282	318	336	300
2006	320	342	289	333	356	307
2007	333	362	293	347	377	311
2008	346	379	295	360	400	315
2009	359	398	297	373	424	318
2010	372	417	300	387	450	322
2011	387	438	302	402	476	323
2012	401	459	302	417	502	322
2013	416	481	301	433	530	321
2014	431	503	300	448	558	320
2015	446	528	299	464	589	319
2016	461	553	298	479	620	316
2017	476	579	296	495	651	312
2018	492	606	292	512	685	308
2019	509	634	289	529	720	305
2020	526	663	286	547	757	301
2021	542	694	284	564	795	296

5.2.2 Reserve Requirements

KUA has adopted a 15 percent reserve margin for capacity planning in accordance with FAC 25-6.035. A 15 percent reserve margin is typical for utilities in Florida and throughout the Southeast.

5.2.3 Existing Generating Capacity

With the addition of Cane Island 3, KUA's summer generating capacity is 287 MW.

5.2.4 Existing Purchases

KUA is a member of the FMPA, a legal entity organized in 1978 and existing under the laws of Florida. During 1983, FMPA acquired an 8.8060 percent (73.9 MW) undivided ownership interest in St. Lucie Unit 2 on behalf of KUA and 15 other members of the FMPA. KUA's entitlement share of this unit, based on a power purchase contract and adjusted for transmission losses, is 6.9 MW. FMPA has also entered into a Reliability Exchange Agreement with FPL under which half of KUA's entitlement share of capacity and energy will be supplied from St. Lucie Unit 1 and half from Unit 2.

In addition to the above resources, KUA purchases electric power and energy from other utilities. KUA has a contract to purchase 20 MW of firm capacity from OUC through December 2003. This contract also provides for supplemental purchases of up to 50 MW if the capacity is available from OUC. KUA has a 1.80725 percent (7.9 MW) entitlement share of Stanton 1 through the FMPA Stanton 1 Project and a 7.6628 percent (33.3 MW) share of Stanton 2 through the FMPA Stanton 2 Project. The Stanton 2 percentage includes recently acquired Homestead and Lake Worth shares totaling 3.8314 percent.

In 2002, units at Hansel Plant will range from 19 to 43 years old. Some units will be approaching the end of their economic life. In spite of the ages of the units at Hansel Plant, KUA will continue to operate Hansel Plant until it has a major failure or until maintenance costs become prohibitive. Over the past several years, units at Hansel Plant have been reliably maintained and even upgraded as necessary. Though the units are not as efficient as newer units, they do generate reliably.

5.3 Fuel Price Forecast and Availability

The fuel forecast presents KUA's analysis of fuel prices and current market projections based on the Standard & Poor's Platt's Fuel Price Service fuel price forecast study, which was completed in January 2002 for KUA. The fuel price forecast includes coal, No. 6 fuel oil, No. 2 fuel oil, nuclear, and natural gas in Table 5-3.

5.4 Description of Generation Capacity Additions

Cane Island 3 began commercial operation on January 20, 2002. Using the Base Case load forecast, further capacity additions are required by the summer of 2004. To meet these capacity requirements, KUA is jointly participating in the Stanton A project with OUC, FMPA, and Southern-Florida as described in Section 2.0. Stanton A is under construction and will be in commercial operation on October 1, 2003. With the addition of Stanton A, KUA will need additional capacity in 2009 as shown in Table 5-4. For purposes of this Ten-Year Site Plan, this additional capacity is planned to be purchased power. The existing Cane Island site is designed for further capacity additions. If necessary KUA can construct additional combustion turbine or combined cycle capacity at the site to meet this 2009 projected capacity need. The long time frame before additional capacity is projected to be needed precludes detailed planning of capacity additions at this time.

Table 5-5 presents KUA's expansion plan under the high load scenario, while Table 5-6 presents KUA's expansion plan under the low load scenario.

Table 5-3
Delivered Fuel Price Forecast--Base Case
($/Mbtu)

Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas[1]
2002	1.79	2.89	5.29	0.60	2.98
2003	1.80	3.31	5.90	0.62	3.51
2004	1.79	3.60	6.20	0.63	3.53
2005	1.80	3.76	6.37	0.65	3.54
2006	1.79	3.87	6.55	0.67	3.60
2007	1.80	3.99	6.76	0.68	3.70
2008	1.82	4.11	6.96	0.70	3.80
2009	1.87	4.23	7.13	0.72	3.93
2010	1.88	4.37	7.32	0.74	4.06
2011	1.89	4.53	7.55	0.75	4.17
2012	1.87	4.69	7.78	0.77	4.33
2013	1.88	4.84	8.01	0.79	4.48
2014	1.88	5.01	8.25	0.81	4.62
2015	1.89	5.20	8.52	0.83	4.76
2016	1.90	5.40	8.81	0.85	4.90
2017	1.95	5.62	9.15	0.87	5.07
2018	1.97	5.85	9.52	0.90	5.20
2019	2.00	6.09	9.90	0.92	5.33
2020	2.01	6.32	10.27	0.94	5.51

(1) Commodity only.

Table 5-4
Schedule of Capacity Additions--Base Case
(MW)

Year	Total Firm Capacity(1)	Net Peak Demand(2)	Reserves	Capacity Additions	Revised Reserves
2002	364.8	263.0	38.69%	0	38.69%
2003	364.8	280.4	30.11%	0	30.11%
2004	380.7	294.8	29.14%	0	29.14%
2005	390.7	310.0	26.03%	0	26.03%
2006	400.7	325.2	23.21%	0	23.21%
2007	407.8	338.7	20.42%	0	20.42%
2008	407.8	352.1	15.82%	0	15.82%
2009	407.8	365.2	11.66%	13	15.22%
2010	407.8	378.9	7.63%	15	15.02%
2011	407.8	394.3	3.42%	18	15.08%
2012	407.8	408.8	-0.25%	17	15.16%
2013	407.8	424.5	-3.93%	18	15.15%
2014	407.8	440.1	-7.33%	18	15.17%
2015	407.8	455.6	-10.49%	18	15.19%
2016	407.8	471.3	-13.48%	18	15.16%
2017	407.8	487.4	-16.32%	18	15.07%
2018	407.8	503.9	-19.08%	19	15.06%
2019	407.8	521.1	-21.74%	20	15.11%
2020	407.8	538.8	-24.31%	20	15.04%
2021	407.8	555.8	-26.62%	20	15.12%

(1) Includes Cane Island 3, Stanton A, and Southern PPA.
(2) Peak demand net of Load Management.

Table 5-5
Schedule of Capacity Additions--High Case
(MW)

Year	Total Firm Capacity(1)	Net Peak Demand(2)	Reserves	Capacity Additions	Revised Reserves
2002	364.8	267.1	36.61%	0	36.61%
2003	364.8	288.4	26.48%	0	26.48%
2004	380.7	307.6	23.77%	0	23.77%
2005	390.7	327.6	19.26%	0	19.26%
2006	400.7	347.3	15.39%	0	15.39%
2007	407.8	368.6	10.38%	17	15.25%
2008	407.8	391.2	4.02%	26	15.24%
2009	407.8	415.3	-2.00%	27	15.06%
2010	407.8	441.1	-7.73%	30	15.12%
2011	407.8	467.5	-12.93%	30	15.04%
2012	407.8	493.5	-17.51%	30	15.06%
2013	407.8	520.8	-21.83%	32	15.16%
2014	407.8	549.6	-25.91%	33	15.14%
2015	407.8	580.0	-29.79%	35	15.14%
2016	407.8	611.0	-33.35%	35	15.03%
2017	407.8	642.6	-36.62%	37	15.13%
2018	407.8	675.9	-39.74%	38	15.08%
2019	407.8	711.1	-42.72%	40	15.01%
2020	407.8	748.3	-45.56%	43	15.03%
2021	407.8	785.8	-48.16%	43	15.01%

(1) Includes Cane Island 3, Stanton A, and Southern PPA.
(2) Peak demand net of Load Management.

Table 5-5 Schedule of Capacity Additions--Low Case (MW)					
Year	Total Firm Capacity(1)	Net Peak Demand(2)	Reserves	Capacity Additions	Revised Reserves
2002	364.8	260.6	40.01%	0	40.01%
2003	364.8	273.4	33.43%	0	33.43%
2004	380.7	282.8	34.61%	0	34.61%
2005	390.7	292.6	33.55%	0	33.55%
2006	400.7	300.0	33.56%	0	33.56%
2007	407.8	303.9	34.21%	0	34.21%
2008	407.8	307.5	32.62%	0	32.62%
2009	407.8	311.1	31.09%	0	31.09%
2010	407.8	314.7	29.61%	0	29.61%
2011	407.8	315.8	29.15%	0	29.15%
2012	407.8	314.8	29.55%	0	29.55%
2013	407.8	313.7	30.01%	0	30.01%
2014	407.8	312.5	30.49%	0	30.49%
2015	407.8	311.4	30.97%	0	30.97%
2016	407.8	308.7	32.09%	0	32.09%
2017	407.8	304.9	33.77%	0	33.77%
2018	407.8	301.1	35.45%	0	35.45%
2019	407.8	297.4	37.13%	0	37.13%
2020	407.8	293.8	38.79%	0	38.79%
2021	407.8	288.6	41.30%	0	41.30%

(1) Includes Cane Island 3.
(2) Peak demand net of Load Management.

5.5 Transmission Improvements

As a result of a Ten-Year Transmission Impact Study, jointly prepared for KUA, OUC and FMPA, the following transmission improvements are projected as necessary for KUA by 2010:

- Addition of a second 230/69 kV autotransformer at the Clay Street substation.
- Upgrade the 69 kV transmission line between Clay Street and Hansel Plant using 1590 ACSR kcmil or equivalent.
- Upgrade the 69 kV transmission line between Clay Street and Airport using 1590 kcmil ACSR or equivalent.
- Upgrade the 336 kcmil AAC section of 69 kV transmission line between Hansel Plant and C. A. Wall with 795 kcmil AAC.
- Install a 230/69 kV autotransformer at the OUC SouthWest Substation.
- Construct a new 69 kV transmission line from OUC SouthWest Substation to Hord using 795 kcmil ACSR.
- Construct a new 69 kV transmission line from OUC SouthWest Substation to Lake Cecile using 795 kcmil ACSR.

Appendix A
Schedules

Schedule 1
Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport		Alt. Fuel Days	Commercial In-Service	Expected Retirement	Gen Max. Nameplate	Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Use	Month/Year	Month/Year	kW	Summer MW	Winter MW
Hansel Plant		Osceola County Sec 27/T25S/ R29E											
	8		IC	NG	FO2	PL	TK		02/59	Unknown	3,000	2.0	2.0
	14		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	1.8	1.8
	15		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	1.8	1.8
	16		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	1.8	1.8
	17		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	1.8	1.8
	18		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	1.8	1.8
	19		IC	FO2	--	TK	--		02/83	Unknown	2,500	2.5	2.5
	20		IC	FO2	--	TK	--		02/83	Unknown	2,500	2.5	2.5
	21		CT	NG	FO2	PL	TK		02/83	Unknown	35,000	35.0	35.0
	22		ST	WH	--	--	--		02/83	Unknown	10,000	10.0	10.0
	23		ST	WH	--	--	--		02/83	Unknown	10,000	10.0	10.0
Plant Total											73,350	61.0	61.0

Schedule 1 (Continued)
Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max. Nameplate kW	Summer MW	Winter MW
Crystal River		Citrus County Sec 33/T17S/ R16E											
	8		N	UR	--	TK	--		03/77	Unknown	890,460	5.6(1)	5.6(1)
Plant Total											890,460	5.6	5.6

(1) KUA's 0.6754 percent portion of joint ownership.

Schedule 1 (Continued)
Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport		Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max. Nameplate kW	Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt					Summer MW	Winter MW
Stanton Energy Center		Orange County Sec 13, 14, 23, 24/R31E/T23S and Sec 18, 19/T23S/R32E											
	1		ST	BIT	--	RR	--		07/87	Unknown	464,580	21.0(2)	21.0(2)
Plant Total											464,580	21.0	21.0

(2) KUA's 4.8193 percent ownership portion.

Schedule 1 (Continued)
Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max. Nameplate kW	Summer MW	Winter MW
Indian River		Brevard County Sec. 12/T23S/ R35E											
	A		CT	NG	FO2	PL	TK		07/89	Unknown	41,400	4.0(3)	4.0(3)
	B		CT	NG	FO2-	PL	TK		07/89	Unknown	41,400	4.0(3)	4.0(3)
Plant Total											890,460	8.0	8.0

(3) KUA's 12.2 percent portion of joint ownership.

Schedule 1 (Continued)
Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max. Nameplate kW	Summer MW	Winter MW
Cane Island		Osceola County Sec. 29, 32/ R28E/T25S											
	1		CT	NG	FO2	PL	TK		11/94	Unknown	42,000	15.2(1)	20.3(4)
	2		CT	NG	FO2	PL	TK		06/95	Unknown	80,000	34.4(1)	40.2(4)
	2		ST	WH	--	--	--		06/95	Unknown	40,000	20.0(1)	20.0(4)
Plant Total											162,000	69.6	80.5

(4) KUA's 50 percent ownership portion.

Schedule 2.1
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential				Commercial		
Year	Population	Members per Household	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr
1991	71889	2.88	325	29,014	11,212	351	6,056	57,993
1992	75515	2.916	341	30,128	11,330	362	6,656	54,454
1993	73342	2.954	369	31,553	11,684	386	7,000	55,187
1994	83615	3.002	387	32,699	11,831	411	7,719	53,280
1995			425	34,053	12,494	426	7,997	53,244
1996			447	35,015	12,771	438	8,149	53,763
1997			448	35,603	12,591	465	8,485	54,834
1998			508	36,573	13,894	490	8,587	57,051
1999			505	38,095	13,257	494	8,660	57,073
2000			536	39,971	13,419	520	8,833	58,842
2001			559	41,306	13,537	537	9,069	59,168
2002			571	42,704	13,362	551	9,362	58,876
2003			617	44,004	14,020	572	9,698	59,031
2004			655	45,180	14,490	594	10,003	59,422
2005			695	46,309	15,002	617	10,296	59,945
2006			737	47,439	15,527	638	10,589	60,277
2007			777	48,560	16,005	653	10,875	60,060

Schedule 2.1 (Continued)
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential				Commercial		
Year	Population	Members per Household	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr
2008			818	49,641	16,478	668	11,141	59,952
2009			858	50,673	16,927	682	11,384	59,940
2010			899	51,682	17,403	697	11,610	60,048
2011			947	52,689	17,973	713	11,822	60,352
2012			992	53,663	18,477	729	12,013	60,665
2013			1,040	54,602	19,049	745	12,187	61,140
2014			1,088	55,513	19,604	761	12,349	61,645
2015			1,136	56,398	20,150	777	12,500	62,185
2016			1,186	57,293	20,693	793	12,655	62,686
2017			1,236	58,203	21,235	809	12,816	63,146
2018			1,288	59,134	21,786	825	12,977	63,605
2019			1,343	60,086	22,348	842	13,140	64,061
2020			1,400	61,059	22,922	858	13,304	64,515
2021			1,454	61,964	23,461	874	13,456	64,984

Note: Historical data is complete through calendar year 2001.

Schedule 2.2
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr	Railroads and Railways GWh	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
1991	---	---	---	---	5	---	681
1992	---	---	---	---	5	---	709
1993	---	---	---	---	5	---	760
1994	---	---	---	---	6	---	804
1995	---	---	---	---	6	---	858
1996	---	---	---	---	7	---	892
1997	---	---	---	---	7	---	921
1998	---	---	---	---	8	---	1,006
1999	---	---	---	---	8	---	1,008
2000	---	---	---	---	9	---	1,065
2001	---	---	---	---	10	---	1,105
2002	---	---	---	---	10	---	1,132
2003	---	---	---	---	11	---	1,200
2004	---	---	---	---	11	---	1,260
2005	---	---	---	---	11	---	1,323
2006	---	---	---	---	12	---	1,387

Schedule 2.2 (Continued)
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr	Railroads and Railways GWh	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
2007	---	---	---	---	12	---	1,442
2008	---	---	---	---	12	---	1,498
2009	---	---	---	---	13	---	1,553
2010	---	---	---	---	13	---	1,610
2011	---	---	---	---	14	---	1,674
2012	---	---	---	---	14	---	1,734
2013	---	---	---	---	14	---	1,800
2014	---	---	---	---	15	---	1,864
2015	---	---	---	---	15	---	1,929
2016	---	---	---	---	16	---	1,995
2017	---	---	---	---	16	---	2,061
2018	---	---	---	---	16	---	2,130
2019	---	---	---	---	17	---	2,201
2020	---	---	---	---	17	---	2,275
2021	---	---	---	---	18	---	2,346

Note: Historical data is complete through calendar year 2001..

Schedule 2.3
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1) Year	(2) Sales for Resale GWh	(3) Utility Use and Losses GWh	(4) Net Energy for Load GWh	(5) Avg. No. of Other Customers	(6) Total Avg. No. of Customers
1991	0	40	721	0	35,071
1992	0	36	745	0	36,784
1993	8	41	801	0	38,553
1994	0	37	841	0	40,418
1995	0	58	915	0	42,051
1996	0	51	943	0	43,164
1997	0	50	970	0	44,088
1998	0	37	1,042	0	45,160
1999	0	42	1,050	0	46,755
2000	0	51	1,116	0	48,803
2001	0	46	1,151	0	50,375
2002	0	60	1,192	0	52,066
2003	0	63	1,263	0	53,702
2004	0	66	1,326	0	55,184
2005	0	70	1,393	0	56,605
2006	0	73	1,460	0	58,028

Schedule 2.3 (Continued)
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1) Year	(2) Sales for Resale GWh	(3) Utility Use and Losses GWh	(4) Net Energy for Load GWh	(5) Avg. No. of Other Customers	(6) Total Avg. No. of Customers
2007	0	76	1,518	0	59,435
2008	0	79	1,577	0	60,782
2009	0	82	1,635	0	62,057
2010	0	85	1,695	0	63,293
2011	0	88	1,762	0	64,511
2012	0	91	1,826	0	65,676
2013	0	95	1,894	0	66,789
2014	0	98	1,963	0	67,862
2015	0	102	2,031	0	68,898
2016	0	105	2,099	0	69,948
2017	0	108	2,170	0	71,019
2018	0	112	2,242	0	72,112
2019	0	116	2,317	0	73,226
2020	0	120	2,395	0	74,363
2021	0	123	2,469	0	75,420

Note: Historical data is complete through calendar year 2001.

Schedule 3.1
Historical and Forecast of Summer Peak Demand
Base Case - MW

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Conservation	(10) Net Firm Demand
1991	157	0	157	0	0	0	0	0	157
1992	169	0	169	0	0	0	0	0	169
1993	183	0	183	0	3	0	0	0	180
1994	180	0	180	0	8	0	0	0	172
1995	195	0	195	0	12	0	0	0	183
1996	206	0	206	0	13	0	0	0	193
1997	216	0	216	0	12	0	0	0	204
1998	233	0	233	0	12	0	0	0	221
1999	236	0	236	0	12	0	0	0	224
2000	250	0	250	0	11	0	0	0	239
2001	252	0	252	0	10	0	0	0	242
2002	272	0	272	0	9	0	0	0	263
2003	288	0	288	0	8	0	0	0	280
2004	303	0	303	0	8	0	0	0	295
2005	318	0	318	0	8	0	0	0	310
2006	333	0	333	0	8	0	0	0	325
2007	347	0	347	0	8	0	0	0	339

Schedule 3.1 (Continued)
Historical and Forecast of Summer Peak Demand
Base Case - MW

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Conservation	(10) Net Firm Demand
2008	360	0	360	0	8	0	0	0	352
2009	373	0	373	0	8	0	0	0	365
2010	387	0	387	0	8	0	0	0	379
2011	402	0	402	0	8	0	0	0	394
2012	417	0	417	0	8	0	0	0	409
2013	433	0	433	0	8	0	0	0	425
2014	448	0	448	0	8	0	0	0	440
2015	464	0	464	0	8	0	0	0	456
2016	479	0	479	0	8	0	0	0	471
2017	495	0	495	0	8	0	0	0	487
2018	512	0	512	0	8	0	0	0	504
2019	529	0	529	0	8	0	0	0	521
2020	547	0	547	0	8	0	0	0	539
2021	564	0	564	0	8	0	0	0	556

Note: Historical data is complete through calendar year 2001.

Schedule 3.2
Historical and Forecast of Winter Peak Demand
Base Case - MW

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Conservation	(10) Net Firm Demand
1991	147	0	147	0	0	0	0	0	147
1992	147	0	147	0	0	0	0	0	147
1993	158	0	158	0	3	0	0	0	155
1994	158	0	158	0	8	0	0	0	155
1995	173	0	173	0	12	0	0	0	165
1996	196	0	196	0	13	0	0	0	184
1997	218	0	218	0	12	0	0	0	205
1998	198	0	198	0	12	0	0	0	186
1999	180	0	180	0	12	0	0	0	168
2000	219	0	219	0	11	0	0	0	207
2001	221	0	221	0	10	0	0	0	210
2002	257	0	257	0	9	0	0	0	247
2003	273	0	273	0	8	0	0	0	264
2004	288	0	288	0	8	0	0	0	280
2005	302	0	302	0	8	0	0	0	294
2006	313	0	313	0	8	0	0	0	305
2007	325	0	325	0	8	0	0	0	317

Schedule 3.2 (Continued)
Historical and Forecast of Winter Peak Demand
Base Case - MW

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Conservation	(10) Net Firm Demand
2008	334	0	334	0	8	0	0	0	326
2009	344	0	344	0	8	0	0	0	336
2010	355	0	355	0	8	0	0	0	347
2011	365	0	365	0	8	0	0	0	357
2012	376	0	376	0	8	0	0	0	368
2013	387	0	387	0	8	0	0	0	379
2014	398	0	398	0	8	0	0	0	390
2015	409	0	409	0	8	0	0	0	401
2016	421	0	421	0	8	0	0	0	413
2017	432	0	432	0	8	0	0	0	424
2018	444	0	444	0	8	0	0	0	436
2019	455	0	455	0	8	0	0	0	447
2020	468	0	468	0	8	0	0	0	460
2021	480	0	480	0	8	0	0	0	472

Note: Historical data is complete through calendar year 2001.

Schedule 3.3
Historical and Forecast of Annual Net Energy for Load
Base Case - GWh

(1) Year	(2) Total	(3) Residential Conservation	(4) Commercial/ Industrial Conservation	(5) Retail	(6) Wholesale	(7) Utility Use and Losses	(8) Net Energy for Load	(9) Load Factor (%)
1991	681	0	0	681	0	40	721	52.4%
1992	709	0	0	709	0	36	745	50.3%
1993	760	0	0	760	0	41	801	50.0%
1994	804	0	0	804	0	37	841	53.3%
1995	858	0	0	858	0	58	915	53.3%
1996	892	0	0	892	0	51	943	49.4%
1997	921	0	0	921	0	50	970	51.3%
1998	1,006	0	0	1,006	0	37	1,042	51.1%
1999	1,008	0	0	1,008	0	42	1,050	50.8%
2000	1,065	0	0	1,065	0	51	1,116	51.0%
2001	1,105	0	0	1,105	0	46	1,151	52.1%
2002	1,132	0	0	1,132	0	60	1,192	50.0%
2003	1,200	0	0	1,200	0	63	1,263	50.0%
2004	1,260	0	0	1,260	0	66	1,326	50.0%
2005	1,323	0	0	1,323	0	70	1,393	50.0%
2006	1,387	0	0	1,387	0	73	1,460	50.0%
2007	1,442	0	0	1,442	0	76	1,518	50.0%

Schedule 3.3 (Continued)
Historical and Forecast of Annual Net Energy for Load
Base Case - GWh

(1) Year	(2) Total	(3) Residential Conservation	(4) Commercial/ Industrial Conservation	(5) Retail	(6) Wholesale	(7) Utility Use and Losses	(8) Net Energy for Load	(9) Load Factor (%)
2008	1,498	0	0	1,498	0	79	1,577	50.0%
2009	1,553	0	0	1,553	0	82	1,635	50.0%
2010	1,610	0	0	1,610	0	85	1,695	50.0%
2011	1,674	0	0	1,674	0	88	1,762	50.0%
2012	1,734	0	0	1,734	0	91	1,826	50.0%
2013	1,800	0	0	1,800	0	95	1,894	50.0%
2014	1,864	0	0	1,864	0	98	1,963	50.0%
2015	1,929	0	0	1,929	0	102	2,031	50.0%
2016	1,995	0	0	1,995	0	105	2,099	50.0%
2017	2,061	0	0	2,061	0	108	2,170	50.0%
2018	2,130	0	0	2,130	0	112	2,242	50.0%
2019	2,201	0	0	2,201	0	116	2,317	50.0%
2020	2,275	0	0	2,275	0	120	2,395	50.0%
2021	2,346	0	0	2,346	0	123	2,469	50.0%

Note: Historical data is complete through calendar year 2001.

Schedule 4
Previous Year and 2 Year Forecast of Retail Peak Demand and
Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2001		**2002**		**2003**	
Year	Peak Demand MW	NEL GWh	Peak Demand MW	NEL GWh	Peak Demand MW	NEL GWh
January	246	97	262	86	277	94
February	185	75	204	83	216	90
March	166	81	235	82	249	88
April	207	87	166	82	176	88
May	233	99	199	90	211	97
June	247	111	251	112	266	118
July	249	119	269	119	285	125
August	252	125	272	124	288	129
September	242	104	256	127	271	131
October	204	92	224	108	238	115
November	175	78	184	91	195	97
December	181	85	257	87	273	91

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		Units	Actual 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Nuclear		Gbtu	447	424	425	424	425	425	425	425	424	424	425
(2)	Coal		1,000 Ton	54	68	74	67	65	70	69	65	68	68	64
	Residual													
(3)		Steam	1,000 BBL											
(4)		CC	1,000 BBL											
(5)		CT	1,000 BBL											
(6)		Total	1,000 BBL											
	Distillate													
(7)		Steam	1,000 BBL											
(8)		CC	1,000 BBL											
(9)		CT	1,000 BBL	8	91	61	63	67	72	80	81	81	80	72
(10)		Total	1,000 BBL	8	91	61	63	67	72	80	81	81	80	72
	Natural Gas													
(11)		Steam	1,000 MCF											
(12)		CC	1,000 MCF	3,900	7,500	8,088	7,755	7,750	8,002	8,024	7,817	8,120	8,141	8,004
(13)		CT	1,000 MCF	1,337	805	626	369	389	473	644	658	655	641	575
(14)		Total	1,000 MCF	5,237	8,305	8,634	8,124	8,139	8,475	8,668	8,475	8,775	8,782	8,579
(15)	Other (Specify)		GBtu											

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Firm Inter-region Interchange		GWH											
(2)	Nuclear		GWH	43	40	40	40	40	40	40	40	40	40	40
(3)	Coal		GWH	153	181	197	178	172	187	184	173	180	181	170
	Residual													
(4)		Steam	GWH											
(5)		CC	GWH											
(6)		CT	GWH											
(7)		Total:	GWH	0	0	0	0	0	0	0	0	0	0	0
	Distillate													
(8)		Steam	GWH											
(9)		CC	GWH											
(10)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(11)		Total:	GWH	0	0	0	0	0	0	0	0	0	0	0

Schedule 6.1 (Continued)
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
	Natural Gas													
(12)		Steam	GWH											
(13)		CC	GWH	422	960	1,035	1,010	1,005	1,043	1,043	1,003	1,048	1,050	1,027
(14)		CT	GWH	144	33	25	15	15	16	17	17	18	18	16
(15)		Total:	GWH	566	993	1,060	1,025	1,020	1,059	1,060	1,020	1,066	1,068	1,043
(16)	NUG		GWH											
(17)	Hydro		GWH											
(18)	Other (Specify)	Net Interchange	GWH	389	-22	-34	84	161	174	234	344	349	406	509
(19)	Net Energy for Load		GWH	1,151	1,192	1,263	1,327	1,393	1,460	1,518	1,577	1,635	1,695	1,762

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Firm Inter-Region Interchange		%											
(2)	Nuclear		%	3.74%	3.36%	3.17%	3.01%	2.87%	2.74%	2.64%	2.54%	2.45%	2.36%	2.27%
(3)	Coal		%	13.29%	15.18%	15.60%	13.41%	12.35%	12.81%	12.12%	10.97%	11.01%	10.68%	9.65%
	Residual													
(4)		Steam	%											
(5)		CC	%											
(6)		CT	%											
(7)		Total:	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Distillate													
(8)		Steam	%											
(9)		CC	%											
(10)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(11)		Total:	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Schedule 6.2 (Continued)
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actual										
	Energy Sources		Units	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
	Natural Gas													
(12)		Steam	%											
(13)		CC	%	36.66%	80.54%	81.95%	76.11%	72.15%	71.44%	68.71%	63.60%	64.10%	61.95%	58.59%
(14)		CT	%	12.51%	2.77%	1.98%	1.13%	1.08%	1.10%	1.12%	1.08%	1.10%	1.06%	0.91%
(15)		Total:	%	49.17%	83.31%	83.93%	77.24%	73.22%	72.53%	69.83%	64.68%	65.20%	63.01%	59.19%
(16)	NUG		%											
(17)	Hydro		%											
(18)	Other (Specify)	Net Interchange	%	33.80%	-1.85%	-2.69%	6.33%	11.56%	11.92%	15.24%	21.81%	21.35%	23.95%	28.89%
(19)	Net Energy for Load		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance
at the Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
							Reserve Margin Before Maintenance			Reserve Margin Before Maintenance	
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Qualifying Facilities MW	Total Available Capacity MW	System Firm Net Peak Demand MW	MW	% of Peak	Scheduled Maintenance MW	MW	% of Peak
2001	297	68	0	0	365	242	123	51	0	0	0
2002	297	68	0	0	365	263	102	39	0	0	0
2003	297	68	0	0	365	280	84	30	0	0	0
2004	318	62	0	0	381	295	86	29	0	0	0
2005	318	72	0	0	391	310	81	26	0	0	0
2006	318	82	0	0	401	325	75	23	0	0	0
2007	318	89	0	0	408	339	69	20	0	0	0
2008	318	89	0	0	408	352	56	16	0	0	0
2009	331	89	0	0	421	365	56	15	0	0	0
2010	346	89	0	0	436	379	57	15	0	0	0
2011	364	89	0	0	454	394	59	15	0	0	0

Note: Calendar year 2001 is historical data.

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance
at the Time of Winter Peak

(1) Year	(2) Total Installed Capacity MW	(3) Firm Capacity Import MW	(4) Firm Capacity Export MW	(5) Qualifying Facilities MW	(6) Total Available Capacity MW	(7) System Firm Net Peak Demand MW	(8) Reserve Margin Before Maintenance MW	(9) Reserve Margin Before Maintenance % of Peak	(10) Scheduled Maintenance MW	(11) Reserve Margin Before Maintenance MW	(12) Reserve Margin Before Maintenance % of Peak
2001	190	118	0	0	308	210	98	47	0	0	0
2002	323	68	0	0	391	247	144	58	0	0	0
2003	323	68	0	0	391	264	128	49	0	0	0
2004	345	62	0	0	407	280	127	46	0	0	0
2005	345	72	0	0	417	294	123	42	0	0	0
2006	345	82	0	0	427	305	122	40	0	0	0
2007	345	89	0	0	434	317	118	37	0	0	0
2008	345	89	0	0	434	326	108	33	0	0	0
2009	345	89	0	0	434	336	98	29	0	0	0
2010	348	89	0	0	437	347	91	26	0	0	0
2011	360	89	0	0	449	357	92	26	0	0	0

Note: Calendar year 2000 is historical data.

Schedule 8.1
Planned and Prospective Generating Facility Additions and Changes

Plant Name	Unit No.	Location (County)	Unit Type	Fuel Pri	Fuel Alt	Fuel Transportation Pri	Fuel Transportation Alt	Construction Start Mo/YYYY	C.O.D. Mo/YYYY	Expected Retirement Mo/YY/YY	Gross Capability Sum MW	Gross Capability Win MW	Net Capability Sum MW	Net Capability Win MW	Status
Stanton Energy Center	A	Orange	CC	NG	DFO	PL	TK	11/2001	10/2003	10/2033	21.34	23.15	20.81	22.65	U

Schedule 8.2

Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport						Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate KW	Summer MW	Winter MW	Status
Cane Island		Osceola County Sec 29, 32/R28E / T25S												
	3		CT	NG	FO	PL	TK	08/99	06/01	Unknown	90,453[1]	76.9[1]	88.5[1]	OP[2]
	3		ST	WH		PL	NA	08/99	06/01	Unknown	49,300[1]	45[1]	45[1]	OP[2]

1. KUA's 50 percent ownership share.
2. Commercial operation January 25, 2002.

Schedule 9.1
Status Report and Specifications of Proposed Generating Facilities

		Stanton Energy Center Combined Cycle Unit A	
(1)	Plant Name and Unit Number		
(2)	Capacity		
	a. Summer	20.81	(KUA ownership share)
	b. Winter	22.65	
(3)	Technology Type	Combined Cycle	
(4)	Anticipated Construction Timing		
	a. Field construction start date	11/2001	
	b. Commercial in-service date	10/2003	
(5)	Fuel		
	a. Primary fuel	NG	
	b. Alternate fuel	DFO	
(6)	Air Pollution Control Strategy	Dry Low NO_x Combustors	
(7)	Cooling Method	Mechanical Draft	
(8)	Total Site Area	3,280 acres	(Stanton Site)
(9)	Construction Status	Planned	
(10)	Certification Status	In Progress	
(11)	Status with Federal Agencies	Construction permits approved	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF)	Confidential	
	b. Forced Outage Factor (FOF)	Confidential	
	c. Equivalent Availability Factor (EAF)	Confidential	

Schedule 9.2
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Cane Island 3
(2)	Capacity	
	a. Summer:	243.7 MW
	b. Winter:	267 MW
(3)	Technology Type:	1 x 1 F-Class Combined-Cycle
(4)	Anticipated Construction Timing	
	a. Field construction start-date:	10/99
	b. Commercial in-service date:	01/02
(5)	Fuel	
	a. Primary fuel:	Natural Gas
	b. Alternate fuel:	No. 2 Oil
(6)	Air Pollution Control Strategy:	Dry Low NO_x Combustors
(7)	Cooling Method:	Mechanical Cooling Towers
(8)	Total Site Area:	1,023 Acres
(9)	Construction Status:	Commercial operation 1/25/2002
(10)	Certification Status:	Certified
(11)	Status with Federal Agencies:	No outstanding issues

Schedule 9.2 (Continued)
Status Report and Specifications of Proposed Generating Facilities

(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF):	4.3%
	Forced Outage Factor (FOF):	4.1%
	Equivalent Availability Factor (EAF):	91.8%
	Resulting Capacity Factor (%):	91.8%
	Average Net Operating Heat Rate (ANOHR):	6,815 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years):	30
	Total installed Cost (In-Service year $/kW):	557
	Direct Construction Cost ($/kW):	525
	AFUDC Amount ($/kW):	32
	Escalation ($/kW):	NA
	Fixed O&M ($/kW-yr):	3.00
	Variable O&M ($/MWh):	2.82
	K Factor:	1.2573 (based on summer net capacity rating)

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1)	Point of Origin and Termination:	Orlando/Kissimmee	Orlando/Kissimmee
(2)	Number of Lines:	One	One
(3)	Right-of-Way:	N/A	N/A
(4)	Line Length:	N/A	N/A
(5)	Voltage:	69 kV	69 kV
(6)	Anticipated Construction Timing:	Completed by 2010	Completed by 2010
(7)	Anticipated Capital Investment:	N/A	N/A
(8)	Substations:	OUC SouthWest/ KUA Hord	OUC SouthWest/ KUA Lake Cecile
(9)	Participation with Other Utilities:	OUC	OUC