21 West Church Street
Jacksonville, Florida 32202-3139

JEA

ELECTRIC
WATER
SEWER

March 30, 2005

Michael S. Haff
Bureau of Electric Reliability/Conservation
Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Haff:

Attached you will find 25 copies of JEA's 2005 Ten Year Site Plan filing. If you have any questions regarding this response or any additional questions, please contact me at (904) 665-4658 or Mary Guyton-Baker at (904) 665-6216.

Thank You,

Dale Isley

Dale S. Isley,
Manager, Electric System Planning

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Ten Year Site Plan

JEA®

Building Community®

April 2005

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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 2005 Ten Year Site Plan for JEA covering a planning period from 2005 to 2014.

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 and St. Johns Counties. 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, Progress Energy 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 from JEA. 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.

Purchased Power

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. JEA has the unilateral option, upon three years notice, to cancel 150 MW of the UPS. In this plan, JEA will retain 200 MW of UPS during the contract term and reduce available capacity by 200 MW at the end of the contract term beginning summer 2010.

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. 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 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. Since their inception, 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 does have short-term, seasonal needs for capacity or energy during the summer 2010 and winter 2011.

Clean Power

As part of JEA's Green Works initiative, JEA has agreed to supply 7.5 percent of its peak demand with renewable resources by 2015. In 2004, JEA issued a Request for Proposal (RFP) for renewable resources. As a result of this RFP, JEA is in negotiation for 22 MW of renewable resources. These resources are included in JEA 2005 TYSP.

Also, JEA is continuing its contract negotiations with Biomass Industries, Inc. (BII). JEA has contracted to 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). Commercial date of this unit is not firm at this time. Therefore, JEA's 2005 plan does not include 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 Agreements

Florida Public Utilities Company

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 December 31, 2007. Currently, FPU does not have a contract with JEA to renew this sale. Therefore, starting January 2008, sales to FPU are not included in JEA's load and energy forecast. Sales to FPU in 2004 totaled 468 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 autotransformers to provide safe and reliable transmission service under normal and single contingency conditions.
- Plan the transmission system to withstand single contingencies without loss of customer load. (A single contingency is the unexpected failure of any one line, transformer or generator.)
- Plan the transmission system to operate within 5 percent of nominal voltage during normal and single contingency conditions.
- Plan the transmission system so that circuit breakers can interrupt the maximum available breaker fault current.
- Plan substation relays to sense breaker failures and clear faults in sufficient time to avoid generator instability problems.
- Plan to provide lead time for transmission projects of approximately 3 to 5 years.
- Plan to meet the Florida Reliability Coordinating Council's (FRCC) guidelines on how the Florida electric utilities plan to operate. These guidelines are similar to JEA's transmission planning criteria discussed previously.

- Plan to meet or exceed the FRCC's reliability guidelines for transmission system interface Available Transfer Capabilities. This includes the use of single contingency criteria as well as considering the needs for operating reserve requirements, capacity benefit margins, and those reliability margins as outlined in industry-standard publications.

- Plan to meet or exceed specific subparts of those transmission system reliability-planning criteria published by the North American Electric Reliability Coordinating Council (NERC), including Planning Criteria Categories A, B, C.2 and C.5. Meet or exceed these criteria generally as they are interpreted by the Florida Reliability Coordinating Council, as updated from time to time.

2.3 Demand Side Management

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

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

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

2.4 Green/Clean Power Programs

In 2001 JEA developed a Green Power Program to encourage the widespread application of renewable energy technology in its service territory. JEA has established two Clean Power Capacity goals. The first, contained in JEA's internal Clean Power Strategic Initiative, calls for a minimum of 4% clean power capacity by 2007. The second, as stated in JEA's Memorandum of Understanding with the American Lung Association and Sierra Club, calls for a minimum of 7.5% clean power capacity by 2015.

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. As of January 2005, JEA has provided incentives to over 800 solar systems installed throughout the community resulting in 9 MWs towards our Clean Power Goals. JEA also owns approximately 223 kw of solar photovoltaic modules throughout the city of Jacksonville including systems at all high schools in the JEA service area and one of the largest photovoltaic systems in the southeast at the Jacksonville International Airport (50 KW).

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. Since that time, 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.

In April 2004, JEA received 16 renewable energy proposals in response to a renewable energy RFP issued by JEA in February 2004. The proposals were reviewed for their technical and economic merit. Two proposals were selected for contract negotiations: development of a gas to energy project at the Trailridge Landfill in Baldwin, Florida and utilization of Jacksonville's yard waste as a biomass fuel in an existing Jacksonville boiler. The landfill project will provide a 9.6 MW facility that will utilize the landfill gas generated from the Trailridge Landfill and will recover gas that is currently being flared. When completed, this facility will be one of the largest landfill gas-to-energy projects in the Southeast. The biomass facility is located at a former paper mill in downtown Jacksonville. The existing boiler at the site proposes to burn yard and tree trimming debris from the City of Jacksonville's yard waste collection program. The fuel represents 13 MW of renewable energy. It is JEA's intent to establish long-term, purchased power agreements with these projects.

JEA has recently initiated a Green Home and Yard Coalition comprised of various community stakeholders throughout Northeast Florida. This coalition, which first met in February 2005, will focus on promoting "green" building practices in home construction to improve the overall energy and water efficiency and health of the home. The initial goal of this group is to develop a green strategy for Northeast Florida home building.

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.

A specific price forecasts for St John's River Power Park (SJRPP) was provided by SJRPP Fuels. 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. JEA developed its forecast of western coal for Scherer Unit 4 based on existing contracts and non-volatile escalation of spot prices.

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 31,000 mmBtu/day effective June 2005 and to 61,000 mmBtu/day effective June 2006. 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. The Brandy Branch facility use ultra low sulfur diesel as back up 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 80 percent. JEA's goal is to reach a 90 percent blend rate 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 2004 were 2,668 MW and 2,539 MW respectively. JEA's net energy for load for calendar year 2004 was 13,243 GWH. For the ten year forecasted period, JEA's winter peak demand is expected to increase at an average 2.8 percent per year and the summer peak demand will increase at an average 2.0 percent per year. The net energy for load is forecasted to grow at an average rate of 2.3 percent per year for the ten year period.

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.

Effective January 2008, FPU's wholesale supply contract with JEA ends. At the current time, FPU does not have a contract with JEA to renew this sale. This will result in a decrease in demand and energy which is reflected on the base case forecast of Schedules 2 and 3 in appendix A.

5.0 Facility Requirements

5.1 Future Resource Needs

Based on the peak demand and energy forecasts, existing supply resources and contracts, and transmission considerations, JEA has evaluated future supply capacity needs for the electric system. Table 5-1 displays the likely need for capacity when assuming the base case load forecast for JEA's system for a ten-year period beginning in 2005.

5.2 Public Power Coal Participants (PPC) Coal-Fired

A group of public utilities have joined together to participate in the development of a 800MW coal-fired project in the state of Florida. The primary advantage of a publicly-owned coal-fired project would be to diversify resources, while supplying competitively priced power into the future.

The group is actively assessing sites, performing preliminary environmental and transmission line studies related to the project. JEA's current participation is 236.7MW.

The anticipated in service date is scheduled for Fall 2011.

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

Winter

Year	Installed Capacity MW	Firm Capacity		QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance		Capacity Required For 15% Reserves
		Import MW	Export MW				MW	Percent	MW
2005	3,476	207	383	0	3,301	2,740	560	20%	0
2006	3,722	207	383	0	3,546	2,831	714	25%	0
2007	3,761	207	383	0	3,585	2,924	661	23%	0
2008	3,761	207	383	0	3,585	2,921	664	23%	0
2009	3,761	207	383	0	3,585	3,015	570	19%	0
2010	3,761	207	383	0	3,585	3,111	474	15%	0
2011	3,761	0	383	0	3,378	3,207	171	5%	310
2012	3,761	0	383	0	3,378	3,307	71	2%	425
2013	3,761	0	383	0	3,378	3,407	(29)	-1%	541
2014	3,761	0	383	0	3,378	3,510	(132)	-4%	658

Summer

Year	Installed Capacity MW	Firm Capacity		QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance		Capacity Required For 15% Reserves
		Import MW	Export MW				MW	Percent	MW
2005	3,485	207	376	0	3,317	2,588	729	28%	0
2006	3,501	207	376	0	3,333	2,651	681	26%	0
2007	3,540	207	376	0	3,372	2,716	656	24%	0
2008	3,540	207	376	0	3,372	2,698	673	25%	0
2009	3,540	207	376	0	3,372	2,761	610	22%	0
2010	3,540	0	376	0	3,165	2,824	341	12%	83
2011	3,540	0	376	0	3,165	2,888	277	10%	157
2012	3,540	0	376	0	3,165	2,950	214	7%	228
2013	3,540	0	376	0	3,165	3,014	150	5%	302
2014	3,540	0	376	0	3,165	3,078	86	3%	375

Committed Units:

1. Brandy Branch Combined Cycle - May 2005.
2. Brandy Branch and Kennedy Peak Firing Upgrades winter 2006 and winter 2007, respectively

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 2011. This need encompasses the inclusion of existing supply resources, transmission system considerations, 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.

Year	Season	Expansion Plan
2005	Jan 30th	Convert 2 Brandy Branch CTs to Combined Cycle
2006	Winter	Brandy Branch Plant Peak Firing Upgrades
2007	Winter	Purchase 22 MW Clean Power Northside Units 1, 2 &3 LP Turbine Upgrades Kennedy CT 7 Peak Firing Upgrades
2008		
2009		
2010	Summer	Purchase 60 MW from TEA
2011	Winter Winter	Build 3 - 82 MW 7EA GT Purchase 30 MW from TEA
2012	Winter	Build 1-236 MW Pulverized Coal
2013	Winter	Build 1-250 MW Greenfield CFB
2014		

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, 2005

(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	10/2001	(b)	203,800	159	191	Utility	
Girvin Landfill	1-4	12-301	IC	NG		PL		6/1997	(b)	1.2	1.2	1.2	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.

(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
1994	3,909	278,682	14,027	897	29,571	30,334	4,048	2,731	1,482,241
1995	4,137	283,551	14,590	937	29,972	31,263	4,174	2,742	1,522,247
1996	4,391	288,947	15,197	937	30,162	31,066	4,353	2,975	1,463,193
1997	4,165	295,916	14,075	949	30,709	30,903	4,526	3,025	1,496,198
1998	4,643	301,883	15,380	1,035	31,297	33,070	4,835	3,094	1,562,702
1999	4,529	305,917	14,805	1,036	31,873	32,504	5,130	3,203	1,601,623
2000	4,701	312,103	15,062	1,079	32,351	33,353	5,205	3,309	1,572,983
2001	4,884	319,532	15,285	1,104	32,990	33,465	5,411	3,450	1,568,406
2002	5,108	326,362	15,651	1,157	33,841	34,189	5,479	3,475	1,576,691
2003	5,226	332,492	15,718	1,184	33,762	35,069	5,605	3,630	1,544,077
2004	5,424	348,320	15,503	1,220	32,123	36,889	5,557	3,638	1,483,233
2005	5,587	358,770	15,573	1,257	33,087	37,991	5,724	3,747	1,527,622
2006	5,755	369,533	15,574	1,295	34,080	37,999	5,896	3,859	1,527,857
2007	5,928	380,619	15,575	1,334	35,102	38,004	6,073	3,975	1,527,799
2008	6,106	392,038	15,575	1,374	36,155	38,003	6,255	4,094	1,527,846
2009	6,289	403,799	15,575	1,415	37,240	37,997	6,443	4,217	1,527,863
2010	6,478	415,913	15,575	1,457	38,357	37,985	6,636	4,344	1,527,624
2011	6,672	428,390	15,575	1,501	39,508	37,992	6,835	4,474	1,527,716
2012	6,872	441,242	15,574	1,546	40,693	37,992	7,040	4,608	1,527,778
2013	7,078	454,479	15,574	1,592	41,914	37,983	7,251	4,746	1,527,813
2014	7,290	468,113	15,573	1,640	43,171	37,988	7,469	4,888	1,528,028

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
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	446	681	12,983	20	363,698
2003	115	0	12,130	453	595	13,178	20	369,904
2004	109	0	12,310	475	458	13,243	27	384,108
2005	112	0	12,680	489	619	13,788	28	395,632
2006	115	0	13,061	504	600	14,165	29	407,501
2007	118	0	13,453	519	469	14,441	30	419,726
2008	122	0	13,857	0	675	14,532	31	432,318
2009	126	0	14,273	0	603	14,876	32	445,288
2010	130	0	14,701	0	557	15,258	33	458,647
2011	134	0	15,142	0	500	15,642	34	472,406
2012	138	0	15,596	0	471	16,067	35	486,578
2013	142	0	16,063	0	356	16,419	36	501,175
2014	146	0	16,545	0	265	16,810	37	516,209

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.		Date	Hour Ending	Residential	Comm./Ind.
1991	1,756	0	0	0	0	0	0	1,756	7/24/1991	1700	0	0
1992	1,881	0	0	0	0	0	0	1,881	7/9/1992	1700	0	0
1993	1,998	0	0	0	0	0	0	1,998	7/29/1993	1700	0	0
1994	1,918	0	0	0	0	0	0	1,918	7/18/1994	1700	0	0
1995	2,067	0	0	0	0	0	0	2,067	8/14/1995	1700	0	0
1996	2,114	0	0	0	0	0	0	2,114	6/25/1996	1800	0	0
1997	2,131	0	0	0	0	0	0	2,131	7/28/1997	1800	0	0
1998	2,338	0	0	0	0	0	0	2,338	7/1/1998	1800	0	0
1999	2,427	0	0	0	0	0	0	2,427	8/2/1999	1600	0	0
2000	2,380	0	0	0	0	0	0	2,380	7/20/2000	1400	0	0
2001	2,389	0	0	0	0	0	0	2,389	8/8/2001	1800	0	0
2002	2,530	0	0	0	0	0	0	2,530	7/19/2002	1600	0	0
2003	2,485	0	0	0	0	0	0	2,485	7/10/2003	1600	0	0
2004	2,539	0	0	0	0	0	0	2,539	8/2/2004	1600	0	0
2005	2,760	172	0	0	0	0	0	2,588	---	---	0	0
2006	2,826	175	0	0	0	0	0	2,651	---	---	0	0
2007	2,893	177	0	0	0	0	0	2,716	---	---	0	0
2008	2,878	180	0	0	0	0	0	2,698	---	---	0	0
2009	2,944	183	0	0	0	0	0	2,761	---	---	0	0
2010	3,009	185	0	0	0	0	0	2,824	---	---	0	0
2011	3,076	188	0	0	0	0	0	2,888	---	---	0	0
2012	3,141	191	0	0	0	0	0	2,950	---	---	0	0
2013	3,208	194	0	0	0	0	0	3,014	---	---	0	0
2014	3,275	197	0	0	0	0	0	3,078	---	---	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.		Date	Hour Ending	Residential	Comm./Ind.
1991	1,725	0	0	0	0	0	0	1,725	2/16/1991	1000	0	0
1992	1,881	0	0	0	0	0	0	1,881	1/17/1992	800	0	0
1993	1,791	0	0	0	0	0	0	1,791	3/15/1993	0800	0	0
1994	1,942	0	0	0	0	0	0	1,942	2/3/1994	0800	0	0
1995	2,190	0	0	0	0	0	0	2,190	2/9/1995	0800	0	0
1996	2,401	0	0	0	0	0	0	2,401	2/5/1996	0800	0	0
1997	2,084	0	0	0	0	0	0	2,084	12/20/1996	0900	0	0
1998	1,975	0	0	0	0	0	0	1,975	12/15/1997	1900	0	0
1999	2,403	0	0	0	0	0	0	2,403	1/6/1999	0800	0	0
2000	2,478	0	0	0	0	0	0	2,478	1/27/2000	0800	0	0
2001	2,666	0	0	0	0	0	0	2,666	1/3/2001	0800	0	0
2002	2,607	0	0	0	0	0	0	2,607	1/4/2002	0800	0	0
2003	3,055	0	0	0	0	0	0	3,055	1/24/2003	0800	0	0
2004	2,668	0	0	0	0	0	0	2,668	1/29/2004	0700	0	0
2005	2,910	170	0	0	0	0	0	2,740	---	---	0	0
2006	3,004	173	0	0	0	0	0	2,831	---	---	0	0
2007	3,099	175	0	0	0	0	0	2,924	---	---	0	0
2008	3,099	178	0	0	0	0	0	2,921	---	---	0	0
2009	3,195	180	0	0	0	0	0	3,015	---	---	0	0
2010	3,294	183	0	0	0	0	0	3,111	---	---	0	0
2011	3,393	186	0	0	0	0	0	3,207	---	---	0	0
2012	3,496	189	0	0	0	0	0	3,307	---	---	0	0
2013	3,599	192	0	0	0	0	0	3,407	---	---	0	0
2014	3,704	194	0	0	0	0	0	3,510	---	---	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.
1991	8,835	0	0	0	0	0	0	8,835	0	0
1992	9,028	0	0	0	0	0	0	9,028	0	0
1993	9,609	0	0	0	0	0	0	9,609	0	0
1994	9,609	0	0	0	0	0	0	9,609	0	0
1995	10,326	0	0	0	0	0	0	10,326	0	0
1996	10,515	0	0	0	0	0	0	10,515	0	0
1997	10,665	0	0	0	0	0	0	10,665	0	0
1998	11,470	0	0	0	0	0	0	11,470	0	0
1999	11,782	0	0	0	0	0	0	11,782	0	0
2000	12,190	0	0	0	0	0	0	12,190	0	0
2001	12,322	0	0	0	0	0	0	12,322	0	0
2002	12,983	0	0	0	0	0	0	12,983	0	0
2003	13,204	0	0	0	0	0	0	13,204	0	0
2004	13,243	0	0	0	0	0	0	13,243	0	0
2005	13,788	0	0	0	0	0	0	13,788	0	0
2006	14,165	0	0	0	0	0	0	14,165	0	0
2007	14,441	0	0	0	0	0	0	14,441	0	0
2008	14,532	0	0	0	0	0	0	14,532	0	0
2009	14,876	0	0	0	0	0	0	14,876	0	0
2010	15,258	0	0	0	0	0	0	15,258	0	0
2011	15,642	0	0	0	0	0	0	15,642	0	0
2012	16,067	0	0	0	0	0	0	16,067	0	0
2013	16,419	0	0	0	0	0	0	16,419	0	0
2014	16,810	0	0	0	0	0	0	16,810	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)
	Actua 2004		Forecast 2005		Forecast 2006	
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	2,668	1,094	2,740	1,115	2,831	1,145
February	2,374	982	2,488	960	2,571	986
March	1,997	968	2,107	1,035	2,177	1,064
April	1,913	945	1,843	1,006	1,888	1,035
May	2,486	1,182	2,158	1,139	2,211	1,171
June	2,479	1,253	2,466	1,266	2,527	1,300
July	2,529	1,302	2,588	1,433	2,651	1,472
August	2,539	1,339	2,528	1,393	2,590	1,431
September	2,480	1,150	2,378	1,219	2,437	1,253
October	2,257	1,100	2,293	1,084	2,368	1,115
November	2,047	935	2,044	1,021	2,111	1,050
December	2,657	993	2.424	1,117	2,503	1,143
Total		13,243		13,788		14,165

Schedule 5

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Actual										
	Fuel	Type	Units	2004	2005	2006	200	200	200	2010	2011	201	2013	2014
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1000 TON	2,598	2,584	2,577	2,711	2,499	2,616	2,544	2,760	3,255	2,987	3,038
	RESIDUAL													
(3)		STEAM	1000 BBL	1,801	1,367	1,778	1,422	1,415	1,467	1,710	1,812	1,664	1,322	1,384
(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	1,801	1,367	1,778	1,422	1,415	1,467	1,710	1,812	1,664	1,322	1,384
	DISTILLATE													
(7)		STEAM	1000 BBL	69	69	69	72	67	70	68	74	87	80	81
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	91	147	89	48	108	72	463	361	173	85	113
(10)		TOTAL:	1000 BBL	160	216	158	120	174	142	531	434	260	164	194
	NATURAL GAS													
(12)		STEAM	1000 MCF	3,667	1,437	1,874	1,499	1,499	1,548	1,796	1,916	1,766	1,410	1,476
(13)		CC	1000 MCF	0	9,279	11,302	8,575	10,173	11,027	16,382	17,160	13,774	10,032	11,208
(14)		CT/GT	1000 MCF	3,933	447	0	0	0	0	31	390	130	49	68
(15)		TOTAL:	1000 MCF	7,601	11,163	13,176	10,074	11,672	12,574	18,209	19,466	15,669	11,492	12,752
(16)	PETROLEUM COKE		1000 TON	1,093	1,328	1,230	1,492	1,588	1,586	1,595	1,695	1,699	2,379	2,389
(20)	OTHER (SPECIFY)		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0

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

Schedule 6.1
Energy Sources (GWH)

	(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actuals										
	Fuel	Type	Units	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	**Annual Firm Inter-Region Intchg.**		GWH	2,365	1,341	1,454	1,283	1,296	1,298	539	0	0	0	0
(2)	**NUCLEAR**		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	**COAL**		GWH	6,088	6,816	6,839	7,212	6,729	6,931	6,827	7,274	8,456	7,784	7,918
(4)	**RESIDUAL**	STEAM	GWH	466	783	1,032	791	802	824	1,007	1,082	977	745	791
(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	466	783	1,032	791	802	824	1,007	1,082	977	745	791
(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	32	68	40	22	50	33	218	172	80	39	51
(11)		TOTAL	GWH	32	68	40	22	50	33	218	172	80	39	51
(12)	**NATURAL GAS**	STEAM	GWH	942	138	182	140	141	146	178	191	172	131	140
(13)		CC	GWH	0	1,258	1,556	1,158	1,383	1,519	2,335	2,435	1,908	1,351	1,521
(14)		CT	GWH	380	39	0	0	0	0	3	34	11	4	6
(15)		TOTAL	GWH	1,321	1,435	1,738	1,297	1,525	1,665	2,516	2,659	2,091	1,486	1,667
(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	2,971	3,238	2,907	3,650	3,945	3,939	3,959	4,269	4,276	6,179	6,198
(19)	**OTHER (SPECIFY)**		GWH	0	108	154	188	187	187	189	187	187	187	186
(20)	**NET ENERGY FOR LOAD**		GWH	13,243	13,788	14,165	14,443	14,532	14,876	15,254	15,642	16,067	16,420	16,810

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	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	**Annual Firm Inter-Region Intchg.**		%	17.9%	9.7%	10.3%	8.9%	8.9%	8.7%	3.5%	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**		%	46.0%	49.4%	48.3%	49.9%	46.3%	46.6%	44.8%	46.5%	52.6%	47.4%	47.1%
(4)	**RESIDUAL**	STEAM	%	3.5%	5.7%	7.3%	5.5%	5.5%	5.5%	6.6%	6.9%	6.1%	4.5%	4.7%
(5)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		TOTAL	%	3.5%	5.7%	7.3%	5.5%	5.5%	5.5%	6.6%	6.9%	6.1%	4.5%	4.7%
(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	%	0.2%	0.5%	0.3%	0.2%	0.3%	0.2%	1.4%	1.1%	0.5%	0.2%	0.3%
(11)		TOTAL	%	0.2%	0.5%	0.3%	0.2%	0.3%	0.2%	1.4%	1.1%	0.5%	0.2%	0.3%
(12)	**NATURAL GAS**	**STEAM**	%	7.1%	1.0%	1.3%	1.0%	1.0%	1.0%	1.2%	1.2%	1.1%	0.8%	0.8%
(13)		CC	%	0.0%	9.1%	11.0%	8.0%	9.5%	10.2%	15.3%	15.6%	11.9%	8.2%	9.1%
(14)		CT	%	2.9%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%	0.0%	0.0%
(15)		TOTAL	%	10.0%	10.4%	12.3%	9.0%	10.5%	11.2%	16.5%	17.0%	13.0%	9.1%	9.9%
(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**		%	22.4%	23.5%	20.5%	25.3%	27.1%	26.5%	26.0%	27.3%	26.6%	37.6%	36.9%
(19)	**OTHER (SPECIFY)**		%	0.0%	0.8%	1.1%	1.3%	1.3%	1.3%	1.2%	1.2%	1.2%	1.1%	1.1%
(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		QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance		Scheduled Maintenance MW	Reserve Margin After Maintenance	
		Import MW	Export MW				MW	Percent		MW	Percent
2005	3,476	207	383	0	3,301	2,740	560	20%	0	560	20%
2006	3,722	207	383	0	3,546	2,831	714	25%	0	714	25%
2007	3,761	229	383	0	3,607	2,924	683	23%	0	683	23%
2008	3,761	229	383	0	3,607	2,921	686	23%	0	686	23%
2009	3,761	229	383	0	3,607	3,015	592	20%	0	592	20%
2010	3,761	229	383	0	3,607	3,111	496	16%	0	496	16%
2011	4,019	52	383	0	3,688	3,207	481	15%	0	481	15%
2012	4,255	22	383	0	3,894	3,307	587	18%	0	587	18%
2013	4,505	22	383	0	4,144	3,407	737	22%	0	737	22%
2014	4,505	22	383	0	4,144	3,510	634	18%	0	634	18%

Summer

Year	Installed Capacity MW	Firm Capacity		QF MW	Available Capacity MW	Firm Peak Demand MW	Reserve Margin Before Maintenance		Scheduled Maintenance MW	Reserve Margin After Maintenance	
		Import MW	Export MW				MW	Percent		MW	Percent
2005	3,485	207	376	0	3,317	2,588	729	28%	0	729	28%
2006	3,501	207	376	0	3,333	2,651	681	26%	0	681	26%
2007	3,540	229	376	0	3,394	2,716	678	25%	0	678	25%
2008	3,540	229	376	0	3,394	2,698	695	26%	0	695	26%
2009	3,540	229	376	0	3,394	2,761	632	23%	0	632	23%
2010	3,540	83	376	0	3,248	2,824	424	15%	0	424	15%
2011	3,768	22	376	0	3,415	2,888	527	18%	0	527	18%
2012	4,004	22	376	0	3,651	2,950	700	24%	0	700	24%
2013	4,254	22	376	0	3,901	3,014	886	29%	0	886	29%
2014	4,254	22	376	0	3,901	3,078	822	27%	0	822	27%

Committed Units:

1. Brandy Branch Combined Cycle - May 2005.
2. Brandy Branch and Kennedy Peak Firing Upgrades winter 2006 and winter 2007, respectively.

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						Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Construction Start Date	Commercial In-Service Date	Expected Retirement/ Shutdown	Gen Max Nameplate kW	Summer MW	Winter MW	Status
Brandy Branch	2	Brandy Branch	GT	NG	FO2	PL	TK		05/01/01	01/30/05		158	191	Conversion
Brandy Branch	3	Brandy Branch	GT	NG	FO2	PL	TK		10/12/01	01/30/05		158	191	Conversion
Brandy Branch	4	Brandy Branch	CC	NG	FO2	PL	TK		01/30/05			544	610	V
Brandy Branch	1	Brandy Branch	GT	NG	FO2	PL	TK		01/01/06			3.75	4.13	A
Brandy Branch	4	Brandy Branch	CC	NG	FO2	PL	TK		01/01/06			13.0	13.0	A
Northside	1	Northside	ST	PC	BIT	WA	RR		11/1966			8.5	8.5	A
Northside	2	Northside	ST	PC	BIT	WA	RR		3/1972			8.5	8.5	A
Northside	3	Northside	ST	NG	FO6	PL	WA		7/1977			18	18	A
Kennedy	7	Kennedy	GT	NG	FO2	PL	TK		01/01/07			3.75	4.13	A
CT - 7EA	1	Greenfield	GT	NG	FO2	PL	TK		01/01/11			75	86	P
CT - 7EA	2	Greenfield	GT	NG	FO2	PL	TK		01/01/11			75	86	P
CT - 7EA	3	Greenfield	GT	NG	FO2	PL	TK		01/01/11			75	86	P
PCoal	1	Greenfield	FC	Bit	Coal	WA	WA		12/01/11			236	236	P
CFB	Unknown	Greenfield	FC	PC	Coal	WA	WA		01/01/13			250	250	P
Planned and Prospective Purchased Power Additions and Changes														
Trail Ridge									01/01/07	01/01/17		9	9	P
Jefferson Surfil									01/01/07	01/01/17		13	13	P
TEA									06/01/10	09/15/10		60	0	P
TEA									12/15/10	03/15/11		0	30	P
UPS										05/31/10		200	200	R

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	No Updates To Report
(2)	Net Capacity:	
(3)	Summer MW	
(4)	Winter MW	
(5)	Technology Type:	
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	
(8)	Commercial In-Service date:	
(9)	Fuel	
(10)	Primary	
(11)	Alternate	
(12)	Air Pollution Control Strategy:	
(13)	Cooling Method:	
(14)	Total Site Area:	
(15)	Construction Status:	
(16)	Certification Status:	
(17)	Status with Federal Agencies:	
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	
(20)	Forced Outage Factor (FOF):	
(21)	Equivalent Availability Factor (EAF):	
(22)	Resulting Capacity Factor (%):	
(23)	Average Net Operating Heat Rate (ANOHR):	
(24)	Projected Unit Financial Data:	
(25)	Book Life:	
(26)	Total Installed Cost (In-Service year $/kW):	
(27)	Direct Construction Cost ($/kW):	
(28)	AFUDC Amount ($/kW):	
(29)	Escalation ($/kW):	
(30)	Fixed O&M ($/kW-yr):	
(31)	Variable O&M ($/MWh):	

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

(1)	Point of Origin and Termination	No Updates To Report
(2)	Number of Lines	
(3)	Right of Way	
(4)	Line Length	
(5)	Voltage	
(6)	Anticipated Construction Time	
(7)	Anticipated Capital Investment	
(8)	Substations	
(9)	Participation with Other Utilities	