Ten Year Site Plan

JEA

Building Community

April 2003

Table of Contents

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 2003 Ten Year Site Plan for JEA covering a planning period from 2003 to 2012.

2.0 Existing Facilities

2.1 Power Supply

Electric System Summary

JEA's electric service area covers all of Duval County and portions of Clay County and St. Johns County. JEA's service area covers approximately 900 square miles.

The generating capability of JEA's system currently consists of the Kennedy, Northside, and Brandy Branch generating stations, and joint ownership in St. Johns River Power Park and Scherer generating stations. The total net capability of JEA's generation system is 3,476 MW in the winter and 3,257 MW in the summer. Details of the existing facilities are displayed in TYSP Schedule 1.

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 714 circuit-miles of transmission lines at five voltage levels: 69kV, 138kV, 230kV, and 500kV. JEA's transmission system includes a 230 kV 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 Power Company. JEA, FP&L, Florida Power Corporation (FPC) and the City of Tallahassee each own transmission interconnections with Georgia Power Company. 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 FPL's Duval Substation.

Jointly Owned Generating Units

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. Unit 1 began commercial operation in March of 1987 and Unit 2 followed in May of 1988. Both owners are entitled to 50 percent of the output of SJRPP. Since FP&L's ownership is only 20 percent, the remaining 30 percent of capacity and energy output is reflected as a firm sale. The two units have operated efficiently since commercial operation. To reduce fuel costs and increase fuel diversity, a blend of petroleum coke and coal is currently being burned in the units.

JEA and FP&L have purchased an undivided interest in Georgia Power Company's Robert W. Scherer Unit 4. Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. JEA purchased 150 megawatts of Scherer Unit 4 in July 1991 and purchased an additional 50 megawatts on June 1, 1995. Georgia Power Company delivers the power from the unit to the jointly owned 500 kV transmission lines.

Power Purchases

Unit Power Sales (UPS)

Southern Company and JEA entered a unit power sales contract in which JEA purchases 200 MW of firm capacity and energy from specific Southern Company coal units through the year 2010. JEA has the unilateral option, upon three years notice, to cancel 150 MW of the UPS.

The Energy Authority (TEA)

The Energy Authority (TEA), actively trades energy with a large number of counterparties throughout the southeastern 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. TEA identifies 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 similar levels of reliability to capacity available within Florida. TEA, with input from JEA, selects the best offer. TEA then enters into a back to back power purchase agreement 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. Over the past five years, TEA has purchased capacity and energy on behalf of JEA for six seasonal periods. Of these six seasons, approximately 65% of the purchases were out of state resources and approximately 35% were Florida resources.

In this Ten Year Site Plan, JEA's only seasonal need occurs in winter 2005. It is JEA's plan for TEA to fully fill this future short-term purchase need.

Biomass Industries, Inc.

As part of JEA's Green Works initiative to supply 7.5 percent of its peak demand with renewable resources by 2015, JEA has contracted with Biomass Industries, Inc. (BII). JEA has purchased 70 MW peak and 35 MW off-peak, firm renewable energy from a gasified biomass fueled electric generation plant proposed to be constructed by BII in South Florida. The proposed facility is to be fueled by an energy crop (bamboo and E-grass) to be grown by BII.

The initial term of the purchase is 15 years from the commercial operation date of the facility. The parties, by mutual agreement, have the right to extend the initial contract term for two additional five-year periods, on terms to be agreed upon by the parties. Under the contract, JEA will be obligated to take and pay for energy produced by the facility, up to the limits stated above, and at a fixed price stated in the contract (subject to periodic escalations).

The facility currently is scheduled to be in service in November 2004. The start date for the contract has been extended from June 2003 to accommodate licensing, permitting and financing issues faced by BII.

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.

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

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

Power Sales

JEA returned Kennedy Combustion Turbine Unit 4 (GT 4) to service from retirement status in March 1994. Concurrently, JEA sold to SECI priority dispatch rights for one-seventh of the aggregate GT output capacity of JEA's older diesel fueled combustion turbines, which include Kennedy Units 3, 4, and 5, and Northside Units 3, 4, 5, and 6. For planning purposes, JEA and SECI assume SECI's base committed capacity is 53 MW. Full entitlement sales began January 1, 1995 and were extended through August 31, 2004.

JEA also furnishes wholesale power to Florida Public Utilities Company (FPU) for resale in the City of Fernandina Beach in Nassau County, north of Jacksonville. JEA is contractually committed to supply FPU until 2007. Sales to FPU in 2002 totaled 436 GWh (3.5 percent of JEA's total system energy requirements).

2.2 Transmission

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 auto-transformers to provide safe and reliable transmission service under normal and single contingency conditions without undue expected loss of component life.
- Plan the transmission system to withstand single contingencies without loss of customer load.
- 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.
- Meet the Florida Reliability Coordinating Council's (FRCC) and NERC Planning Standards.

2.3 Demand Side Management

In 2000, 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 is primarily due to the low cost of new generation, high efficiency of new generation, low interest rates, and low fuel price projections. On February 21, 2001, the PSC approved JEA's Plan for zero DSM goals for 2001-2010.

JEA agreed to continue several DSM programs, including the residential education seminars, residential energy audits, commercial educational programs, commercial energy audits, and community conservation initiatives. As promised, JEA continued these programs in 2001. With the rising costs of all fuel types in 2002, JEA continues to look for cost effective DSM measures.

2.4 Green/Clean Power Programs

In addition, in 2001 JEA developed a Green Power Program to encourage the widespread application of renewable energy technology in its service territory. As part of the Green Power Program, JEA implemented the solar incentive program in early 2002. Under the terms of the program, JEA provides cash incentives for customers to install solar photovoltaic and solar thermal systems at their homes or business. JEA has installed approximately 170 kw of solar photovoltaic modules throughout the city of Jacksonville with approximately 50% of the installations at local public high schools. JEA expects over 200 customers to take advantage of the program in 2003 and expects demand reduction to total over 9 MW by 2007.

Also, JEA owns and operates three internal combustion engine generators located at the Girvin Road Landfill. This facility was placed in service in July, 1997 and is fueled by gas produced by the landfill (the gas consists of approximately 52% methane and 48% carbon dioxide and nitrogen). The facility originally had four generators with an aggregate net capacity of 3.0 MW, but since then gas generation has declined and one generator has been removed and placed in service at the Buckman Wastewater Treatment facility. JEA also receives approximately 1500 kw of landfill gas from the North Landfill which is pumped to the Northside Generating Station and used to generate power in Unit 3. JEA will continue to monitor and evaluate these and other programs in order to determine the most cost-effective ways of encouraging customers to conserve energy.

3.0 Fuel Price Forecast

JEA's fuel price forecast is a major input in the development of JEA's future resource plan. JEA uses a diverse mix of fuels; the forecast includes coal, natural gas, residual fuel oil, diesel fuel, and petroleum coke. Sensitivity cases were considered based on high and low fuel price projections.

Specific price forecasts for St John's River Power Park (SJRPP) and Scherer Unit 4 were provided by SJRPP Fuels and Georgia Power respectively. Eastern and off-shore coals are the primary fuels burned at SJRPP. In addition, the SJRPP forecast is based on a 16 percent blend of petroleum coke and includes limestone and diesel fuel components. Western coal is burned in Scherer Unit 4.

The fuel price forecast for JEA's natural gas supply takes into account commodity and transportation components. For natural gas, the transportation portion is based on JEA's purchase of 40,000 mmBtu/day of firm transportation on the Florida Gas Transmission Company (FGT) system under rate schedule FTS-1 and 14,000 mmBtu/day under rate schedule FTS-2. In addition, JEA receives 20,000 mmBtu/day of delivered gas volumes from El Paso Municipal (EPM). The EPM volume will increase to 61,000 mmBtu/day coincident with the expected June 2005 completion of JEA's combined cycle conversion at Brandy Branch. The EPM volumes are currently supplied via the FGT system.

A blend of residual fuel oil and natural gas is burned in Northside Unit 3. The price forecast for residual fuel oil is based on the allowable sulfur level of 1.8 percent. Forecasts are also provided for high and low sulfur diesel fuel. 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.

Northside Units 1 and 2 have been repowered to operate on a blend of petroleum coke and coal. The current petroleum coke blend rate is 75 to 80 percent. JEA's goal is to reach a 90 percent blend rate in 2003 and to eventually begin operating entirely on petroleum coke. In addition, limestone is blended with the petroleum coke for SO_2 removal. The price forecast for petroleum coke includes limestone and is based on a conservative estimate of the long term petroleum coke market.

4.0 Load and Energy Forecast

JEA's winter and summer hourly net integrated system peak demand for 2002 were 2610 MW and 2530 MW respectively. JEA's annual net energy for load for calendar year 2002 was 12,983 GWH. JEA's winter peak demand, summer peak demand and net energy for load are growing at approximately 3 percent per year.

JEA's base case forecast of peak demand and energy is based on a trend analysis of weather normalized historical data. JEA's trend analysis methodology has dramatically increased the accuracy of JEA's forecasts. Prior to implementing the trend analysis methodology in 1996, JEA's five-year average absolute error for its one-year-ahead sales forecast was 3.67%. Since implementing the trend analysis methodology JEA's most recent five-year average absolute error has been 0.46%. In addition to achieving this eight-fold improvement in forecast accuracy, JEA has also experienced a twelve-fold decrease in the cycle time to produce the forecast. Schedules 2 and 3 provide a summary of the base case forecast for the 2003 Ten Year Site Plan.

5.0 Facility Requirements

5.1 Brandy Branch Combined Cycle Conversion

On February 28, 2001, the Florida Public Service Commission issued an Order Granting Petition For Determination of Need for the Brandy Branch Combined Cycle Conversion. On March 12, 2002, JEA's site certification was approved. The governor's signature and DEP's issuance of the permits for construction followed.

JEA is converting two of the Brandy Branch simple cycle units into a combined cycle unit. The Brandy Branch Plant was designed with future expansion in mind, namely adding the steam turbine unit to the site. This expansion will occur in the northwest quadrant of the current plant, adjacent to the existing combustion turbines.

The conversion is accomplished by adding two heat recovery steam generators (HRSGs) to two of the three existing combustion turbines, one steam turbine generator, and balance of plant equipment. One HRSG will be added to each of the two combustion turbines and the two HRSGs will share the steam turbine generator. This conversion will create a one-block 2 x 1 combined cycle unit. The nominal rating of the steam turbine addition is assumed to be 185 MW. The total capacity of the Brandy Branch power plant, including the remaining simple cycle unit and the combined cycle unit after the conversion, will be 705 MW. The combined cycle unit is currently scheduled for commercial operation June 2005 which represents a one year shift in last year's schedule. The shift in the commercial date is due in part to a new Load & Energy Forecast which represents on average a 60 MW decrease in peak demand resulting in the one year delay.

5.2 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 2003.

Table 5-1
Resource Needs After Committed Units
Forecast of Capacity and Demand 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	Capacity Required For 15% Reserves MW
2003	3,476	207	445	0	3,238	2,633	606	23%	0
2004	3,476	207	383	0	3,301	2,722	578	21%	0
2005	3,094	277	383	0	2,988	2,813	176	6%	246
2006	3,666	277	383	0	3,560	2,905	655	23%	0
2007	3,666	277	383	0	3,560	2,999	562	19%	0
2008	3,666	277	383	0	3,560	3,093	467	15%	0
2009	3,666	277	383	0	3,560	3,189	371	12%	107
2010	3,666	277	383	0	3,560	3,287	274	8%	219
2011	3,666	70	383	0	3,353	3,386	(33)	-1%	541
2012	3,666	70	383	0	3,353	3,487	(134)	-4%	657

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
2003	3,257	207	428	0	3,036	2,504	532	21%	0
2004	3,257	207	428	0	3,036	2,571	465	18%	0
2005	3,441	277	376	0	3,342	2,639	703	27%	0
2006	3,441	277	376	0	3,342	2,708	634	23%	0
2007	3,441	277	376	0	3,342	2,778	565	20%	0
2008	3,441	277	376	0	3,342	2,848	494	17%	0
2009	3,441	277	376	0	3,342	2,918	424	15%	13
2010	3,441	70	376	0	3,135	2,990	146	5%	303
2011	3,441	70	376	0	3,135	3,062	74	2%	386
2012	3,441	70	376	0	3,135	3,135	0	0%	470

Committed Units:
1. Brandy Branch CTs 2 & 3 - Outage for conversion starts September 2004.
2. Brandy Branch Combined Cycle - June 2005

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 2009. This need encompasses the inclusion of existing supply resources, transmission system considerations, the Biomass Industries purchase and the Brandy Branch Combined Cycle conversion.

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.

Reference Plan		
Year	**Season**	**Expansion Plan**
2003		
2004		
2005	Winter Winter Summer	Purchase 70 MW Biomass Industries, Inc Purchase 245 MW Convert 2 Brandy Branch CTs to Combined Cycle (Additional 185 Summer/ 190 Winter MWs)
2006		
2007		
2008		
2009	Winter	Build 1-323 MW Greenfield Combined Cycle
2010	Summer	Build 1-250 MW Greenfield CFB
2011		
2012	Winter	Build 1-174 MW Greenfield GT

6.0 Project Status

6.1 Brandy Branch Combustion Turbines and Combined Cycle Conversion

Site Description

Simple Cycle Plant

JEA's Brandy Branch Generating Station currently consists of three gas/oil fired simple cycle combustion turbine electric generating units. These combustion turbines are GE PG7241 (FA) units with a nominal rating of 173 MW ISO each. The combustion turbines are dual fuel capable and operate with natural gas as the primary fuel and distillate oil as the backup fuel. Construction of the Brandy Branch units began in late 1999 with the completion of the first two units in May 2001 and the third unit in October 2001. The Brandy Branch site is shown on Figure 6-1.

Combined Cycle Conversion

The conversion project consists of converting Brandy Branch CTs 2 and 3 to combined cycle units. A Heat Recovery Steam Generator (HRSG) will be installed on each combustion turbine exhaust that will recover energy to produce steam that in turn will power a new steam turbine generator. The steam turbine, STG 4, will have a nominal output of 185 MW net and a maximum output of 227 MW gross. The combined cycle plant (CT 2, CT 3 and STG 4) will have a net nominal output of 531 MW. Included are all turbine controls, steam condenser, cooling tower, high energy piping, feed water and condensate pumps, related foundations, site improvements, new exhaust stacks, and duct work. To provide the additional service water required for the combined cycle unit, one of the two existing Floridan wells was modified to increase flow capacity, and a third deep well was constructed. As a condition of the Consumptive Use Permit, an upper and lower aquifer monitoring well was installed. Also. wetland soils, vegetation, and hydrology will be monitored for a period of 3 years. The EPC (Engineer, Procure and Construct) contract was awarded on October 4, 2001. Construction broke ground in mid October 2002 and the current commercial date for the CC plant, CT-2, CT-3 and Steam Turbine Generator STG-4, is June 1, 2005.

Water Supply
Service and fire water for use at the generating station is normally supplied from onsite wells. Potable water, construction water, and a backup supply for service water will be provided from the City of Baldwin.

The service water will be demineralized using rental filtration and demineralizer equipment to provide high quality water for NO_x water injection.

Land Use
The plant site is near the City of Baldwin. Baldwin is west of Jacksonville on Highway 301 a short distance north of Interstate 10. The plant site is a short distance north of Highway 90 east of Baldwin. The generation area will consist of the plant buildings, structures, and equipment required for the power plant.

Environmental Features
The combustion turbines selected for this project are state-of-the-art machines capable of firing natural gas and distillate oil.

Emissions

The combustion turbines utilize a dry low NO_x combustion system to regulate the distribution of fuel delivered to a multi-nozzle, total premix combustion arrangement. The fuel flow distribution is calculated to maintain unit load and fuel split for optimal combustion turbine emissions. In addition, when operating on distillate oil, demineralized water is injected into the combustion chamber to reduce the firing temperature, which reduces the formation of NO_x. The ratio of the flow rate of demineralized water to No. 2 oil is approximately equal. Selective catalytic reduction (SCR) will be utilized to reduce NO_x emissions for the combined cycle configuration.

Fuel Storage

Natural gas will be the primary fuel for the Brandy Branch plant, with diesel as a backup fuel. Natural gas will be delivered to the site by a pipeline. JEA currently purchases natural gas transportation from Florida Gas Transmission Company (FGT) under FTS-1. FGT operates the 16-inch Jacksonville Lateral to the Brandy Branch area. No. 2 oil will be delivered by truck and stored in the No. 2 oil tank. It is estimated that sufficient distillate oil will be stored on-site for 48 hours of fired operation for each combustion turbine located at Brandy Branch.

Noise

Various sound reduction methods are being utilized for this project. The combustion turbine manufacturer has guaranteed noise limits of 85dBA for near field and 65 dBA for far field.

Certification Status

The installation of simple cycle combustion turbines is not regulated by the Power Plant Siting Act. Individual permits have been obtained for these projects in accordance with regulations. On February 28, 2001, the Florida Public Service Commission issued an Order Granting Petition For Determination of Need for the Brandy Branch Combined Cycle Conversion. On March 12, 2002, JEA's site certification was approved. The governor's signature and DEP's issuance of the permits for construction followed.

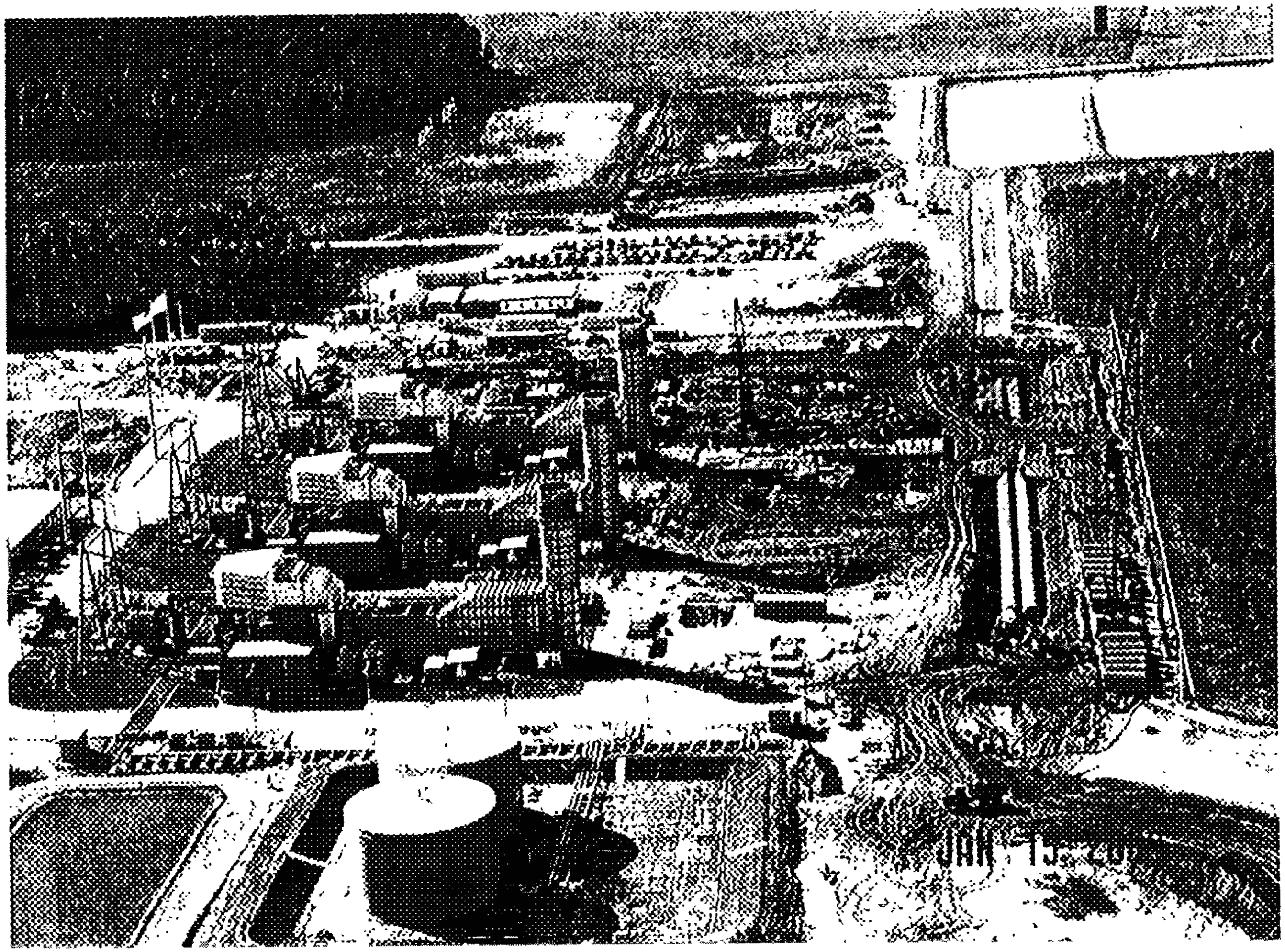
6.2 Other Environmental Considerations

Environmental Programs

JEA participates in the American Public Power Association's (APPA) nationwide Tree Power program. In addition, 400,000 trees have been planted through the JEA Future Tree and Free Tree programs.

JEA also participates in the Department of Energy (DOE) voluntary CO_2 reporting program. Projects receiving CO_2 reduction credits annually include the above mentioned programs as well as gas conversion projects at all three existing stations, landfill-gas utilization projects, free residential and non-residential energy audits, free new home construction workshops, heat rate improvements, and power factor improvements.

Figure 6-1
The Brandy Branch Site



7.0 Glossary

7.1 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

Appendix A

Ten-Year Site Plan

Schedules

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, 2003

(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	Alt.	Fuel Transport Primary	Alt.	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen Max Nameplate kW	Net MW Capability Summer	Winter	Ownership	Status
Kennedy										372,400	312	379		
	3-5	12-031	GT	FO2		WA	TK	7/1973	(b)	168,600	153	188	Utility	
	7	12-031	GT	NG	FO2	PL	WA	6/2000		203,800	159	191	Utility	
Northside										1,158,700	1,267	1,301		
	1	12-031	ST	PC	BIT	WA	RR	11/1966	(b)	297,500	275	275	Utility	
	2	12-031	ST	PC	BIT	WA	RR	3/1972	(b)	297,500	275	275	Utility	
	3	12-031	ST	NG	FO6	PL	WA	7/1977	(b)	563,700	505	505	Utility	
	3-6	12-031	GT	FO2		WA	TK	1/1975	(b)	248,400	212	246	Utility	
Brandy Branch										611,400	476	574		
	1		GT	NG	FO2	PL	TK	5/2001	(b)	203,800	159	191	Utility	
	2		CT	NG	FO2	PL	TK	5/2001	(b)	203,800	159	191	Utility	
	3		CT	NG	FO2	PL	TK	10/2000	(b)	203,800	159	191	Utility	
Girvin Landfill	1-4	12-301	IC	NG		PL		6/1997	(b)	3	1	1	Utility	
St. Johns River Power Park										1,359,200	1,002	1,021		
	1	12-301	ST	BIT/PC		RR	WA	3/1987	3/2027	679,600	501	510	Joint	(a)
	2	12-301	ST	BIT/PC		RR	WA	5/1988	5/2028	679,600	501	510	Joint	(a)
Scherer	4	13-207	ST	SUB	BIT	RR	RR	2/1989	2/2029	846,000	200	200	Joint	(b)
JEA System Total											**3,257**	**3,476**		

NOTE:
(a) Net capability reflects the JEA's 80% ownership of Power Park. Nameplate is original nameplate of the unit.
(b) Nameplate and net capability reflects the JEA's 23.64% ownership in Scherer 4.
(c) 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)
	Rual 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
1993	3,830	270,818	14,143	862	29,378	29,327	3,889	2,670	1,456,427
1994	3,909	278,682	14,027	897	29,571	30,324	4,048	2,731	1,482,265
1995	4,137	283,551	14,589	937	29,972	31,269	4,174	2,742	1,522,385
1996	4,391	288,947	15,195	937	30,162	31,079	4,353	2,975	1,463,160
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	15,284	1,104	32,990	33,476	5,411	3,450	1,568,311
2002	5,108	326,362	15,651	1,157	33,841	34,189	5,479	3,475	1,576,570
2003	5,226	332,492	15,718	1,184	33,762	35,062	5,605	3,630	1,544,049
2004	5,398	339,202	15,915	1,223	34,239	35,712	5,790	3,746	1,545,671
2005	5,544	346,048	16,022	1,256	34,723	36,167	5,947	3,865	1,538,510
2006	5,704	353,032	16,158	1,292	35,214	36,693	6,118	3,988	1,534,097
2007	5,865	360,157	16,285	1,329	35,711	37,202	6,291	4,115	1,528,710
2008	6,042	367,426	16,445	1,369	36,216	37,790	6,481	4,246	1,526,250
2009	6,190	374,841	16,514	1,402	36,728	38,175	6,639	4,381	1,515,337
2010	6,353	382,406	16,614	1,439	37,247	38,637	6,814	4,521	1,507,357
2011	6,518	390,124	16,706	1,476	37,773	39,083	6,990	4,665	1,498,619
2012	6,700	397,997	16,833	1,517	38,307	39,614	7,186	4,813	1,492,930

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

	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Calendar Year	Street & Highway Lighting GWH	Other Sales to Ultimate Customers GWH	Total Sales to Ultimate Customers GWH	Sales For Resale GWH	Utility Use & Losses GWH	Net Energy For Load GWH	Other Customers (Average No.)	Total No.of Customers
1993	61	0	8,642	339	628	9,609	17	302,883
1994	63	0	8,917	304	388	9,609	19	311,003
1995	72	0	9,320	339	667	10,326	21	316,286
1996	70	0	9,751	363	401	10,515	21	322,105
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	445	681	12,982	20	363,698
2003	115	0	12,130	510	596	13,235	20	369,905
2004	118	0	12,529	530	615	13,674	20	377,207
2005	122	0	12,868	550	632	14,051	20	384,656
2006	125	0	13,240	570	651	14,461	20	392,254
2007	129	0	13,613	591	669	14,873	20	400,003
2008	132	0	14,024	611	690	15,324	20	407,907
2009	136	0	14,367	631	707	15,705	20	415,970
2010	139	0	14,746	651	726	16,123	20	424,193
2011	143	0	15,127	672	744	16,543	20	432,581
2012	147	0	15,549	692	765	17,007	20	441,137

Schedule 3
History And Forecast of Seasonal Peak Demand and Annual Net Energy For Load

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Calendar	Summer Peak Demand @ Generator - MW			Annual Net Energy for Load (GWH)		Winter Peak Demand @ Generator - MW		
Year	Total	Interruptible	Net Firm Demand	Total	Load Factor %	Total	Interruptible	Net Firm Demand
1991	1,756	0	1,756	8,835	57	1,725	0	1,725
1992	1,881	0	1,881	9,028	55	1,881	0	1,881
1993	1,998	0	1,998	9,609	55	1,791	0	1,791
1994	1,918	0	1,918	9,609	56	1,942	0	1,942
1995	2,067	0	2,067	10,326	54	2,190	0	2,190
1996	2,114	0	2,114	10,515	50	2,401	0	2,401
1997	2,131	0	2,131	10,665	57	2,084	0	2,084
1998	2,338	0	2,338	11,470	56	1,975	0	1,975
1999	2,427	0	2,427	11,782	55	2,403	0	2,403
2000	2,380	0	2,380	12,190	56	2,478	0	2,478
2001	2,389	0	2,389	12,322	53	2,666	0	2,666
2002	2,530	0	2,530	12,982	51	2,610	0	2,610
2003	2,667	163	2,504	13,235	54	2,787	154	2,941
2004	2,739	168	2,571	13,674	54	2,881	159	3,040
2005	2,812	173	2,639	14,051	54	2,976	163	3,140
2006	2,886	178	2,708	14,461	53	3,073	168	3,241
2007	2,961	183	2,778	14,873	53	3,172	173	3,345
2008	3,037	189	2,848	15,324	53	3,272	179	3,450
2009	3,113	195	2,918	15,705	53	3,373	184	3,557
2010	3,190	200	2,990	16,123	53	3,476	189	3,666
2011	3,268	206	3,062	16,543	52	3,581	195	3,776
2012	3,347	213	3,135	17,007	52	3,688	201	3,889

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 2002		Forecast 2003		Forecast 2004	
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	2,610	1,052	2,787	1,082	2,881	1,112
February	2,394	879	2,531	937	2,616	997
March	2,346	969	2,144	990	2,216	1,021
April	2,081	936	1,899	964	1,950	994
May	2,318	1,146	2,224	1,074	2,285	1,108
June	2,456	1,163	2,542	1,201	2,611	1,240
July	2,530	1,286	2,667	1,376	2,739	1,422
August	2,488	1,256	2,606	1,324	2,676	1,368
September	2,312	1,202	2,451	1,182	2,517	1,220
October	2,212	1,112	2,334	1,037	2,411	1,069
November	1,993	941	2,080	982	2,149	1,012
December	2,233	1,040	2,466	1,084	2,548	1,114
Total		12,982		13,235		13,674

Schedule 5
Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel Requirements	Type	Units	Actuals 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	**NUCLEAR**		**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**		**1000 TON**	**2,627**	**2,952**	**2,713**	**2,684**	**2,720**	**2,796**	**2,819**	**2,837**	**2,675**	**2,593**	**2,679**
	RESIDUAL													
(3)		STEAM	1000 BBL	1,681	537	607	611	612	611	614	611	612	609	613
(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**	**1,681**	**537**	**607**	**611**	**612**	**611**	**614**	**611**	**612**	**609**	**613**
	DISTILLATE													
(7)		STEAM	1000 BBL	24	16	16	15	18	15	15	16	18	22	18
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	277	83	94	208	120	163	289	68	103	147	194
(10)		**TOTAL:**	**1000 BBL**	**301**	**99**	**110**	**224**	**138**	**178**	**304**	**84**	**121**	**169**	**212**
	NATURAL GAS													
(12)		STEAM	1000 MCF	9,648	5,296	5,978	3,988	2,854	3,087	3,475	2,475	2,778	3,106	2,883
(13)		CC	1000 MCF	0	0	0	8,540	14,561	14,701	15,350	23,884	24,945	25,906	27,029
(14)		CT/GT	1000 MCF	8,801	6,047	9,439	2,390	1,330	1,670	2,017	879	1,179	1,643	2,926
(15)		**TOTAL:**	**1000 MCF**	**18,449**	**11,343**	**15,417**	**14,918**	**18,745**	**19,458**	**20,842**	**27,238**	**28,902**	**30,655**	**32,838**
(16)	**PETROLEUM COKE**		**1000 TON**	**676**	**1,080**	**1,215**	**1,223**	**1,223**	**1,222**	**1,227**	**1,221**	**1,655**	**1,955**	**1,962**
(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 Units 1 and 2 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	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	**Annual Firm Inter-Region Intchg.**		GWH	1,694	1,539	1,538	1,275	1,091	1,127	1,236	1,131	509	122	130
(2)	**NUCLEAR**		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	**COAL**		GWH	6,851	7,012	6,503	6,448	6,503	6,758	6,807	6,827	6,444	6,246	6,423
(4)	**RESIDUAL**	STEAM	GWH	1,007	324	378	238	166	182	208	131	151	173	150
(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	1,007	324	378	238	166	182	208	131	151	173	150
(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	132	39	45	104	59	80	140	33	52	73	97
(11)		TOTAL	GWH	132	39	45	104	59	80	140	33	52	73	97
(12)	**NATURAL GAS**	STEAM	GWH	909	486	567	357	249	273	312	197	226	260	224
(13)		CC	GWH	0	0	0	1,234	2,102	2,132	2,251	3,144	3,276	3,338	3,513
(14)		CT	GWH	793	560	882	224	123	155	188	80	108	151	268
(15)		TOTAL	GWH	1,702	1,045	1,450	1,815	2,474	2,561	2,751	3,421	3,610	3,748	4,005
(16)	**NUG**		GWH	0	0	0	0	0	0	0	0	0	0	0
(17)	**HYDRO**		GWH	0	0	0	0	0	0	0	0	0	0	0
(18)	**Petroleum Coke**		GWH	1,016	3,276	3,686	3,712	3,711	3,709	3,723	3,705	4,900	5,725	5,746
(19)	**OTHER (SPECIFY)**		GWH	581	0	76	458	457	457	459	457	458	456	456
(20)	**NET ENERGY FOR LOAD**		GWH	12,982	13,235	13,674	14,051	14,461	14,873	15,324	15,705	16,123	16,543	17,007

NOTE

1. Coal includes JEA's share of SJRPP, Scherer 4 and Northside Units 2 Coal.
2. OTHER is JEA's net interchange.

Schedule 6.2
Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actuals										
	Fuel	Type	Units	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	Annual Firm Inter-Region Intchg.		%	13.0%	11.6%	11.2%	9.1%	7.5%	7.6%	8.1%	7.2%	3.2%	0.7%	0.8%
(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		%	52.8%	53.0%	47.6%	45.9%	45.0%	45.4%	44.4%	43.5%	40.0%	37.8%	37.8%
(4)	RESIDUAL	STEAM	%	7.8%	2.4%	2.8%	1.7%	1.1%	1.2%	1.4%	0.8%	0.9%	1.0%	0.9%
(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	%	7.8%	2.4%	2.8%	1.7%	1.1%	1.2%	1.4%	0.8%	0.9%	1.0%	0.9%
(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	%	1.0%	0.3%	0.3%	0.7%	0.4%	0.5%	0.9%	0.2%	0.3%	0.4%	0.6%
(11)		TOTAL	%	1.0%	0.3%	0.3%	0.7%	0.4%	0.5%	0.9%	0.2%	0.3%	0.4%	0.6%
(12)	NATURAL GAS	STEAM	%	7.0%	3.7%	4.1%	2.5%	1.7%	1.8%	2.0%	1.3%	1.4%	1.6%	1.3%
(13)		CC	%	0.0%	0.0%	0.0%	8.8%	14.5%	14.3%	14.7%	20.0%	20.3%	20.2%	20.7%
(14)		CT	%	6.1%	4.2%	6.5%	1.6%	0.8%	1.0%	1.2%	0.5%	0.7%	0.9%	1.6%
(15)		TOTAL	%	13.1%	7.9%	10.6%	12.9%	17.1%	17.2%	18.0%	21.8%	22.4%	22.7%	23.5%
(16)	NUG		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(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		%	7.8%	24.8%	27.0%	26.4%	25.7%	24.9%	24.3%	23.6%	30.4%	34.6%	33.8%
(19)	OTHER (SPECIFY)		%	4.5%	0.0%	0.6%	3.3%	3.2%	3.1%	3.0%	2.9%	2.8%	2.8%	2.7%
(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 Units 2 Coal.
2. OTHER is JEA's net interchange.

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
2003	3,476	207	445	0	3,238	2,633	606	23%	0	606	23%
2004	3,476	207	383	0	3,301	2,722	578	21%	0	578	21%
2005	3,094	522	383	0	3,233	2,813	421	15%	0	421	15%
2006	3,666	277	383	0	3,560	2,905	655	23%	0	655	23%
2007	3,666	277	383	0	3,560	2,999	562	19%	0	562	19%
2008	3,666	277	383	0	3,560	3,093	467	15%	0	467	15%
2009	4,018	277	383	0	3,912	3,189	723	23%	0	723	23%
2010	4,018	277	383	0	3,912	3,287	626	19%	0	626	19%
2011	4,268	70	383	0	3,955	3,386	569	17%	0	569	17%
2012	4,459	70	383	0	4,146	3,487	659	19%	0	659	19%

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
2003	3,257	207	428	0	3,036	2,504	532	21%	0	532	21%
2004	3,257	207	428	0	3,036	2,571	465	18%	0	465	18%
2005	3,441	277	376	0	3,342	2,639	703	27%	0	703	27%
2006	3,441	277	376	0	3,342	2,708	634	23%	0	634	23%
2007	3,441	277	376	0	3,342	2,778	565	20%	0	565	20%
2008	3,441	277	376	0	3,342	2,848	494	17%	0	494	17%
2009	3,736	277	376	0	3,637	2,918	719	25%	0	719	25%
2010	3,986	70	376	0	3,680	2,990	691	23%	0	691	23%
2011	3,986	70	376	0	3,680	3,062	619	20%	0	619	20%
2012	4,145	70	376	0	3,839	3,135	704	22%	0	704	22%

Committed Units:

1. Brandy Branch CTs 2 & 3 - Outage for conversion starts September 2004.
2. Brandy Branch Combined Cycle - June 2005

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel Type		Fuel Transport		Construction Start Date	Commercial In-Service Date	Expected Retirement	Gen Max Nameplate kW	Net Capability		
Plant Name	Unit	Location	Unit Type	Primary	Alternate	Primary	Alternate					Summer MW	Winter MW	Status
Brandy Branch-	4	Brandy Branch	CC	NG	FO2	PL	TK		06/01/05			501	573	U
Greenfield	1	Unknown	CC	NG	FO2	PL	TK		01/01/09			295	352	P
Greenfield	2	Unknown	FC	PC	Coal	WA	WA		06/01/10			250	250	P
Greenfield	3	Unknown	GT	NG	FO2	PL	TK		01/01/12		195,280	158	191	P

Schedule 9		
Status Report and Specifications of Proposed Generating Facilities		
(1)	Plant Name and Unit Number:	Brandy Branch Combined Cycle
(2)	Net Capacity:	
(3)	Summer MW	502
(4)	Winter MW	572
(5)	Technology Type:	Combined Cycle
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	October 15, 2002
(8)	Commercial In-Service date:	June 1, 2005
(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:	153 acres
(15)	Construction Status:	Active
(16)	Certification Status:	Site Certification Complete
(17)	Status with Federal Agencies:	All applicable items filed in Site Certification Application
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	3.20 percent
(20)	Forced Outage Factor (FOF):	1.70 percent
(21)	Equivalent Availability Factor (EAF):	95.10 percent
(22)	Resulting Capacity Factor (%):	50.00 percent
(23)	Average Net Operating Heat Rate (ANOHR):	7000 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30 years
(26)	Total Installed Cost (In-Service year $/kW):	
(27)	Direct Construction Cost ($/kW):	$ 624
(28)	AFUDC Amount ($/kW):	Included in direct construction cost
(29)	Escalation ($/kW):	Included in direct construction cost
(30)	Fixed O&M ($/kW-yr):	1.90
(31)	Variable O&M ($/MWh):	2.18

Schedule 10.1 Status Report and Specifications of Proposed Directly Associated Transmission Lines Northside (Center Park - Northside)		
(1)	Point of Origin and Termination	Convert Center Pk-Northside to 230 kV
(2)	Number of Lines	One (1) line
(3)	Right of Way	No new ROW Required
(4)	Line Length	11.03 Miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	18 Months- In service date 2006
(7)	Anticipated Capital Investment	$2,000,000
(8)	Substations	Line terminations at Center Pk and Northside Substations
(9)	Participation with Other Utilities	None

Schedule 10.2
Status Report and Specifications of Proposed Directly Associated Transmission Lines
Northside (New Center Park-Greenland)

(1)	Point of Origin and Termination	New SJRPP Center Park-Greenland 230 kV Line
(2)	Number of Lines	One (1) line
(3)	Right of Way	New ROW Required
(4)	Line Length	19.3 Miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	37 months - In service date 2006
(7)	Anticipated Capital Investment	$ 16,000,000 OH Construction
(8)	Substations	Line terminations at Center Park, Greenland, and SJRPP Substations
(9)	Participation with Other Utilities	None

Schedule 10.3
Status Report and Specifications of Proposed Directly Associated Transmission Lines
With Combined Cycle Unit (New Brandy Branch-Normandy line)

(1)	Point of Origin and Termination	New Brandy Branch-Normandy 230 kV Line
(2)	Number of Lines	One (1) line
(3)	Right of Way	New ROW may be Required
(4)	Line Length	9.0 Miles
(5)	Voltage	230 kV
(6)	Anticipated Construction Time	22 months In service date 2005 to coincide with in service date of Combined Cycle Unit
(7)	Anticipated Capital Investment	$ 6,000,000 OH Construction
(8)	Substations	Line terminations at Brandy Branch and Normandy
(9)	Participation with Other Utilities	None