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JEA

March 26, 2008

Robert Graves
Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

080000

Dear Mr. Graves:

Attached you will find 25 copies of JEA's 2008 Ten Year Site Plan filing. If you have any questions regarding this response or any additional questions, please contact me at (904) 665-6216 or Don Gilbert at (904) 665-7109.

Thank You,

Delivered to Clk by R. Graves on 4/1/08. R.V.N.

Mary Guyton Baker

Mary Guyton Baker, PE
Electric System Planning, JEA

DOCUMENT NUMBER-DATE
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Ten Year Site Plan

JEA®

Building Community®

April 2008

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 2008 Ten Year Site Plan for JEA covering a planning period from 2008 to 2017.

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 3,621 MW in the winter and 3,371MW 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); five diesel-fired combustion turbine-generator units (Kennedy CTs 3 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.

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.

Constellation Energy Commodities Group, Inc

Constellation Energy Commodities Group, Inc (Constellation) 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 Constellation 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 the Ten Year Site Plan, JEA identifies areas of seasonal, capacity needs in which JEA will engage TEA for acquisition of capacity during those seasons.

Clean Power

In 2004, JEA issued a Request for Proposal (RFP) for renewable resources. As a result of this RFP, JEA has under contract 9 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
Anheuser 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 furnishes wholesale power to Florida Public Utilities Company (FPU) for resale to the City of Fernandina Beach in Nassau County, north of Jacksonville. 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 2007 totaled 473 GWh (3.42 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), and the Beaches Energy Service (BES). Interconnections with FP&L are at 230 kV to the Sampson and Duval Substations. The interconnection to SECI is at 230 kV at their Black Creek substation and the interconnection to BES is at 138 kV at their JB Penman Substation.

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.
- 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 Corporation (NERC), including Planning Criteria Categories A, B, C.2 and C.5. Meet or exceed these criteria generally as they are interpreted by the FRCC, 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 133 MW and 117 MW of interruptible load in the winter and summer of 2008, respectively. The interruptible load represents approximately 4.3 percent of the total peak demand in the winter of 2008 and 4.0 percent of the forecasted total peak demand in the summer of 2008. JEA forecasts that its interruptible load will remain constant throughout the forecast period.

2.3.2 Demand Side Management

In 2004, JEA studied numerous Demand Side Management (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, at that time. 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 has continued to look for cost-effective DSM measures.

In fiscal year 2006/07, JEA contracted with Summit Blue Consulting to identify potential DSM programs for JEA over the five year period, 2008 – 2012. The RIM test was used to determine the cost-effectiveness of the portfolio of DSM programs recommended. Summit Blue has recommended two basic prototypes in the portfolio: Energy Efficiency programs (EE) and Demand Response (DR) programs. Summit Blue identified the following five DSM programs within these prototypes:

Energy Efficiency Programs

- Residential Lighting
- Low income
- Residential New Construction

Demand Response Programs

- Direct Load Control (DLC)
- Interruptible Rate

The EE and DLC programs are structured for use by the residential customer while the Interruptible Rate program is structured for commercial/industrial customer use. Summit Blue's recommended portfolio along with JEA's Planning Reserve Guidelines are currently being further evaluated to determine a DSM plan that, with JEA's existing non-firm load, will be achievable and robust.

2.4 Green/Clean Power Programs

2.4.1 Existing 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. JEA has made considerable progress toward clean power initiatives. This progress includes installation of clean power systems, commitment to purchase power agreements, legislative and public education activities, and research and development into clean power technologies.

JEA currently has approximately 78 MW of renewable capacity committed toward its goal, including approximately 321 kW of solar photovoltaic (PV) capacity, 9 MW of solar thermal capacity, 6 MW in landfill biogas capacity, 800 kW in digester biogas capacity, 10 MW of wind capacity, 9.6 MW of landfill gas in development, and 43 MW of generating unit efficiency improvements. Over the past several years, JEA has received several awards for its clean power program.

Solar and the Solar Incentive Program. JEA has installed 36 solar PV systems, totaling 220 kW, on all of the public high schools in Duval County, as well as many of JEA's facilities and one of the largest solar PV systems in the Southeast at the Jacksonville International Airport. To further promote the acceptance and installation of solar energy systems, JEA implemented the Solar Incentive Program in 2002 - 2005. This program provided cash incentives for customers to install solar PV and solar thermal systems on their homes or businesses. JEA has provided $1.6M in total incentives to residential and commercial customers since the program's inception.

JEA paid incentives for more than 25 solar PV systems for a total of 98 kW. In addition to the PV incentive program, JEA established a residential net-metering program to encourage the use of customer-sited solar PV systems.

JEA has provided incentives for over 400 solar domestic hot water systems. A recent JEA customer survey shows that solar customers are very satisfied with their hot water system and the solar installer. JEA is collaborating with other Florida utilities to develop a joint marketing program for solar hot water systems to increase system installations across the State.

Biomass. In 2001, JEA signed a 15 year PPA with Biomass Investment Group (BIG) to purchase 70 MW of renewable energy. This developer proposed to grow a biomass crop (e-grass or arundo donax) as a fuel for a gasification plant in Florida. The project has been delayed many times and, since the commercial operation date of this unit is not firm, this project is not included as a resource for JEA's system. Although JEA committed to this project, the developer has not been able to bring it to commercial status as was originally planned.

JEA started negotiations in 2004 with Evergreen Paper and Energy to construct a 13 MW biomass facility, fueled with Jacksonville's yard waste. However, the negotiations with Evergreen reached an impasse and were cancelled in 2007.

In a continuing effort to evaluate biomass projects, JEA has initiated a biomass power plant feasibility study. The focus of this study will be to consider JEA's options for development of a standalone biomass facility or co-firing in JEA existing facilities. A characterization of the quantity, long-term availability and price of local biomass feedstock will also be conducted.

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. 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 is used to generate power at Northside Unit 3.

The JEA Buckman Wastewater Treatment Plant previously dewatered and incinerated the sludge from the treatment process and disposed of the ash in a landfill. The new facility manages the sludge using two anaerobic digesters and a sludge dryer to produce a fertilizer pellet product. The methane gas from the digesters is used by the sludge dryer and the 800 kW generator.

Wind. As part of its ongoing effort to utilize more sources of renewable energy, JEA entered into a 20-year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive green tags associated with this green power project. Under the wind generation agreement, JEA purchases (over a 20 year period) 10 MW of capacity from NPPD's wind generation facility. In turn, NPPD will buy back the energy at specified on/off peak charges.

2.4.2 Renewable Project Request for Proposal Solicitation

In February 2004, JEA issued a Request for Proposals (RFP) for Renewable Energy Generation for 1 MW to 300 MW. The RFP covered all renewable energy resources, including but not limited to solar, wind, biomass, biogas. This RFP resulted in energy being delivered to JEA's service territory. JEA received 13 acceptable responses with capacity between 8 MW and 50 MW. Four of the projects were existing biomass projects. Several of the projects competed for the same fuel - four used the City yard waste as fuel and three used the Trail Ridge landfill gas for fuel. JEA entered into negotiations with Landfill Energy Systems (9.6MW) on the Trail Ridge landfill gas and signed a Power Purchase Agreement in May 2006. The project is expected to be operational by December 2008. Once the facility is completed, it will be one of the largest LFG-to-energy facilities in the Southeast. JEA started negotiations with Evergreen Paper and Energy (13 MW - City's yard waste) but these negotiations were cancelled by JEA in 2007 due to an impasse in negotiation.

In April 2007, JEA received responses to JEA's Letters of Interest from companies interested in providing renewable energy projects to JEA. Of the 19 responses received, 13 were for biomass projects, the remaining were hydro, landfill gas and digester gas projects. As a result, JEA issued Request for Proposals for the biomass respondents on August 13, 2007. Proposals were due on September 21, 2007 (extended to September 28, 2007). JEA received four acceptable proposals and rejected five proposals because they did not meet the screening criteria. Proposals were evaluated against JEA's base case of generation. Incremental costs ranged from $10/MWH to $59/MWH above base case and $51M to $306M in net additional cost to JEA over 20 years. JEA chose not to negotiate with any of the proposers because of the high costs and the inability of proposers to demonstrate fuel or site availability or project financing.

In March 2008, JEA issued another Request for Proposals for renewable energy, specifically targeting solar and wind projects. These responses are due in May 2008.

Research Efforts. Many of Florida's renewable resources such as offshore wind, tidal, and energy crops need additional research and development before they can become large-scale energy technologies. JEA's renewable efforts have focused on the development of these technologies through a partnership with the University of North Florida's (UNF) Engineering Department. UNF and JEA are evaluating the following:

- JEA is working with the UNF to quantify the winter peak reductions of a solar hot water system. This analysis provides solar systems an additional benefit to utilities beyond the renewable energy benefits.
- UNF along with the University of Florida is evaluating the effect of biodiesel fuel in a utility-scale combustion turbine. Biodiesel has been tested extensively on diesel engines, but combustion turbine testing has been very limited.
- UNF is evaluating the tidal hydro-electric potential for North Florida particularly in the Intercoastal Waterway where small proto-type turbines have already been tested.
- JEA, UNF and other Florida municipal utilities have partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for offshore wind development in Florida.
- JEA is also providing solar PV equipment to UNF for installation of a solar system on the UNF Engineering building to be used for student education.
- In recent years, JEA developed a 15-acre biomass energy farm, where the energy yields of various hardwoods and grasses were evaluated over a 3 year period. JEA also participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.

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.

The fuel price projections for natural gas, fuel oil, and coal used in this Ten Year Site Plan were developed based on those included in the US Energy Information Administration (EIA) Annual Energy Outlook 2007 (AEO2007). AEO 2007 presents projections of energy supply, demand, and prices through 2030. The projections presented within AEO2007 are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics. The AEO2007 in its entirety can be found on the EIA website.

The AEO2007 includes various cases in addition to the Reference Case. Each of these cases incorporates various changes to the reference case assumptions. Of the various cases considered by the EIA as part of AEO2007, two cases have been carried forward to the analyses considered in this Application in addition to the Reference Case – the High Price Case and the Low Price Case. Both the High Price Case and the Low Price Case rely on assumptions consistent with the Reference Case with the exception of assumptions related to crude oil and natural gas resources. The High Price Case reflects more pessimistic assumptions related to these resources while the Low Price Case reflects more optimistic assumptions. Both the High Price and Low Price Cases are fully integrated NEMS simulations, consistent with the Reference Case.

The fuel price forecast for St John's River Power Park (SJRPP) includes limestone and diesel fuel components. The fuel price forecast 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.

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 2007 were 2722 MW, 2897 MW, and 13,854 GWH, respectively.

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.

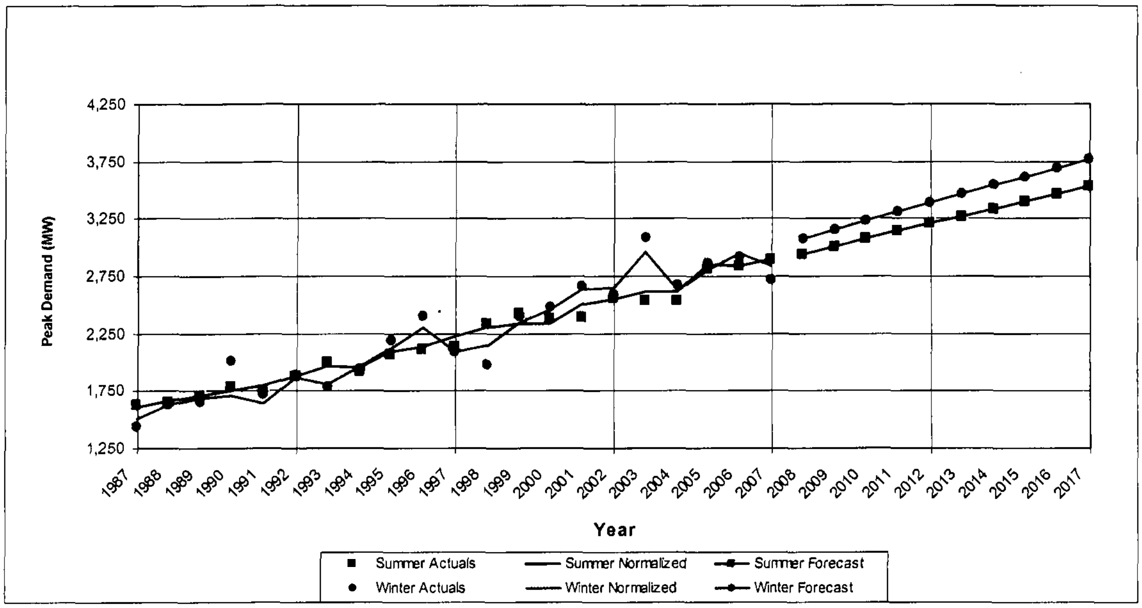
The results of the summer and winter peak demand forecasts are shown in Table 4-1 for total demand, firm demand, and interruptible demand levels. During the TYSP forecast period, the Total Internal Demand (TID) for the summer peak is forecast to increase at an average annual growth rate of 1.8 percent overall. The summer and winter interruptible load is held constant throughout the study period. The average annual increase in summer firm peak demand is 1.9 percent. During the winter period, the growth rate of the TID for the winter peak is projected to increase at an average annual growth rate of 2.0 percent. The average annual increase in winter firm peak demand is 2.1 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 2,946 MW in 2008 to 3,637 MW in 2017, and the firm summer peak demand is projected to increase from 2,824 MW in 2008 to 3,414 MW in 2017. 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
Peak Demand Forecast

	Total Peak Demand		Non-Firm Demand		Firm Peak Demand	
Year	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)
2008	3,079	2,941	133	117	2,946	2,824
2009	3,155	3,007	133	117	3,022	2,890
2010	3,232	3,072	133	117	3,099	2,955
2011	3,309	3,138	133	117	3,176	3,021
2012	3,386	3,204	133	117	3,253	3,087
2013	3,462	3,269	133	117	3,329	3,152
2014	3,539	3,335	133	117	3,406	3,218
2015	3,616	3,400	133	117	3,483	3,283
2016	3,693	3,466	133	117	3,560	3,349
2017	3,770	3,531	133	117	3,637	3,414
Average Annual % Change	2.0%	1.8%	0.0%	0.0%	2.1%	1.9%

Figure 4-1
Historical and Forecast Summer and Winter Peaks



4.2 Net Energy for Load (NEL) Forecast

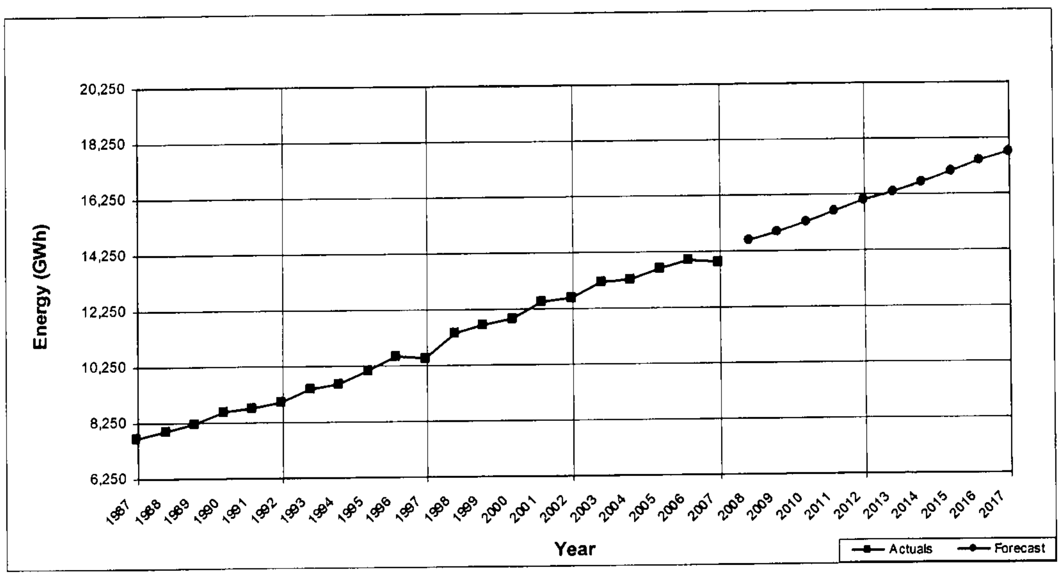
The NEL forecast is developed on a monthly and annual basis as a function of time and heating and cooling degree-day data. Inputs into the forecast include energy production, JEA territory sales, off-system sales, and heating and cooling degree-days. The JEA forecast modeling methodology separately accounts 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 1.9 percent during the site plan period. NEL is forecast to increase from 14,700 GWh in 2008 to 17,820 GWh in 2017. 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
2008	14,700	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	16,419	1,170	2,742
2014	16,769	1,170	2,742
2015	17,119	1,170	2,742
2016	17,512	1,170	2,742
2017	17,820	1,170	2,742
Average Annual % Increase	1.9%	0.0%	0.0%

Figure 4-2
Historical and Forecast Net Energy for Load



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, installation of committed units, and existing unit changes in capacity for JEA's system for the term of this ten-year site plan.

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

Winter (1)

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
2008	3,621	282	383	0	3,521	2,914	607	21%	0
2009	3,559	366	383	0	3,542	3,022	520	17%	0
2010	3,750	366	383	0	3,733	3,099	634	20%	0
2011	3,750	9	383	0	3,376	3,176	200	6%	276
2012	3,750	9	383	0	3,376	3,253	123	4%	364
2013	3,750	9	383	0	3,376	3,329	47	1%	453
2014	3,750	9	383	0	3,376	3,406	(30)	-1%	541
2015	3,750	9	383	0	3,376	3,483	(107)	-3%	629
2016	3,750	9	383	0	3,376	3,560	(184)	-5%	718
2017	3,750	9	383	0	3,376	3,637	(260)	-7%	806

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	Capacity Required For 15% Reserves MW
2008	3,371	207	376	0	3,202	2,824	378	13%	46
2009	3,470	216	376	0	3,310	2,890	420	15%	13
2010	3,470	9	376	0	3,103	2,955	148	5%	296
2011	3,470	9	376	0	3,103	3,021	82	3%	371
2012	3,470	9	376	0	3,103	3,087	16	1%	447
2013	3,470	9	376	0	3,103	3,152	(49)	-2%	522
2014	3,470	9	376	0	3,103	3,218	(115)	-4%	597
2015	3,470	9	376	0	3,103	3,283	(180)	-5%	673
2016	3,470	9	376	0	3,103	3,349	(246)	-7%	748
2017	3,470	9	376	0	3,103	3,414	(311)	-9%	824

Notes

1. Winter 2008 Peak is actual
2. Committed Capacity Additions
   - Clean Power Purchases 9 MW winter 2008/09.
   - Constellation Winter Purchases of 75 MW, 150 MW and 150 MW 2007/08, 2008/09 and 2009/10, respectively.
   - Kennedy CT 8 - 1/22/2009.
3. Kennedy CTs 3 winter 2008/09 retirement.
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 January 22, 2009.

5.2.2 Southeast Generating Station (SEGS)

The SEGS is located in Duval County; south of J. Turner Butler Boulevard, east of Interstate 95, and north of the St. Johns County border. Currently, JEA has no generation stations east of the St. Johns River where JEA's territory is growing the most. This site's ultimate build out capability is projected to be approximately 1,000 MW to meet future generation needs. This location provides increased system reliability and ease of tie into the existing electrical transmission system.

JEA is proceeding with the installation of two additional combustion turbine units at this new greenfield site. These units will also burn natural gas-fired and are simple-cycle GE frame 7FA combustion turbine units, with diesel backup fuel. The scheduled commercial operation date for these units is June 2010.

JEA's reference plan contained in the 2007 TYSP filing included the addition of more than 200 MW of coal fired generation at the Taylor Energy Center. JEA's back up plan was to convert the 2 7FA CTs installed in 2010 to a single 2x1 combined cycle unit in June 2012. With the cancellation of the Taylor Energy Center in 2007, JEA initiated the actions necessary to put this back-up plan into motion.

5.2.3 Nuclear Fission

The use of a uranium fueled nuclear fission process to create energy has been utilized in the United States for several decades. In the past, nuclear power in the United States has faced obstacles related to public perception, capital costs, and environmental issues concerning disposal of spent fuel. Collectively, these factors explain why nuclear plants had fallen out of favor as a generating resource. However, rising fuel prices, rising greenhouse gas emission concerns, and increasing energy demand are making nuclear fission a viable option for producing power in the future. New reactor designs are being submitted for approval by the Nuclear Regulatory Commission (NRC).

JEA is actively exploring the possibility of participation in new nuclear power generation projects that may be constructed at the latter end of this ten year site plan or in the subsequent ten year period.

5.3 Resource Plan

The analysis of JEA's electric system to determine the current plan included a review of existing electric supply resources including renewable energy, 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 a small amount of 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
2008	Winter	Constellation Purchase (75 MW – Seasonal)
	Summer	TEA Purchase (50 MW - Seasonal)
2009	Winter	Clean Power Purchase (9 MW) Constellation Purchase (150 MW - Seasonal) Build Kennedy CT 8 - 1/22/09 (177 MW) Retire Kennedy CTs 3 – 1/1/09 (63 MW)
	Summer	TEA Purchase (25 MW - Seasonal)
2010	Winter	Constellation Purchase (150 MW - Seasonal)
	Summer	UPS Contract Expires – 6/1/10 (207 MW) Build 2 - 7FA CT at SEGS - 06/01/10 (177 MW each)
2011	Summer	TEA Purchase (75 MW - Seasonal)
2012	Summer	2x1 Combined Cycle Conversion at SEGS (185 MW)
2013		
2014	Summer	SJRPP Sale Return From FPL – 02/28/14 (383 MW)
2015		
2016		
2017		

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, 2008

(1) Plant Name	(2) Unit Number	(3) Location	(4) Unit Type	(5) Fuel Type Primary	(6) Fuel Type Alt.	(7) Fuel Transport Primary	(8) Fuel Transport Alt.	(9) Commercial In-Service Mo/Yr	(10) Expected Retirement Mo/Yr	(11) Gen Max Nameplate kW	(12) Net MW Capability Summer	(13) Net MW Capability Winter	(14) Ownership	(15) 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	1,322	1,356		
	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	524	524	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											**3,371**	**3,621**		

NOTE:
(a) Units expected to be maintained throughout the study period.
(b) Retired 2007.
(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
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	5,478	364,284	15,039	1,328	39,919	33,279	5,832	4,521	1,290,035
2008	5,813	386,540	15,039	1,410	42,358	33,279	6,188	4,797	1,290,035
2009	5,938	394,855	15,039	1,440	43,269	33,279	6,321	4,900	1,290,035
2010	6,077	404,072	15,039	1,474	44,279	33,279	6,469	5,014	1,290,035
2011	6,215	413,281	15,039	1,507	45,288	33,279	6,616	5,129	1,290,035
2012	6,369	423,517	15,039	1,544	46,410	33,279	6,780	5,256	1,290,035
2013	6,493	431,729	15,039	1,574	47,310	33,279	6,912	5,358	1,290,035
2014	6,631	440,933	15,039	1,608	48,319	33,279	7,059	5,472	1,290,035
2015	6,769	450,143	15,039	1,642	49,328	33,279	7,206	5,586	1,290,035
2016	6,925	460,467	15,039	1,679	50,459	33,279	7,372	5,714	1,290,035
2017	7,047	468,585	15,039	1,709	51,349	33,279	7,502	5,815	1,290,035

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
1998	77	0	10,590	438	442	11,470	3	336,295
1999	86	0	10,781	454	547	11,782	3	341,012
2000	120	0	11,105	482	603	12,190	2	347,782
2001	109	0	11,508	453	361	12,322	2	355,994
2002	112	0	11,856	446	681	12,983	2	363,698
2003	115	0	12,130	453	595	13,178	2	369,904
2004	76	0	12,057	468	718	13,243	2	384,108
2005	111	0	12,596	486	615	13,696	2	395,606
2006	110	0	12,694	522	595	13,811	7	398,581
2007	113	0	12,751	624	479	13,854	5	408,729
2008	120	0	13,530	662	508	14,700	5	433,700
2009	122	0	13,822	676	519	15,016	5	443,029
2010	125	0	14,144	692	531	15,367	6	453,371
2011	128	0	14,467	708	543	15,717	6	463,704
2012	131	0	14,825	725	556	16,106	6	475,189
2013	134	0	15,112	739	568	16,419	6	484,403
2014	136	0	15,434	755	580	16,769	6	494,729
2015	139	0	15,757	771	591	17,119	6	505,064
2016	143	0	16,118	788	605	17,512	6	516,646
2017	145	0	16,402	802	616	17,820	6	525,756

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.
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	2,562	0	0	0	0	0	0	2,562	7	19	1600	0	0
2003	2,535	0	0	0	0	0	0	2,535	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	2,897	0	0	0	0	0	0	2,897	8	7	1700	0	0
2008	2,941	117	0	0	0	0	0	2,824	---	---	---	0	0
2009	3,007	117	0	0	0	0	0	2,890	---	---	---	0	0
2010	3,072	117	0	0	0	0	0	2,955	---	---	---	0	0
2011	3,138	117	0	0	0	0	0	3,021	---	---	---	0	0
2012	3,204	117	0	0	0	0	0	3,087	---	---	---	0	0
2013	3,269	117	0	0	0	0	0	3,152	---	---	---	0	0
2014	3,335	117	0	0	0	0	0	3,218	---	---	---	0	0
2015	3,400	117	0	0	0	0	0	3,283	---	---	---	0	0
2016	3,466	117	0	0	0	0	0	3,349	---	---	---	0	0
2017	3,531	117	0	0	0	0	0	3,414	---	---	---	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.
1998	1,938	0	0	0	0	0	0	1,938	3	13	0700	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	2,590	0	0	0	0	0	0	2,590	1	4	0800	0	0
2003	3,083	0	0	0	0	0	0	3,083	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	2,914	0	0	0	0	0	0	2,914	1	3	0800	0	0
2009	3,155	133	0	0	0	0	0	3,022	---	---	---	0	0
2010	3,232	133	0	0	0	0	0	3,099	---	---	---	0	0
2011	3,309	133	0	0	0	0	0	3,176	---	---	---	0	0
2012	3,386	133	0	0	0	0	0	3,253	---	---	---	0	0
2013	3,462	133	0	0	0	0	0	3,329	---	---	---	0	0
2014	3,539	133	0	0	0	0	0	3,406	---	---	---	0	0
2015	3,616	133	0	0	0	0	0	3,483	---	---	---	0	0
2016	3,693	133	0	0	0	0	0	3,560	---	---	---	0	0
2017	3,770	133	0	0	0	0	0	3,637	---	---	---	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.
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	13,854	0	0	0	0	0	0	13,854	0	0
2008	14,700	0	0	0	0	0	0	14,700	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	16,419	0	0	0	0	0	0	16,419	0	0
2014	16,769	0	0	0	0	0	0	16,769	0	0
2015	17,119	0	0	0	0	0	0	17,119	0	0
2016	17,512	0	0	0	0	0	0	17,512	0	0
2017	17,820	0	0	0	0	0	0	17,820	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 2007		Forecast 2008		Forecast 2009	
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	2,722	1,091	3,079	1,174	3,155	1,202
February	2,526	1,000	2,554	1,058	2,618	1,047
March	2,162	983	2,174	1,105	2,228	1,131
April	2,181	1,016	2,196	1,075	2,245	1,101
May	2,229	1,127	2,635	1,217	2,694	1,246
June	2,605	1,272	2,775	1,341	2,837	1,373
July	2,821	1,395	2,941	1,505	3,007	1,542
August	2,897	1,513	2,896	1,489	2,960	1,525
September	2,673	1,288	2,715	1,298	2,776	1,329
October	2,465	1,173	2,519	1,158	2,580	1,186
November	1,979	965	2,417	1,083	2,476	1,108
December	2,328	1,031	2,862	1,199	2,932	1,226
Total		13,854		14,700		15,016

Schedule 5
Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	**NUCLEAR**		**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**		**1000 TON**	**3,029**	**3,008**	**2,976**	**2,953**	**3,205**	**2,944**	**3,043**	**3,486**	**3,558**	**3,476**	**3,790**
	RESIDUAL													
(3)		STEAM	1000 BBL	272	227	341	232	364	226	183	86	71	114	123
(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**	**272**	**227**	**341**	**232**	**364**	**226**	**183**	**86**	**71**	**114**	**123**
	DISTILLATE													
(7)		STEAM	1000 BBL	21	20	21	21	21	21	21	21	21	21	22
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	31	60	15	5	10	7	8	5	11	12	13
(10)		TOTAL:	**1000 BBL**	**53**	**80**	**36**	**26**	**31**	**28**	**30**	**26**	**33**	**33**	**35**
	NATURAL GAS													
(12)		STEAM	1000 MCF	5,079	9,229	8,168	5,585	8,712	5,456	4,426	2,122	1,792	2,803	3,013
(13)		CC	1000 MCF	10,943	10,508	11,232	18,195	15,402	29,305	33,247	30,710	31,639	35,486	31,737
(14)		CT/GT	1000 MCF	1,412	3,447	4,371	9,886	15,886	15,402	18,769	16,752	17,668	20,243	18,406
(15)		TOTAL:	**1000 MCF**	**17,434**	**23,184**	**23,770**	**33,666**	**40,000**	**50,163**	**56,441**	**49,583**	**51,099**	**58,532**	**53,156**
(16)	**PETROLEUM COKE**		**1000 TON**	**1,290**	**1,241**	**1,336**	**1,265**	**1,224**	**1,278**	**1,278**	**1,278**	**1,270**	**1,223**	**1,281**
(20)	**OTHER (SPECIFY)**		**TRILLION BTU**	**0**	0	0	0	0	0	0	0	0	0	0

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

Schedule 6.1
Energy Sources (GWH)

	(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actuals										
	Fuel	Type	Units	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	**Annual Firm Inter-Region Intchg.**		GWH	1,466	1,623	1,807	748	13	0	0	0	0	0	0
(2)	**NUCLEAR**		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	**COAL**		GWH	6,641	6,469	6,136	6,530	7,173	6,702	6,747	7,871	8,055	7,919	8,602
(4)	**RESIDUAL**	STEAM	GWH	156	124	184	127	202	118	93	42	35	55	60
(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	156	124	184	127	202	118	93	42	35	55	60
(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	11	25	6	2	4	3	3	2	4	5	6
(11)		TOTAL	GWH	11	25	6	2	4	3	3	2	4	5	6
(12)	**NATURAL GAS**	STEAM	GWH	466	828	735	507	808	472	370	168	139	220	240
(13)		CC	GWH	1,487	1,519	1,624	2,657	2,271	4,287	4,858	4,510	4,667	5,246	4,666
(14)		CT	GWH	126	326	411	901	1,473	588	412	243	306	296	302
(15)		TOTAL	GWH	2,079	2,672	2,769	4,065	4,553	5,346	5,640	4,920	5,113	5,761	5,209
(16)	**NUG**		GWH	0	26	78	78	78	79	78	78	78	79	78
(17)	**HYDRO**		GWH	0	0	0	0	0	0	0	0	0	0	0
(18)	**Petroleum Coke**		GWH	3,499	3,760	4,036	3,817	3,693	3,859	3,858	3,856	3,834	3,693	3,866
(19)	**OTHER (SPECIFY)**		GWH	3	0	0	0	0	0	0	0	0	0	0
(20)	**NET ENERGY FOR LOAD**		GWH	13,854	14,700	15,016	15,367	15,717	16,106	16,419	16,769	17,119	17,512	17,820

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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	Annual Firm Inter-Region Intchg.		%	10.6%	11.0%	12.0%	4.9%	0.1%	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		%	47.9%	44.0%	40.9%	42.5%	45.6%	41.6%	41.1%	46.9%	47.1%	45.2%	48.3%
(4)	RESIDUAL	STEAM	%	1.1%	0.8%	1.2%	0.8%	1.3%	0.7%	0.6%	0.3%	0.2%	0.3%	0.3%
(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	%	1.1%	0.8%	1.2%	0.8%	1.3%	0.7%	0.6%	0.3%	0.2%	0.3%	0.3%
(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%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		TOTAL	%	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)	NATURAL GAS	STEAM	%	3.4%	5.6%	4.9%	3.3%	5.1%	2.9%	2.3%	1.0%	0.8%	1.3%	1.3%
(13)		CC	%	10.7%	10.3%	10.8%	17.3%	14.5%	26.6%	29.6%	26.9%	27.3%	30.0%	26.2%
(14)		CT	%	0.9%	2.2%	2.7%	5.9%	9.4%	3.6%	2.5%	1.4%	1.8%	1.7%	1.7%
(15)		TOTAL	%	15.0%	18.2%	18.4%	26.5%	29.0%	33.2%	34.3%	29.3%	29.9%	32.9%	29.2%
(16)	NUG		%	0.0%	0.2%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.4%
(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		%	25.3%	25.6%	26.9%	24.8%	23.5%	24.0%	23.5%	23.0%	22.4%	21.1%	21.7%
(19)	OTHER (SPECIFY)		%	0.0%	0.0%	0.0%	0.0%	0.0%	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
2008	3,621	282	383	0	3,521	2,914	607	21%	0	607	21%
2009	3,559	366	383	0	3,542	3,022	520	17%	0	520	17%
2010	3,750	366	383	0	3,733	3,099	634	20%	0	634	20%
2011	4,132	9	383	0	3,758	3,176	582	18%	0	582	18%
2012	4,132	9	383	0	3,758	3,253	505	16%	0	505	16%
2013	4,368	9	383	0	3,994	3,329	665	20%	0	665	20%
2014	4,368	9	383	0	3,994	3,406	588	17%	0	588	17%
2015	4,368	9	0	0	4,377	3,483	894	26%	0	894	26%
2016	4,368	9	0	0	4,377	3,560	817	23%	0	817	23%
2017	4,368	9	0	0	4,377	3,637	740	20%	0	740	20%

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
2008	3,371	257	376	0	3,252	2,824	428	15%	0	428	15%
2009	3,470	241	376	0	3,335	2,890	445	15%	0	445	15%
2010	3,770	9	376	0	3,403	2,955	447	15%	0	447	15%
2011	3,770	84	376	0	3,478	3,021	457	15%	0	457	15%
2012	4,006	9	376	0	3,639	3,087	552	18%	0	552	18%
2013	4,006	9	376	0	3,639	3,152	487	15%	0	487	15%
2014	4,006	9	0	0	4,015	3,218	797	25%	0	797	25%
2015	4,006	9	0	0	4,015	3,283	731	22%	0	731	22%
2016	4,006	9	0	0	4,015	3,349	666	20%	0	666	20%
2017	4,006	9	0	0	4,015	3,414	600	18%	0	600	18%

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														
Kennedy	4	Kennedy	GT	NG	FO2	PL	TK			01/01/08		51	63	RT
Kennedy	5	Kennedy	GT	NG	FO2	PL	TK			01/01/08		51	63	RT
Kennedy	3	Kennedy	GT	NG	FO2	PL	TK			01/01/09		51	63	RT
SJRPP	1	SJRPP	ST	Bit/PC		RR	WA		02/28/14			191	188	A
SJRPP	2	SJRPP	ST	Bit/PC		RR	WA		02/28/14			191	188	A
Planned and Prospective Generating Facility Additions														
Kennedy	8	Kennedy	GT	NG	FO2	PL	TK		01/22/09			150	191	U
Kennedy	1	SE Generating Station	GT	NG	FO2	PL	TK		06/01/10			150	191	P
Kennedy	2	SE Generating Station	GT	NG	FO2	PL	TK		06/01/10			150	191	P
2x1 CC- Conversion	3	SE Generating Station	HRSG	NG	FO3	PL	TK		06/01/12			201	236	P
Planned and Prospective Purchased Power Changes and Additions														
Constellation									12/15/07	03/15/08		0	75	Contracted
TEA									06/01/08	09/15/08		50	0	Planned
Trail Ridge									12/15/08	12/15/18		9	9	Contracted
Constellation									12/15/08	03/15/09		0	150	Contracted
TEA									06/01/09	09/15/09		25	0	Planned
Constellation									12/15/09	03/15/10		0	150	Contracted
UPS										06/01/10		207	207	Contract Ends
TEA									06/01/11	09/15/11		75	0	Planned

Schedule 9.0
Status Report and Specifications of Proposed Generating Facilities
2007 Dollars

(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:	01/22/09
(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):	2.00 %
(20)	Forced Outage Factor (FOF):	3.00 %
(21)	Equivalent Availability Factor (EAF):	95.00 %
(22)	Resulting Capacity Factor (%):	5.0 – 10.0 %
(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):	$ 471.75
(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):	$ 4.62
(31)	Variable O&M ($/MWh):	$ 17.44

Schedule 9.1 Status Report and Specifications of Proposed Generating Facilities 2007 Dollars		
(1)	Plant Name and Unit Number:	Southeast Generating Station CTs 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 06/01/10
(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):	2.00 %
(20)	Forced Outage Factor (FOF):	3.00 %
(21)	Equivalent Availability Factor (EAF):	95.00 %
(22)	Resulting Capacity Factor (%):	5.0 – 10.0 %
(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):	$ 555.85
(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):	$ 4.62
(31)	Variable O&M ($/MWh):	$ 17.44

Schedule 9.2 Status Report and Specifications of Proposed Generating Facilities 2007 Dollars		
(1)	Plant Name and Unit Number:	Southeast Generating Station Unit 3 – HRSG
(2)	Capacity:	
(3)	Summer MW	236 MW
(4)	Winter MW	236 MW
(5)	Technology Type:	Heat Recovery Steam Generator
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	
(8)	Commercial In-Service date:	May 2012
(9)	Fuel	
(10)	Primary	Natural Gas
(11)	Alternate	
(12)	Air Pollution Control Strategy:	Selective Catalytic Reduction (SCR)
(13)	Cooling Method:	Mechanical Draft Cooling Tower
(14)	Total Site Area:	
(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):	3.00%
(20)	Forced Outage Factor (FOF):	3.00%
(21)	Equivalent Availability Factor (EAF):	94.0 %
(22)	Resulting Capacity Factor (%):	50 -60%
(23)	Average Net Operating Heat Rate (ANOHR):	7,191 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30 years
(26)	Total Installed Cost (In-Service year $/kW):	$1,293.35/kw
(27)	Direct Construction Cost ($/kW):	Included in direct construction cost
(28)	AFUDC Amount ($/kW):	Included in direct construction cost
(29)	Escalation ($/kW):	Included in direct construction cost
(30)	Fixed O&M ($/kW-yr):	$ 6.83
(31)	Variable O&M ($/MWh):	$ 5.04

[1] Based on operation at average ambient conditions.

Schedule 10.0 Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination	Southeast Generating Station to Bartram Substation
(2)	Number of Lines	one
(3)	Right of Way	New (easement)
(4)	Line Length	8.84 miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	~ 48 Months
(7)	Anticipated Capital Investment	~ $20 Million
(8)	Substations	Southeast Generating Station and Bartram
(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	Bartram Substation to Sampson (FPL) Substation
(2)	Number of Lines	one
(3)	Right of Way	Existing (easement)
(4)	Line Length	4.04 miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	~ 48 Months
(7)	Anticipated Capital Investment	~ $10 Million
(8)	Substations	Bartram and Sampson
(9)	Participation with Other Utilities	Yes (FPL)

Schedule 10.2 Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination	Bartram Substation to Switzerland Substation
(2)	Number of Lines	two
(3)	Right of Way	Existing (easement)
(4)	Line Length	6.88 circuit miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	~ 48 Months
(7)	Anticipated Capital Investment	~ $14 Million
(8)	Substations	Bartram and Switzerland
(9)	Participation with Other Utilities	No

Schedule 10.3 Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination	Jax Heights Substation to Duval (FPL) Substation
(2)	Number of Lines	one
(3)	Right of Way	Existing and Fee (easement)
(4)	Line Length	12.5 miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	~ 48 Months
(7)	Anticipated Capital Investment	~ $34 Million
(8)	Substations	Jax Heights and Duval
(9)	Participation with Other Utilities	Yes (FPL)

Schedule 10.4 Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination	Imeson Substation and Anheuser Busch Substation
(2)	Number of Lines	one
(3)	Right of Way	Existing (easement)
(4)	Line Length	2.7 miles
(5)	Voltage	138 kV
(6)	Anticipated Construction Time	~ 15 Months
(7)	Anticipated Capital Investment	~ $10 Million
(8)	Substations	Imeson and Anheuser Busch
(9)	Participation with Other Utilities	No

Schedule 10.5 Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination	Ritter Park Substation and Anheuser Busch Substation
(2)	Number of Lines	one
(3)	Right of Way	Existing (easement)
(4)	Line Length	1.8 miles
(5)	Voltage	138 kV
(6)	Anticipated Construction Time	~ 15 Months
(7)	Anticipated Capital Investment	~ $10 Million
(8)	Substations	Ritter Park and Anheuser Busch
(9)	Participation with Other Utilities	No

Schedule 10.6 Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination	Georgia Street Substation and Dillon Substation
(2)	Number of Lines	two
(3)	Right of Way	Existing and new (easement)
(4)	Line Length	6.12 circuit miles
(5)	Voltage	69 kV
(6)	Anticipated Construction Time	~ 9 Months
(7)	Anticipated Capital Investment	~ $2 Million
(8)	Substations	Georgia Street and Dillon
(9)	Participation with Other Utilities	No