DISTRIBUTION CENTER

07 MAR 29 PM 2:47

JEA

ORIGINAL

March 28, 2007

Tom Ballinger
Bureau of Electric Reliability/Conservation
Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Ballinger:

Attached you will find 25 copies of JEA's 2007 Ten Year Site Plan filing. If you have any questions regarding this response or any additional questions, please contact me at (904) 665-6216.

Thank You,

Mary Guyton Baker

Mary Guyton Baker,
PE, Electric System Planning

CMP ____
COM ____
CTR ____
ECR ____
GCL ____
OPC ____
RCA ____
SCR ____
SGA ____
SEC ____
OTH 2 cys to Lim P.

DOCUMENT NUMBER-DATE
02742 MAR 29 07
FPSC-COMMISSION CLERK

Ten Year Site Plan

JEA®

Building Community®

April 2007

Table of Contents

APPENDIX A: Ten Year Site Plan Schedules

List of Tables

List of Figures

1.0 Introduction

The objective of JEA's Ten-Year Site Plan is to develop an environmentally sound power supply strategy, which provides reliable electric service at the lowest practical cost. This report represents the 2007 Ten Year Site Plan for JEA covering a planning period from 2007 to 2016.

2.0 Existing Facilities

2.1 Power Supply System Description

2.1.1 System Summary

JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers all of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles and serves more than 400,000 customers.

JEA consists of three financially separate entities: the JEA Electric System, the St. Johns River Power Park bulk power system, and the Robert W. Scherer bulk power system. The total net capability of JEA's generation system is 3,620 MW in the winter and 3,370 MW in the summer. Details of the existing facilities are displayed in Appendix A, TYSP Schedule 1.

The JEA Electric System

The Electric System consists of generating facilities located on three plant sites within the City; the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), and the Brandy Branch Generating Station (Brandy Branch). Collectively, these plants consist of two dual-fired (petroleum coke/coal) Circulating Fluidized Bed steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); four dual-fired (gas/diesel) combustion turbine-generator units (Kennedy CT 7, Brandy Branch CTs 1, 2, and 3); seven diesel-fired combustion turbine-generator units (Kennedy CTs 3, 4, and 5 and Northside CTs 3, 4, 5, and 6); and one combined cycle heat recovery steam generator unit (Brandy Branch steam Unit 4), see Appendix A, TYSP Schedule 1.

The Bulk Power Systems

St. John's River Power Park

The St. Johns River Power Park (SJRPP) is jointly owned by JEA (80 percent) and FP&L (20 percent). SJRPP consists of two nominal 638 MW bituminous coal fired units located north of the Northside Generating Station in Jacksonville, FL. Unit 1 began commercial operation in March of 1987 and Unit 2 followed in May of 1988. The two units have operated efficiently since commercial operation. To reduce fuel costs and increase fuel diversity, a 28% blend of petroleum coke and coal is currently being burned in the units.

Although JEA is the majority owner of SJRPP, both owners are entitled to 50 percent of the output of SJRPP. Since FP&L's ownership is only 20 percent, JEA has agreed to sell, and FPL has agreed to purchase, on a "take-or-pay" basis, 37.5 percent of JEA's 80 percent share of the generating capacity and related energy of SJRPP. This sale will continue until the earlier of the Joint Ownership Agreement expiration in 2022 or the realization of the sale limits. According to JEA's calculation, FP&L will reach this limit in February 2014. JEA believes that its calculation is accurate and consistent with the terms of the Power Park Joint Ownership Agreement. Therefore, for the purposes of this Ten Year Site Plan, the 37.5% sale to FP&L is suspended as of February 28, 2014.

Robert W. Scherer Generating Station

Robert W. Scherer Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. JEA and FP&L have purchased an undivided interest of this unit from Georgia Power Company. JEA has a 23.6 percent ownership interest in Unit 4 (200 net MW) and proportionate ownership interests in associated common facilities and the associated coal stockpile. JEA purchased 150 megawatts of Scherer Unit 4 in July 1991, and purchased an additional 50 megawatts on June 1, 1995. Georgia ITS delivers the power from the unit to the jointly owned 500 kV transmission lines.

2.1.2 Purchased Power

Southern Company Unit Power Sales

Southern Company and JEA entered a Unit Power Sales (UPS) contract in which JEA currently purchases 200 MW of firm capacity and energy from specific Southern Company coal units through May 31, 2010. These capacity obligations are firm and subject only to the availability of Miller Units 1 through 4 and Scherer Unit 3. The capacity and energy are priced based on the specific cost of these units. In addition, JEA occasionally purchases economy interchange power from Southern Company over and above the UPS. JEA plans to continue to hold the transmission rights for this capacity after the expiration of the UPS Purchase.

Progress Energy Ventures

Progress Energy Ventures (PEV) and JEA entered into a power purchase and sale agreement through The Energy Authority (TEA) in October 2006. The purchase power agreement entitles JEA to 75 MW, 150 MW and 150 MW of peaking capacity and energy for the three consecutive winter seasons 2007/08 through 2009/10. The contract states that PEV will delivery the firm energy to the Georgia side of the Florida /Georgia ITS.

The Energy Authority

The Energy Authority (TEA), actively trades energy with a large number of counterparties throughout the United States, and is generally able to acquire capacity and energy from other market participants when any of TEA's members, including JEA, require additional resources.

TEA generally acquires the necessary short-term purchase for the season of need based on market conditions among a number of potential suppliers within Florida and Georgia. TEA has reserved firm transmission rights across the Georgia ITS to the Florida/Georgia border, therefore capacity from generating units located in Georgia should provide levels of reliability similar to capacity available within Florida. TEA, with input from JEA, selects the best offer. TEA then enters into back-to-back power purchase agreements with the supplier and with the purchaser, JEA.

TEA's ability to acquire capacity and/or energy and TEA's firm transmission rights across the Georgia ITS gives JEA a degree of assurance that a plan which includes short-term market purchases is viable. In this Ten Year Site Plan, JEA identifies two seasonal needs capacity during the summer seasons of 2008 (25 MW) and 2010 (50 MW).

Clean Power

In 2004, JEA issued a Request for Proposal (RFP) for renewable resources. As a result of this RFP, JEA has under contract 22 MW of renewable resources. These resources are included in this TYSP.

Cogeneration

JEA has encouraged and continues to monitor opportunities for cogeneration. Cogeneration facilities reduce the demand from JEA's system and/or provide additional capacity to the system. JEA purchases power from four customer-owned qualifying facilities (QF's), as defined in the Public Utilities Regulatory Policy Act of 1978, having a total installed summer peak capacity of 17 MW and winter peak capacity of 19 MW. JEA purchases energy from these QF's on as-available, non-firm basis.

The following JEA customers have Qualifying Facilities located within JEA's service territory.

Table 2-1
JEA Service Territory Qualifying Facilities

Cogenerator Name	Unit Type	In-Service Date	Net Capability[1] – MW	
			Summer	Winter
Anheiser Busch	COG[2]	Apr-88	8	9
Baptist Hospital	COG	Oct-82	7	8
Ring Power Landfill	SPP[3]	Apr-92	1	1
St Vincent's Hospital	COG	Dec-91	1	1
Total			17	19

Notes:
[1]Net generating capability, not net generation sold to JEA.
[2]Cogenerator.
[3]Small Power Producer.

2.1.3 Power Sales Agreements

Florida Public Utilities Company

JEA also furnishes wholesale power to Florida Public Utilities Company (FPU) for resale to the City of Fernandina Beach in Nassau County, north of Jacksonville. JEA was contractually committed to supply FPU until December 31, 2007. As of September 2006, JEA and FPU have signed an agreement for a 10 year renewal term beginning January 1, 2008 and extending through December 31, 2017. Sales to FPU in 2006 totaled 522 GWh (3.8 percent of JEA's total system energy requirements).

2.2 Transmission and Distribution

2.2.1 Transmission

JEA's transmission system consists of bulk power transmission facilities operating at 69 kV or higher. This includes all transmission lines and associated facilities where each transmission line ends at the substation's termination structure. JEA owns 728 circuit-miles of transmission lines at four voltage levels: 69kV, 138kV, 230kV, and 500kV. JEA's transmission system includes a 230 kV open loop surrounding JEA's service territory. JEA is currently interconnected with Florida Power & Light (FP&L), Seminole Electric Cooperative (SECI), Florida Public Utilities (FPU) and the City of Jacksonville Beach. Interconnections with FP&L are at 230 kV to the Sampson and Duval Substations. The interconnection to SECI is at 230 kV and the interconnection to FPU is at 138 kV.

JEA and FP&L jointly own two 500 kV transmission lines that are interconnected with Georgia ITS. JEA, FP&L, Progress Energy and the City of Tallahassee each own transmission interconnections with Georgia ITS. JEA's ownership entitlement over these transmission lines is 1,228 out of 3,600 MW of import capability. JEA's system is interconnected with the 500 kV transmission lines at FP&L's Duval Substation.

JEA continues to monitor and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. JEA continually reviews needs and options for increasing the capability of the transmission system. JEA has set forth the following planning criteria for the transmission system:

- Plan to limit the loading of transmission lines and autotransformers to provide safe and reliable transmission service under normal and single-contingency conditions.
- Plan the transmission system to withstand single-contingencies without loss of customer load. (A single-contingency is the unexpected failure of any one line, transformer or generator.)
- Plan the transmission system to operate within 5 percent of nominal voltage during normal and single-contingency conditions.
- Plan the transmission system so that circuit breakers can interrupt the maximum available breaker fault current.
- Plan substation relays to sense breaker failures and clear faults in sufficient time to avoid generator instability problems.
- Plan to provide lead-time for transmission projects of approximately 3 to 5 years.
- Plan to meet the Florida Reliability Coordinating Council's (FRCC) guidelines on how the Florida electric utilities plan to operate. These guidelines are similar to JEA's transmission planning criteria discussed previously.
- Plan to meet or exceed the FRCC's reliability guidelines for transmission system interface Available Transfer Capabilities. This includes the use of single-contingency criteria as well as considering the needs for operating reserve requirements, capacity benefit margins, and those reliability margins as outlined in industry-standard publications.
- Plan to meet or exceed specific subparts of those transmission system reliability-planning criteria published by the North American Electric Reliability Coordinating Council (NERC), including Planning Criteria Categories A, B, C.2 and C.5. Meet or exceed these criteria generally as they are interpreted by the Florida Reliability Coordinating Council, as updated from time to time.

2.2.2 Distribution

The JEA distribution system operations at three primary voltage levels; 4.16 kV, 13.2 kV, and 26.4 kV. The 26.4 kV system serves approximately 86% of JEA's load, including 75% of the 4.16 kV substations. The current standard is to serve all new distribution loads, except loads in the downtown network, with 26.4 kV systems. Conversion of the aging 4 kV infrastructure continues to be implemented.

2.3 Demand Side Management

2.3.1 Interruptible Load

Interruptible load is load that can be shed during times of peak demand, reducing the need for capacity additions to meet peak demands. Typically, interruptible load is capacity that is available during off-peak times, but is not guaranteed during times of peak demand. JEA forecasts 125 MW and 145 MW of interruptible load in the winter and summer of 2007, respectively. The interruptible load represents approximately 4.2 percent of the total peak demand in the winter of 2007 and 5.0 percent of the forecasted total peak demand in the summer of 2007. JEA forecasts that its interruptible load will remain constant throughout the forecast period.

2.3.2 Demand Side Management

In 2004, JEA studied numerous DSM measures, evaluated the measures using the Commission-approved Florida Integrated Resource Evaluator (FIRE) model, and developed goals and a plan based upon these results. The Rate-Impact Measure or RIM test was used to determine the cost-effectiveness of the DSM alternatives appropriate for a municipal utility. Some investor-owned utilities in the state also use the RIM test to determine cost-effective DSM alternatives.

None of the alternatives tested were found to be cost-effective for JEA. The inability to find cost-effective DSM measures was primarily due to the low cost of new generation, high efficiency of new generation, low interest rates, and low fuel price projections. In August 2004, the PSC approved JEA's Plan for zero DSM goals for 2005-2014.

JEA agreed to continue several DSM programs, including residential energy audits, commercial energy audits, and community conservation initiatives. With the rising costs of permitable generation technologies and all fuel types, JEA continues to look for cost-effective DSM measures.

2.4 Green/Clean Power Programs

2.4.1 Existing Programs

Clean Power Programs and Green Power Programs

In 2001, JEA developed its Green Power Program to encourage the widespread application of renewable energy technology. JEA established a Clean Power Capacity goal of 7.5 percent clean power capacity by 2015. To support these goals, JEA has installed more than 230 kW of solar photovoltaic panels on high schools and other community buildings, and has invested in landfill gas renewable energy projects. In addition, JEA started the Solar Incentive Program to promote the acceptance and installation of solar energy systems in customers' homes and businesses.

Solar Incentive Program

As part of the Green Power Program, JEA implemented the Solar Incentive Program in early 2002. This program provides cash incentives for customers to install solar thermal systems at their homes or businesses. JEA is not involved with the pricing of solar energy systems; rather, the customer and solar vendor determine such issues. JEA has provided incentives to more than 900 solar systems installed throughout the community, resulting in approximately 9.0 MW toward its Clean Power Capacity goal.

Residential Net Metering Policy

JEA has established a residential net-metering program to encourage the use of customer-sited solar photovoltaic systems. This policy stipulates that the solar photovoltaic system must be installed according to JEA engineering standards to ensure system compatibility and safety for JEA personnel. JEA will install a meter that runs backward when the customer's system is generating more energy than the customer is using. Thus, the amount of electricity that the customer is billed for by JEA is reduced by the amount of electricity exported to the JEA system. JEA does not pay the customer for any electricity in the event that the customer's system generates more energy than the customer uses for a given billing period. However, this amount is credited forward to the next billing cycle. This program, in combination with the Solar Incentive Program, has created a strong incentive for the development of customer-sited solar generation.

Landfill Gas

JEA owns and operates three internal combustion engine generators located at the Girvin Road landfill. This facility was placed into service in July 1997, and is fueled by gas produced by the landfill, which consists of approximately 52 percent methane and 48 percent carbon dioxide (CO_2) and nitrogen. The facility originally had four generators with an aggregate net capacity of 3 MW. Since that time, gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater

Treatment facility. JEA also receives approximately 1,500 kW of landfill gas from the North Landfill, which is pumped to the Northside Generating Station and used to generate power in Northside Unit 3.

Request for Proposals

On February 6, 2004, JEA issued a Request for Proposals (RFP) for Renewable Energy Generation for 1 MW to 300 MW. The RFP covers all renewable energy resources that result in energy being delivered to JEA's service territory. More than 80 companies requested a copy of the RFP. The pre-bid meeting was held on March 3, 2004, with bids due April 6, 2004. JEA received 16 responses to the RFP, consisting of renewable energy projects ranging from 1 MW to 80 MW. Of the 300 MW proposed, 114 MW were from existing biomass facilities. The remaining proposals represented only five unique projects for 121 MW, since several projects competed for the same fuel or land use. JEA is currently in negotiations with two of these projects. The first contract is a 9 MW landfill unit and the second contract is a 13 MW biomass unit both scheduled to go on-line in fall 2008.

Lighting Solutions Program

JEA's Lighting Solutions Program helps customers improve their lighting systems, one of the most cost-effective measures a customer can make. Improving lighting not only saves money on energy bills, but the improvement increases the overall quality of the light provided by the system. In a typical office building, lighting, heating, and cooling represent between 54 percent and 71 percent of total energy use, depending on the climate, making those systems the best targets for energy savings. With energy accounting for approximately 19 percent of the total expenditures for the typical office building, improvements in these areas deserve consideration.

This program offers indoor and outdoor lighting services, including lighting energy audits, energy management programs, basic and advanced lighting design, retrofits and group re-lamping, lighting maintenance, and perimeter accent and site lighting. Customers receive the benefits of an evaluation of lighting opportunities, design and engineering of lighting solutions, third-party financing, turnkey installation, and on-going maintenance. Lighting project implementation will provide the customer with reduced energy costs, increased energy efficiency, enhanced energy management, and increased productivity and overall comfort.

3.0 Fuel Price Forecast

Fuel price forecasting is a major input in the development of JEA's future resource plan. JEA uses a diverse mix of fuels in its generating units. The forecast includes coal, natural gas, residual fuel oil, diesel fuel, and petroleum coke.

Fuel price projections for each of JEA's current fuels and future units considered in the economic analysis, including the Taylor Energy Center (TEC), were provided by Hill & Associates in the TEC Need for Power Application. The fuel price projections were provided for 2006 through 2030.

The fuel price forecasts provided by Hill & Associates were developed based in part on the expertise of several companies. Forecasts for coal and petroleum coke were developed by Hill & Associates, while natural gas and fuel oil price forecasts were provided by Pace Global Energy Services. Rail transportation rates were provided by Hellerworx, Inc., and ocean vessel rates were provided by Simpson, Spence & Young Consultancy & Research Ltd. The overall delivered fuel price forecasts were developed with the input of the TEC Fuels Committee, which consists of representatives from each of the Participants of TEC.

The fuel price forecast for St John's River Power Park (SJRPP) is based on a 28 percent blend of petroleum coke, and includes limestone and diesel fuel components for Scherer Unit 4 is based on western coal. Northside Units 1 and 2 operate on a blend of 80% petroleum coke and 20% coal. In addition, limestone is blended with the petroleum coke for SO_2 removal.

The fuel price forecast for JEA's natural gas supply takes into account commodity and transportation components. A blend of 1.8 percent sulfur residual fuel oil and natural gas is burned in Northside Unit 3. The 1970's-vintage combustion turbine units at Kennedy and Northside Generating Stations are permitted to burn high sulfur diesel. The new combustion turbine units at Brandy Branch and Kennedy are permitted to burn low sulfur diesel as a backup to natural gas. For operational reasons, all Kennedy combustion turbine units currently burn low sulfur diesel fuel. The Brandy Branch facility uses ultra low sulfur diesel as backup fuel.

4.0 Load and Energy Forecast

JEA's winter and summer hourly net integrated system peak demand and net energy for load for calendar year 2006 were 2919 MW, 2835 MW, and 13,811 GWH, respectively.

4.4.1 Peak Demand Forecast

To forecast peak demand, JEA has developed a regression analysis technique that utilizes SAS and Excel software. JEA develops a forecast of total load, including interruptible and curtailable customers, and then subtracts these customers to derive an estimate of firm demand.

The peak demand forecast is driven by temperature and time-series data. The forecasting process involves the collection of historical hourly system load data and daily temperature data. Since the historical system peak typically occurs on non-holiday weekdays, JEA has found that the most accurate historical forecasting method involves removing the data for weekends and holidays from the historical database. To further eliminate historical data that would tend to understate peak demand levels, summer load data is further reduced if a day was a summer rain day and if the 5 p.m. load is lower than the 3 p.m. load. Since JEA's demand peaks in the late afternoon during the summer, the highest value between 2 p.m. and 8 p.m. was identified as the daily peak for the remaining summer days. For winter days, the daily peak occurs early in the morning because of heating requirements. To eliminate historical data that would tend to distort the analysis, daily load data is removed if a cold front moved in and caused the 11 a.m. load to be higher than the load between 1 a.m. and 11 a.m.

After the summer and winter data are adjusted as described above, a regression analysis is conducted to forecast the summer and winter peaks. The forecast temperatures used in the regression are 97° F (summer) and 25° F (winter) where the winter seasonal extreme for a year is the lowest temperature during the months of December, January, and February, and the summer seasonal extreme is the highest temperature during the months of July, August, and September.

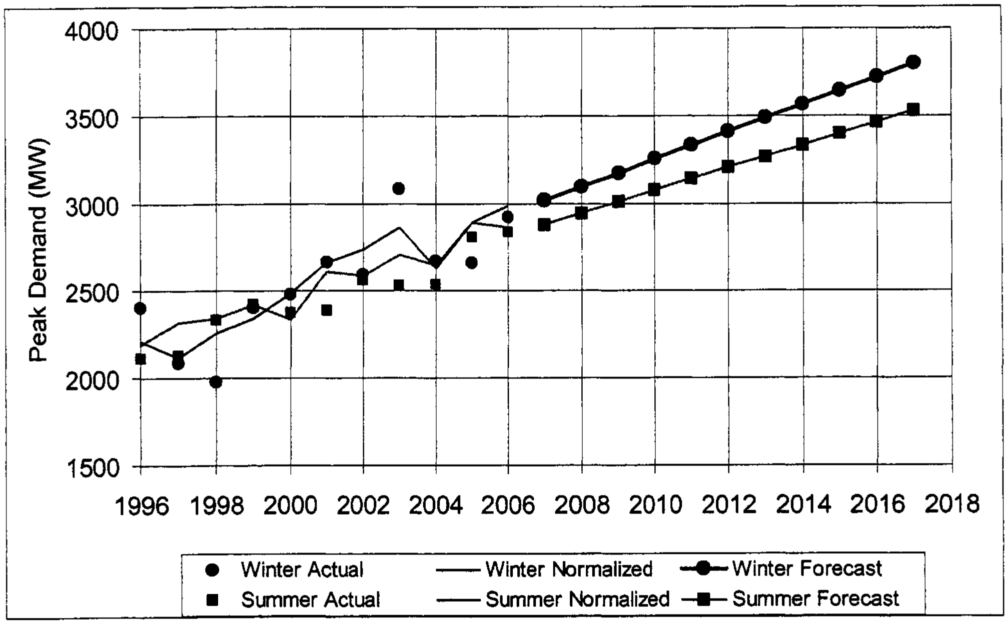
The results of the summer and winter peak demand forecasts are shown in Table 4-1 for total demand, firm demand, and interruptible demand levels. During the TYSP forecast period, total summer peak demand is forecast to increase at an average annual growth rate of 1.9 percent overall. The summer and winter interruptible load is held constant throughout the study period. The average annual increase in summer firm peak demand is 2.0 percent. During the winter period, the total growth rate in winter peak demand is projected to increase at an average annual growth rate of 2.1 percent. The average annual increase in winter firm peak demand is 2.2 percent.

Since the winter peak demand is projected to continue to increase at a higher average annual growth rate, the trend in which the winter peak is above the summer peak on a weather-normalized basis is expected to continue. Table 4-1 indicates that the firm winter peak demand is projected to increase from 2,877 MW in 2007 to 3,568 MW in 2016, and the firm summer peak demand is projected to increase from 2,731 MW in 2007 to 3,321 MW in 2016. Table 4-1 lists the forecast summer and winter peaks for JEA. Figure 4-1 shows the historical and forecast summer and winter peaks for JEA.

Table 4-1
2007 Peak Demand Forecast

Calendar Year	Total Peak Demand		Non-Firm Demand		Firm Peak Demand	
	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)
2007	3,002	2,876	125	145	2,877	2,731
2008	3,079	2,941	125	145	2,954	2,796
2009	3,155	3,007	125	145	3,030	2,862
2010	3,232	3,072	125	145	3,107	2,927
2011	3,309	3,138	125	145	3,184	2,993
2012	3,386	3,204	125	145	3,261	3,059
2013	3,462	3,269	125	145	3,337	3,124
2014	3,539	3,335	125	145	3,414	3,190
2015	3,616	3,400	125	145	3,491	3,255
2016	3,693	3,466	125	145	3,568	3,321
Average Annual % Change	2.1%	1.9%	0.0%	0.0%	2.2%	2.0%

Figure 4-1
Historical and Forecast Summer and Winter Peaks



4.4.2 Net Energy for Load (NEL) Forecast

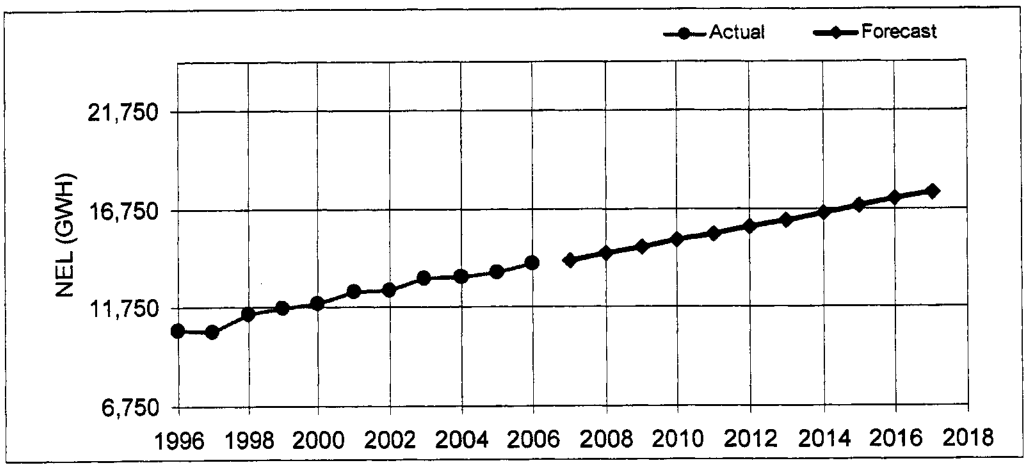
The NEL forecast is developed on a monthly and annual basis as a function of time and heating and cooling degree-day data. Inputs into the forecast include energy production, JEA territory sales, off-system sales, and heating and cooling degree-days. The JEA forecast modeling methodology separately accounts for and projects the temperature dependent and non-temperature dependent energy requirements over time, then combines these components to derive the system total NEL forecast. The temperature dependent NEL is modeled as a function of parameter estimates for historical and projected heating degree-days (HDD) and cooling degree-days (CDD). The HDD and CDD parameter estimate projections were based on the 1985 through 2006 historical averages.

The NEL forecast for JEA is shown in Table 4-2. The NEL is forecast to increase at an average annual growth rate of 2.0 percent during the 2007 through 2016 site plan period. NEL is forecast to increase from 14,315 GWh in 2007 to 17,511 GWh in 2016. Figure 4-2 shows the historical and forecast NEL for JEA.

Table 4-2
JEA Forecasted Net Energy for Load

Calendar Year	NEL (GWh)	Heating and Cooling Degree-Days	
		HDD	CDD
2007	14,315	1,170	2,742
2008	14,701	1,170	2,742
2009	15,016	1,170	2,742
2010	15,367	1,170	2,742
2011	15,717	1,170	2,742
2012	16,106	1,170	2,742
2013	16,418	1,170	2,742
2014	16,768	1,170	2,742
2015	17,119	1,170	2,742
2016	17,511	1,170	2,742
Average Annual % Increase	2.0%	NA	NA

Figure 4-2
Historical and Forecast NEL



5.0 Facility Requirements

5.1 Future Resource Needs

Based on the peak demand and energy forecasts, existing supply resources and contracts, and transmission considerations, JEA has evaluated future supply capacity needs for the electric system. Table 5-1 displays the likely need for capacity when assuming the base case load forecast for JEA's system for a ten-year period beginning in 2007.

Table 5-1
Resource Needs After Committed Units
Forecast of Capacity and Demand at Time Of Peak

Year	Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance Percent	Capacity Required For 15% Reserves MW
Winter									
2007	3,621	207	383	0	3,446	2,877	569	20%	0
2008	3,621	282	383	0	3,521	2,954	567	19%	0
2009	3,559	379	383	0	3,555	3,030	525	17%	0
2010	3,552	379	383	0	3,548	3,107	441	14%	(25)
2011	3,552	22	383	0	3,191	3,184	7	0%	(470)
2012	3,552	22	383	0	3,191	3,261	(70)	-2%	(559)
2013	3,552	22	383	0	3,191	3,337	(146)	-4%	(647)
2014	3,552	22	383	0	3,191	3,414	(223)	-7%	(735)
2015	3,552	22	383	0	3,191	3,491	(300)	-9%	(824)
2016	3,552	22	383	0	3,191	3,568	(377)	-11%	(912)
Summer									
2007	3,371	207	376	0	3,202	2,731	471	17%	0
2008	3,371	207	376	0	3,202	2,796	406	15%	(14)
2009	3,320	229	376	0	3,173	2,862	311	11%	(118)
2010	3,313	22	376	0	2,959	2,927	32	1%	(407)
2011	3,313	22	376	0	2,959	2,993	(34)	-1%	(483)
2012	3,313	22	376	0	2,959	3,059	(99)	-3%	(558)
2013	3,313	22	376	0	2,959	3,124	(165)	-5%	(634)
2014	3,313	22	376	0	2,959	3,190	(231)	-7%	(709)
2015	3,313	22	376	0	2,959	3,255	(296)	-9%	(784)
2016	3,313	22	376	0	2,959	3,321	(362)	-11%	(860)

Committed Capacity:

1. 22 MW Clean Power Purchases winter 2008.
2. 75 MW winter 2007/08
   150 MW winter 2008/09
   150 MW winter 2009/10
3. Kennedy CTs 3, 4 and 5 retired January, 2009.
4. UPS Purchase expires June 1, 2010.

5.2 Projects In Progress

5.2.1 Kennedy CT 8

JEA is proceeding with the installation of an additional combustion turbine at the Kennedy Generating Station. This additional unit will be a natural gas-fired simple-cycle GE frame 7FA combustion turbine, with ultra-low-sulfur diesel as a backup fuel. The scheduled commercial operation date for the unit is December 15, 2008.

5.2.2 Taylor Energy Center (TEC) Coal-Fired Unit

JEA, in conjunction with FMPA, RCID, and the City of Tallahassee is proceeding with plans to construct and operate a solid-fuel fired power plant at a site in Taylor County Florida. Alternative power supply proposals were received and evaluated. The results support the self-build option for the generation need. The need for power petition was submitted in September 2006 to the Florida Public Service Commission (FPSC). The need hearing was held in January 2007. The Commission has not made a ruling on the petition. The anticipated in-service date for TEC is scheduled for summer 2012. For the purposes of this analysis, JEA has included this unit in its capacity mix beginning June 1, 2012.

5.3 Resource Plan

The analysis of JEA's electric system to determine the current plan included a review of existing electric supply resources, forecasts of customer energy requirements and peak demands, forecasts of fuel prices and availability, and an analysis of alternatives for resources to meet future capacity and energy needs.

Forecasts of system peak demand growth and energy consumption were utilized for the resource plan. A range of demand growth and energy consumption was reviewed, with the base case peak demand indicating a need for additional capacity to meet system reserve requirements beginning in the year 2008. This need encompasses the inclusion of existing supply resources and transmission system considerations.

In addition to cost considerations, environmental and land use considerations were factored into the resource plans. This ensured that the plans selected were socially and environmentally responsible and demonstrated JEA's total commitment to the community.

Based on modeling of the JEA system, forecast of demand and energy, forecast of fuel prices and availability, and environmental considerations, Table 5-2 presents the least-cost expansion plan which meets strategic goals. The expansion plan demonstrates strength with small variance in supply alternatives over the numerous sensitivities.

Table 5-2 Reference Plan		
Year	**Season**	**Expansion Plan**
2007		
2008	Winter Summer	Progress Energy Venture Purchase (75 MW – Seasonal) TEA Purchase (25 MW - Seasonal)
2009	Winter	Clean Power Purchase (22 MW) Progress Energy Venture Purchase (150 MW - Seasonal) Build Kennedy CT 8 - 12/15/08 (177 MW) Retire Kennedy CTs 3, 4 & 5
2010	Winter	Progress Energy Venture Purchase (150 MW - Seasonal)
	Summer	UPS Contract Expires (207 MW) Build 7FA CT - 06/01/10 (177 MW) TEA Purchase (50 MW - Seasonal)
2011	Winter	Build 7FA CT - 12/15/10 (177 MW)
2012	Summer	Build TEC Pulverized Coal (236 MW)
2013		
2014	Summer	SJRPP Sale Return From FPL (383 MW)
2015		
2016		

6.0 Glossary

6.1 List of Abbreviations

Type of Generation Units

CC	Combined Cycle
CT	Combined Cycle – Combustion Turbine Portion
CW	Combined Cycle – Steam Turbine Portion, Waste Heat Boiler (only)
GT	Combustion Turbine
FC	Fluidized Bed Combustion
IC	Internal Combustion
ST	Steam Turbine, Boiler, Non-Nuclear

Status of Generation Units

FC	Existing generator planned for conversion to another fuel or energy source
M	Generating unit put in deactivated shutdown status
P	Planned, not under construction
RT	Existing generator scheduled to be retired
RP	Proposed for repowering or life extension
TS	Construction complete, not yet in commercial operation
U	Under construction, less than 50% complete
V	Under construction, more than 50% complete

Types of Fuel

BIT	Bituminous Coal
FO2	No. 2 Fuel Oil
FO6	No. 6 Fuel Oil
MTE	Methane
NG	Natural Gas
SUB	Sub-bituminous Coal
PC	Petroleum Coke

Fuel Transportation Methods

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water

Appendix A

Ten-Year Site Plan

Schedules

Ten-Year Site Plan Schedules

The following Appendix presents the schedules required by the Florida Public Service Commission to be included as part of the Ten-Year Site Plan.

Schedule 1
Existing Generating Facilities
As of January 1, 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit Number	Location	Unit Type	Fuel Type Primary	Fuel Type Alt.	Fuel Transport Primary	Fuel Transport Alt.	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen Max Nameplate kW	Net MW Capability Summer	Net MW Capability Winter	Ownership	Status
Kennedy										372,400	201	254		
	3	12-031	GT	FO2		WA	TK	7/1973	(a)	168,600	51	63	Utility	
	4	12-031	GT	FO2		WA	TK	7/1973		168,600	51	63	Utility	(b)
	5	12-031	GT	FO2		WA	TK	7/1973		168,600	51	63	Utility	(b)
	7	12-031	GT	NG	FO2	PL	WA	6/2000		203,800	150	191	Utility	
Northside										1,263,700	1,321	1,355		
	1	12-031	ST	PC	BIT	WA	RR	2003	(a)	350,000	293	293	Utility	
	2	12-031	ST	PC	BIT	WA	RR	2002	(a)	350,000	293	293	Utility	
	3	12-031	ST	NG	FO6	PL	WA	7/1977	(a)	563,700	523	523	Utility	
	3-6	12-031	GT	FO2		WA	TK	1/1975	(a)	248,400	212	246	Utility	
Brandy Branch										676,000	651	796		
	1		GT	NG	FO2	PL	TK	5/2001	(a)	203,800	150	191	Utility	
	2		CT	NG	FO2	PL	TK	5/2001	(a)	203,800	150	191	Utility	
	3		CT	NG	FO2	PL	TK	5/2001	(a)	203,800	150	191	Utility	
	4		CC	NG	FO2	PL	TK	1/2005	(a)	268,400	201	223	Utility	
Girvin Landfill	1-4	12-301	IC	NG		PL		6/1997	(a)	1.2	1.2	1.2	Utility	
St. Johns River Power Park										1,359,200	1,002	1,020		
	1	12-301	ST	BIT/PC		RR	WA	3/1987	3/2027	679,600	501	510	Joint	(c)
	2	12-301	ST	BIT/PC		RR	WA	5/1988	5/2028	679,600	501	510	Joint	(c)
Scherer	4	13-207	ST	SUB	BIT	RR	RR	2/1989	2/2029	846,000	194	194	Joint	(d)
JEA System Total											**3,370**	**3,620**		

NOTE:
(a) Units expected to be maintained throughout the study period.
(b) Placed in Reserve Shutdown 4/15/05.
(c) Net capability reflects the JEA's 80% ownership of Power Park. Nameplate is original nameplate of the unit.
(d) Nameplate and net capability reflects the JEA's 23.64% ownership in Scherer 4.
(e) Numbers may not add due to rounding.

Schedule 2.1
History And Forecast of Energy Consumption and Number of Customers By Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Rural and Residential			Commercial			Industrial		
Calendar Year	GWH Sales	Average No. of Customers	Average kWh/ Customer	GWH Sales	Average No. of Customers	Average kWh/ Customer	GWH Sales	Average No. of Customers	Average kWh/ Customer
1997	4,165	295,916	14,075	949	30,709	30,903	4,526	3,025	1,496,198
1998	4,643	301,883	15,380	1,035	31,297	33,070	4,835	3,094	1,562,702
1999	4,529	305,917	14,805	1,036	31,873	32,504	5,130	3,203	1,601,623
2000	4,701	312,103	15,062	1,079	32,351	33,353	5,205	3,309	1,572,983
2001	4,884	319,532	15,285	1,104	32,990	33,465	5,411	3,450	1,568,406
2002	5,108	326,362	15,651	1,157	33,841	34,189	5,479	3,475	1,576,691
2003	5,226	332,492	15,718	1,184	33,762	35,069	5,605	3,630	1,544,077
2004	5,400	348,320	15,503	1,185	32,123	36,889	5,396	3,638	1,483,233
2005	5,550	358,770	15,469	1,249	33,087	37,738	5,686	3,747	1,517,473
2006	5,637	357,232	15,780	1,289	37,136	34,704	5,658	4,206	1,345,307
2007	5,843	370,274	15,780	1,336	38,492	34,704	5,864	4,359	1,345,307
2008	6,000	380,253	15,780	1,372	39,530	34,704	6,022	4,477	1,345,307
2009	6,129	388,413	15,780	1,401	40,378	34,704	6,152	4,573	1,345,307
2010	6,272	397,471	15,780	1,434	41,320	34,704	6,295	4,679	1,345,307
2011	6,415	406,530	15,780	1,467	42,261	34,704	6,439	4,786	1,345,307
2012	6,574	416,596	15,780	1,503	43,308	34,704	6,598	4,904	1,345,307
2013	6,701	424,669	15,780	1,532	44,147	34,704	6,726	4,999	1,345,307
2014	6,844	433,728	15,780	1,565	45,089	34,704	6,869	5,106	1,345,307
2015	6,987	442,786	15,780	1,597	46,030	34,704	7,013	5,213	1,345,307
2016	7,147	452,940	15,780	1,634	47,086	34,704	7,174	5,332	1,345,307

Schedule 2.2
History And Forecast of Energy Consumption and Number of Customers By Class

Calendar Year	(11) Street & Highway Lighting GWH	(12) Other Sales to Ultimate Customers GWH	(13) Total Sales to Ultimate Customers GWH	(14) Sales For Resale GWH	(15) Utility Use & Losses GWH	(16) Net Energy For Load GWH	(17) Other Customers (Average No.)	(18) Total No.of Customers
1997	71	0	9,711	383	571	10,665	22	329,672
1998	77	0	10,590	438	442	11,470	21	336,295
1999	86	0	10,781	454	547	11,782	19	341,012
2000	120	0	11,105	482	603	12,190	19	347,782
2001	109	0	11,508	453	361	12,322	22	355,994
2002	112	0	11,856	446	681	12,983	20	363,698
2003	115	0	12,130	453	595	13,178	20	369,904
2004	76	0	12,057	468	718	13,243	27	384,108
2005	111	0	12,596	486	615	13,696	28	395,632
2006	110	0	12,694	522	595	13,811	29	398,603
2007	114	0	13,157	541	617	14,315	30	413,155
2008	117	0	13,512	556	633	14,701	31	424,290
2009	120	0	13,802	568	647	15,016	32	433,395
2010	123	0	14,124	581	662	15,367	33	443,503
2011	125	0	14,446	594	677	15,717	34	453,611
2012	128	0	14,803	609	694	16,106	35	464,844
2013	131	0	15,090	621	707	16,418	36	473,851
2014	134	0	15,412	634	722	16,768	37	483,959
2015	137	0	15,734	647	737	17,119	38	494,067
2016	140	0	16,095	662	754	17,511	39	505,397

Schedule 3.1
History and Forecast of Summer Peak Demand
(MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)	(12)	(13)
Calendar Year	Total Demand	Interruptible Load	Load Management		QF Load Served By QF Generation	Incremental Conservation		Net Firm Peak Demand	Time Of Peak			Cumulative Conservation Since 1980	
			Residential	Comm./Ind.		Residential	Comm./Ind.		Month	Day	H.E.	Residential	Comm./Ind.
1996	2,114	0	0	0	0	0	0	2,114	6	25	1800	0	0
1997	2,131	0	0	0	0	0	0	2,131	7	28	1800	0	0
1998	2,338	0	0	0	0	0	0	2,338	7	1	1800	0	0
1999	2,427	0	0	0	0	0	0	2,427	8	2	1600	0	0
2000	2,380	0	0	0	0	0	0	2,380	7	20	1400	0	0
2001	2,389	0	0	0	0	0	0	2,389	8	8	1800	0	0
2002	2,530	0	0	0	0	0	0	2,530	7	19	1600	0	0
2003	2,485	0	0	0	0	0	0	2,485	7	10	1600	0	0
2004	2,539	0	0	0	0	0	0	2,539	8	2	1600	0	0
2005	2,815	0	0	0	0	0	0	2,815	8	17	1800	0	0
2006	2,835	0	0	0	0	0	0	2,835	8	4	1700	0	0
2007	2,586	145	0	0	0	0	0	2,731	---	---	---	0	0
2008	2,651	145	0	0	0	0	0	2,796	---	---	---	0	0
2009	2,717	145	0	0	0	0	0	2,862	---	---	---	0	0
2010	2,782	145	0	0	0	0	0	2,927	---	---	---	0	0
2011	2,848	145	0	0	0	0	0	2,993	---	---	---	0	0
2012	2,914	145	0	0	0	0	0	3,059	---	---	---	0	0
2013	2,979	145	0	0	0	0	0	3,124	---	---	---	0	0
2014	3,045	145	0	0	0	0	0	3,190	---	---	---	0	0
2015	3,110	145	0	0	0	0	0	3,255	---	---	---	0	0
2016	3,176	145	0	0	0	0	0	3,321	---	---	---	0	0

Schedule 3.2
History and Forecast of Winter Peak Demand
(MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)	(12)	(13)
Calendar Year	Total Demand	Interruptible Load	Load Management		QF Load Served By QF Generation	Incremental Conservation		Net Firm Peak Demand	Time Of Peak			Cumulative Conservation Since 1980	
			Residential	Comm./Ind.		Residential	Comm./ind.		Month	Day	H.E.	Residential	Comm./Ind.
1997	2,084	0	0	0	0	0	0	2,084	12	20	0900	0	0
1998	1,975	0	0	0	0	0	0	1,975	12	15	1900	0	0
1999	2,403	0	0	0	0	0	0	2,403	1	6	0800	0	0
2000	2,478	0	0	0	0	0	0	2,478	1	27	0800	0	0
2001	2,666	0	0	0	0	0	0	2,666	1	3	0800	0	0
2002	2,607	0	0	0	0	0	0	2,607	1	4	0800	0	0
2003	3,055	0	0	0	0	0	0	3,055	1	24	0800	0	0
2004	2,668	0	0	0	0	0	0	2,668	1	29	0700	0	0
2005	2,860	0	0	0	0	0	0	2,860	1	24	0800	0	0
2006	2,919	0	0	0	0	0	0	2,919	2	14	0800	0	0
2007	2,722	0	0	0	0	0	0	2,722	1	30	0800	0	0
2008	2,829	125	0	0	0	0	0	2,954	---	---	---	0	0
2009	2,905	125	0	0	0	0	0	3,030	---	---	---	0	0
2010	2,982	125	0	0	0	0	0	3,107	---	---	---	0	0
2011	3,059	125	0	0	0	0	0	3,184	---	---	---	0	0
2012	3,136	125	0	0	0	0	0	3,261	---	---	---	0	0
2013	3,212	125	0	0	0	0	0	3,337	---	---	---	0	0
2014	3,289	125	0	0	0	0	0	3,414	---	---	---	0	0
2015	3,366	125	0	0	0	0	0	3,491	---	---	---	0	0
2016	3,443	125	0	0	0	0	0	3,568	---	---	---	0	0

Schedule 3.3
History and Forecast of Annual Net Energy For Load
(GWH)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Calendar Year	Total Energy For Load	Interruptible Load	Load Management		QF Load Served By QF Generation	Incremental Conservation		Net Energy For Load	Cumulative Conservation Since 1980	
			Residential	Comm./Ind.		Residential	Comm./ind.		Residential	Comm./Ind.
1997	10,665	0	0	0	0	0	0	10,665	0	0
1998	11,470	0	0	0	0	0	0	11,470	0	0
1999	11,782	0	0	0	0	0	0	11,782	0	0
2000	12,190	0	0	0	0	0	0	12,190	0	0
2001	12,322	0	0	0	0	0	0	12,322	0	0
2002	12,983	0	0	0	0	0	0	12,983	0	0
2003	13,204	0	0	0	0	0	0	13,204	0	0
2004	13,243	0	0	0	0	0	0	13,243	0	0
2005	13,696	0	0	0	0	0	0	13,696	0	0
2006	13,811	0	0	0	0	0	0	13,811	0	0
2007	14,315	0	0	0	0	0	0	14,315	0	0
2008	14,701	0	0	0	0	0	0	14,701	0	0
2009	15,016	0	0	0	0	0	0	15,016	0	0
2010	15,367	0	0	0	0	0	0	15,367	0	0
2011	15,717	0	0	0	0	0	0	15,717	0	0
2012	16,106	0	0	0	0	0	0	16,106	0	0
2013	16,418	0	0	0	0	0	0	16,418	0	0
2014	16,768	0	0	0	0	0	0	16,768	0	0
2015	17,119	0	0	0	0	0	0	17,119	0	0
2016	17,511	0	0	0	0	0	0	17,511	0	0

Schedule 4
Previous Year Actual and Two Year Forecast of Peak Demand And Net Energy For Load By Month
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual 2006		Forecast 2007		Forecast 2008	
Month	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)
January	2,571	1,060	2,722	1,147	2,954	1,174
February	2,919	1,011	2,386	999	2,450	1,058
March	2,024	991	2,032	1,078	2,086	1,105
April	2,264	1,034	2,039	1,049	2,088	1,075
May	2,572	1,202	2,446	1,187	2,505	1,217
June	2,637	1,281	2,576	1,308	2,638	1,341
July	2,776	1,415	2,731	1,469	2,796	1,505
August	2,835	1,469	2,689	1,453	2,753	1,489
September	2,636	1,245	2,521	1,267	2,581	1,298
October	2,289	1,080	2,358	1,130	2,419	1,158
November	2,167	993	2,263	1,057	2,322	1,083
December	2,334	1,030	2,679	1,172	2,749	1,199
Total		13,811		14,315		14,701

Schedule 5
Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	**NUCLEAR**		**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**		**1000 TON**	**2,535**	**2,601**	**2,475**	**2,598**	**2,651**	**2,813**	**2,791**	**2,862**	**3,321**	**3,518**	**3,573**
	RESIDUAL													
(3)		STEAM	1000 BBL	841	1,781	1,369	1,231	1,231	1,744	1,340	1,475	1,060	902	1,083
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT/GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		**TOTAL:**	**1000 BBL**	**841**	**1,781**	**1,369**	**1,231**	**1,231**	**1,744**	**1,340**	**1,475**	**1,060**	**902**	**1,083**
	DISTILLATE													
(7)		STEAM	1000 BBL	32	32	31	32	33	35	35	36	41	44	45
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	99	129	95	85	284	245	212	179	73	94	89
(10)		**TOTAL:**	**1000 BBL**	**131**	**161**	**126**	**118**	**317**	**280**	**247**	**215**	**114**	**138**	**134**
	NATURAL GAS													
(12)		STEAM	1000 MCF	3,500	2,041	1,621	1,462	1,481	1,986	1,573	1,698	1,266	1,119	1,313
(13)		CC	1000 MCF	9,200	6,688	13,172	12,893	17,337	20,821	16,817	14,106	9,397	9,084	9,949
(14)		CT/GT	1000 MCF	1,359	954	959	1,107	4,190	4,588	3,805	3,304	1,378	1,988	1,969
(15)		**TOTAL:**	**1000 MCF**	**14,059**	**9,683**	**15,752**	**15,463**	**23,007**	**27,395**	**22,194**	**19,108**	**12,040**	**12,190**	**13,231**
(16)	**PETROLEUM COKE**		**1000 TON**	**1,439**	**2,235**	**2,231**	**2,242**	**1,853**	**1,497**	**1,948**	**2,141**	**2,290**	**2,307**	**2,320**
(20)	**OTHER (SPECIFY)**		**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

NOTE:

1. Coal includes JEA's share of SJRPP, JEA's share of Scherer 4 and Northside Coal.

	(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actuals										
	Fuel	Type	Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	Annual Firm Inter-Region Intchg.		GWH	1,932	1,667	1,655	1,662	748	0	0	0	0	0	0
(2)	NUCLEAR		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWH	5,490	6,031	5,756	6,008	6,127	6,430	6,523	6,646	7,870	8,260	8,374
(4)	RESIDUAL	STEAM	GWH	473	1,054	765	682	711	1,008	770	839	582	497	593
(5)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)		TOTAL	GWH	473	1,054	765	682	711	1,008	770	839	582	497	593
(8)	DISTILLATE	STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	13	59	43	40	136	117	102	85	34	44	41
(11)		TOTAL	GWH	13	59	43	40	136	117	102	85	34	44	41
(12)	NATURAL GAS	STEAM	GWH	309	186	135	120	125	178	136	148	103	88	105
(13)		CC	GWH	1,275	839	1,827	1,779	2,472	3,028	2,354	1,951	1,246	1,204	1,334
(14)		CT	GWH	123	81	89	103	391	431	357	308	127	179	180
(15)		TOTAL	GWH	1,707	1,106	2,050	2,003	2,988	3,637	2,846	2,407	1,476	1,471	1,619
(16)	NUG		GWH	0	0	16	187	187	187	187	187	187	187	187
(17)	HYDRO		GWH	0	0	0	0	0	0	0	0	0	0	0
(18)	Petroleum Coke		GWH	4,196	4,395	4,410	4,426	4,451	4,338	5,679	6,256	6,620	6,661	6,697
(19)	OTHER (SPECIFY)		GWH	0	2	5	9	19	1	0	0	0	0	0
(20)	NET ENERGY FOR LOAD		GWH	13,811	14,315	14,701	15,016	15,367	15,717	16,106	16,418	16,768	17,119	17,511

Schedule 6.1
Energy Sources (GWH)

NOTE:

1. Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal.

Schedule 6.2
Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actuals										
	Fuel	Type	Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	**Annual Firm Inter-Region Intchg.**		%	14.0%	11.6%	11.3%	11.1%	4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(2)	**NUCLEAR**		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	**COAL**		%	39.8%	42.1%	39.2%	40.0%	39.9%	40.9%	40.5%	40.5%	46.9%	48.2%	47.8%
(4)	**RESIDUAL**	STEAM	%	3.4%	7.4%	5.2%	4.5%	4.6%	6.4%	4.8%	5.1%	3.5%	2.9%	3.4%
(5)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		TOTAL	%	3.4%	7.4%	5.2%	4.5%	4.6%	6.4%	4.8%	5.1%	3.5%	2.9%	3.4%
(8)	**DISTILLATE**	STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		CT	%	0.1%	0.4%	0.3%	0.3%	0.9%	0.7%	0.6%	0.5%	0.2%	0.3%	0.2%
(11)		TOTAL	%	0.1%	0.4%	0.3%	0.3%	0.9%	0.7%	0.6%	0.5%	0.2%	0.3%	0.2%
(12)	**NATURAL GAS**	**STEAM**	%	2.2%	1.3%	0.9%	0.8%	0.8%	1.1%	0.8%	0.9%	0.6%	0.5%	0.6%
(13)		CC	%	9.2%	5.9%	12.4%	11.8%	16.1%	19.3%	14.6%	11.9%	7.4%	7.0%	7.6%
(14)		CT	%	0.9%	0.6%	0.6%	0.7%	2.5%	2.7%	2.2%	1.9%	0.8%	1.0%	1.0%
(15)		TOTAL	%	12.4%	7.7%	13.9%	13.3%	19.4%	23.1%	17.7%	14.7%	8.8%	8.6%	9.2%
(16)	**NUG**		%	0.0%	0.0%	0.1%	1.2%	1.2%	1.2%	1.2%	1.1%	1.1%	1.1%	1.1%
(17)	**HYDRO**		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(18)	**Petroleum Coke**		%	30.4%	30.7%	30.0%	29.5%	29.0%	27.6%	35.3%	38.1%	39.5%	38.9%	38.2%
(19)	**OTHER (SPECIFY)**		%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(20)	**NET ENERGY FOR LOAD**		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

NOTE:

1. Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal.

Schedule 7
Forecast of Capacity, Demand, and Scheduled Maintenance at Time Of Peak

Winter

Year	Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance Percent	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance Percent
2007	3,621	207	383	0	3,446	2,722	724	27%	0	724	27%
2008	3,621	282	383	0	3,521	2,954	567	19%	0	567	19%
2009	3,750	379	383	0	3,746	3,030	716	24%	0	716	24%
2010	3,743	379	383	0	3,739	3,107	632	20%	0	632	20%
2011	4,125	22	383	0	3,764	3,184	580	18%	0	580	18%
2012	4,125	22	383	0	3,764	3,261	503	15%	0	503	15%
2013	4,361	22	383	0	4,000	3,337	663	20%	0	663	20%
2014	4,361	22	383	0	4,000	3,414	586	17%	0	586	17%
2015	4,361	22	0	0	4,383	3,491	892	26%	0	892	26%
2016	4,361	22	0	0	4,383	3,568	815	23%	0	815	23%

Summer

Year	Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance Percent	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance Percent
2007	3,371	207	376	0	3,202	2,731	471	17%	0	471	17%
2008	3,371	232	376	0	3,227	2,796	431	15%	0	431	15%
2009	3,499	229	376	0	3,352	2,862	490	17%	0	490	17%
2010	3,671	72	376	0	3,367	2,927	440	15%	0	440	15%
2011	3,850	22	376	0	3,496	2,993	503	17%	0	503	17%
2012	4,086	22	376	0	3,732	3,059	674	22%	0	674	22%
2013	4,086	22	376	0	3,732	3,124	608	19%	0	608	19%
2014	4,086	22	0	0	4,108	3,190	918	29%	0	918	29%
2015	4,086	22	0	0	4,108	3,255	853	26%	0	853	26%
2016	4,086	22	0	0	4,108	3,321	787	24%	0	787	24%

Schedule 8

Planned and Prospective Generating Facility and Purchased Power Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel Type		Fuel Transport		Construction	Commercial/Change	Expected	Gen Max	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Date	In-Service Date	Retirement/ Shutdown	Nameplate kW	Summer MW	Winter MW	Status
Planned and Prospective Generating Facility Changes														
SJRPP	1	SJRPP	ST	Bit/PC		RR	WA		03/01/14			191.0	188.0	A
SJRPP	2	SJRPP	ST	Bit/PC		RR	WA		03/01/14			191.0	188.0	A
Kennedy	3	Kennedy	GT	NG	FO2	PL	TK			01/01/09		51.0	62.7	RT
Kennedy	4	Kennedy	GT	NG	FO2	PL	TK			01/01/09		51.0	62.7	RT
Kennedy	5	Kennedy	GT	NG	FO2	PL	TK			01/01/09		51.0	62.7	RT
Planned and Prospective Generating Facility Additions														
CT - 7FA	8	Kennedy	GT	NG	FO2	PL	TK		12/15/08			158.6	191.2	P
CT - 7FA	1	Greenfield	GT	NG	FO2	PL	TK		06/01/10			158.6	191.2	P
CT - 7FA	2	Greenfield	GT	NG	FO2	PL	TK		12/15/10			158.6	191.2	P
PCoal	1	Taylor Energy Center	FC	Bit	Coal	WA	WA		06/01/12			236.0	236.0	P
Planned and Prospective Purchased Power Additions														
PEV									12/15/07	03/15/08		0.0	75.0	Contracted
PEV									12/15/08	03/15/09		0.0	150.0	Contracted
PEV									12/15/09	03/15/10		0.0	150.0	Contracted
TEA									06/01/08	09/15/08		25.0	0.0	Planned
Trail Ridge									12/15/08	12/15/18		9.1	9.1	Contracted
Evergreen									12/15/08	12/15/18		13.0	13.0	Contracted
TEA									06/01/10	09/15/10		50.0	0.0	Planned
UPS										05/31/10		200.0	200.0	Contract Ends

Schedule 9.0 Status Report and Specifications of Proposed Generating Facilities		
(1)	Plant Name and Unit Number:	Kennedy CT 8
(2)	Capacity:	Gas / Oil
(3)	Summer MW	149 MW / 158 MW
(4)	Winter MW	186 MW / 191 MW
(5)	Technology Type:	Simple Cycle Combustion Turbine
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	
(8)	Commercial In-Service date:	12/15/08
(9)	Fuel	
(10)	Primary	Natural Gas
(11)	Alternate	Diesel Fuel Oil
(12)	Air Pollution Control Strategy:	Low NO_x Burners
(13)	Cooling Method:	N/A
(14)	Total Site Area:	
(15)	Construction Status:	Design/Permitting
(16)	Certification Status:	Not Required
(17)	Status with Federal Agencies:	Not Filed
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	1.00 percent
(20)	Forced Outage Factor (FOF):	2.00 percent
(21)	Equivalent Availability Factor (EAF):	97.00 percent
(22)	Resulting Capacity Factor (%):	5.0 – 10.0 percent
(23)	Average Net Operating Heat Rate (ANOHR):	10,816 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30 years
(26)	Total Installed Cost (In-Service year $/kW):	$ 749.75
(27)	Direct Construction Cost ($/kW):	Included in total installed cost
(28)	AFUDC Amount ($/kW):	Included in total installed cost
(29)	Escalation ($/kW):	Included in total installed cost
(30)	Fixed O&M ($/kW-yr):	$ 5.06
(31)	Variable O&M ($/MWh):	$ 25.95

Schedule 9.1
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Greenfield Units 1-2
(2)	Capacity:	Gas Oil
(3)	Summer MW	149 MW 158 MW
(4)	Winter MW	186 MW 191 MW
(5)	Technology Type:	Simple Cycle Combustion Turbine
(6)	Anticipated Construction Timing:	Unit 1 Unit 2
(7)	Field Construction Start-date:	
(8)	Commercial In-Service date:	06/01/10 12/15/10
(9)	Fuel	
(10)	Primary	Natural Gas
(11)	Alternate	Diesel Fuel Oil
(12)	Air Pollution Control Strategy:	Low NO_x Burners
(13)	Cooling Method:	N/A
(14)	Total Site Area:	
(15)	Construction Status:	Planned
(16)	Certification Status:	Not Required
(17)	Status with Federal Agencies:	Not Filed
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	1.00 percent
(20)	Forced Outage Factor (FOF):	2.00 percent
(21)	Equivalent Availability Factor (EAF):	97.00 percent
(22)	Resulting Capacity Factor (%):	5.0 – 10.0 percent
(23)	Average Net Operating Heat Rate (ANOHR):	10,816 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30 years
(26)	Total Installed Cost (In-Service year $/kW):	$ 826.60
(27)	Direct Construction Cost ($/kW):	Included in total installed cost
(28)	AFUDC Amount ($/kW):	Included in total installed cost
(29)	Escalation ($/kW):	Included in total installed cost
(30)	Fixed O&M ($/kW-yr):	$ 5.58
(31)	Variable O&M ($/MWh):	$ 28.60

Schedule 9.2 Status Report and Specifications of Proposed Generating Facilities		
(1)	Plant Name and Unit Number:	Taylor Energy Center (TEC) Unit 1
(2)	Capacity:	
(3)	Summer MW	754. 1MW
(4)	Winter MW	785.3 MW
(5)	Technology Type:	Supercritical Pulverized Coal
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	April 2008
(8)	Commercial In-Service date:	May 2012
(9)	Fuel	
(10)	Primary	Bituminous Coal / Petroleum Coke
(11)	Alternate	N/A
(12)	Air Pollution Control Strategy:	BACT Compliant
(13)	Cooling Method:	Mechanical Draft
(14)	Total Site Area:	Approximately 3,000 Acres
(15)	Construction Status:	Not Started
(16)	Certification Status:	Underway
(17)	Status with Federal Agencies:	Underway
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	4.38%
(20)	Forced Outage Factor (FOF):	5.23%
(21)	Equivalent Availability Factor (EAF):	90%
(22)	Resulting Capacity Factor (%):	90%
(23)	Average Net Operating Heat Rate (ANOHR):	9,238 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30
(26)	Total Installed Cost (In-Service year $/kW):	2,664
(27)	Direct Construction Cost ($/kW):	2,152
(28)	AFUDC Amount ($/kW):	208
(29)	Escalation ($/kW):	304
(30)	Fixed O&M ($/kW-yr):	24.31
(31)	Variable O&M ($/MWh):	1.43

(1) Based on operation at average ambient conditions.
(2) In 2007 dollars.
(3) JEA's Share is 31.5%.

Schedule 10 Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination	Greenland Substation to Nocatee Substation
(2)	Number of Lines	two
(3)	Right of Way	New (Fee owned)
(4)	Line Length	4.4 miles (each line)
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	~ 36 Months
(7)	Anticipated Capital Investment	~ $8.5 Million
(8)	Substations	Greenland and Nocatee
(9)	Participation with Other Utilities	No

Schedule 10.1 Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination	Greenland Substation to Bartram Substation
(2)	Number of Lines	one
(3)	Right of Way	Existing
(4)	Line Length	3 miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	~ 26 Months
(7)	Anticipated Capital Investment	~ $2.4 Million
(8)	Substations	Greenland and Bartram
(9)	Participation with Other Utilities	No