Stanton Energy Center Combined Cycle Unit A

010142-EM

Need for Power Application

Kissimmee Utility Authority – Volume 1C

January 29, 2001

BLACK & VEATCH

11401 Lamar, Overland Park, Ka

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1C.1.0 Overview and Summary

1C.1.1 Overview

Stanton A is planned as a new combined cycle addition to the existing Stanton Energy Center site, located 12 miles southeast of Orlando, Florida. The Stanton Energy Center site was originally certified for an ultimate capacity of approximately 2,000 MW based on four coal fired units. The existing Stanton Unit 1 is a 444 MW net coal fired facility and Stanton 2 is a 446 MW net coal fired generating facility. Stanton 1 was placed in operation on July 1, 1987 followed by Stanton 2 which was placed in operation on June 1, 1996. Stanton A will provide very economical power for the Kissimmee Utility Authority (KUA) with a minimal environmental impact. Stanton A will be a 2 x 1 GE 7FA combined cycle unit. The net output of the unit is estimated to be 633 MW at 70° F under new and clean conditions and will be jointly owned by KUA, Orlando Utilities Commission (OUC), Florida Municipal Power Agency (FMPA) and Southern-Florida. KUA will be a 10 percent joint owner of the 35 percent (221.6 MW) capacity to be owned by the utility applicants. KUA's ownership portion of generation from Stanton A will be approximately 22 MW. KUA will also receive 10 percent of the 65 percent capacity owned by Southern-Florida and supplied under a power purchase agreement (PPA). Details specific to the project are presented in Volume 1A. This volume, Volume 1C, contains information specific to KUA's need for the project.

KUA strives to meet its responsibility to supply its customer's loads in a reliable manner at the lowest achievable cost while maintaining a concern for the environment. KUA is committed to meet its customer's needs and identify projects that will provide economical power through the combination of demand-side and supply-side resources. KUA has been a strong supporter of conservation and demand-side programs where cost-effective. With KUA's ability to pursue very economical supply-side resources, it is difficult for demand-side programs to be cost-effective.

KUA achieves savings through economy interchange and central dispatch which are obtained through participation in the Florida Municipal Power Pool (FMPP) which consists of OUC, Lakeland, KUA, and the FMPA All-Requirements Project.

KUA's mission to provide low cost power while striving to meet or exceed environmental regulations will continue with Stanton A. Stanton A will burn natural gas as the primary fuel with Selective Catalytic Reduction providing a very clean burning, highly efficient unit.

As discussed in the remainder of this application, KUA has evaluated appropriate alternatives to Stanton A to determine if they are lower in cumulative present worth revenue requirements.

KUA believes that Stanton 2 represents the minimal cost and performance risk to its customers due to the proven performance of the "F" class combined cycle technology. As demonstrated in this application, Stanton A has proven to be KUA's most cost-effective alternative through exhaustive evaluations as well as a thorough test of the marketplace.

1C.1.2 Summary

KUA historically has been one of the fastest growing utilities in the United States with a 5.7 percent annual growth rate in peak demand over the last 10 years. Rapid growth is projected to continue with a 3.7 percent annual growth rate in peak demand projected through the end of the 20 year planning period. The development of the proposed World Exposition Center (Expo Center) in KUA's service territory is projected to contribute significantly to KUA's load growth. KUA has incorporated estimates of the direct loads from the Expo Center into KUA's forecast. Indirect loads from the Expo Center are likely to be significant and currently are only considered in sensitivity projections.

KUA is currently using a 15 percent reserve margin for planning purposes. KUA has a supplemental resale contract with Florida Power Corporation which allows KUA to purchase the capacity necessary to maintain a 15 percent reserve margin with the Expo Center's loads. While this purchase has not been explicitly included in KUA's expansion plans, KUA can implement it, if necessary, as the Expo Center loads develop. In 2004, KUA's reserve margin is projected to be negative with and without the Expo Center requiring the addition of capacity.

KUA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. The low cost of Stanton A precludes demand-side alternatives from being cost-effective. Stanton A was found to be the least-cost alternative under both base and sensitivity conditions.

1C.2.0 Description of System

1C.2.1 KUA Structure

The first recorded mention of electric lights, in what was at the time called Kissimmee City, was made during a City Council meeting held 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, in order for the plan to be a success, requests for 300 lights would be required to secure the first electric light plant in the area. During the years to follow, discussions about electric lighting persisted. By 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 the 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¢ per night for each sixteen candle power incandescent light and $7.50 per month for arc lights of standard power.

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

The decades that span the 1900s to the 1980s were spent laying the operational groundwork and infrastructure KUA relies upon so heavily today. The utility's initial purchase, in 1901, was a 16 kilowatt generator. In the 1920s, three diesel engines were added to the system, providing electricity to approximately 200 customers. The 1930s marked the pioneer interconnection between St. Cloud and Kissimmee, and during the 1940s and 1950s the utility worked diligently to increase its distribution capacity. The 1970s proved monumental when Kissimmee and St. Cloud interconnected with the rest of the continental United States through Florida Power Corporation at Lake Bryan.

From 1972 to 1982, the utility experienced multiple management changes, including five different Utility Directors. In 1982, James C. Welsh, the current President and General Manager, replaced Don Hornak as Utility Director. As KUA settled in with a new Director, many accomplishments were realized. One such accomplishment occurred when KUA became joint owners in the St. Lucie nuclear power plant with Florida Power & Light. Additionally, KUA marked its first entry into combustion turbine technology. KUA also reentered the steam electric generation business with the installation of a 50 MW combined cycle unit after many years of sole dependence on diesel type units.

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 an independent board consisting of individuals with strong business backgrounds would best run the authority. 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, voters approved the Charter for Kissimmee Utility Authority.

KUA now operates as an independent utility authority owned by the City of Kissimmee and operated by a five-member Board of Directors plus the mayor of the City of Kissimmee who serves as a nonvoting member. 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. Since becoming an independent utility authority, KUA has enjoyed stable management and has been operated by the Board of Directors in a very business like environment.

1C.2.2 Generation System

KUA owns and operates or has ownership interest in generating units comprised of several technologies, including nuclear, coal fired, diesel, simple cycle combustion turbine, and combined cycle. Table 1C.2-1 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 18 to 42 years. All of these diesel units are located at the Roy B. Hansel Generating Station in Kissimmee. Six of these diesel units are fueled by natural gas with No. 2 oil as pilot oil while the remaining two burn No. 2 oil only. The total nameplate capacity of the eight

Table 1C.2-1
Kissimmee Utility Authority Existing Generating Facilities

Plant	Unit No.	Location (County)	Type	Fuel Primary	Fuel Alternate	Fuel Transportation Primary	Fuel Transportation Alternate	Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability Summer (MW)	Net Capability Winter (MW)
Hansel	8	Osceola	IC	NG	FO2	PL	TK	02/59	-/98	3.00	3	3
	14		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	15		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	16		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	17		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	18		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	19		IC	FO2	---	TK	---	02/83	01/13	2.50	3	3
	20		IC	FO2	---	TK	---	02/83	01/13	2.50	3	3
	21		CT	NG	---	PL	TK	02/83	01/13	35.00	28	32
	22		ST	WH	---	---	---	02/83	01/13	10.00	10	10
	23		ST	WH	---	---	---	02/83	01/13	10.00	10	10
Plant Total										**73.35**	**67**	**71**
Crystal River	3	Citrus	N	UR	---	TK	---	03/77	Unknown	890.46	6[1]	6[1]
Plant Total										**890.46**	**6**	**6**
Stanton Energy Center	1	Orange	ST	BIT	---	RR	---	07/87	Unknown	464.58	21[2]	21[2]
Plant Total										**464.58**	**21**	**21**
Indian River	A	Brevard	CT	NG	FO2	PL	TK	07/89	Unknown	41 40	4.5[3]	5.5[3]
	B		CT	NG	FO2	PL	TK	07/89	Unknown	41.40	4.5[3]	5.5[3]
Plant Total										**82.80**	**9**	**11**
Cane Island	1	Osceola	CT	NG	F02	PL	TK	01/95	Unknown	40.00	15[4]	20[4]
	2		CC	NG	F02	PL	TK	06/95	Unknown	122.00	54[4]	60[4]
Plant Total										**162**	**69**	**80**
System Total as of January 1, 2000											**172**	**189**

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

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. This plant consists of a 35 MW (nameplate) combustion turbine which provides waste heat for two 10 MW (nameplate) steam turbine generators. 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 aeroderivative combustion turbine with a nameplate rating of 42 MW. Unit 2 is a 1 x 1 General Electric Frame 7EA combined cycle with a nameplate rating of 120 MW. KUA and FMPA have also committed to build Cane Island Unit 3, which is a nominal 250 MW combined cycle unit. This unit is currently under construction with an expected commercial operation date of June 28, 2001. KUA's 50 percent ownership share of the Cane Island Units is 206 MW (nameplate).

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 22.3 MW (nameplate), in the Orlando Utilities Commission's (OUC) Stanton Energy Center Unit 1 and a 12.2 percent, or 10 MW (Nameplate), of OUC's Indian River Combustion Turbine Project Units A and B.

1C.2.3 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 No. 1 and half from Unit No. 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 also has a contract with OUC to purchase up to 40 MW from the Stanton 2 plant. The contract ends in December 2000. 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 entitlement acquired from

Homestead and Lake Worth totaling 3.8314 percent. Table 1C.2-2 presents KUA's purchase power resources.

KUA is a member of the Florida Reliability Coordinating Council (FRCC). The FRCC has established an energy broker system which provides economic interchange of electric energy between member utilities, including KUA. KUA has purchased and sold energy through this broker system, and intends to continue such transactions whenever conditions are favorable. Currently, these economy transactions are conducted through the Florida Municipal Power Pool (FMPP).

1C.2.4 Transmission Systems

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 delivered from two 230 kV lines from Cane Island, one 230 kV line from the Taft substation, and a 230/69 kV autotransformer at Taft substation serving KUA's 69 kV line; (iii) the City of St. Cloud, Florida now being operated by OUC, 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.

1C.2.5 Service Area

KUA serves a total area of approximately 85 square miles, which includes the City of Kissimmee and surrounding areas of Osceola County. As of January 1, 2001, KUA served approximately 48,115 electric customers. Of these, 40,172 were residential, 7,272 were general service nondemand, and the remaining 671 were general service demand customers. KUA's electric service area, shown on Figure 1C.2-1, is entirely located in Osceola County.

Table 1C.2-2
KUA's Purchase Power[1]

CY	Utility/Unit (MW)				Annual Total
	St. Lucie 1 & 2	Stanton 1[2]	Stanton 2[3]	OUC[4]	
2000	6.9	7.9	33.3	60	108.1
2001	6.9	7.9	33.3	20	68.1
2002	6.9	7.9	33.3	20	68.1
2003	6.9	7.9	33.3	20	68.1
2004	6.9	7.9	33.3	0	48.1
2005	6.9	7.9	33.3	0	48.1
2006	6.9	7.9	33.3	0	48.1
2007	6.9	7.9	33.3	0	48.1
2008	6.9	7.9	33.3	0	48.1
2009	6.9	7.9	33.3	0	48.1
2010	6.9	7.9	33.3	0	48.1
2011	6.9	7.9	33.3	0	48.1
2012	6.9	7.9	33.3	0	48.1
2013	6.9	7.9	33.3	0	48.1
2014	6.9	7.9	33.3	0	48.1
2015	6.9	7.9	33.3	0	48.1
2016	6.9	7.9	33.3	0	48.1
2017	6.9	7.9	33.3	0	48.1
2018	6.9	7.9	33.3	0	48.1
2019	6.9	7.9	33.3	0	48.1

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 and 40 MW short-term purchase in 2000.

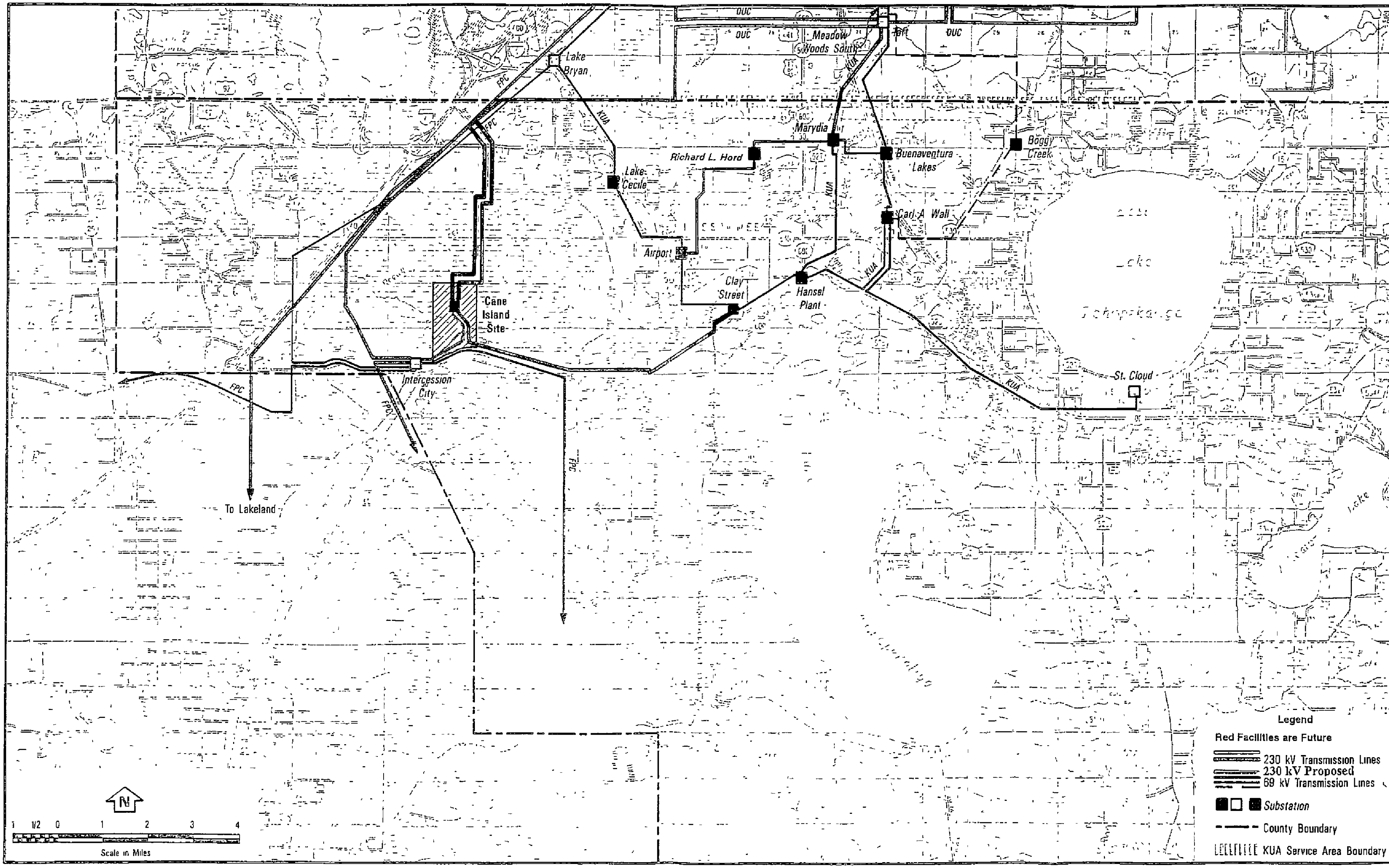

Figure 2-1
Service Area Map

1C.3.0 Evaluation Criteria

KUA as a municipal utility is structured similarly to OUC. For evaluation purposes, the economic criteria for OUC are used for KUA. These evaluation and economic criteria are presented in Section 1A.5.0.

1C.4.0 Forecast of Power Demand and Energy Consumption

1C.4.1 Introduction

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.

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.

1C.4.2 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:

$$Y = a + \sum_{i-1}^{n}[b_i * X_i] + e$$

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.

1C.4.3 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.

1C.4.3.1 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 1999. 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 Metropolitan Statistical Area (MSA) in which Kissimmee is located.

MSAs are 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.

1C.4.3.2 Econometric Projections

The BEBR has estimated that during the next 15 years employment will grow at an average annual rate of 2.2 percent, down from 3.5 percent from 1980 through 1995. Real personal income is estimated to grow at an average annual rate of 3.0 percent, down from 4.1 percent from 1980 through 1995. In general, the slower percentage growth rates of employment and income for Florida are related to a slowing annual population growth rate. Florida's average annual population growth rate is forecast to be 1.6 percent from 1995 through 2010, down from 2.5 percent from 1980 through 1995. Although Osceola County economic and population forecasts show slower growth, Osceola County's annual growth rate continues to exceed the surrounding counties.

Due to publication delays, KUA was forced to use 1998's Long-Term Economic Forecast for economic data. However, the 1999 population forecast was available and was used in the projection of economic data beyond 2010.

1C.4.3.3 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.

The second key assumption of significance to the 2000 sales forecast is the inclusion of estimated annual rate increases scheduled for implementation beginning in October 2000. Currently, rate increases are scheduled as shown in Table 1C.4-1.

Table 1C.4-1
Scheduled Rate Increases

Effective Date	Average Across-the-Board Rate Increase
10/2000	1.6505%
10/2001	1.6508%

1C.4.4 Sales Forecast

1C.4.4.1 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 yielded total annual residential electricity sales.

1C.4.4.1.1 Residential Customers. In the development of the 1999 econometric model for residential customers, Osceola County population (POPA) estimates were used as a potential explanatory variable. Based on KUA's statistical evaluation, POPA outperformed Osceola County total housing starts (TS) in representing the fluctuations in residential customers. Auto-regressive (AR) factors were introduced to minimize the effects of serial correlation. In effect, the AR variable incorporates the residual from previous observations into the regression model for the current observation. The resulting equation and statistics are shown in Table 1C.4-2.

1C.4.4.1.2 Residential Energy Use Per Customer. Residential electricity use per customer was based on the relationship between historical income per household, the previous year's real price of electricity and weather impacts. The resulting equation and statistics are shown in Table 1C.4-2.

1C.4.4.1.3 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.*

<table>
<tr><th colspan="2">Table 1C.4-2
Sales Forecast Equations and Statistics</th></tr>
<tr><td>RSCUSTT = 246.750*POPA + 0.487*_AUTO[-1] + 0.441*AUTO[-2]

RSCUSTT :Total Residential Customers
POPA :Total Population in Osceola County
_AUTO[-1] :First Order Auto-Regressive Term
_AUTO[-2] :Second Order Auto-Regressive Term</td><td><u>Key Statistics</u>:
Adjusted R^2: 0.9982
Durbin-Watson: 2.0970
Bayesian Information Criterion: 270</td></tr>
<tr><td>RSUPC = - 8.562*PRICERES[-12] + 21.805*INCPERHH + 1.367*BM_CDD + 2.295*BM_HDD + 0.534*BM_CDD[-1] + 0.806*BM_HDD[-1] + 0.431*_AUTO[-1]

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[-1] :First Order Auto-Regressive Term</td><td><u>Key Statistics</u>:
Adjusted R^2: 0.9201
Durbin-Watson: 2.078
Bayesian Information Criterion: 68.19</td></tr>
<tr><td>GSNCUSTT = 146.836*POPA + 0.994*_AUTO[-1]
GSNCUSTT :Total General Service Nondemand Customers
POPA :Total Population in Osceola County
_AUTO[-1] :First Order Auto-Regressive Term</td><td><u>Key Statistics</u>:
Adjusted R^2: 0.9981
Durbin-Watson: 1.936
Bayesian Information Criterion: 94.86</td></tr>
<tr><td>GSNKWHT = - 69023.372*PRICEGSN(-12) + 5956.965*RYTOT + 9159.405*BM_CDD + 6367.537*BM_HDD + 5359.291*BM_CDD(-1) + 4364.508*BM_HDD(-1) + 0.324*_AUTO[-1]

GSNKWHT :Total General Service Nondemand Energy Sales
PRICEGSN :General Service Nondemand Real Price of Electricity
RYTOT :Real Personal Income Osceola County
BM_CDD :Billing Month Adjusted Cooling Degree Days
BM_HDD :Billing Month Adjusted Heating Degree Days
_AUTO[-1] :First Order Auto-Regressive Term</td><td><u>Key Statistics</u>:
Adjusted R^2: 0.9539
Durbin-Watson: 1.934
Bayesian Information Criterion:
6.905e+005</td></tr>
</table>

By aligning the sales and degree days, the model became more responsive to changes in temperature.

1C.4.4.2 General Service Nondemand Forecast

The model for the general service nondemand rate classification comprises forecasts for a number of customers and energy sales and includes temporary service and KUA rate classifications.

1C.4.4.2.1 General Service Nondemand Customers. Osceola County population was used as the basis for forecasting the number of general service nondemand customers. The resulting equation and statistics that were developed to forecast the number of general service nondemand customers are shown in Table 1C.4-2.

1C.4.4.2.2 General Service Nondemand Electricity Sales. The general service nondemand model for annual electricity sales is primarily driven by the real price of electricity and real personal income. Weather is also a strong influence on general service nondemand sales. Last year, the model included a variable to reflect the impact of a rate reclassification in October 1990 on customers and sales. This year the model was developed by excluding data prior to October 1991, thereby bypassing the rate reclassification completely. The resulting equation, used to forecast the energy sales in kilowatt-hours for the general service nondemand customer class, is shown in Table 1C.4-2.

1C.4.4.3 General Service Demand 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 approximately 760 customers. 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 continued to decline over the course of the last several years. The initial, and most abrupt, decrease occurred as a result of a shift in rate classification (October 1990) which encouraged the migration of smaller GSD customers to the nondemand classification (GSND). However, the decline did not stop there. In fact, since the beginning of 1992, the net gain in customers is two.

Generally, the general service demand class is a more diversified mix of customers, and are typically fewer in number. Because of class diversity, the general service demand rate classification is also less amenable to statistical methods.

The general service demand customer forecast was evaluated using Box-Jenkins and exponential smoothing models. The historical series for GSD customers does not increase linearly and uniformly or vary with seasons or regularity. The exponential smoothing model forecasts the number of customers to be level at 763 with no projected increase over the forecast horizon.

The forecast of no growth is reasonable given the unexplained variation in GSD customers. Though the net gain in customers since the beginning of 1992 is two, the fluctuations in customers have been as great as 9 percent in 3 months. This size of a drop in general service demand is certainly suspicious. Without understanding the reasons behind data volatility, it is difficult 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.

KUA's Manager of Distribution and planners from the City of Kissimmee were subsequently consulted regarding future large customer expansions. In addition to the information provided by City planners and KUA staff, a review of the energy sales growth rates in GSD shows the smallest increase in energy sales to be approximately 1 percent. Based on conversations with KUA staff and City planners and review of past performance, an annual energy sales increase of 1 percent is recommended for the forecast horizon. It is important to note that the World Expo Center energy sales are in addition to this projected annual growth of 1 percent.

1C.4.4.4 Outdoor Lighting Forecast

Street lighting, vapor lighting, and outdoor lighting were combined into one class for forecasting purposes. This year, the best prediction of future outdoor lighting is simply a linear trend. Because outdoor lighting's contribution to total energy sales is stable and represents less than 0.8 percent, this method of forecasting is both acceptable and relatively accurate.

1C.4.5 Net Energy for Load and Peak Demand Forecast

1C.4.5.1 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 1C.4-3 through 1C.4-5 present KUA's base, high and low case NEL forecasts. Net energy for load is projected to grow at an average annual rate of 3.5 percent from 1999 through 2019 compared to 5.4 percent from 1989 through 1998.

1C.4.5.2 Peak Demand Forecast

The forecast of peak load was prepared using average winter and summer load factors of 52 percent and 50 percent, respectively. 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 is available, peak load is also sensitive to other variables such as cloud cover, humidity, and barometric pressure.

Table 1C.4-6 presents KUA's winter and summer base-, high-, and low-case peak demand forecasts. A 3.7 percent annual summer peak demand growth rate is projected for 2000 through 2019. This growth rate is lower than KUA's historical annual growth rate of 5.7 percent during the last 10 years.

1C.4.6 High and Low Sensitivities

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).

The high and low load forecast sensitivities were developed based on changes in the independent economic variables, specifically, the BEBR's high and low population forecast. The economic forecast provided by BEBR is projected to 2010, and BEBR's long-term population forecast is projected to 2020. The BEBR economic forecast was used through 2010. To develop economic data beyond 2010, the economic data were 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 1C.4-3
Base Case Load Forecast (Includes World Expo Center)

Year	Residential Average Accounts Billed	Residential Sales (MWh)	GS Nondemand Average Accounts Billed	GS Nondemand Sales (MWh)	GS Demand Average Accounts Billed	GS Demand Sales (MWh)	Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
2000	39,766	525,936	8,818	164,977	763	358,262	8,899	49,347	1,058,073	55,688	1,113,762
2001	41,082	554,147	9,146	174,282	763	375,902	9,367	50,991	1,113,699	58,616	1,172,314
2002	42,357	579,853	9,474	183,376	763	402,493	9,853	52,954	1,175,575	61,872	1,237,448
2003	43,642	607,124	9,808	193,098	763	426,550	10,354	54,213	1,237,126	65,112	1,302,238
2004	44,949	637,861	10,148	203,911	763	452,011	10,870	55,861	1,304,653	68,666	1,373,319
2005	46,255	668,996	10,488	214,877	763	467,880	11,388	57,506	1,363,141	71,744	1,434,885
2006	47,427	697,487	10,795	224,938	763	472,438	11,855	58,985	1,406,717	74,038	1,480,755
2007	48,064	726,408	11,102	235,132	763	475,954	12,324	60,468	1,449,818	76,306	1,526,124
2008	49,808	756,254	11,413	245,641	763	479,505	12,805	61,984	1,494,204	78,642	1,572,847
2009	51,041	787,063	11,730	256,479	763	483,092	13,298	63,535	1,539,931	81,049	1,620,980
2010	52,293	818,629	12,050	267,570	763	486,715	13,798	65,107	1,586,712	83,511	1,670,223
2011	53,518	849,962	12,362	278,548	763	490,374	14,287	66,643	1,633,172	85,956	1,719,128
2012	54,763	882,095	12,678	289,794	763	494,069	14,785	68,204	1,680,744	88,460	1,769,204
2013	56,036	915,207	12,999	301,382	763	497,802	15,295	69,799	1,729,686	91,036	1,820,722
2014	57,340	949,329	13,326	313,326	763	501,571	15,816	71,429	1,780,043	93,686	1,873,729
2015	58,662	984,218	13,656	325,540	763	505,379	16,345	73,081	1,831,482	96,394	1,927,876
2016	59,953	1,018,762	13,978	337,610	763	509,225	16,861	74,694	1,882,458	99,077	1,981,534
2017	61,264	1,054,117	14,304	349,964	763	513,109	17,385	76,331	1,934,575	101,820	2,036,395
2018	62,603	1,090,481	14,635	632,684	763	517,032	17,921	78,002	1,988,118	104,638	2,092,756
2019	63,972	1,127,884	14,973	375,784	763	520,994	18,469	79,708	2,043,131	107,533	2,150,664

Table 1C.4-4
High Load Forecast (Includes World Expo Center)

	Residential		GS Nondemand		GS Demand						
Year	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
2000	40,220	536,419	8,990	187,849	763	361,869	9,652	49,973	1,095,789	57,673	1,153,462
2001	41,934	574,115	9,487	204,252	763	385,493	10,599	52,184	1,174,458	61,814	1,236,272
2002	43,675	611,205	9,990	222,597	763	424,631	11,435	54,428	1,269,868	66,835	1,336,703
2003	45,500	651,672	10,514	242,726	763	459,300	12,278	56,777	1,365,975	71,893	1,437,869
2004	47,413	697,465	11,061	265,066	763	476,681	13,155	59,237	1,452,367	76,440	1,528,807
2005	49,385	745,391	11,623	288,592	763	500,758	14,056	61,771	1,548,797	81,516	1,630,312
2006	51,274	791,700	12,160	311,561	763	516,098	14,918	64,197	1,634,277	86,015	1,720,292
2007	53,221	840,111	12,711	335,707	763	523,288	15,807	66,696	1,714,914	90,259	1,805,172
2008	55,252	891,327	13,285	361,403	763	530,622	16,735	69,301	1,800,087	94,741	1,894,828
2009	57,370	945,514	13,883	388,759	763	538,103	17,704	72,016	1,890,079	99,478	1,989,557
2010	59,551	1,002,178	14,497	417,525	763	454,733	18,702	74,812	1,984,137	104,428	2,088,566
2011	61,682	1,058,666	15,097	446,254	763	553,516	19,677	77,542	2,078,112	109,374	2,187,487
2012	63,878	1,117,744	15,713	476,545	763	561,454	20,682	80,355	2,176,334	114,544	2,290,878
2013	66,161	1,179,968	16,354	508,467	763	569,551	21,728	83,278	2,279,714	119,985	2,399,699
2014	68,533	1,245,511	17,019	542,410	763	577,810	22,816	86,316	2,388,547	125,713	2,514,260
2015	70,971	1,313,816	17,703	577,995	763	586,235	23,934	89,437	2,501,980	131,683	2,633,663
2016	73,361	1,381,967	18,371	613,591	763	594,828	25,030	92,495	2,615,415	137,653	2,753,069
2017	75,818	1,453,018	19,059	650,907	763	603,592	26,157	95,640	2,733,674	143,878	2,877,552
2018	78,365	1,527,576	19,772	690,322	763	612,532	27,326	98,900	2,857,756	150,408	3,008,165
2019	81,005	1,605,821	20,510	731,960	763	621,651	28,539	102,278	2,987,972	157,262	3,145,233

Table 1C.4-5
Low Load Forecast (Includes World Expo Center)

Year	Residential		GS Nondemand		GS Demand		Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)					
2000	38,633	506,234	8,590	153,483	763	351,048	8,003	47,986	1,018,768	53,619	1,072,387
2001	38,724	513,320	8,686	147,813	763	359,689	7,718	48,174	1,028,541	54,134	1,082,675
2002	38,840	517,859	8,785	148,818	763	372,497	7,653	48,387	1,046,828	55,096	1,101,924
2003	38,968	523,321	8,882	151,368	763	384,662	7,682	48,612	1,067,033	56,160	1,123,192
2004	39,107	531,152	8,978	155,002	763	396,225	7,754	48,848	1,090,133	57,375	1,147,509
2005	39,213	538,190	9,061	158,289	763	401,027	7,824	49,037	1,105,330	58,175	1,163,505
2006	39,100	540,843	9,085	159,728	763	403,708	7,796	48,948	1,112,075	58,530	1,170,605
2007	38,963	542,910	9,099	160,874	763	403,708	7,757	48,825	1,115,249	58,697	1,173,946
2008	38,833	544,940	9,112	161,982	763	403,708	7,719	48,708	1,118,349	58,860	1,177,209
2009	38,709	546,931	9,124	163,050	763	403,708	7,682	48,596	1,121,371	59,020	1,180,391
2010	38,550	548,091	9,125	163,766	763	403,708	7,627	48,438	1,123,192	59,115	1,182,307
2011	39,192	545,194	9,071	162,823	763	403,708	7,476	48,027	1,119,202	58,905	1,178,107
2012	37,813	541,765	9,010	161,653	763	403,708	7,314	47,586	1,114,439	58,655	1,173,094
2013	37,440	538,315	8,949	160,483	763	403,708	7,152	47,152	1,109,658	58,403	1,168,061
2014	37,074	534,845	8,887	159,315	763	403,708	6,992	46,724	1,104,859	58,150	1,163,010
2015	36,668	530,444	8,814	157,795	763	403,708	6,812	46,245	1,098,759	57,829	1,156,589
2016	36,034	521,410	8,680	154,474	763	403,708	6,524	45,477	1,086,116	57,164	1,143,280
2017	35,380	511,920	8,539	150,993	763	403,708	6,225	44,682	1,072,846	56,466	1,129,312
2018	34,740	502,578	8,400	147,613	763	403,708	5,932	43,903	1,059,830	55,781	1,115,611
2019	34,113	493,382	8,263	144,331	763	403,708	5,644	43,139	1,047,064	55,109	1,102,172

Table 1C.4-6
Summary of Gross Peak Demand

	Winter Peak Demand (MW)			Summer Peak Demand (MW)		
Year	Base	High	Low	Base	High	Low
2000	243	250	237	252	260	246
2001	254	266	237	264	277	246
2002	272	293	243	282	304	253
2003	290	321	250	301	333	260
2004	307	345	257	319	358	267
2005	321	367	261	333	380	271
2006	334	389	264	346	403	274
2007	344	407	264	356	422	275
2008	354	427	265	367	443	275
2009	364	447	266	378	464	276
2010	375	469	266	389	486	277
2011	386	491	266	400	509	276
2012	397	513	265	412	532	275
2013	408	537	264	423	557	274
2014	419	562	262	435	583	272
2015	431	588	261	448	610	271
2016	443	614	259	460	637	268
2017	455	641	256	472	665	265
2018	467	669	253	485	694	262
2019	480	699	250	498	725	259

1C.4.7 Major Additional Loads

The developers of the World Exposition Center (Expo Center) are planning a major commercial development on an 800 acre site in the northwest quarter of KUA's service territory in Osceola County. The construction of this world-class, mixed-used facility is currently in the planning stages and was, at one point, expected to be operational in 2000.

Phase I of the current plan, slated to be completed by the first part of 2000, includes a 2.4 million square foot exposition hall, 1.3 million square foot outside parking area, and 8.6 million square foot parking garage. Phase 1A, scheduled to be completed by the first part of 2001, includes a 1.0 million square foot hotel, 1.3 million square foot county convention center, and 79,000 square feet of commercial office space.

Phase II of construction is projected to be completed during 2002-2004 in stages after Phase I and Phase IA are operational. Phase II facilities include three resort hotels totaling 1.6 million square feet, two office buildings totaling 0.5 million square feet, a 1.0 million square foot retail and entertainment complex, a public safety facility, and 2.0 million square feet of additional parking.

Complete build-out of this facility may require an estimated $1.1 billion. The total employment projection for the project and supporting industries is nearly 30,000 jobs with an estimated annual payroll of $700 million.

At this time, the World Expo Center team is still engaged in planning and negotiating, and plans to build are not yet certain. However, if completed in accordance with current plans, the peak demand and energy requirements of the Expo Center will significantly impact KUA's current system demand and least-cost planning methodology. Accordingly, KUA has conducted a detailed consumption analysis to determine the potential peak demand and energy use of this facility. Due to the lack of data on facilities of this magnitude, demand and energy consumption per square foot from similar-use facilities were used as planning-level estimates.

Table 1C.4-7 shows the base, high and low case annual peak demand and energy forecasts for the World Expo Center. For the current forecast, this project has been delayed 1 year from the original construction plans. This assumption is based on delays which have already taken place, and seem likely to continue.

Table 1C.4-7
World Exposition Center Load Forecast
Annual Peak Demand and Energy

Year	Low Forecast		Base Forecast		High Forecast	
	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)
2002	4.0	5,710	6.6	12,850	10.0	22,355
2003	7.6	10,956	12.9	22,952	19.8	39,703
2004	9.9	15,019	17.5	31,160	27.6	54,195
2005	11.0	20,229	19.6	47,245	30.8	73,398
2006	12.4	23,804	22.3	48,680	35.4	84,453
2007-2019	12.4	23,804	22.3	48,680	35.4	84,453

Source: 1998 Cane Island 3 Need for Power Application Table 1B.5-3, delayed 2 years, and reduced by 50 percent based on revised projections shown in the Journal of Osceola County Business (7/99).

1C.5.0 Demand-Side Programs

According to Section 403.519, Florida Statutes, in its determination of need, the Florida Public Service Commission (FPSC) must take into consideration conservation measures that could mitigate or delay the need of the proposed plant. Based on this requirement, 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.

1C.5.1 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 600 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.
- Fix up 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.

1C.5.1.1 Residential Load Management (SAVE)

KUA currently offers a residential direct load control program which 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 4,891 customers as of September 30, 2000. 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 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 1C.5-1 shows KUA's historical and forecasted estimate of peak demand reductions resulting from this load management program.

Table 1C.5-1 KUA Load Management Impact				
Year	Average Active Customers	Low Case Load Management Impact (MW)	Base Case Load Management Impact (MW)	High Case Load Management Impact (MW)
1993	1,914	-	3.16	-
1994	5,040	-	8.32	-
1995	7,213	-	11.90	-
1996	7,648	-	12.62	-
1997	6,870	-	11.98	-
1998	6,201	-	12.15	-
1999	5,532	-	12.00	-
2000	-	8.9	11.00	13.1
2001	-	7.9	10.00	12.1
2002	-	7.9	10.00	12.1
2003	-	7.9	10.00	12.1
2004	-	7.9	10.00	12.1
2005	-	7.9	10.00	12.1
2006	-	7.9	10.00	12.1
2007	-	7.9	10.00	12.1
2008	-	7.9	10.00	12.1
2009	-	7.9	10.00	12.01

1C.5.1.1.1 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 1C.5-2.

Table 1C.5-2
SAVE Program, Load Management Credits

Appliance	Control Period	Monthly Credit	With Water Heater Control
Water Heater	Year Round	$2.50	--
Central AC (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

1C.5.1.1.2 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.

1C.5.1.2 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.

1C.5.1.3 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 which 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.

1C.5.1.4 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.

1C.5.2 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 as discussed in Section 1A.8.0. For the residential sector, KUA is already implementing the following three DSM measures which 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 which is the BuildSmart EPI less than 90 for new construction. The results of that analysis follow along with the analysis of the commcial off-peak battery charging measure.

1C.5.2.1 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 1C.5-3 presents the FIRE model results of the DSM analysis.

Table 1C.5-3
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.

1C.6.0 Reliability Criteria

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand plus maintain an additional margin of capacity should unforeseen events result in higher system demand or lower than anticipated availability of capacity. This section presents the development of the reliability criteria used by KUA.

1C.6.1 Development of Reliability Criteria

A number of methods are used in the electric utility industry to calculate a utility's system reliability. Two basic methods, known as the Traditional Reserve Margin and the Loss of Load Probability, apply deterministic and probabilistic methods, respectively, to calculate the reliability of a system. The methods are discussed below.

1C.6.1.1 Traditional Reserve Margin

The most commonly used deterministic method is the Traditional Reserve Margin method, which is calculated as follows:

$$\frac{\text{System Net Capacity} - \text{System Net Peak Demand}}{\text{System Net Peak Demand}}$$

From the equation, it is seen that should the net capacity or net peak demand deviate from the predicted levels, the actual reserve margin will vary. For a relatively small or isolated utility system, an unanticipated plant outage or higher than expected growth in system demand can quickly reduce or eliminate the planned reserve margin. A weakness with the formula is that it does not indicate what the appropriate reserve margin is for a given system; the appropriate reserve level must be determined elsewhere.

In establishing the appropriate reserve margin levels, KUA considers the Florida Reliability Coordinating Council (FRCC) minimum planned reserve margin criteria of 15 percent. The Florida Public Service Commission (FPSC) has also established a minimum planned reserve margin criterion of 15 percent in 25-6.035 (1) Fla. Admin. Code, for the purposes of sharing responsibility for grid reliability. Consequently, KUA has established a 15 percent minimum planned reserve margin criteria for both the summer and winter periods

1C.6.1.2 Loss of Load Probability

The second commonly used method of calculating the reliability of a utility system is the Loss of Load Probability (LOLP) method. This method has the advantage in that it can result in a measure of how much capacity and reserves are needed to meet a target level of reliability (most utilities adopt a LOLP of one day in 10 years). Given the nature of KUA's relatively small, high interconnected system, LOLP for KUA's system is driven almost entirely by the interconnections. Since the reliability of the interconnections is driven by the capacity from other systems available to the interconnection, the reliability of interconnections is difficult to predict and is generally out of the control of KUA. For these reasons, KUA does not use LOLP as the reliability criterion and instead uses the reserve margin criterion. LOLP is much better suited for measuring reliability of large systems such as FRCC.

1C.6.2 Reliability Need

KUA's need for capacity is driven by the summer peak demand which exceeds the winter peak demand as shown in Table 1C.4-6. KUA's available capacity is also less in the summer than the winter as shown in Table 1C.2-1.

Table 1C.6-1 compares KUA's net system capacity with summer peak demand during the forecasting period. The reserve margins displayed in the table assume no capacity additions beyond Cane Island 3, from which KUA will receive 120 MW. The capacity required in order for KUA to achieve its summer reserve margin requirements is also shown.

Table 1C.6-1
Projected Reserve Margins – Summer / Base Case

					System Peak Demand (MW)		Reserve Margin (%)		Excess / (Deficit) to Maintain 15 % Reserve Margin (MW)	
Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management
2000	176	108.1	0	284	252	241	12.7	17.8	(6)	7
2001	297	68.1	0	365	264	254	38.8	43.7	61	73
2002	297	68.1	0	365	282	272	29.4	34.2	41	52
2003	297	68.1	0	365	301	291	21.3	25.4	19	30
2004	297	48.1	0	345	319	309	8.2	11.7	(22)	(11)
2005	297	48.1	0	345	333	323	3.6	6.8	(38)	(27)
2006	297	48.1	0	345	346	336	(0.3)	2.7	(53)	(42)
2007	297	48.1	0	345	356	346	(3.1)	(0.3)	(65)	(53)
2008	297	48.1	0	345	367	357	(6.0)	(3.4)	(77)	(66)
2009	297	48.1	0	345	378	368	(8.7)	(6.3)	(90)	(78)
2010	297	48.1	0	345	389	379	(11.3)	(9.0)	(103)	(91)
2011	297	48.1	0	345	400	390	(13.8)	(11.5)	(115)	(104)
2012	297	48.1	0	345	412	402	(16.3	(14.2)	(129)	(118)
2013	297	48.1	0	345	423	413	(18.4)	(16.5)	(142)	(130)
2014	297	48.1	0	345	435	425	(20.7)	(18.8)	(155)	(144)
2015	297	48.1	0	345	448	438	(23.0)	(21.2)	(170)	(159)
2016	297	48.1	0	345	460	450	(25.0)	(23.3)	(184)	(173)
2017	297	48.1	0	345	472	462	(26.9)	(25.3)	(198)	(187)
2018	297	48.1	0	345	485	475	(28.9)	(27.4)	(213)	(201)
2019	297	48.1	0	345	498	488	(30.7)	(29.3)	(228)	(216)

Note: ( ) indicates a negative value.

1C.7.0 Economic Analysis

The economic analysis for the cost-effectiveness of the project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of KUA's customers. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

A four phase economic analysis was conducted to determine KUA's optimum capacity expansion plan. The four phases included supply-side evaluations, demand-side evaluations, proposal evaluations, and sensitivity analyses. The results of the supply-side analyses are included in this section and discussed in detail. The results of the demand-side evaluation analyses are presented in Section 1C.5.0. The proposal evaluations are presented in Section 1A.6. The sensitivity analyses are discussed in Section 1C.8.0.

1C.7.1 Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program and has been used in several other Need for Power proceedings before the FPSC. The program operates on an hourly chronological basis and is used to determine a set of capacity expansion plans based on capacity requirements, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of available generating unit alternatives and purchase power options to maintain user-defined reliability criteria. The reserve requirement utilized was a minimum reserve margin of 15 percent. All capacity expansion plans were analyzed over a twenty-year period from 2000 to 2019.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's detailed chronological production costing program, POWRPRO, was used to obtain the annual production cost for the expansion plan.

1C.7.2 Expansion Candidates

The expansion candidates for the POWROPT evaluation represent the conventional alternatives presented in Section 1A.7.0. Table 1C.7-1 summarizes the expansion alternatives considered for KUA in the optimization study for supply-side alternatives.

Table 1C.7-1
Summary of KUA Generation Alternatives (2000 $, unless otherwise noted)

Description	Capital Costs	Capacity[1]	O&M Costs Variable	O&M Costs Fixed	Fuel Type	Full Load Heat Rate (HHV)[1]	Forced Outage Rate	Scheduled Maintenance	First Year Available
	$1,000	MW	$/MWh	$/kW-yr		Btu/kWh	percent	days/year	
Pulverized Coal (25%)[3]	128,291	111.5	3.73	14.17	Coal	9,979	3.0	30	2006
LM 6000 SC	36,778	35.7	2.53	13.92	Nat. Gas	9,621	5.0	14	2003
7FA SC	73,877	156	2.24	3.63	Nat. Gas	10,940	1.96	7	2005
7FA SC (50 %)	36,939	78	2.24	3.63	Nat. Gas	10,940	1.96	7	2005
WH 501 F 1x1 (50%)[3]	74,736	125	2.49	4.66	Nat. Gas	7,128	2.86	15	2005
7FA 2x1 CC (self-build)[3]	29,021[4]	61	[redacted]	[redacted]	Nat. Gas	[redacted]	4.0	[redacted]	2003[5]
7FA 2x1 CC (joint development)[3]	[redacted]	21	[redacted]	[redacted]	Nat. Gas	[redacted]	[redacted]	[redacted]	2003[5]

1. At 70 – 72 °F, depending on the generation alternative (after degradation).
2. (2003 $)
3. Reflects KUA's portion of total generation alternative capacity.
4. Mixed year dollars to reflect commercial operation date of October 1, 2003.
5. October 1, 2003.

1C.7.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and planned reserve margins. The evaluations were based upon the cost and performance characteristics described in detail in Section 1A.7.0 and summarized in Table 1C.7-1. Production costs were modeled at temperatures which closely approximate (within 2 degrees) the average annual temperature for KUA. Winter and summer unit ratings were used to determine capacity requirements. KUA has not made a final decision regarding joining GridFlorida, the proposed regional transmission organization (RTO). For evaluation purposes, it is assumed that KUA joins GridFlorida and as a result transmission wheeling costs and losses are not included in the economic evaluations because they are assumed to be the same in all plans.

The expansion plan outlined in Table 1C.7-2 shows that the joint development project with Southern-Florida is the least-cost capacity addition plan for KUA under the base case scenario. For comparison purposes, Table 1C.7-3 displays the least-cost expansion capacity addition plan for KUA that does not include the joint-development project with Southern-Florida, while Table 1C.7-4 displays the least-cost expansion capacity addition plan if KUA decides not to participate in the Stanton A project as either a joint development project with Southern-Florida or as a self build project. Table 1C.7-5 displays the least cost expansion plan if the extension of the Southern-Florida PPA for an additional five years is not an option. The units and power purchases comprising the expansion plans are listed in the tables according to their year of commercial operation. Tables 1C.7-6 and 1C.7-7 present the summer capacity balances for the expansion plans presented in Tables 1C.7-2 and 1C.7-3, respectively. For both capacity expansion plans in Tables 1C.7-2 and 1C.7-3, KUA is assumed to sell the excess capacity presented in Table 1C.7-8 to OUC. For the joint development expansion plan in Table 1C.7-2, the excess capacity is sold to OUC at the rates contained in the PPA and for the self build expansion plan the excess capacity is sold at KUA's carrying costs. In essence, KUA's entitlement is merely reduced and transferred to OUC in the 3 years in which Stanton A would provide excess capacity to KUA. Appendix 1C.B presents tables showing the fuel, O&M, and capital costs for expansion plans on an annual basis.

It is clear from a comparison of Tables 1C.7-2, 1C.7-3, and 1C.7-4 that the joint development project with Southern-Florida provides the most cost-effective solution to satisfy KUA's forecast capacity requirements. The joint development project with Southern-Florida results in a projected $1.621 million in cumulative present worth savings over the self build alternative and over $20 million in cumulative present worth savings if Stanton A were not available as a self build alternative. Since participation in

Stanton A as a self build option would not be an alternative for KUA if the Southern-Florida joint development project is implemented, the realistic savings for KUA for participation in the Southern-Florida joint development project are $20 million. Finally, since decisions to extend the Southern-Florida PPA for the additional five year options must be made collectively by OUC, KUA, and FMPA, Table 1C7-5 indicates that not extending the PPA increases KUA's cost $6.4 million which is still $13.6 million less thant if Stanton A were not available. In addition, involvement in the joint development project provides KUA with the flexibility and strategic advantages discussed in Section 1A.6.4.

Table 1C.7-2
KUA Least-Cost Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,105	141,705
2002		56,466	190,116
2003		52,923	232,128
2004	21 MW Joint Development with Southern – Florida (10/03)	47,478	267,026
	40 MW Southern – Florida Power Purchase (10/03)		
2005		49,187	300,501
2006		53,765	334,382
2007		58,157	368,316
2008	78 MW (50%) GE 7FA Simple Cycle (06/08)	63,915	402,848
2009		70,042	437,886
2010		73,457	471,911
2011		81,044	506,669
2012		82,915	539,596
2013	Terminate 40 MW Southern – Florida Power Purchase (11/13)	87,942	571,932
	Extend 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW GE LM6000 Simple Cycle (06/14)	95,845	604,564
2015		103,434	637,170
2016	36 MW GE LM6000 Simple Cycle (06/16)	111,101	669,600
2017		119,133	701,798
2018	36 MW GE LM6000 Simple Cycle (06/18)		
	Terminate 40 MW Southern-Florida Purchase (11/18)	127,578	733,724
2019	36 MW GE LM6000 Simple Cycle (06/19)	136,554	765,365

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

Table 1C.7-3 KUA Least-Cost Runner-Up Base Case Expansion Plan			
Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,105	141,705
2002		56,466	190,116
2003		52,791	232,023
2004	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	48,982	268,026
2005		49,618	301,795
2006		53,228	335,338
2007		57,854	369,095
2008	78 MW (50%) GE 7FA Simple Cycle (06/08)	63,802	403,565
2009		69,769	438,467
2010		73,306	472,422
2011		80,840	507,093
2012		82,790	539,971
2013		87,789	572,250
2014	36 MW GE LM6000 Simple Cycle (06/14)	95,468	604,754
2015		102,931	637,202
2016	36 MW GE LM6000 Simple Cycle (06/16)	110,566	669,475
2017		118,723	701,562
2018	78 MW (50%) GE 7FA Simple Cycle (06/18)	130,679	734,265
2019		141,217	766,986
Note: Capacity is stated at average annual temperature for KUA.			

Table 1C.7-4
KUA Least-Cost Second Runner-Up Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,105	141,705
2002		56,466	190,116
2003		52,040	231,427
2004	36 MW GE LM6000 Simple Cycle (06/04)	50,305	268,403
2005		52,632	304,223
2006	36 MW GE LM6000 Simple Cycle (06/06)	57,444	340,423
2007		62,528	376,907
2008		65,805	412,459
2009	36 MW GE LM6000 Simple Cycle (06/09)	71,300	448,127
2010		76,488	483,556
2011	36 MW GE LM6000 Simple Cycle (06/11)	82,262	518,836
2012		88,774	554,090
2013		92,902	588,250
2014	78 MW (50%) GE 7FA Simple Cycle (06/14)	100,914	622,607
2015		108,481	656,805
2016	36 MW GE LM6000 Simple Cycle (06/16)	114,498	690,226
2017		119,751	722,591
2018		126,780	754,317
2019	36 MW GE LM6000 Simple Cycle (06/16)	134,025	785,373

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

Table 1C.7-5 KUA Joint Development Without PPA Extension Option Base Case Expansion Plan			
Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,105	141,705
2002		56,466	190,116
2003		52,923	232,128
2004	21 MW Joint Development with Southern – Florida (10/03) 40 MW Southern – Florida Power Purchase (10/03)	47,478	267,026
2005		49,187	300,501
2006		53,765	334,382
2007		58,157	368,316
2008	78 MW (50%) GE 7FA Simple Cycle (06/14)	63,915	402,848
2009		70,042	437,886
2010		73,457	471,911
2011		81,044	506,669
2012		82,915	539,596
2013	Terminate 40 MW Southern – Florida Power Purchase (11/13)	88,116	571,996
2014	257 MW (50%) WH 501F 2x1 Combined Cycle (06/14)	98,457	605,517
2015		110,184	640,252
2016		116,082	674,135
2017		121,780	707,048
2018		129,520	739,460
2019	36 MW LM 6000 Simple Cycle (06/19)	139,208	771,717
Note: Capacity is stated at average annual temperature for KUA.			

Table 1C.7-6
KUA Summer Capacity Balance (After Expansion Plan Outlined in Table 1C.7-2)

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
2000	241	0	241	176	108.1	284	43	36.2	7
2001	254	0	254	297	68.1	365	111	38.1	73
2002	272	0	272	297	68.1	365	93	40.8	52
2003	291	0	291	297	68.1	365	74	43.7	30
2004	309	40	349	318	86.8	364	55	52.4	3
2005	323	24	347	318	86.8	380	57	52.1	5
2006	336	10	346	318	86.8	394	58	51.9	6
2007	346	0	346	318	86.8	404	58	51.9	6
2008	357	0	357	388	86.8	474	117	53.6	64
2009	368	0	368	388	86.8	474	106	55.2	51
2010	379	0	379	388	86.8	474	95	56.9	38
2011	390	0	390	388	86.8	474	84	58.5	26
2012	402	0	402	388	86.8	474	72	60.3	12
2013	413	0	413	388	86.8	474	61	62.0	(1)
2014	425	0	425	421	86.8	507	82	63.8	19
2015	438	0	438	421	86.8	507	69	65.7	4
2016	450	0	450	454	86.8	540	90	67.5	23
2017	462	0	462	454	86.8	540	78	69.3	9
2018	475	0	475	487	86.8	573	98	71.3	27
2019	488	0	488	520	48.1	568	80	73.2	6

Table 1C.7-7
KUA Summer Capacity Balance (After Expansion Plan Outlined in Table 1C.7-3)

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
2000	241	0	241	176	108.1	284	43	36.2	7
2001	254	0	254	297	68.1	365	111	38.1	73
2002	272	0	272	297	68.1	365	93	40.8	52
2003	291	0	291	297	68.1	365	74	43.7	30
2004	309	40	349	356	48.1	364	55	52.4	3
2005	323	24	347	356	48.1	380	57	52.1	5
2006	336	10	346	356	48.1	394	58	51.9	6
2007	346	0	346	356	48.1	404	58	51.9	6
2008	357	0	357	426	48.1	474	117	53.6	64
2009	368	0	368	426	48.1	474	106	55.2	51
2010	379	0	379	426	48.1	474	95	56.9	38
2011	390	0	390	426	48.1	474	84	58.5	26
2012	402	0	402	426	48.1	474	72	60.3	12
2013	413	0	413	426	48.1	474	61	62.0	(1)
2014	425	0	425	459	48.1	507	82	63.8	19
2015	438	0	438	459	48.1	507	69	65.7	4
2016	450	0	450	492	48.1	540	90	67.5	23
2017	462	0	462	492	48.1	540	78	69.3	9
2018	475	0	475	562	48.1	610	135	71.3	64
2019	488	0	488	562	48.1	610	122	73.2	49

Table 1C.7-8
Excess KUA Entitlement Sold to OUC

Period	MW[1]
10/01/03-09/30/04	40
10/01/04-09/30/05	24
10/01/05-09/30/06	10
1. Based on 633 MW rating at 70° F.	

1C.8.0 Sensitivity Analysis

KUA performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1C.8.1 through 1C.8.7 and includes high and low fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are identified. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

1C.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1C.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1C.8-2 presents the runner-up expansion plan. The plan including the self build alternative on a cumulative present worth basis over a 20 year planning horizon is only $200,000 lower than the plan with the joint development project.

1C.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1C.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1C.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with a $0.8 million cumulative present worth savings over the self build plan.

1C.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1C.8-5 and Table 1C.8-6 presents the runner-up expansion plan. Under this screen, the expansion plan with the joint development project is $2.1 million lower in cumulative present worth cost.

1C.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1C.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1C.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows a $0.4 million savings over the plan with the self build project.

1C.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1C.8-9 and Table 1C.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $2.9 million.

1C.8.6 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 1C.4. Table 1C.8-11 indicates the summer need for capacity based upon the high load and energy forecast.

As indicated in Table 1C.8-11, the high load and energy growth scenario results in a minimal 4 MW capacity shortfall in the summer of 2003 growing to a 53 MW shortfall in 2004. It has been assumed that KUA will purchase power on the spot market to make up the resultant deficit in 2003.

Table 1C.8-12 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1C.8-13 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the joint development project is $5.4 million lower in cost than the plan including self build alternative.

1C.8.7 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 1C.4.0. Table 1C.8-14 indicates the summer need for capacity based upon the low load and energy forecast.

Capacity additions are not required for the low load and energy forecast, however, for evaluations the effect of adding the joint development project and the self build project are presented in Tables 1C.8-15 and 1C.8-16, respectively.

Table 1C.8-15 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1C.8-16 presents the runner-up expansion plan. Again, the plan with the joint development project is least cost by $6.0 million in cumulative present worth cost over the 20 year period.

1C.8.8 Sensitivity Analysis Summary

The plan with the Southern-Florida joint development project is the lowest cost in all but one of the sensitivity analyses. In several of these analyses, the extension of the PPA for an additional five years is part of the expansion plan. Since extension of the PPA must be done collectively, it may not be possible for KUA to obtain the five year extension. Costs would then increase for the plans with the joint development project. However, a more realistic comparison would be to compare a plan that does not include participation in any project at Stanton Energy Center. For that comparison there would be substantial savings associated with the Southern-Florida joint development project.

Table 1C.8-1
KUA High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,945	142,482
2002		58,330	192,491
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	55,134	236,258
2004		52,393	274,769
2005		53,463	311,155
2006		58,080	347,755
2007		64,441	385,356
2008	36 MW LM6000 Simple Cycle (06/08)	70,300	423,337
2009		77,383	462,047
2010		82,516	500,268
2011	36 MW LM6000 Simple Cycle (06/11)	92,858	540,093
2012		99,036	579,422
2013	36 MW LM6000 Simple Cycle (06/13)	107,486	618,944
2014		117,083	658,807
2015		125,664	698,421
2016	36 MW LM6000 Simple Cycle (06/16)	135,677	738,024
2017		147,901	777,997
2018	36 MW LM6000 Simple Cycle (06/18)	161,858	818,502
2019		174,712	858,985

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

Table 1C.8-2
KUA High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,945	142,482
2002		58,330	192,491
2003	21 MW Joint Development with Southern–Florida (10/03)	55,251	236,351
	40 MW Southern-Florida Power Purchase (10/03)		
2004		50,776	273,673
2005		52,967	309,721
2006		58,544	346,614
2007		64,405	384,194
2008	78 MW 7FA Simple Cycle (06/08)	71,372	422,754
2009		78,956	462,252
2010		84,118	501,215
2011		94,251	541,637
2012		97,760	580,459
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	105,300	619,177
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	115,693	658,566
2015		126,525	698,452
2016	36 MW LM6000 Simple Cycle (06/16)	136,912	738,415
2017			
2018	36 MW LM6000 Simple Cycle (06/18)	148,923	778,665
	Terminate 40 MW Southern–Florida Power Purchase (11/18)	160,795	818,904
2019	36 MW LM6000 Simple Cycle (06/19)	173,713	859,155

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

Table 1C.8-3
KUA Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		74,370	141,024
2002		54,486	187,737
2003	21 MW Joint Development with Southern–Florida (10/03)	50,186	227,576
	40 MW Southern-Florida Power Purchase (10/03)		
2004		44,908	260,585
2005		45,684	291,677
2006		49,457	322,843
2007		52,975	353,753
2008	78 MW 7FA Simple Cycle (06/08)	57,608	384,877
2009		62,455	416,120
2010		64,847	446,157
2011		70,494	476,391
2012		71,114	504,631
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	74,479	532,017
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	80,276	559,348
2015		86,031	586,468
2016	36 MW LM6000 Simple Cycle (06/16)	91,895	613,291
2017		97,631	639,678
2018	36 MW LM6000 Simple Cycle (06/18)	104,038	665,713
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	111,040	691,443

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

Table 1C.8-4
KUA Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		74,370	141,024
2002		54,486	187,737
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	50,050	227,467
2004		46,423	261,590
2005		46,092	292,960
2006		48,902	323,776
2007		52,675	354,512
2008	78 MW 7FA Simple Cycle (06/08)	57,488	385,571
2009		62,157	416,665
2010		64,692	446,630
2011		70,273	476,768
2012		70,967	504,950
2013		74,322	532,278
2014	36 MW LM6000 Simple Cycle (06/14)	79,835	559,459
2015		85,500	586,412
2016	36 MW LM6000 Simple Cycle (06/16)	91,341	613,074
2017		97,153	639,331
2018	78 MW 7FA Simple Cycle (06/18)	106,187	665,905
2019		113,472	692,198

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

Table 1C.8-5
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		54,063	54,063
2001		46,179	96,821
2002		42,078	132,896
2003	21 MW Joint Development with Southern–Florida (10/03)	48,077	171,061
	40 MW Southern-Florida Power Purchase (10/03)		
2004		49,471	207,424
2005		53,768	244,018
2006		58,427	280,837
2007		63,154	317,687
2008	78 MW 7FA Simple Cycle (06/08)	68,896	354,909
2009		75,314	392,585
2010		79,130	429,237
2011		87,394	466,719
2012		89,126	502,112
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	94,343	536,802
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	102,349	571,648
2015		110,563	606,502
2016	36 MW LM6000 Simple Cycle (06/16)	118,357	641,050
2017		126,967	675,365
2018	36 MW LM6000 Simple Cycle (06/18)	136,061	709,414
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	146,296	743,312

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

Table 1C.8-6
KUA AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		54,063	54,063
2001		46,179	96,821
2002		42,078	132,896
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	48,013	171,010
2004		50,841	208,380
2005		54,241	245,296
2006		57,723	281,671
2007		62,981	318,420
2008	78 MW 7FA Simple Cycle (06/08)	69,004	355,701
2009		75,156	393,297
2010		79,042	429,909
2011		87,185	467,301
2012		89,086	502,679
2013		94,265	537,340
2014	36 MW LM6000 Simple Cycle (06/14)	101,954	572,051
2015		110,154	606,776
2016	36 MW LM6000 Simple Cycle (06/16)	117,890	641,187
2017		126,771	675,449
2018	78 MW 7FA Simple Cycle (06/18)	139,838	710,444
2019		150,942	745,419

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

Table 1C.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,958	72,958
2001		64,161	132,366
2002		59,619	183,480
2003	21 MW Joint Development with Southern–Florida (10/03)	67,899	237,380
	40 MW Southern-Florida Power Purchase (10/03)		
2004		70,271	289,032
2005		76,250	340,926
2006		82,215	392,736
2007		88,883	444,598
2008	112 MW Pulverized Coal (06/08)	96,814	496,903
2009		106,897	550,378
2010		110,984	601,785
2011		119,186	652,902
2012		121,684	701,224
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	128,605	748,512
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014		136,325	794,925
2015		144,060	840,339
2016		152,392	884,821
2017	36 MW LM6000 Simple Cycle (06/17)	164,319	929,231
2018	Terminate 40 MW Southern–Florida Power Purchase (11/18)	176,803	973,476
2019	78 MW 7FA Simple Cycle (06/19)	191,457	1,017,839

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

Table 1C.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,958	72,958
2001		64,161	132,366
2002		59,619	183,480
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	67,775	237,282
2004		71,709	289,990
2005		76,700	342,191
2006		81,646	393,642
2007		88,614	445,348
2008	112 MW Pulverized Coal (06/08)	96,479	497,472
2009		106,833	550,915
2010		110,787	602,231
2011		119,032	653,282
2012		121,558	701,554
2013		128,304	748,731
2014		135,902	795,000
2015		143,464	840,226
2016	36 MW LM6000 Simple Cycle (06/16)	154,494	885,322
2017		166,477	930,315
2018		176,409	974,461
2019	36 MW LM6000 Simple Cycle (06/19)	189,113	1,018,281

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

Table 1C.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		62,899	131,197
2002		57,961	180,889
2003	21 MW Joint Development with Southern–Florida (10/03)	64,881	232,394
	40 MW Southern-Florida Power Purchase (10/03)		
2004		65,887	280,822
2005		71,296	329,345
2006		76,525	377,569
2007		82,100	425,474
2008	78 MW 7FA Simple Cycle (06/08)	88,299	473,179
2009		95,686	521,046
2010		99,875	567,307
2011		109,396	614,225
2012		110,759	658,209
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	116,444	701,025
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	124,728	743,490
2015		132,312	785,200
2016	36 MW LM6000 Simple Cycle (06/16)	139,525	825,927
2017		147,465	865,782
2018	36 MW LM6000 Simple Cycle (06/18)	154,721	904,501
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	163,339	942,348

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

Table 1C.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		62,898	131,196
2002		57,961	180,889
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	64,735	232,277
2004		67,382	281,805
2005		71,828	330,690
2006		76,052	378,616
2007		81,875	426,389
2008	78 MW 7FA Simple Cycle (06/08)	88,273	474,080
2009		95,446	521,827
2010		99,797	568,053
2011		109,258	614,911
2012		110,758	658,895
2013		116,399	701,695
2014	36 MW LM6000 Simple Cycle (06/14)	124,528	744,091
2015		131,855	785,658
2016	36 MW LM6000 Simple Cycle (06/16)	139,069	826,251
2017		147,135	866,017
2018	78 MW 7FA Simple Cycle (06/18)	159,363	905,897
2019		169,780	945,237

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

Table 1C.8-11
KUA Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	247	0	0	176	108.1	284	37	37	0\
2001	265	0	0	297	68.1	365	100	40	60
2002	292	0	0	297	68.1	365	73	44	29
2003	321	0	0	297	68.1	365	44	48	(4)
2004	346	0	0	297	48.1	345	0	53	(53)
2005	368	0	0	297	48.1	345	0	78	(78)
2006	391	0	0	297	48.1	345	0	105	(105)
2007	410	0	0	297	48.1	345	0	127	(127)
2008	431	0	0	297	48.1	345	0	151	(151)
2009	452	0	0	297	48.1	345	0	175	(175)
2010	474	0	0	297	48.1	345	0	200	(200)
2011	497	0	0	297	48.1	345	0	227	(227)
2012	520	0	0	297	48.1	345	0	253	(253)
2013	545	0	0	297	48.1	345	0	282	(282)
2014	571	0	0	297	48.1	345	0	312	(312)
2015	598	0	0	297	48.1	345	0	343	(343)
2016	625	0	0	297	48.1	345	0	374	(374)
2017	653	0	0	297	48.1	345	0	406	(406)
2018	682	0	0	297	48.1	345	0	439	(439)
2019	713	0	0	297	48.1	345	0	475	(475)

Table 1C.8-12
KUA High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		76,013	76,013
2001		80,875	150,897
2002		61,970	204,026
2003	21 MW Joint Development with Southern–Florida (10/03)	59,209	251,028
	40 MW Southern-Florida Power Purchase (10/03)	54,817	291,320
2004	36 MW LM6000 Simple Cycle (06/04)	62,223	333,668
2005	78 MW 7FA Simple Cycle (06/05)	70,369	378,012
2006		76,554	422,680
2007		81,721	466,832
2008		89,568	511,638
2009	36 MW LM6000 Simple Cycle (06/09)	98,818	557,410
2010	36 MW LM6000 Simple Cycle (06/10)	109,719	604,467
2011		116,344	650,668
2012	36 MW LM6000 Simple Cycle (06/12)	126,625	697,228
2013	36 MW LM6000 Simple Cycle (06/13)	137,302	743,974
	Terminate 40 MW Southern–Florida Power Purchase (11/13)	149,361	791,059
2014	78 MW 7FA Simple Cycle (06/14)	160,972	838,045
2015	36 MW LM6000 Simple Cycle (06/15)	172,454	884,654
2016	36 MW LM6000 Simple Cycle (06/16)	185,799	931,150
2017	36 MW LM6000 Simple Cycle (06/17)	203,166	978,226
2018	36 MW LM6000 Simple Cycle (06/18)		
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	78 MW 7FA Simple Cycle (06/19)		

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

Table 1C.8-13
KUA High Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		76,013	76,013
2001		80,875	150,897
2002		61,970	204,026
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	59,114	250,953
2004	36 MW LM6000 Simple Cycle (06/04)	56,249	292,298
2005	78 MW 7FA Simple Cycle (06/05)	62,535	334,858
2006		69,686	378,772
2007		76,349	423,321
2008		81,604	467,409
2009	36 MW LM6000 Simple Cycle (06/09)	89,408	512,135
2010	36 MW LM6000 Simple Cycle (06/10)	98,585	557,799
2011		109,371	604,707
2012	36 MW LM6000 Simple Cycle (06/12)	115,988	650,767
2013	36 MW LM6000 Simple Cycle (06/13)	127,355	697,595
2014	78 MW 7FA Simple Cycle (06/14)	140,771	745,522
2015		152,841	793,704
2016	36 MW LM6000 Simple Cycle (06/16)	163,127	841,319
2017	36 MW LM6000 Simple Cycle (06/17)	175,725	888,812
2018	36 MW LM6000 Simple Cycle (06/18)	189,140	936,145
2019	36 MW LM6000 Simple Cycle (06/19)	204,936	983,631

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

Table 1C.8-14
KUA Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
2000	237	0	0	176	108.1	284	47	36	11
2001	238	0	0	297	68.1	365	127	36	91
2002	245	0	0	297	68.1	365	120	37	83
2003	252	0	0	297	68.1	365	113	38	75
2004	259	0	0	297	48.1	345	86	39	47
2005	263	0	0	297	48.1	345	82	39	42
2006	266	0	0	297	48.1	345	79	40	39
2007	267	0	0	297	48.1	345	78	40	38
2008	267	0	0	297	48.1	345	78	40	38
2009	268	0	0	297	48.1	345	77	40	36
2010	269	0	0	297	48.1	345	76	40	35
2011	268	0	0	297	48.1	345	77	40	36
2012	267	0	0	297	48.1	345	78	40	38
2013	266	0	0	297	48.1	345	79	40	39
2014	264	0	0	297	48.1	345	81	40	41
2015	263	0	0	297	48.1	345	82	39	42
2016	260	0	0	297	48.1	345	85	39	46
2017	257	0	0	297	48.1	345	88	39	49
2018	254	0	0	297	48.1	345	91	38	53
2019	251	0	0	297	48.1	345	94	38	56

Table 1C.8-15
KUA Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		68,424	68,424
2001		67,713	131,121
2002		50,042	174,024
2003	21 MW Joint Development with Southern–Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	45,187	209,895
2004		41,431	240,348
2005		42,026	268,950
2006		44,718	297,130
2007		46,696	324,377
2008		48,112	350,370
2009		49,486	375,125
2010		50,945	398,723
2011		53,364	421,610
2012		54,278	443,164
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	54,739	463,292
2014		53,210	481,408
2015		54,930	498,724
2016		56,028	515,078
2017		57,482	530,613
2018		59,263	545,444
2019		60,249	559,404

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

Table 1C.8-16
KUA Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		68,424	68,424
2001		67,713	131,121
2002		50,042	174,024
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	45,017	209,760
2004		42,677	241,129
2005		42,243	269,878
2006		43,900	297,542
2007		46,321	324,570
2008		47,659	350,319
2009		49,017	374,840
2010		50,479	398,221
2011		52,909	420,913
2012		53,934	442,331
2013		55,067	462,579
2014		56,657	481,868
2015		58,612	500,345
2016		60,030	517,867
2017		61,718	534,548
2018		63,238	550,373
2019		64,947	565,422

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

1C.9.0 Financial Analysis

KUA has not made a final decision regarding financing KUA's 3.5 percent equity share of Stanton A. The relatively small amount of equity required may come from a number of sources including retained earnings, tax exempt bond proceeds from either existing or future issues, short term commercial paper or similar instruments, or even the FMPA Pooled Loan Project. For evaluation purposes, a weighted average cost of capital of approximately 8 percent was used.

KUA's strong financial position will support any of the above methods of finance. In Fiscal 1999, KUA operating revenues were $79.7 million with an operating income of $12.0 million. KUA's debt service coverage was 1.81 for Fiscal 1999.

Appendix 1C.A
Economic Evaluation Spreadsheets

Kissimmee Utility Authority

Case

Scenario Southern-Florida Base Case

Economic

CPW Discount Rate	8 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
Joint 7FA SC	78	36,939	12	2008 417	46,242	5,175
LM 6000	36	36,778	8	2014 417	53,095	5,941
LM 6001	36	36,778	8	2016 417	55.783	6.242
LM 6002	36	36,778	8	2018 417	58.607	6.558
LM 6003	36	36,778	8	2019 417	60,072	6.722

Finance

Fixed Charge Rate	11 19%
Interest During Const.	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	71,138	3,968	0	0	75,105	0	75,105	141,705
2002	52,644	3,823	0	0	56,466	0	56,466	190,116
2003	47,624	4,214	807	(9)	52,635	288	52,923	232.128
2004	41,706	4,567	89	(35)	46,327	1,151	47,478	267,026
2005	41,846	4,918	1,306	(35)	48,035	1,151	49,187	300,501
2006	44,969	5,226	2,453	(35)	52,614	1,151	53,765	334,382
2007	48,305	5.524	3,212	(35)	57,006	1,151	58,157	368,316
2008	50,583	5,780	3,417	(34)	59,745	4,170	63,915	402,848
2009	54,101	6,078	3,572	(34)	63,716	6,326	70,042	437,886
2010	57,163	6,419	3,584	(34)	67,131	6,326	73,457	471,911
2011	64,409	6,747	3,596	(34)	74,718	6,326	81,044	506,669
2012	65,852	7,162	3,609	(34)	76,589	6,326	82,915	539,596
2013	70,412	7,554	3,684	(34)	81,616	6,326	87,942	571,932
2014	73,833	7,839	4,415	(34)	86,053	9,792	95,845	604,564
2015	78,153	8,311	4,736	(34)	91,167	12,267	103,434	637,170
2016	81,433	8,593	5,201	(34)	95,193	15,908	111,101	669,600
2017	86,048	9,051	5,557	(33)	100,624	18,509	119,133	701,798
2018	90,458	9,331	5,487	(33)	105,243	22,335	127,578	733,724
2019	94,870	9,258	3,471	(33)	107,566	28,989	136,554	765,365

Notes

(1) Includes start-up costs

(2) Fixed costs are included only for new units

(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case

Scenario Self Build KUA Base

Economic

CPW Discount Rate	8 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003 833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008 417	46,242	5,175
LM 6000	36	36,778	8	2014 412	53,089	5,941
LM 6000	36	36,778	8	2016 412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018 412	59,187	6,623

Finance

Fixed Charge Rate	11 19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	71,138	3,968	0	0	75,105	0	75,105	141,705
2002	52,644	3,823	0	0	56,466	0	56,466	190,116
2003	47,606	4,211	82	13	51,911	880	52,791	232,023
2004	41,884	4,564	(1,037)	51	45,462	3,520	48,982	268,026
2005	42,069	4,923	(947)	53	46,098	3,520	49,618	301,795
2006	45,290	5,222	(857)	54	49,708	3,520	53,228	335,338
2007	48,397	5,523	358	55	54,334	3,520	57,854	369,095
2008	50,861	5,777	570	57	57,264	6,539	63,802	403,565
2009	54,211	6,075	730	58	61,075	8,695	69,769	438,467
2010	57,387	6,416	749	59	64,611	8,695	73,306	472,422
2011	64,570	6,748	767	61	72,146	8,695	80,840	507,093
2012	66,085	7,162	786	62	74,096	8,695	82,790	539,971
2013	70,669	7,556	806	64	79,094	8,695	87,789	572,250
2014	74,166	7,839	1,238	66	83,308	12,160	95,468	604,754
2015	78,354	8,308	1,567	67	88,296	14,635	102,931	637,202
2016	81,599	8,583	2,038	69	92,290	18,276	110,566	669,475
2017	86,331	9,043	2,402	71	97,847	20,877	118,723	701,562
2018	93,641	9,504	2,721	72	105,939	24,740	130,679	734,265
2019	100,702	9,964	2,977	74	113,717	27,500	141,217	766,986

Notes

(1) Includes start-up costs

(2) Fixed costs are included only for new units

(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case

Scenario Base Case Second Runner Up

Economic

CPW Discount Rate	8 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM 6000	36	36,778	8	2004 417	41,478	4,641
LM 6000	36	36,778	8	2006 417	43,578	4,876
LM 6000	36	36,778	8	2009 417	46,928	5,251
LM 6000	36	36,778	8	2011 417	49 304	5 517
Joint 7FA SC	78	36,939	12	2014 417	53,627	6,001
LM 6000	36	36,778	8	2019 417	60,072	6,722

Finance

Fixed Charge Rate	11 19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	71,138	3,968	0	0	75,105	0	75,105	141,705
2002	52,644	3,823	0	0	56,466	0	56,466	190,116
2003	47,871	4,169	0	0	52,040	0	52,040	231,427
2004	42,857	4,420	322	0	47,598	2,707	50,305	268,403
2005	42,666	4,763	562	0	47,991	4,641	52,632	304,223
2006	44,100	4,944	914	0	49,958	7,486	57,444	340,423
2007	46,652	5,177	1,181	0	53,010	9,518	62,528	376,907
2008	49,598	5,478	1,211	0	56,287	9,518	65,805	412,459
2009	51,454	5,660	1,605	0	58,719	12,581	71,300	448,127
2010	53,872	5,938	1,908	0	61,719	14,769	76,488	483,556
2011	55,799	6,137	2,338	0	64,275	17,987	82,262	518,836
2012	59,377	6,437	2,673	0	68,488	20,286	88,774	554,090
2013	63,112	6,764	2,740	0	72,616	20,286	92,902	588,250
2014	67,101	6,983	3,043	0	77,127	23,787	100,914	622,607
2015	71,544	7,361	3,289	0	82,194	26,287	108,481	656,805
2016	77,096	7,744	3,372	0	88,211	26,287	114,498	690,226
2017	81,889	8,119	3,456	0	93,464	26,287	119,751	722,591
2018	88,413	8,538	3,542	0	100,493	26,287	126,780	754,317
2019	90,996	8,725	4,097	0	103,817	30,208	134,025	785,373

Notes

(1) Includes start-up costs

(2) Fixed costs are included only for new units

(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case

Scenario KUA Joint Development without PPA extension Option

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
Joint WH 501F 1x1	125	74,736	23	2014 417	110,182	12,329
LM 6000	36	36,778	8	2019 417	60 072	6,722

Finance

Fixed Charge Rate:	11.19%
Interest During Const..	6%
Finance Term (yrs)	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72 163	72,163
2001	71,138	3,968	0	0	75,105	0	75,105	141,705
2002	52,644	3,823	0	0	56,466	0	56,466	190,116
2003	47,624	4,214	807	(9)	52,635	288	52,923	232,128
2004	41,706	4,567	89	(35)	46,327	1,151	47,478	267,026
2005	41,846	4,918	1,306	(35)	48,035	1,151	49,187	300,501
2006	44,969	5,226	2,453	(35)	52,614	1,151	53,765	334,382
2007	48,305	5,524	3,212	(35)	57,006	1,151	58,157	368,316
2008	50,583	5,780	3,417	(34)	59,745	4,170	63,915	402,848
2009	54,101	6,078	3,572	(34)	63,716	6,326	70,042	437,886
2010	57,163	6,419	3,584	(34)	67,131	6,326	73,457	471,911
2011	64,409	6,747	3,596	(34)	74,718	6,326	81,044	506,669
2012	65,852	7,162	3,609	(34)	76,589	6,326	82,915	539,596
2013	71,171	7,547	3,106	(34)	81,790	6,326	88,116	571,996
2014	76,450	7,490	1,033	(34)	84,939	13,518	98,457	605,517
2015	82,412	7,743	1,408	(34)	91,529	18,655	110,184	640,252
2016	87,858	8,159	1,443	(34)	97,427	18,655	116,082	674,135
2017	93,084	8,595	1,479	(33)	103,125	18,655	121,780	707,048
2018	100,304	9,077	1,516	(33)	110,865	18,655	129,520	739,460
2019	105,169	9,476	2,020	(33)	116,632	22,576	139,208	771,717

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case	
Scenario	Self Build KUA High Fuel

Economic	
CPW Discount Rate	8.0%
Capital Escalation Rate	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	3,520
LM 6000	36	36,778	8	2008.417	45,784	5,123
LM 6000	36	36,778	8	2011.417	49,304	5,517
LM 6000	36	36,778	8	2013.417	51,800	5,796
LM 6000	36	36,778	8	2016.417	55,783	6,242
LM 6000	36	36,778	8	2018.417	58,607	6,558

Finance	
Fixed Charge Rate	11.19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	71,976	3,969	0	0	75,945	0	75,945	142,482
2002	54,507	3,823	0	0	58,330	0	58,330	192,491
2003	49,942	4,217	82	13	54,254	880	55,134	236,258
2004	45,268	4,591	(1,037)	51	48,873	3,520	52,393	274,769
2005	45,921	4,916	(947)	53	49,943	3,520	53,463	311,155
2006	50,143	5,220	(857)	54	54,560	3,520	58,080	347,755
2007	54,966	5,542	358	55	60,921	3,520	64,441	385,356
2008	57,241	5,771	722	57	63,791	6,509	70,300	423,337
2009	61,615	6,069	997	58	68,740	8,643	77,383	462,047
2010	66,372	6,420	1,022	59	73,873	8,643	82,516	500,268
2011	72,851	6,654	1,430	61	80,996	11,862	92,858	540,093
2012	76,031	7,040	1,742	62	84,875	14,160	99,036	579,422
2013	80,385	7,308	2,187	64	89,945	17,542	107,486	618,944
2014	86,909	7,619	2,532	66	97,126	19,957	117,083	658,807
2015	94,913	8,131	2,596	67	105,707	19,957	125,664	698,421
2016	100,546	8,371	3,093	69	112,079	23,598	135,677	738,024
2017	109,305	8,844	3,483	71	121,702	26,199	147,901	777,997
2018	118,512	9,224	4,025	72	131,833	30,025	161,858	818,502
2019	127,773	9,653	4,454	74	141,955	32,757	174,712	858,985

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case	
Scenario	Southern-Florida High Fuel

Economic	
CPW Discount Rate	8 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
Joint 7FA SC	78	36,939	12	2008 417	46,242	5,175
LM 6000	36	36,778	8	2014 417	53,095	5,941
LM 6000	36	36,778	8	2016 417	55,783	6,242
LM 6000	36	36,778	8	2018 417	58,607	6,558
LM 6000	36	36,778	8	2019 417	60,072	6,722

Finance	
Fixed Charge Rate.	11 19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M		Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
		Variable ($1,000)	Fixed[2] ($1,000)					
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	71,976	3,969	0	0	75,945	0	75,945	142,482
2002	54,507	3,823	0	0	58,330	0	58,330	192,491
2003	49,946	4,219	807	(9)	54,963	288	55,251	236,351
2004	44,972	4,599	89	(35)	49,625	1,151	50,776	273,673
2005	45,627	4,917	1,306	(35)	51,816	1,151	52,967	309,721
2006	49,750	5,224	2,453	(35)	57,393	1,151	58,544	346,614
2007	54,530	5,546	3,212	(35)	63,253	1,151	64,405	384,194
2008	58,039	5,780	3,417	(34)	67,202	4,170	71,372	422,754
2009	63,009	6,084	3,572	(34)	72,630	6,326	78,956	462,252
2010	67,815	6,427	3,584	(34)	77,792	6,326	84,118	501,215
2011	77,608	6,755	3,596	(34)	87,925	6,326	94,251	541,637
2012	80,695	7,165	3,609	(34)	91,434	6,326	97,760	580,459
2013	87,764	7,560	3,684	(34)	98,974	6,326	105,300	619,177
2014	93,665	7,855	4,415	(34)	105,901	9,792	115,693	658,566
2015	101,194	8,362	4,736	(34)	114,258	12,267	126,525	698,452
2016	107,160	8,676	5,201	(34)	121,004	15,908	136,912	738,415
2017	115,750	9,140	5,557	(33)	130,414	18,509	148,923	778,665
2018	123,605	9,402	5,487	(33)	138,461	22,335	160,795	818,904
2019	131,912	9,374	3,471	(33)	144,724	28,989	173,713	859,155

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case	
Scenario	Southern-Florida Low Fuel

Economic	
CPW Discount Rate	8 0%
Capital Escalation Rate.	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	[redacted]
Joint 7FA SC	78	36,939	12	2008 417	46,242	5,175
LM 6000	36	36,778	8	2014 417	53,095	5,941
LM 6000	36	36,778	8	2016 417	55,783	6,242
LM 6000	36	36,778	8	2018 417	58,607	6,558
LM 6000	36	36,778	8	2019 417	60,072	6,722

Finance	
Fixed Charge Rate	11 19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	70,404	3,965	0	0	74,370	0	74,370	141,024
2002	50,657	3,828	0	0	54,486	0	54,486	187,737
2003	44,884	4,217	807	(9)	49,899	288	50,186	227,576
2004	39,104	4,599	89	(35)	43,757	1,151	44,908	260,585
2005	38,342	4,920	1,306	(35)	44,533	1,151	45,684	291,677
2006	40,659	5,228	2,453	(35)	48,306	1,151	49,457	322,843
2007	43,103	5,543	3,212	(35)	51,823	1,151	52,975	353,753
2008	44,281	5,774	3,417	(34)	53,438	4,170	57,608	384,877
2009	46,518	6,074	3,572	(34)	56,130	6 326	62 455	416,120
2010	48,538	6,433	3,584	(34)	58,521	6,326	64,847	446,157
2011	53,875	6,731	3,596	(34)	64,168	6,326	70,494	476,391
2012	54,066	7,147	3,609	(34)	64,789	6,326	71,114	504,631
2013	56,957	7,547	3,684	(34)	68,154	6,326	74,479	532,017
2014	58,278	7,825	4,415	(34)	70,484	9,792	80,276	559,348
2015	60,756	8,304	4,736	(34)	73,764	12,267	86,031	586,468
2016	62,217	8,602	5,201	(34)	75,986	15,908	91,895	613,291
2017	64,546	9,052	5,557	(33)	79,122	18,509	97,631	639,678
2018	66,916	9,333	5,487	(33)	81,703	22,335	104,038	665,713
2019	69,336	9,278	3,471	(33)	82,051	28,989	111,040	691,443

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case

Scenario Self Build KUA Low Fuel

Economic

CPW Discount Rate	8 0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003 833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014 412	53,089	5,941
LM 6000	36	36,778	8	2016 412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018.412	59,187	6,623

Finance

Fixed Charge Rate	11 19%
Interest During Const ·	6%
Finance Term (yrs).	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	70,404	3,965	0	0	74,370	0	74,370	141,024
2002	50,657	3,828	0	0	54,486	0	54,486	187,737
2003	44,861	4,214	82	13	49,170	880	50,050	227,467
2004	39,293	4,596	(1,037)	51	42,903	3,520	46,423	261,590
2005	38,542	4,924	(947)	53	42,572	3,520	46,092	292,960
2006	40,963	5,223	(857)	54	45,382	3,520	48,902	323,776
2007	43,198	5,543	358	55	49,155	3,520	52,675	354,512
2008	44,552	5,770	570	57	50,949	6,539	57,488	385,571
2009	46,603	6,071	730	58	53,463	8,695	62,157	416,665
2010	48,758	6,431	749	59	55,997	8,695	64,692	446,630
2011	54,017	6,733	767	61	61,578	8,695	70,273	476,768
2012	54,277	7,147	786	62	62,272	8,695	70,967	504,950
2013	57,211	7,547	806	64	65,628	8,695	74,322	532,278
2014	58,547	7,824	1,238	66	67,675	12,160	79,835	559,459
2015	60,929	8,302	1,567	67	70,865	14,635	85,500	586,412
2016	62,365	8,592	2,038	69	73,065	18,276	91,341	613,074
2017	64,761	9,043	2,402	71	76,277	20,877	97,153	639,331
2018	69,170	9,483	2,721	72	81,447	24,740	106,187	665,905
2019	72,977	9,945	2,977	74	85,973	27,500	113,472	692,198

Notes

(1) Includes start-up costs

(2) Fixed costs are included only for new units

(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case

Scenario Southern-Florida AEO

Economic

CPW Discount Rate.	8 0%
Capital Escalation Rate	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	[redacted]
Joint 7FA SC	70	36,939	12	2008 417	46,242	5,175
LM 6000	36	36,778	8	2014 417	53,095	5,941
LM 6000	36	36,778	8	2016 417	55,783	6,242
LM 6000	36	36,778	8	2018 417	58,607	6,558
LM 6000	36	36,778	8	2019 417	60,072	6,722

Finance

Fixed Charge Rate	11.19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	49,846	4,217	0	0	54,063	0	54,063	54,063
2001	42,158	4,021	0	0	46,179	0	46,179	96,821
2002	38,243	3,835	0	0	42,078	0	42,078	132,896
2003	42,769	4,222	807	(9)	47,789	288	48,077	171,061
2004	43,664	4,602	89	(35)	48,320	1,151	49,471	207,424
2005	46,419	4,926	1,306	(35)	52,617	1,151	53,768	244,018
2006	49,620	5,237	2,453	(35)	57,276	1,151	58,427	280,837
2007	53,269	5,557	3,212	(35)	62,003	1,151	63,154	317,687
2008	55,556	5,787	3,417	(34)	64,726	4,170	68,896	354,909
2009	59,360	6,091	3,572	(34)	68,988	6,326	75,314	392,585
2010	62,822	6,433	3,584	(34)	72,805	6,326	79,130	429,237
2011	70,737	6,769	3,596	(34)	81,068	6,326	87,394	466,719
2012	72,045	7,180	3,609	(34)	82,800	6,326	89,126	502,112
2013	76,791	7,577	3,684	(34)	88,018	6,326	94,343	536,802
2014	80,298	7,879	4,415	(34)	92,557	9,792	102,349	571,648
2015	85,229	8,365	4,736	(34)	98,296	12,267	110,563	606,502
2016	88,639	8,642	5,201	(34)	102,448	15,908	118,357	641,050
2017	93,835	9,099	5,557	(33)	108,458	18,509	126,967	675,365
2018	98,873	9,399	5,487	(33)	113,726	22,335	136,061	709,414
2019	104,493	9,376	3,471	(33)	117,307	28,989	146,296	743,312

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case	
Scenario	Self Build KUA AEO

Economic	
CPW Discount Rate	8 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003 833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008 417	46,242	5,175
LM 6000	36	36,778	8	2014 412	53,089	5,941
LM 6000	36	36,778	8	2016 412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018 412	59,187	6,623

Finance	
Fixed Charge Rate·	11 19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	49,846	4,217	0	0	54,063	0	54,063	54,063
2001	42,158	4,021	0	0	46,179	0	46,179	96,821
2002	38,243	3,835	0	0	42,078	0	42,078	132,896
2003	42,818	4,220	82	13	47,133	880	48,013	171,010
2004	43,706	4,601	(1,037)	51	47,321	3,520	50,841	208,380
2005	46,687	4,928	(947)	53	50,721	3,520	54,241	245,296
2006	49,768	5,238	(857)	54	54,203	3,520	57,723	281,671
2007	53,488	5,559	358	55	59,461	3,520	62,981	318,420
2008	56,054	5,785	570	57	62,465	6,539	69,004	355,701
2009	59,585	6,088	730	58	66,461	8,695	75,156	393,297
2010	63,108	6,432	749	59	70,348	8,695	79,042	429,909
2011	70,895	6,767	767	61	78,490	8,695	87,185	467,301
2012	72,362	7,181	786	62	80,392	8,695	89,086	502,679
2013	77,121	7,579	806	64	85,570	8,695	94,265	537,340
2014	80,614	7,876	1,238	66	89,794	12,160	101,954	572,051
2015	85,522	8,363	1,567	67	95,519	14,635	110,154	606,776
2016	88,875	8,631	2,038	69	99,614	18,276	117,890	641,187
2017	94,329	9,092	2,402	71	105,894	20,877	126,771	675,449
2018	102,742	9,562	2,721	72	115,098	24,740	139,838	710,444
2019	110,345	10,047	2,977	74	123,442	27,500	150,942	745,419

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case	
Scenario	Southern-Florida 2000 + AEO

Economic	
CPW Discount Rate	8 0%
Capital Escalation Rate	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
Coal	112	128,291	42	2008 417	167,486	18,742
LM 6000	36	36,778	8	2017 417	57,178	6,398
Joint 7FA SC	70	36,939	12	2019 417	60,674	6,789

Finance	
Fixed Charge Rate	11 19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life.	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,741	4,217	0	0	72,958	0	72,958	72,958
2001	60,154	4,007	0	0	64,161	0	64,161	132,366
2002	55,784	3,836	0	0	59,619	0	59,619	183,480
2003	62,586	4,227	807	(9)	67,611	288	67,899	237,380
2004	64,463	4,603	89	(35)	69,119	1,151	70,271	289,032
2005	68,896	4,931	1,306	(35)	75,099	1,151	76,250	340,926
2006	73,407	5,238	2,453	(35)	81,064	1,151	82,215	392,736
2007	78,996	5,558	3,212	(35)	87,731	1,151	88,883	444,598
2008	74,221	6,200	4,343	(34)	84,730	12,084	96,814	496,903
2009	75,113	6,735	5,191	(34)	87,004	19,893	106,897	550,378
2010	78,743	7,138	5,244	(34)	91,091	19,893	110,984	601,785
2011	86,566	7,464	5,298	(34)	99,293	19,893	119,186	652,902
2012	88,577	7,895	5,353	(34)	101,791	19,893	121,684	701,224
2013	94,958	8,317	5,471	(34)	108,712	19,893	128,605	748,512
2014	101,926	8,705	5,835	(34)	116,432	19,893	136,325	794,925
2015	109,103	9,203	5,894	(34)	124,167	19,893	144,060	840,339
2016	116,879	9,698	5,956	(34)	132,499	19,893	152,392	884,821
2017	124,153	10,113	6,461	(33)	140,694	23,625	164,319	929,231
2018	133,637	10,628	6,280	(33)	150,512	26,291	176,803	973,476
2019	146,413	11,071	3,754	(33)	161,205	30,252	191,457	1,017,839

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case	
Scenario	Self Build KUA 2000 + AEO

Economic	
CPW Discount Rate	8 0%
Capital Escalation Rate	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003 833	31,458	3.520
Joint 7FA SC	78	36.939	12	2008 417	46,242	5.175
LM 6000	36	36,778	8	2014 412	53,089	5.941
LM 6000	36	36,778	8	2016 412	55,776	6,241
Joint 7FA SC	78	36.939	12	2018 412	59,187	6.623

Finance	
Fixed Charge Rate	11 19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,741	4,217	0	0	72,958	0	72,958	72,958
2001	60,154	4,007	0	0	64,161	0	64,161	132,366
2002	55,784	3,836	0	0	59,619	0	59,619	183,480
2003	62,574	4,226	82	13	66,895	880	67,775	237,282
2004	64,572	4,602	(1,037)	51	68,189	3,520	71,709	289,990
2005	69,146	4,928	(947)	53	73,180	3,520	76,700	342,191
2006	73,689	5,240	(857)	54	78,126	3,520	81,646	393,642
2007	79,125	5,556	358	55	85,094	3,520	88,614	445,348
2008	74,276	6,197	1,496	57	82,026	14,453	96,479	497,472
2009	75,436	6,728	2,350	58	84,571	22,262	106,833	550,915
2010	78,920	7,137	2,408	59	88,525	22,262	110,787	602,231
2011	86,783	7,458	2,469	61	96,770	22,262	119,032	653,282
2012	88,816	7,888	2,530	62	99,296	22,262	121,558	701,554
2013	95,070	8,315	2,593	64	106,042	22,262	128,304	748,731
2014	102,214	8,702	2,658	66	113,640	22,262	135,902	795,000
2015	109,208	9,202	2,725	67	121,202	22,262	143,464	840,226
2016	115,650	9,647	3,225	69	128,591	25,903	154,494	885,322
2017	124,192	10,091	3,619	71	137,973	28,504	166,477	930,315
2018	133,488	10,635	3,709	72	147,905	28,504	176,409	974,461
2019	141,229	11,117	4,268	74	156,688	32,425	189,113	1,018,281

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case	
Scenario	Southern-Florida No Real

Economic	
CPW Discount Rate	8 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
Joint 7FA SC	78	36,939	12	2008 417	46,242	5,175
LM 6000	36	36,778	8	2014 417	53,095	5,941
LM 6000	36	36,778	8	2016 417	55,783	6,242
LM 6000	36	36,778	8	2018 417	58,607	6,558
LM 6000	36	36,778	8	2019 417	60,072	6,722

Finance	
Fixed Charge Rate	11 19%
Interest During Const ·	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,740	4,217	0	0	72,957	0	72,957	72,957
2001	58,924	3,974	0	0	62,899	0	62,899	131,197
2002	54,123	3,838	0	0	57,961	0	57,961	180,889
2003	59,577	4,218	807	(9)	64,593	288	64,881	232,394
2004	60,114	4,567	89	(35)	64,735	1,151	65,887	280,822
2005	63,944	4,929	1,306	(35)	70,145	1,151	71,296	329,345
2006	67,720	5,235	2,453	(35)	75,374	1,151	76,525	377,569
2007	72,218	5,554	3,212	(35)	80,949	1 151	82,100	425,474
2008	74,933	5,813	3,417	(34)	84,129	4,170	88,299	473,179
2009	79,681	6,142	3,572	(34)	89,360	6,326	95,686	521,046
2010	83,499	6,500	3,584	(34)	93,549	6,326	99,875	567,307
2011	92,684	6,824	3,596	(34)	103,070	6,326	109,396	614,225
2012	93,614	7,244	3,609	(34)	104,433	6,326	110,759	658,209
2013	98,826	7,642	3,684	(34)	110,118	6,326	116,444	701,025
2014	102,592	7,963	4,415	(34)	114,936	9,792	124,728	743,490
2015	106,911	8,432	4,736	(34)	120,045	12,267	132,312	785,200
2016	109,733	8,716	5,201	(34)	123,617	15,908	139,525	825,927
2017	114,267	9,164	5,557	(33)	128,955	18,509	147,465	865,782
2018	117,509	9,423	5,487	(33)	132,387	22,335	154,721	904,501
2019	121,515	9,398	3,471	(33)	134,350	28,989	163,339	942,348

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case	
Scenario	Self Build KUA No Real

Economic	
CPW Discount Rate	8 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003 833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008 417	46,242	5,175
LM 6000	36	36,778	8	2014 412	53,089	5,941
LM 6000	36	36,778	8	2016 412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018 412	59,187	6,623

Finance	
Fixed Charge Rate	11 19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,740	4,217	0	0	72,957	0	72,957	72,957
2001	58,924	3,974	0	0	62,898	0	62,898	131,196
2002	54,123	3,838	0	0	57,961	0	57,961	180,889
2003	59,546	4,215	82	13	63,855	880	64,735	232,277
2004	60,283	4,565	(1,037)	51	63,862	3,520	67,382	281,805
2005	64,268	4,934	(947)	53	68,308	3,520	71,828	330,690
2006	68,105	5,231	(857)	54	72,532	3,520	76,052	378,616
2007	72,387	5,554	358	55	78,354	3,520	81,875	426,389
2008	75,296	5,812	570	57	81,734	6,539	88,273	474,080
2009	79,822	6,141	730	58	86,752	8,695	95,446	521,827
2010	83,796	6,499	749	59	91,103	8,695	99,797	568,053
2011	92,910	6,825	767	61	100,563	8,695	109,258	614,911
2012	93,968	7,246	786	62	102,063	8,695	110,758	658,895
2013	99,188	7,646	806	64	107,704	8,695	116,399	701,695
2014	103,101	7,963	1,238	66	112,368	12,160	124,528	744,091
2015	107,156	8 430	1,567	67	117,220	14,635	131,855	785,658
2016	109,975	8 710	2,038	69	120,793	18,276	139,069	826,251
2017	114,629	9,157	2,402	71	126,259	20,877	147,135	866,017
2018	122,177	9,652	2 721	72	134 623	24,740	159,363	905,897
2019	129,093	10,136	2,977	74	142,280	27,500	169,780	945,237

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case

Scenario Southern-Florida High Load

Economic

CPW Discount Rate	8 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1 000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
LM 6000	36	36 778	8	2004 417	41 478	4 641
Joint 7FA SC	78	36,939	12	2005 417	42,941	4,805
LM 6000	36	36,778	8	2009 417	46,928	5,251
LM 6000	36	36,778	8	2010 417	48 102	5,383
LM 6000	36	36,778	8	2012 417	50,537	5,655
LM 6000	36	36,778	8	2013 417	51,800	5,796
Joint 7FA SC	78	36,939	12	2014 417	53,627	6,001
LM 6000	36	36,778	8	2015 417	54,423	6,090
LM 6000	36	36,778	8	2016 417	55,783	6,242
LM 6000	36	36,778	8	2017 417	57,178	6,398
LM 6000	36	36,778	8	2018 417	58,607	6,558
Joint 7FA SC	78	36939	12	2019 417	60,674	6 789

Finance

Fixed Charge Rate	11 19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	71 674	4 339	0	0	76,013	0	76,013	76,013
2001	76 691	4,184	0	0	80,875	0	80,875	150 897
2002	57,795	4,175	0	0	61,970	0	61,970	204,026
2003	53 429	4 694	807	(9)	58 921	288	59,209	251,028
2004	45,519	5,063	410	(35)	50 958	3 859	54,817	291,320
2005	46,100	5,506	2,056	(35)	53 627	8 596	62,223	333,668
2006	50 490	5 958	3 358	(35)	59 772	10 598	70 369	378,012
2007	55 473	6 378	4 139	(35)	65 956	10 598	76 554	422,680
2008	60 132	6 861	4 165	(34)	71 124	10 598	81 721	466 832
2009	64 099	7 286	4 556	(34)	75 907	13 661	89,568	511,638
2010	66 907	7 727	5,229	(34)	79 829	18,989	98 818	557,410
2011	74,882	8,087	5,552	(34)	88 487	21 232	109,719	604,467
2012	77 155	8 686	6 006	(34)	91,813	24,530	116,344	650,668
2013	81,121	9,021	6,248	(34)	96,357	30,268	126,625	697,228
2014	87,880	8,977	4,295	(34)	101,119	36,184	137,302	743,974
2015	92 773	9 391	4,994	(34)	107 125	42,236	149,361	791 059
2016	97,051	9,683	5,857	(34)	112,557	48,415	160,972	838,045
2017	100 919	10,061	6 759	(33)	117,705	54 748	172 454	884,654
2018	106 503	10,386	7,703	(33)	124 560	61 240	185,799	931,150
2019	115,834	10 942	8,490	(33)	135,233	67,933	203 166	978,226

Notes

(1) Includes start-up costs

(2) Fixed costs are included only for new units

(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case	
Scenario	Self Build KUA High Load

Economic	
CPW Discount Rate	8 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1 000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	21			2003 833	31 458	3,520
LM 6000	36	36 778	8	2004 417	41 478	4,641
Joint 7FA SC	78	36,939	12	2005 417	42,941	4,805
LM 6000	36	36 778	8	2009 417	46,928	5 251
LM 6000	36	36,778	8	2010 417	48,102	5 383
LM 6000	36	36 778	8	2012 417	50,537	5,655
LM 6000	36	36,778	8	2013 417	51,800	5 796
Joint 7FA SC	78	36 939	12	2014 417	53,627	6 001
LM 6000	36	36 778	8	2016 417	55 783	6 242
LM 6000	36	36 778	8	2017 417	57 178	6 398
LM 6000	36	36,778	8	2018 417	58 607	6 558
LM 6000	36	36778	8	2019 417	60,072	6,722

Finance	
Fixed Charge Rate	11 19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1 000)	O&M Variable ($1 000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	71,674	4,339	0	0	76 013	0	76,013	76,013
2001	76,691	4 184	0	0	80,875	0	80,875	150 897
2002	57 795	4 175	0	0	61 970	0	61,970	204 026
2003	53,445	4 694	82	13	58 234	880	59 114	250 953
2004	45 623	5 063	(715)	51	50 022	6 228	56,249	292 298
2005	46 212	5 502	(197)	53	51 570	10 964	62 535	334 858
2006	50 663	5,955	48	54	56 719	12 967	69 686	378 772
2007	55 670	6,371	1 286	55	63 383	12,967	76,349	423 321
2008	60,408	6 856	1,318	57	68 638	12 967	81,604	467 409
2009	64 328	7,278	1 715	58	73 376	16 030	89,408	512 135
2010	67 067	7,708	2 394	59	77,228	21,358	98,585	557 799
2011	74 914	8,072	2,723	61	85 771	23,600	109,371	604 707
2012	77 184	8,658	3,183	62	89,088	26,899	115,988	650 767
2013	81,606	9,100	3,948	64	94,718	32,637	127 355	697 595
2014	88,057	9,524	4,572	66	102,218	38 552	140 771	745,522
2015	96 615	10 251	4 856	67	111 789	41,053	152 841	793 704
2016	102,321	10 633	5 410	69	118,433	44 694	163 127	841 319
2017	107,176	11 150	6 301	71	124 698	51 027	175 725	888,812
2018	112 877	11 438	7 234	72	131 621	57 519	189,140	936,145
2019	120,418	12 062	8,209	74	140,764	64 172	204 936	983,631

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case	
Scenario	Southern-Florida Low Load

Economic	
CPW Discount Rate	8 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	

Finance	
Fixed Charge Rate	11 19%
Interest During Const	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	64,345	4,079	0	0	68,424	0	68,424	68,424
2001	64,062	3,650	0	0	67,713	0	67,713	131 121
2002	46,675	3,367	0	0	50,042	0	50,042	174,024
2003	40,487	3,615	807	(9)	44,899	288	45,187	209,895
2004	36,383	3,842	89	(35)	40,280	1,151	41,431	240,348
2005	35,577	4,026	1,306	(35)	40,874	1,151	42,026	268,950
2006	36,982	4,166	2,453	(35)	43,567	1,151	44,718	297,130
2007	38,122	4,246	3,212	(35)	45,545	1,151	46,696	324,377
2008	39,402	4,378	3,215	(34)	46,960	1,151	48,112	350,370
2009	40,684	4,467	3,218	(34)	48,335	1,151	49,486	375,125
2010	41,998	4,609	3,221	(34)	49,794	1,151	50,945	398,723
2011	44,333	4,690	3,225	(34)	52,213	1,151	53,364	421,610
2012	45,089	4,844	3,228	(34)	53,127	1,151	54,278	443,164
2013	46,030	4,876	2,716	(34)	53,588	1,151	54,739	463,292
2014	47,104	4 839	149	(34)	52,058	1,151	53,210	481,408
2015	48,710	4,949	153	(34)	53,778	1,151	54,930	498,724
2016	49,764	4,990	157	(34)	54,877	1,151	56,028	515,078
2017	51,136	5,068	161	(33)	56,331	1,151	57,482	530,613
2018	52,841	5,139	165	(33)	58,112	1,151	59,263	545,444
2019	53,824	5,138	169	(33)	59,098	1,151	60,249	559,404

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case

Scenario Self Build KUA Low Load

Economic

CPW Discount Rate	8 0%
Capital Escalation Rate	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003 833	31,458	3,520

Finance

Fixed Charge Rate	11 19%
Interest During Const ·	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	64,345	4,079	0	0	68,424	0	68,424	68,424
2001	64,062	3,650	0	0	67,713	0	67,713	131,121
2002	46 675	3,367	0	0	50,042	0	50,042	174,024
2003	40,432	3,610	82	13	44,137	880	45,017	209,760
2004	36,308	3,834	(1,037)	51	39,156	3,520	42,677	241,129
2005	35,601	4,015	(947)	53	38,722	3,520	42,243	269,878
2006	37,025	4,158	(857)	54	40,380	3,520	43,900	297,542
2007	38,146	4,242	358	55	42,801	3,520	46,321	324,570
2008	39,346	4,369	367	57	44,138	3,520	47,659	350,319
2009	40,604	4,458	376	58	45,497	3,520	49,017	374,840
2010	41,916	4,598	386	59	46,959	3,520	50,479	398,221
2011	44,251	4,681	395	61	49,389	3,520	52,909	420,913
2012	45,112	4,833	405	62	50,413	3,520	53,934	442,331
2013	46,163	4,904	415	64	51,547	3,520	55,067	462,579
2014	47 663	4,983	426	66	53 137	3 520	56,657	481,868
2015	49,469	5,119	437	67	55 092	3 520	58,612	500,345
2016	50,830	5,164	447	69	56,510	3,520	60,030	517,867
2017	52,401	5,267	459	71	58,198	3,520	61,718	534,548
2018	53,864	5,312	470	72	59,718	3,520	63,238	550,373
2019	55,496	5,375	482	74	61,427	3,520	64,947	565,422

Notes
(1) Includes start-up costs.
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water