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Jacksonville, Florida 32202-3139

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SAFETY & ELECTRIC RELIABILITY

JEA

July 27, 2000

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

000000-PU

Dear Mr. Haff:

Pursuant to the Commission's authority under Section 366.05(7), Florida Statues, we are responding with the supplemental information requested for the JEA's 2000 Ten Year Site Plan filing.

If you have any questions regarding this response or any additional questions, please contact Mary Guyton-Baker at (904) 665-6216 or me at (904) 665-6196.

Thank You,

Chuck Bond

Chuck Bond
Manager, Capacity Planning

APP
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JEA

Supplemental Data Request
Review of 2000 Ten-Year Site Plans

This data is being made pursuant to the Commission's authority under Section 366.05(7), Florida Statutes.

General

1. **Provide all data requested on the attached forms. If any of the requested data is already included in JEA's Ten-Year Site Plan, state so on the appropriate form.**

See Attachments.

2. **For the proposed repowering of Northside Units 1 and 2, discuss the current status of the Department of Energy's (DOE) contribution as part of its Clean Coal program, including whether or not the DOE has made a firm commitment to JEA for the contribution.**

Since the early 1970s, the Department of Energy (DOE) and its predecessor organizations have pursued a broadly based research and development (R&D) program directed toward increasing the nation's opportunities to use coal while decreasing environmental concerns associated with coal utilization. The R&D program consists of activities that support the development of innovative concepts for a wide variety of coal technologies through the proof-of-concept stage.

The implementation of a technology demonstration program with cost-shared funding from the federal government has been endorsed by the President, Congress and industry as a way to accelerate the development of technology to meet near-term energy and environmental goals, to reduce risk to an acceptable level and to provide the incentives necessary for continued R&D directed at providing solutions to long-range energy supply problems.

The primary goal of the Clean Coal Technology (CCT) Program, as funded by Congress in 1985, is to make available to the U.S. energy marketplace a number of advanced, more efficient, economically advantageous and environmentally responsive technologies for expanded coal utilization. The CCT Program also addresses related energy issues including long range requirements for increased power demand, need for energy security and increased competitiveness in the international marketplace.

JEA's CFB project was selected for demonstration in the CCT Program as one of the projects that would best further the goals of the program. Under the Cooperative Agreement the DOE will share allowable cost expenditures up to $73,072,464. Through June 2000, JEA has received $8,078,158 in shared cost from DOE. The balance will be collected on a monthly basis as additional shared costs are incurred. The Cooperative Agreement also requires JEA to test burn two (2) domestic coals and coal fuel blends (coal/petcoke) for two (2) week periods during a two (2) year demonstration.

The JEA Authority, whose members are appointed by the City, has approved the Repowering Project including entering into the DOE agreement. City Council approval is not required.

The Northside 1 & 2 Repowering Project reflects completion duration's, from a notice-to-proceed date, of 30 months for unit 2 and 33 months for unit 1. The notice-to-proceed date is based on receipt of the Environmental Resources Permit (ERP). JEA received the ERP on July 27, 1999. Currently, Unit 1 is scheduled to be in service winter 2002 and Unit 2 is scheduled to be in service summer 2002.

JEA

Planning

3. **Provide the cumulative present worth revenue requirements of the "Reference Plan" shown on page 13 of JEA's Ten-Year Site Plan.**

Reference Plan

ES-1 Reference Plan				
Year	Month / Season	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	Winter April June Summer	Purchase 250 MW Seasonal Capacity Shutdown Kennedy Unit 10 Build 1-168 MW CT at Kennedy Purchase 125 MW Seasonal Capacity	288,510	288,510
2001	January October October December	Build 2-168 MW CTs at Brandy Branch Retire Southside Unit 4 Retire Southside Unit 5 Build 1-168 MW CT at Brandy Branch	260,712	555,773
2002	Winter April April	Purchase 25 MW Northside 1 Repowering - CFB Northside 2 Repowering - CFB	222,692	779,498
2003	June	Convert 2 Brandy Branch CTs to Combined Cycle (558 MW Total Unit; 186 Additional MWs)	232,914	956,524
2004			244,932	1,128,040
2005			259,770	1,295,123
2006	June	Build 1-260 MW CC @ Greenfield Site	305,334	1,459,278
2007			320,595	1,638,016
2008	Summer	Purchase 50 MW	356,042	1,811,866
2009	Winter June	Purchase 50 MW Build 1-168 MW CT @ Greenfield Site	381,043	1,990,720
10 Year Extension			3,037,569	5,028,289

4. Illustrate what JEA's generation expansion plan would be as a result of sensitivities to the base case demand and fuel price forecast. Include the cumulative present worth revenue requirements.

Low Fuel Price Escalation

Low Fuel Price Escalation				
Year	Month / Season	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	Winter	Purchase 250 MW Seasonal Capacity	285,441	285,441
	April	Shutdown Kennedy Unit 10		
	June	Build 1-168 MW CT at Kennedy		
	Summer	Purchase 125 MW Seasonal Capacity		
2001	January	Build 2-168 MW CTs at Brandy Branch	257,836	549,861
	October	Retire Southside Unit 4		
	October	Retire Southside Unit 5		
	December	Build 1-168 MW CT at Brandy Branch		
2002	Winter	Purchase 100 MW	224,772	771,118
	April	Northside 1 Repowering - CFB		
	April	Northside 2 Repowering - CFB		
2003	January	Convert 2 Brandy Branch CTs to Combined Cycle (558 MW Total Unit; 186 Additional MWs)	229,943	949,798
2004			241,008	1,119,126
2005	Summer	Purchase 50 MW	269,760	1,283,532
2006	January	Build 1-260 MW CC @ Greenfield Site	299,832	1,454,000
2007	Summer	Purchase 50 MW	328,985	1,629,517
2008	Summer	Purchase 100 MW	362,669	1,807,917
2009	January	Build 2-168 MW CT @ Greenfield Site	388,204	1,990,099
10 Year Extension			3,054,803	5,044,902

High Fuel Price Escalation

High Fuel Price Escalation (Same as Basecase Plan)				
Year	Month / Season	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth
2000	Winter	Purchase 250 MW Seasonal Capacity	290,944	290,944
	April	Shutdown Kennedy Unit 10		
	June	Build 1-168 MW CT at Kennedy		
	Summer	Purchase 125 MW Seasonal Capacity		
2001	January	Build 2-168 MW CTs at Brandy Branch	263,052	560,461
	October	Retire Southside Unit 4		
	October	Retire Southside Unit 5		
	December	Build 1-168 MW CT at Brandy Branch		
2002	Winter	Purchase 100 MW	229,055	786,195
	April	Northside 1 Repowering - CFB		
	April	Northside 2 Repowering - CFB		
2003	January	Convert 2 Brandy Branch CTs to Combined Cycle (558 MW Total Unit; 186 Additional MWs)	234,694	968,279
2004			247,317	1,141,106
2005	Summer	Purchase 50 MW	278,207	1,309,816
2006	January	Build 1-260 MW CC @ Greenfield Site	309,065	1,485,621
2007	Summer	Purchase 50 MW	341,026	1,666,543
2008	Summer	Purchase 100 MW	378,256	1,851,473
2009	January	Build 2-168 MW CT @ Greenfield Site	405,597	2,041,485
10 Year Extension			3,250,797	5,292,282

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Low Load and Energy Growth

Low Load and Energy Plan				
Year	Month / Season	Expansion Plan	Annual Costs	Cumulative Present Worth
			($1,000)	
2000	Winter	Purchase 250 MW Seasonal Capacity	287,994	287,994
	April	Shutdown Kennedy Unit 10		
	June	Build 1-168 MW CT at Kennedy		
	Summer	Purchase 125 MW Seasonal Capacity		
2001	January	Build 2-168 MW CTs at Brandy Branch	254,406	554,779
	October	Retire Southside Unit 4		
	October	Retire Southside Unit 5		
	December	Build 1-168 MW CT at Brandy Branch		
2002	Winter	Purchase 100 MW	224,043	773,093
	April	Northside 1 Repowering - CFB		
	April	Northside 2 Repowering - CFB		
2003	Annual	Purchase 50 MW (10 year term)	220,506	951,193
2004			231,676	1,113,572
2005	Summer	Purchase 50 MW	260,910	1,271,612
2006	January	Convert 2 Brandy Branch CTs to Combined Cycle (558 MW Total Unit; 186 Additional MWs)	266,021	1,436,487
2007	Summer	Purchase 50 MW	295,021	1,592,212
2008	Summer	Purchase 100 MW	328,794	1,752,194
2009	January	Build 2-168 MW CT @ Greenfield Site	353,078	1,917,360
10 Year Extension			2,818,331	4,735,691

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High Load and Energy Growth

High Load and Energy Plan				
Year	**Month / Season**	**Expansion Plan**	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	Winter	Purchase 250 MW Seasonal Capacity	297,808	297,808
	April	Shutdown Kennedy Unit 10		
	June	Build 1-168 MW CT at Kennedy		
	Summer	Purchase 125 MW Seasonal Capacity		
2001	January	Build 2-168 MW CTs at Brandy Branch	277,015	573,684
	October	Retire Southside Unit 4		
	October	Retire Southside Unit 5		
	December	Build 1-168 MW CT at Brandy Branch		
2002	Winter	Purchase 150 MW	284,764	811,400
	Summer	Purchase 100 MW		
	April	Northside 1 Repowering - CFB		
	April	Northside 2 Repowering - CFB		
2003	January	Convert 2 Brandy Branch CTs to Combined Cycle (558 MW Total Unit; 186 Additional MWs)	295,680	1,037,769
	Annual	Purchase 50 MW (10 year term)		
	Summer	Purchase 100 MW		
2004	Winter	Purchase 50 MW	353,381	1,255,505
	Summer	Purchase 200 MW		
2005	January	Build 1-518 MW CC @ Greenfield Site	396,297	1,496,568
2006	January	Build 2-168 MW CT @ Greenfield Site	448,609	1,746,997
2007	January	Build 1-260 MW CC @ Greenfield Site	511,691	2,009,606
2008	January	Build 1-260 MW CC @ Greenfield Site	583,258	2,287,083
2009	January	Build 1-168 MW CT @ Greenfield Site	657,046	2,580,076
	Summer	Purchase 50 MW		
10 Year Extension			4,735,691	7,804,993

JEA

5. **Provide a table of annual and cumulative present worth revenue requirements for all combinations of units that were evaluated in order to arrive at JEA's base case generation expansion plan. Include the type and timing of the unit or units that comprise each alternative, and the effect of these unit additions on JEA's reliability criteria**

Listed below are the alternative plans selected if the Combined Cycle conversion at Brandy Branch is not done. The alternative plans under the basecase, high and low fuel forecast and high and low load and energy forecast are listed below.

Basecase Plan Alternate Plan				
Year	**Month / Season**	**Expansion Plan**	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	Winter	Purchase 250 MW Seasonal Capacity	303,918	303,918
	April	Shutdown Kennedy Unit 10		
	June	Build 1-168 MW CT at Kennedy		
	Summer	Purchase 125 MW Seasonal Capacity		
2001	January	Build 2-168 MW CTs at Brandy Branch	260,819	585,454
	October	Retire Southside Unit 4		
	October	Retire Southside Unit 5		
	December	Build 1-168 MW CT at Brandy Branch		
2002	Winter	Purchase 100 MW	247,808	809,271
	April	Northside 1 Repowering - CFB		
	April	Northside 2 Repowering - CFB		
2003	Summer	Purchase 50 MW Seasonal Capacity	248,313	1,006,263
2004	Summer	Purchase 50 MW Seasonal Capacity		
	Winter	Purchase 50 MW Seasonal Capacity		
	Annual	Purchase 50 MW Annual Capacity	280,479	1,189,119
2005	Summer	Purchase 50 MW Seasonal Capacity	295,891	1,380,450
	Winter	Purchase 50 MW Seasonal Capacity		
2006	January	Build 1-168 MW CTs at Brandy Branch	326,568	1,567,431
2007	Summer	Purchase 50 MW	357,714	1,758,599
2008	January	Build 1-260 MW CC @ Greenfield Site	393,713	1,952,578
2009	Summer	Purchase 50 MW	420,647	2,150,355
10 Year Extension			420,647	5,493,803

Low Fuel Price Escalation Alternate Plan					
Year	Month / Season	Expansion Plan	Annual Costs	Cumulative Present Worth	LOLP
			($1,000)		Percent
2000	Winter	Purchase 250 MW Seasonal Capacity	288,601	288,601	0.000011
	April	Shutdown Kennedy Unit 10			
	June	Build 1-168 MW CT at Kennedy			
	Summer	Purchase 125 MW Seasonal Capacity			
2001	January	Build 2-168 MW CTs at Brandy Branch	260,818	543,556	0.000014
	October	Retire Southside Unit 4			
	October	Retire Southside Unit 5			
	December	Build 1-168 MW CT at Brandy Branch			
2002	Winter	Purchase 100 MW	227,620	761,055	0.000010
	April	Northside 1 Repowering - CFB			
	April	Northside 2 Repowering - CFB			
2003	Summer	Purchase 50 MW Seasonal Capacity	237,018	982,444	0.000026
2004	Summer	Purchase 50 MW Seasonal Capacity	259,247	1,219,150	0.000016
	Winter	Purchase 50 MW Seasonal Capacity			
	Annual	Purchase 50 MW Annual Capacity			
2005	January	Build 1-260 MW CC @ Greenfield Site	290,805	1,478,701	0.000017
2006	Summer	Purchase 50 MW Seasonal Capacity	296,981	1,737,805	0.000004
2007	Summer	Purchase 100 MW	330,028	2,019,269	0.000010
2008	Summer	Purchase 150 MW	364,857	2,323,440	0.000000
	Winter	Purchase 50 MW Seasonal Capacity			
2009	January	Build 1-168 MW CT at Brandy Branch	395,721	2,645,924	0.000000
	January	Build 1-260 MW CC @ Greenfield Site			
10 Year Extension			3,163,570	5,809,495	0.000000

High Fuel Price Escalation Alternate Plan					
Year	Month / Season	Expansion Plan	Annual Costs	Cumulative Present Worth	LOLP
			($1,000)		Percent
2000	Winter	Purchase 250 MW Seasonal Capacity	290,944	290,944	0.000011
	April	Shutdown Kennedy Unit 10			
	June	Build 1-168 MW CT at Kennedy			
	Summer	Purchase 125 MW Seasonal Capacity			
2001	January	Build 2-168 MW CTs at Brandy Branch	263,052	548,082	0.000014
	October	Retire Southside Unit 4			
	October	Retire Southside Unit 5			
	December	Build 1-168 MW CT at Brandy Branch			
2002	Winter	Purchase 100 MW	229,055	766,953	0.000010
	April	Northside 1 Repowering - CFB			
	April	Northside 2 Repowering - CFB			
2003	Summer	Purchase 50 MW Seasonal Capacity	238,668	989,882	0.000026
2004	Summer	Purchase 50 MW Seasonal Capacity	261,452	1,228,602	0.000016
	Winter	Purchase 50 MW Seasonal Capacity			
	Annual	Purchase 50 MW Annual Capacity			
2005	January	Build 1-260 MW CC @ Greenfield Site	287,703	1,485,385	0.000005
2006	January	Convert 1 Brandy Branch CT to Combined Cycle	307,467	1,753,638	0.000004
2007	Summer	Purchase 100 MW	339,734	2,043,379	0.000010
2008	January	Build 1-260 MW CC @ Greenfield Site	380,460	2,360,557	0.000000
2009	January	Convert 1 Brandy Branch CT to Combined Cycle	403,895	2,689,703	0.000000
10 Year Extension			3,227,499	5,917,201	0.000000

Low Load and Energy Plan Alternate Plan					
Year	Month / Season	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)	LOLP Percent
2000	Winter	Purchase 250 MW Seasonal Capacity	287,994	287,994	0.000009
	April	Shutdown Kennedy Unit 10			
	June	Build 1-168 MW CT at Kennedy			
	Summer	Purchase 125 MW Seasonal Capacity			
2001	January	Build 2-168 MW CTs at Brandy Branch	254,406	536,680	0.000058
	October	Retire Southside Unit 4			
	October	Retire Southside Unit 5			
2002	January	Build 1-168 MW CT at Brandy Branch	224,043	750,762	0.000005
	Winter	Purchase 100 MW			
	April	Northside 1 Repowering - CFB			
	April	Northside 2 Repowering - CFB			
2003	Summer	Purchase 50 MW Seasonal Capacity	231,659	967,145	0.000012
2004	Summer	Purchase 50 MW Seasonal Capacity	242,832	1,188,864	0.000020
2005	January	Build 1-168 MW CT at Brandy Branch	249,804	1,411,822	0.000008
	Summer	Purchase 50 MW Seasonal Capacity			
2006	Summer	Purchase 50 MW Seasonal Capacity	275,011	1,651,758	0.000010
2007	January	Build 1-260 MW CC @ Greenfield Site	304,212	1,911,204	0.000000
2008			322,474	2,180,041	0.000000
2009	Summer	Purchase 500 MW	350,181	2,465,413	0.000000
10 Year Extension			2,800,729	5,266,141	0.000000

High Load and Energy Plan Alternate Plan					
Year	Month / Season	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)	LOLP Percent
2000	Winter	Purchase 250 MW Seasonal Capacity	297,808	297,808	0.000021
	April	Shutdown Kennedy Unit 10			
	June	Build 1-168 MW CT at Kennedy			
	Summer	Purchase 125 MW Seasonal Capacity			
2001	January	Build 2-168 MW CTs at Brandy Branch	277,015	568,594	0.000046
	October	Retire Southside Unit 4			
	October	Retire Southside Unit 5			
	December	Build 1-168 MW CT at Brandy Branch			
2002	Winter	Purchase 150 MW	284,764	840,698	0.000013
	Summer	Purchase 100 MW			
	April	Northside 1 Repowering - CFB			
	April	Northside 2 Repowering - CFB			
2003	January	Convert 1 Brandy Branch CT 1 to Combined Cycle	298,450	1,119,467	0.000025
		Convert 1 Brandy Branch CT 2 to Combined Cycle			
	Annual	Purchase 50 MW (10 year term)			
	Summer	Purchase 100 MW			
2004	Winter	Purchase 50 MW	356,030	1,444,543	0.000021
	Summer	Purchase 200 MW			
2005	January	Build 1-518 MW CC @ Greenfield Site	398,863	1,800,539	0.000002
2006	January	Build 2-168 MW CT @ Greenfield Site	451,288	2,194,271	0.000000
2007	January	Build 1-260 MW CC @ Greenfield Site	514,150	2,632,761	0.000000
2008	January	Build 1-260 MW CC @ Greenfield Site	585,752	3,121,086	0.000000
2009	January	Build 1-168 MW CT @ Greenfield Site	659,769	3,658,750	0.000000
	Summer	Purchase 50 MW			
10 Year Extension			5,244,687	8,903,438	0.000000

6. **For each of the generating units contained in JEA's Ten-Year Site Plan, discuss "drop-dead" date for a decision on whether or not to construct each unit. Provide a time line for the construction of each unit, including regulatory approval, final decision point, and vendor order.**

Kennedy CT / Brandy Branch CTs / Brandy Branch CC Conversion

JEA personnel and Black & Veatch prepared a purchase specification issued on March 16, 1998 and received bids on April 16, 1998. Negotiations were conducted with two bidders, Westinghouse Electric Company and General Electric. Based on these negotiations and the competitive bid price proposals, General Electric was awarded the bid on May 28, 1998 by JEA's Awards Committee for four GE PG 7241 FA combustion turbines.

The first combustion turbine was delivered to Kennedy in October 1999. The second and third CTs were delivered to Brandy Branch in February and April 2000 and the fourth CT is scheduled to be delivered to Brandy Branch in March 2001.

Construction was begun on Kennedy on March 4, 1999 and was essentially completed in April 2000. The unit then went through commissioning and was declared commercial on June 9, 2000.

JEA obtained the permits for the Brandy Branch facility in late 1999. Fluor Global Services was selected to manage the Project and proceeded to mobilize construction in February 2000. To date, most of the underground facilities have been installed, switchyard piers and backfill essentially completed, steel transmission towers are being installed, Brandy Branch CT Units 1 and 2 are set along with their associated generators, duct work and stacks. Foundation installation for the Shared Services Building is well advanced and building steel erection and siding installation has been started. Other concrete foundation work has been active including fuel oil tanks, demineralized water tank, electrical control buildings and Brandy Branch CT Unit 3's foundation.

Commercial operation for CTs 1 and 2 has been revised from December 2000 to May 2001. CT 3 is scheduled for commercial operation in December 2001.

JEA committed to proceed with the permitting and installation of a combined cycle steam turbine unit scheduled for commercial operation for June 2004 using CTs 2 and 3 exhaust as a heat source. Permitting for this fourth unit has been started by JEA and

Black & Veatch. It is planned that the permit applications will be submitted in the fall of 2000. Equipment procurement awards are scheduled to begin in January 2002. Construction is scheduled in November 2001 after final site certification approval.

7. **Identify and discuss any firm power purchases that JEA expects to make from other entities over the planning horizon. If an unidentified or unconfirmed future power purchase is part of JEA's generation expansion plan, explain the nature of that purchase.**

JEA entered into agreements with The Energy Authority (TEA) to purchase firm capacity and energy for the winter and summer 2000 seasons listed below.

Sink	Seller/Buyer	Source	Contract Term		Capacity	
					Summer	Winter
JEA	TEA	Lakeland	03/01/99	02/28/01	25	25
JEA	TEA	MEAG	12/15/99	03/15/00	0	200
JEA	TEA	GRU	12/01/99	03/15/00	0	50
JEA	TEA	Lakeland	05/15/00	09/15/00	25	0
JEA	TEA	Reedy Creek	05/20/00	05/31/00	30	0
JEA	TEA	Reedy Creek	06/01/00	09/15/00	50	0
JEA	TEA	GRU	05/20/00	09/15/00	35	0
JEA	TEA	GRU	05/20/00	09/15/00	12	0

JEA through TEA is in the process of acquiring capacity to fill its winter needs 2001 and 2002 needs. TEA is currently in negotiations for the 250MW, Winter 2001 need which was created by the delay in the commercial operation of Brandy Branch CTs 1 and 2 to May 2000. The 270 MW, winter 2002 need was reported in JEA's 2000 TYSP filing. These currently uncommitted capacity purchases will be filled with firm capacity and energy agreements before the season's start.

8. **Discuss how transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.**

A constraint is viewed as a transmission limitation that occurs under normal conditions due to

- ✓ the line ratings being exceeded in a transmission corridor
- ✓ the transfer capability of such corridor is limited or constrained, or

- ✓ lack of reactive support in a particular area or corridor of the transmission system
- ✓ auto transformers are constrained which could limit the transfer capability of interconnected lines (such as the North East Central Corridor Constraint, Lake Tarpon-Sheldon Constraint, Central South East Constraints, N.W. Central Constraint, Sanford-North Longwood Constraint, etc; defined as possible transmission constraints by the FRCC).

If the above are defined as constraints, then, JEA does not have any transmission constraints under normal conditions.

The only transmission system weaknesses JEA experiences are under contingency conditions if the planning criterion is violated. In that case, JEA develops plans to resolve the Planning Criteria violation via the construction of new lines, installation of auto-transformers, Capacitors, ACCL Reactors, etc.

JEA's 1999 Contingency Evaluation:
Cases evaluated Summer Peak Load conditions for years 00, 01, 02, 03, 06
All the solutions listed below have been already included in JEA's budgeting process.

Contingency	Overload	% Overload (*)	Solution	In SVC Date
Blount Island-Ft Caroline 138 kV	Center Pk 230/138 Auto	102.9	Install 2nd Center Pk Auto. 400 MVA capacity	5/01
	Center Pk-Northside 230 kV	108.1	Rebuild Center Pk-Nside 138 to 230 kV	10/01
Blount Island-Northside 138 kV	Center Pk 230/138 Auto	103.7	Install 2nd Center Pk Auto. 400 MVA cap	5/01
Brooklyn-Kennedy 69 kV,1	Brooklyn-Kennedy 69 kV,2	174.2	Install 6.5 Ohm, ACCL Reactors on both lines	5/01
Cecil Fd-Firestone 138 kV	Firestone 230/69	113.1	Install second 400 MVA auto at Firestone Substation	5/03 Pending Commerce Prj.
Center Pk 230 /69 auto	Ft Caroline Mayport	101.5	Line uprated to 217 MVA, will be upgraded to 289 MVA	Pending a City Rd Prj.
Center Pk-Forrest 230 kV	Center Pk-Robinwood 230 kV	124.1	Install 2\400 MVA autos at Forrest Substation &	5/02
			loop in the Robinwood-Baymeadows lines, plus build the	5/03
			Craven-Forrest 138 kV line. Also change derrated breakers	11/01
			at Robinwood to increase line capacity from 637 to 668 MVA.	
			Install 2nd Center Pk-Greenland 230 kV line	5/03
Center Pk-Robinwood 230 kV	Center Pk 230/138 Auto	124.9	Install 2nd Center Pk Auto. 400 MVA cap	5/01
Center Pk-SJRPP 230 kV	Center Pk-Northside 230 kV	110.2	Rebuild Center Pk-Nside 138 to 230 kV	10/01
Firestone 230/69 kV	Cecil Fd-Normandy 138	101.8	Convert this overloaded line to 230 kV.	5/03 Pending Commerce Sub
Forrest-Greenland 230 kV	Center Pk-Robinwood 230 kV	118.3	Install 2nd Center Pk 230/138 Auto	5/01
			Upgraded derated breakers at Robinwood to increase	11/01
			rating from 637 to 668 MVA	
Ft Caroline-Mayport 138 kV	Robinwood 230/138 kV	106.5	Install 2nd Center Pk 230/138 Auto	5/01
Ft Caroline-Mill Cve 230 kV	Dillon-Imeson 138 kV	102.1	Install 2nd Center Pk-Greenland 230 kV line	5/03
Ft Caroline-SJRPP 230 kV	Center Pk 230/138 kV	121.6	Install 2nd 230/138 kV auto at Center Pk	5/01
	Robinwood 230/138 kV	120.7	Install 2nd 230/138 kV auto at Center Pk	5/01
Greenland 230/138 kV	Hartley 230/138 Kv	101.1	Install 2nd 230/138 kV auto at Center Pk	5/01
Greenland-Switzerland 230 kV	Neptune-Jax Beach	147.7	Line has been uprated by Jax Beach Utilities to 289 MVA	N\A
Northside 230/138 kV	Center Pk-Northside 230 kV	106.1	Rebuild Center Pk-Nside 138 to 230 kV	10/01
Northside-West Jax 230 kV	Center Pk-Northside 230 kV	101.5	Rebuild Center Pk-Nside 138 to 230 kV	10/01
Normandy 230/138	Normandy 130/138	110.6	Replace an existing auto with another of 400 MVA capacity	5/03

(*)= Overloads listed are the worst overloads per outage which usually happens in the latter years.

9. Discuss how generating unit performance was modeled in the planning process.

JEA models forced outage rates, net heat rates at specific capacity levels and maintenance outage schedules in EGEAS when performing integrated resource planning. The model uses these parameters to determine the availability and efficiency of the units to contribute to the needs of the system.

10. Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

For planning purposes, JEA uses the CPI for escalation of capital costs and operations and maintenance expenses. JEA used an interest rate of 7.65%, which is a 15-year, taxable rate for the interest rate on new generation construction. However, JEA's current corporate financing strategy is to finance generation with internal funds or with shorter-term variable rate debt. No variations in the financial assumptions were analyzed.

11. Discuss how strategic concerns are incorporated in the planning process.

Issues in such areas of environmental, fuel diversification and supply and deregulation are among JEA's strategic concerns.

- ✓ Environmental

  JEA continues to strive to meet or exceed environmental regulations set forth at the federal, state, and municipal levels to ensure the safety and health of all residents in and near Jacksonville and surrounding communities.

  Upon commercial operation of the solid fuel repowering of Northside Units 1 and 2, JEA established a goal to reduce environmental emissions of SO_2, NO_x, and particulates by 10 percent for the Northside Station steam units in comparison to 1994/1995 levels. This initiative will provide a cleaner environment for the residents with the addition of generation resources. With the increased power output and capacity factor of the repowered generating units, annual emission rates will be greatly reduced.

Actual historical emissions of Kennedy Generating Station Unit 10 were used as offsets for permitting the simple cycle combustion turbine at this site, effectively replacing an old residual oil burning unit with a state-of-the-art, natural-gas fired combustion turbine with low sulfur diesel backup fuel. Similarly, the installation of 3-170 MW simple cycle CTs at the permitted Brandy Branch facility will coincide with the shutdown of the aging oil/gas Southside Generation Station, located in downtown Jacksonville, resulting in greatly reduced emissions while increasing system capacity for meeting future power demand.

These reduced emission levels and unit additions, shutdowns and retirements are supplied to the model, EGEAS, to manage unit operations that will not violate the Northside community commitment or any other unit/ system emission constraint and also select unit additions that will best fit the limitations at the least cost.

✓ Fuel Diversification

JEA continues to recognize the importance of fuel diversity of individual units as well as fuel diversity of the electric system. With the retirements/shutdown of dual fueled units, JEA adds to the system units that are also capable of burning more than one fuel source. The CFB's in Northside's repowered units will be capable of operating on Petroleum Coke, coal and biomas. The GE7FA's are capable of burning natural gas and distillate fuel oil. The dual fuel capability of these units is supplied to the model as an input and the model utilizes the cheapest fuel given that supply is available. Northside Units 1 and 2, however, were modeled using only Petroleum Coke.

✓ Fuel Supply

These limits are supplied to the model, EGEAS, to maintain unit operations that will not violate the Northside or other unit/ system emission constraint and also select unit additions that will best fit the limitations at the least cost.

✓ Deregulation

Implementation of deregulation of the utility industry continues to move forward. Some states are wrestling with issues such as buy vs build, utility financing, and market value of assets in a deregulated environment. Although Florida has yet to implement deregulation in the state, the issues are being discussed and considered. Through a sensitivity to the load and energy forecast, JEA attempted to analyze the system with a low load and energy growth scenario to represent both a deregulated utility industry or a slow economy.

12. Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act during the planning horizon. Provide the rationale for any new or upgraded transmission line.

A transmission line must be certified under The Transmission Line Siting Act if the transmission line crosses over county lines. None of the transmission lines recommended for constructions under JEA's current Transmission Expansion Plan cross over county lines. Therefore neither certification nor explanation is required.

Environmental

13. Identify and discuss all proposed or reasonably expected State and Federal environmental regulations or legislation that impacted JEA's generation expansion plan.

The JEA is in compliance with all existing regulatory requirements. This consists of maintaining compliance with emission limits and work practice requirements such as inspections and maintenance, and record-keeping and reporting requirements.

All future generation, including projects currently being licensed, will utilize Best Available Control Technology to control emissions and will conform to applicable record-keeping and reporting requirements. These requirements are subject to change as regulations and interpretation of the regulations change.

Load Forecasting

14. Provide, on a system-wide basis, historical annual heating degree day (HDD) data for the period from 1990-1999 and forecasted HDD data for the period 2000-2009.

See the table under #16 below.

15. Provide, on a system-wide basis, historical annual cooling degree day (CDD) data for the period from 1990-1999 and forecasted CDD data for the period 2000-2009.

See the table under #16 below.

16. Provide, on a system wide basis, the historical annual average real retail price of electricity in JEA's service territory for the period 1990-1999. Also, provide the forecasted annual average real retail price of electricity in JEA's service territory for 2000-2009. Indicate the type of price deflator used to calculate the historical prices and forecasted real retail prices.

In past years, JEA has been reporting the nominal price of electricity. This year's reporting is the real price of electricity as requested.

	HDD	CDD	Price of Electricity	Price Deflator
Year	Days	Days	$/MWh	CPI
1990	774	3,068	59.92	130.7
1991	1,085	3,166	57.66	136.2
1992	1,301	2,750	56.03	140.3
1993	1,391	2,670	54.27	144.5
1994	1,036	2,785	50.61	148.2
1995	1,443	2,783	47.96	152.4
1996	1,541	2,540	46.77	156.9
1997	1,174	2,519	43.41	160.5
1998	1,011	3,050	41.98	163.0
1999	1,206	2,611	40.31	166.6
2000	1,434	2,551	39.14	171.6
2001	1,434	2,551	38.00	176.7
2002	1,434	2,551	36.89	182.0
2003	1,434	2,551	35.82	187.5
2004	1,434	2,551	34.77	193.1
2005	1,434	2,551	33.76	198.9
2006	1,434	2,551	32.78	204.9
2007	1,434	2,551	31.82	211.0
2008	1,435	2,552	30.90	217.4
2009	1,436	2,553	30.00	223.9

JEA

17. **Provide the following data to support Schedule 4 of JEA's Ten-Year Site Plan: 12 monthly peak demands for the years 1996, 1997, and 1998; and the date on which these monthly peaks occurred.**

Month	Actual 1997 Peak Demand MW	Actual 1997 Day Peak Occurred	Actual 1998 Peak Demand MW	Actual 1998 Day Peak Occurred	Actual 1999 Peak Demand MW	Actual 1999 Day Peak Occurred
January	1986	18	1689	20	2403	6
February	1716	12	1806	4	2004	23
March	1558	4	1938	13	1823	16
April	1570	7	1534	1	1939	27
May	1830	20	2082	21	2055	26
June	1970	25	2319	29	2147	4
July	2130	28	2338	1	2376	30
August	2127	18	2211	27	2427	2
September	1964	15	2007	4	2172	7
October	1765	1	1955	8	1922	12
November	1726	17	1591	11	1677	4
December	1975	15	1829	31	2052	2

Existing Generating Unit Operating Performance

(1) Plant Name	(2) Unit No.	(3) Planned Outage Factor (POF) Historical (3)	(3) Planned Outage Factor (POF) Projected (4)	(4) Forced Outage Factor (FOF) Historical (3)	(4) Forced Outage Factor (FOF) Projected (4)	(5) Equivalent Availability Factor (EAF) Historical (3)	(5) Equivalent Availability Factor (EAF) Projected (4)	(6) Average Net Operating Heat Rate (ANOHR) Historical (3)	(6) Average Net Operating Heat Rate (ANOHR) Projected (4)
(1) Kennedy	10	1.68	Shut down	3.87	Shut down	94.45	Shut down	11,558	Shut down
Kennedy GT	33	3.47	2.37	1.51	6.00	95.01	91.63	18,590	15,252
Kennedy GT	34	4.13	2.37	16.29	6.00	79.59	91.63	17,804	15,252
Kennedy GT	35	3.97	2.37	1.28	6.00	94.75	91.63	20,093	15,252
(2) Northside	1	5.85	4.57	2.91	3.40	91.24	92.03	10,047	10,085
(2) Northside	2	Cold Storage	4.79	Cold Storage	2.50	Cold Storage	92.71	Cold Storage	9,946
Northside	3	7.37	3.16	2.04	4.00	90.59	92.84	10,615	10,568
Northside GT	33	0.46	2.30	1.18	5.00	98.36	92.70	17,567	13,533
Northside GT	34	0.49	2.30	1.20	5.00	98.39	92.70	18,719	13,533
Northside GT	35	1.72	2.30	1.14	5.00	97.14	92.70	18,667	13,533
Northside GT	36	0.42	2.30	0.60	5.00	98.96	92.70	19,593	13,533
(1) Southside	4	0.91	0.00	3.95	4.00	95.14	96.00	12,581	11,211
(1) Southside	5	4.49	0.00	1.76	3.00	93.74	97.00	10,998	10,230
SJRPP	1	5.79	2.85	3.31	5.00	90.90	92.15	9,606	9,239
SJRPP	2	1.92	3.07	3.74	5.00	94.35	91.93	9,425	9,130
Scherer	4	5.05	4.30	4.48	2.60	90.47	93.10	10,166	10,006

Note:

(1) Unit Retired or Shutdown in study period.
(2) Unit repowered or refueled in study period.
(3) Historical - Average of past three years.
(4) Projected - Average of next ten years.

Financial Escalation Assumptions

(1) Year	(2) General Inflation %	(3) Plant Construction Cost %	(4) Fixed O & M Cost %	(5) Variable O & M Cost %
1999	2.3	2.3	2.3	2.3
2000	2.3	2.3	2.3	2.3
2001	2.3	2.3	2.3	2.3
2002	2.3	2.3	2.3	2.3
2003	2.3	2.3	2.3	2.3
2004	2.3	2.3	2.3	2.3
2005	2.3	2.3	2.3	2.3
2006	2.3	2.3	2.3	2.3
2007	2.3	2.3	2.3	2.3
2008	2.3	2.3	2.3	2.3

Loss of Load Probability, Reserve Margin, and Expected Unserved Energy Base Case Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Annual Isolated			Annual Assisted		
Year	Loss of Load Probability (Days/Year)	Reserve Margin % (Including Firm Purch.)	Expected Unserved Energy (MWh)	Loss of Load Probability (Days/Year)	Reserve Margin % (Including Firm Purch.)	Expected Unserved Energy (MWh)
2000				0.000011	15	403
2001				0.000014	20	269
2002				0.000018	15	255
2003				0.000013	18	409
2004				0.000024	21	638
2005				0.000040	20	979
2006				0.000007	16	356
2007				0.000020	18	723
2008				0.000027	20	882
2009				0.000014	16	1,056

NOTE:

Calculations based on total load, firm and interruptible (Not exercising the interruption).

History and Forecast of Summer Peak Demand
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					Residential		Commercial / Industrial		Firm Peak
Year	Total	Wholesale	Retail	Interruptible	Load Management	Conservation	Load Management	Conservation	Demand
1990	1,789	40	1,749	0	0	0	0	0	1,789
1991	1,756	47	1,709	0	0	0	0	0	1,756
1992	1,881	56	1,825	0	0	0	0	0	1,881
1993	1,998	60	1,938	0	0	0	0	0	1,998
1994	1,918	53	1,865	0	0	0	0	0	1,918
1995	2,067	66	2,001	0	0	0	0	0	2,067
1996	2,114	64	2,050	0	0	0	0	0	2,114
1997	2,051	70	1,981	80	0	0	0	0	2,131
1998	2,232	86	2,146	106	0	0	0	0	2,338
1999	2,281	92	2,189	146	0	0	0	0	2,427
2000	2,590	98	2,492	150	0	0	0	0	2,440
2001	2,732	103	2,629	154	0	0	0	0	2,579
2002	2,883	108	2,775	158	0	0	0	0	2,725
2003	3,041	113	2,928	162	0	0	0	0	2,880
2004	3,209	118	3,090	166	0	0	0	0	3,043
2005	3,385	123	3,262	170	0	0	0	0	3,215
2006	3,571	128	3,443	174	0	0	0	0	3,397
2007	3,768	133	3,635	178	0	0	0	0	3,589
2008	3,975	138	3,837	183	0	0	0	0	3,792
2009	4,193	143	4,050	188	0	0	0	0	4,006

History and Forecast of Winter Peak Demand
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					Residential		Commercial / Industrial		Firm Peak
Year	Total	Wholesale	Retail	Interruptible	Load Management	Conservation	Load Management	Conservation	Demand
1990	2,012	73	1,939	0	0	0	0	0	2,012
1991	1,725	64	1,661	0	0	0	0	0	1,725
1992	1,881	69	1,812	0	0	0	0	0	1,881
1993	1,791	66	1,725	0	0	0	0	0	1,791
1994	1,936	70	1,866	0	0	0	0	0	1,936
1995	2,190	82	2,108	0	0	0	0	0	2,190
1996	2,401	88	2,313	0	0	0	0	0	2,401
1997	1,950	72	1,878	36	0	0	0	0	1,986
1998	1,910	68	1,842	65	0	0	0	0	1,975
1999	2,303	93	2,210	100	0	0	0	0	2,403
2000	2,616	98	2,519	102	0	0	0	0	2,514
2001	2,760	103	2,658	105	0	0	0	0	2,656
2002	2,912	108	2,805	107	0	0	0	0	2,805
2003	3,072	112	2,960	110	0	0	0	0	2,962
2004	3,241	117	3,124	113	0	0	0	0	3,129
2005	3,420	122	3,297	116	0	0	0	0	3,304
2006	3,608	127	3,480	118	0	0	0	0	3,489
2007	3,806	132	3,674	121	0	0	0	0	3,685
2008	4,015	137	3,878	124	0	0	0	0	3,891
2009	4,236	142	4,094	128	0	0	0	0	4,109

History and Forecast of Winter Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					Residential		Commercial / Industrial		Firm Peak
Year	Total	Wholesale	Retail	Interruptible	Load Management	Conservation	Load Management	Conservation	Demand
1990	1,789	40	1,749	0	0	0	0	0	1,789
1991	1,756	47	1,709	0	0	0	0	0	1,756
1992	1,881	56	1,825	0	0	0	0	0	1,881
1993	1,998	60	1,938	0	0	0	0	0	1,998
1994	1,918	53	1,865	0	0	0	0	0	1,918
1995	2,067	66	2,001	0	0	0	0	0	2,067
1996	2,114	64	2,050	0	0	0	0	0	2,114
1997	2,051	70	1,981	80	0	0	0	0	2,131
1998	2,232	86	2,146	106	0	0	0	0	2,338
1999	2,281	92	2,189	146	0	0	0	0	2,427
2000	2,516	98	2,418	150	0	0	0	0	2,366
2001	2,579	103	2,476	154	0	0	0	0	2,425
2002	2,644	108	2,536	158	0	0	0	0	2,486
2003	2,710	113	2,597	162	0	0	0	0	2,548
2004	2,778	118	2,659	166	0	0	0	0	2,612
2005	2,847	123	2,724	170	0	0	0	0	2,677
2006	2,918	128	2,790	174	0	0	0	0	2,744
2007	2,991	133	2,858	178	0	0	0	0	2,813
2008	3,066	138	2,928	183	0	0	0	0	2,883
2009	3,143	143	2,999	188	0	0	0	0	2,955

History and Forecast of Summer Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					Residential		Commercial / Industrial		Firm Peak
Year	Total	Wholesale	Retail	Interruptible	Load Management	Conservation	Load Management	Conservation	Demand
1990	2,012	73	1,939	0	0	0	0	0	2,012
1991	1,725	64	1,661	0	0	0	0	0	1,725
1992	1,881	69	1,812	0	0	0	0	0	1,881
1993	1,791	66	1,725	0	0	0	0	0	1,791
1994	1,936	70	1,866	0	0	0	0	0	1,936
1995	2,190	82	2,108	0	0	0	0	0	2,190
1996	2,401	88	2,313	0	0	0	0	0	2,401
1997	1,950	72	1,878	36	0	0	0	0	1,986
1998	1,910	68	1,842	65	0	0	0	0	1,975
1999	2,303	93	2,210	100	0	0	0	0	2,403
2000	2,542	98	2,444	102	0	0	0	0	2,440
2001	2,606	103	2,503	105	0	0	0	0	2,501
2002	2,671	108	2,563	107	0	0	0	0	2,563
2003	2,737	112	2,625	110	0	0	0	0	2,628
2004	2,806	117	2,689	113	0	0	0	0	2,693
2005	2,876	122	2,754	116	0	0	0	0	2,761
2006	2,948	127	2,821	118	0	0	0	0	2,830
2007	3,022	132	2,890	121	0	0	0	0	2,900
2008	3,097	137	2,960	124	0	0	0	0	2,973
2009	3,175	142	3,033	128	0	0	0	0	3,047

History And Forecast of Net Energy for Load - GWH
High Case

(1) Calendar Year	(2) Total	(3) Residential Conservation	(4) C/I Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
1990	8,538	0	0	8,358	180	258	8,538	48
1991	8,835	0	0	8,604	231	487	8,835	57
1992	9,028	0	0	8,710	318	431	9,028	55
1993	9,609	0	0	9,260	349	628	9,609	55
1994	9,609	0	0	9,296	313	388	9,609	57
1995	10,326	0	0	9,977	349	667	10,326	54
1996	10,515	0	0	10,141	374	398	10,515	50
1997	10,665	0	0	10,271	394	570	10,665	57
1998	11,470	0	0	11,019	451	442	11,470	56
1999	11,740	0	0	11,286	454	547	11,740	55
2000	12,532	0	0	11,449	455	628	12,532	54
2001	13,221	0	0	12,099	475	647	13,221	54
2002	13,948	0	0	12,791	493	664	13,948	54
2003	14,716	0	0	13,525	504	687	14,716	54
2004	15,525	0	0	14,306	533	686	15,525	54
2005	16,379	0	0	15,135	551	692	16,379	54
2006	17,280	0	0	16,016	571	693	17,280	54
2007	18,230	0	0	16,952	590	688	18,230	54
2008	19,233	0	0	17,945	609	679	19,233	54
2009	20,290	0	0	18,999	624	668	20,290	54

History And Forecast of Net Energy for Load - GWH
Low Case

(1) Calendar Year	(2) Total	(3) Residential Conservation	(4) C/I Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
1990	8,538	0	0	8,358	180	258	8,538	48
1991	8,835	0	0	8,604	231	487	8,835	57
1992	9,028	0	0	8,710	318	431	9,028	55
1993	9,609	0	0	9,260	349	628	9,609	55
1994	9,609	0	0	9,296	313	388	9,609	57
1995	10,326	0	0	9,977	349	667	10,326	54
1996	10,515	0	0	10,141	374	398	10,515	50
1997	10,665	0	0	10,271	394	570	10,665	57
1998	11,470	0	0	11,019	451	442	11,470	56
1999	11,740	0	0	11,286	454	547	11,740	55
2000	12,097	0	0	11,036	455	606	12,097	54
2001	12,399	0	0	11,318	475	607	12,399	54
2002	12,709	0	0	11,611	493	605	12,709	54
2003	13,027	0	0	11,915	504	608	13,027	54
2004	13,353	0	0	12,230	533	590	13,353	54
2005	13,687	0	0	12,557	551	579	13,687	54
2006	14,029	0	0	12,896	571	563	14,029	54
2007	14,379	0	0	13,246	590	543	14,379	54
2008	14,739	0	0	13,610	609	521	14,739	54
2009	15,107	0	0	13,986	624	497	15,107	54

Nominal, Delivered Residual Oil Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	1.0%		Escalation	1.8%		Escalation	3.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History:									
1997	N/A	N/A	N/A	17.16	2.704	-1.4	N/A	N/A	N/A
1998	N/A	N/A	N/A	12.86	2.026	-25.1	N/A	N/A	N/A
1999	N/A	N/A	N/A	13.15	2.071	2.3	N/A	N/A	N/A
Forecast:									
2000	20.20	3.206	N/A	19.10	3.032	45.2	N/A	N/A	N/A
2001	17.65	2.802	-12.6	16.70	2.651	-12.6	N/A	N/A	N/A
2002	18.06	2.866	2.3	17.08	2.712	2.3	N/A	N/A	N/A
2003	18.47	2.932	2.3	17.48	2.774	2.3	N/A	N/A	N/A
2004	18.90	2.999	2.3	17.88	2.838	2.3	N/A	N/A	N/A
2005	19.33	3.068	2.3	18.29	2.903	2.3	N/A	N/A	N/A
2006	19.78	3.139	2.3	18.71	2.970	2.3	N/A	N/A	N/A
2007	20.23	3.211	2.3	19.14	3.038	2.3	N/A	N/A	N/A
2008	20.70	3.285	2.3	19.58	3.108	2.3	N/A	N/A	N/A
2009	21.17	3.361	2.3	20.03	3.180	2.3	N/A	N/A	N/A

* Historical oil price information is for all residual fuel oil regardless of sulfur percentage.
The majority of JEA residual fuel oil is burned at the Northside Generating Station and contains approximately 1.8% sulfur.

Sulfur %	Ash %	mmBtu/BBL
1.0	0.02	6.3
1.8	0.02	6.3

Nominal, Delivered Residual Oil Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	1.0%		Escalation	1.8%		Escalation	3.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History:									
1997	N/A	N/A	N/A	17.16	2.704	-1.4	N/A	N/A	N/A
1998	N/A	N/A	N/A	12.86	2.026	-25.1	N/A	N/A	N/A
1999	N/A	N/A	N/A	13.15	2.071	2.3	N/A	N/A	N/A
Forecast:									
2000	22.75	3.611	N/A	21.50	3.413	63.5	N/A	N/A	N/A
2001	20.20	3.206	-11.2	19.10	3.032	-11.2	N/A	N/A	N/A
2002	20.81	3.303	3.0	19.67	3.123	3.0	N/A	N/A	N/A
2003	21.43	3.402	3.0	20.26	3.216	3.0	N/A	N/A	N/A
2004	22.07	3.504	3.0	20.87	3.313	3.0	N/A	N/A	N/A
2005	22.74	3.609	3.0	21.50	3.412	3.0	N/A	N/A	N/A
2006	23.42	3.717	3.0	22.14	3.515	3.0	N/A	N/A	N/A
2007	24.12	3.829	3.0	22.81	3.620	3.0	N/A	N/A	N/A
2008	24.84	3.943	3.0	23.49	3.729	3.0	N/A	N/A	N/A
2009	25.59	4.062	3.0	24.20	3.841	3.0	N/A	N/A	N/A

* Historical oil price information is for all residual fuel oil regardless of sulfur percentage.
The majority of JEA residual fuel oil is burned at the Northside Generating Station and contains approximately 1.8% sulfur.

Sulfur %	Ash %	mmBtu/BBL
1.0	0.02	6.3
1.8	0.02	6.3

Nominal, Delivered Residual Oil Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	1.0%		Escalation	1.8%		Escalation	3.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History:									
1997	N/A	N/A	N/A	17.16	2.704	-1.4	N/A	N/A	N/A
1998	N/A	N/A	N/A	12.86	2.026	-25.1	N/A	N/A	N/A
1999	N/A	N/A	N/A	13.15	2.071	2.3	N/A	N/A	N/A
Forecast:									
2000	15.95	2.532	N/A	15.10	2.397	14.8	N/A	N/A	N/A
2001	13.40	2.127	-16.0	12.70	2.016	-15.9	N/A	N/A	N/A
2002	13.53	2.148	1.0	12.83	2.036	1.0	N/A	N/A	N/A
2003	13.67	2.170	1.0	12.96	2.056	1.0	N/A	N/A	N/A
2004	13.81	2.191	1.0	13.08	2.077	1.0	N/A	N/A	N/A
2005	13.94	2.213	1.0	13.22	2.098	1.0	N/A	N/A	N/A
2006	14.08	2.235	1.0	13.35	2.119	1.0	N/A	N/A	N/A
2007	14.22	2.258	1.0	13.48	2.140	1.0	N/A	N/A	N/A
2008	14.37	2.280	1.0	13.62	2.161	1.0	N/A	N/A	N/A
2009	14.51	2.303	1.0	13.75	2.183	1.0	N/A	N/A	N/A

* Historical oil price information is for all residual fuel oil regardless of sulfur percentage.
The majority of JEA residual fuel oil is burned at the Northside Generating Station and contains approximately 1.8% sulfur.

Sulfur %	Ash %	mmBtu/BBL
1.0	0.02	6.3
1.8	0.02	6.3

Nominal, Delivered Distillate Oil and Natural Gas Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil				Natural Gas	
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History:						
1997	25.6	438.6	-10.0	278.8	27.88	3.1
1998	19.34	328.9	-24.5	242.3	24.23	-13.1
1999	24.71	417.9	27.8	279.1	27.91	15.2
Forecast:						
2000	25.74	441.5	4.2	274.1	2.88	-1.8
2001	22.23	381.3	-13.6	280.2	2.94	2.2
2002	22.74	390.1	2.3	306.7	3.22	9.5
2003	23.26	399.0	2.3	313.1	3.29	2.1
2004	23.80	408.2	2.3	319.7	3.36	2.1
2005	24.35	417.6	2.3	326.4	3.43	2.1
2006	24.91	427.2	2.3	333.4	3.50	2.1
2007	25.48	437.0	2.3	340.5	3.58	2.1
2008	26.07	447.1	2.3	347.8	3.65	2.1
2009	26.67	457.4	2.3	355.3	3.73	2.2

	Sulfur %	Ash %	mmBtu/BBL
Distillate	0.25	0.01	5.83

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil				Natural Gas	
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History:						
1997	25.6	438.6	-10.0	278.8	27.88	3.1
1998	19.34	328.9	-24.5	242.3	24.23	-13.1
1999	24.71	417.9	27.8	279.1	27.91	15.2
Forecast:						
2000	29.25	464.3	18.4	284.3	2.98	1.8
2001	25.74	408.6	-12.0	292.4	3.07	2.9
2002	26.51	420.8	3.0	321.1	3.37	9.8
2003	27.31	433.5	3.0	329.7	3.46	2.7
2004	28.13	446.5	3.0	338.7	3.56	2.7
2005	28.97	459.9	3.0	348.0	3.65	2.7
2006	29.84	473.6	3.0	357.7	3.76	2.8
2007	30.73	487.9	3.0	367.6	3.86	2.8
2008	31.66	502.5	3.0	377.9	3.97	2.8
2009	32.61	517.6	3.0	388.6	4.08	2.8

	Sulfur %	Ash %	mmBtu/BBL
Distillate	0.25	0.01	5.83

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil				Natural Gas	
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History:						
1997	25.60	438.6	-10.0	278.8	27.88	3.1
1998	19.34	328.9	-24.5	242.3	24.23	-13.1
1999	24.71	417.9	27.8	279.1	27.91	15.2
Forecast:						
2000	19.89	315.714	-19.5	264.0	2.77	-5.4
2001	16.38	260.000	-17.6	266.6	2.80	1.0
2002	16.54	262.600	1.0	289.5	3.04	8.6
2003	16.71	265.226	1.0	292.2	3.07	0.9
2004	16.88	267.878	1.0	294.9	3.10	0.9
2005	17.05	270.557	1.0	297.6	3.12	0.9
2006	17.22	273.263	1.0	300.4	3.15	0.9
2007	17.39	275.995	1.0	303.1	3.18	0.9
2008	17.56	278.755	1.0	306.0	3.21	0.9
2009	17.74	281.543	1.0	308.8	3.24	0.9

	Sulfur %	Ash %	mmBtu/BBL
Distillate	0.25	0.01	5.83

Nominal, Delivered SJRPP Coal Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
History:												
1997	36.930	155.823	0.8	0.6%	44.325	175.718	5.4	4.5%	N/A	N/A	N/A	N/A
1998	34.711	146.125	-6.0	11.5%	43.253	170.113	-2.4	10.2%	N/A	N/A	N/A	N/A
1999	34.720	147.000	0.0	4.5%	41.150	161.41	-4.9	27.4%	35.330	134.68	N/A	100.0%
Forecast:												
2000	35.45	150.078	2.1	0.0%	42.39	165.005	-2.0	27.5%	N/A	N/A	N/A	N/A
2001	36.25	153.488	2.3	0.0%	39.26	155.810	-7.4	68.6%	N/A	N/A	N/A	N/A
2002	37.10	157.071	2.3	0.0%	40.36	160.356	2.8	68.6%	N/A	N/A	N/A	N/A
2003	37.97	160.774	2.4	0.0%	34.83	145.106	-13.7	100.0%	N/A	N/A	N/A	N/A
2004	38.88	164.602	2.4	0.0%	35.52	148.008	2.0	100.0%	N/A	N/A	N/A	N/A
2005	39.81	168.560	2.4	0.0%	36.23	150.968	2.0	100.0%	N/A	N/A	N/A	N/A
2006	N/A	N/A	N/A	N/A	36.96	153.987	2.0	100.0%	N/A	N/A	N/A	N/A
2007	N/A	N/A	N/A	N/A	37.70	157.067	2.0	100.0%	N/A	N/A	N/A	N/A
2008	N/A	N/A	N/A	N/A	38.45	160.208	2.0	100.0%	N/A	N/A	N/A	N/A
2009	N/A	N/A	N/A	N/A	39.22	163.413	2.0	100.0%	N/A	N/A	N/A	N/A

Notes: For projection purposes, as specific SJRPP coal contracts expire, it is assumed that replacement tons are purchased on the spot market. JEA coal price projections for Scherer Unit 4 are provided by Georgia Power Company and are not available in this format.

The coal burned at SJRPP is bituminous coal.

Sulfur %	Year	Ash %	Btu/lb
< 1.0%	2000+	7-8%	11,810

Sulfur %	Year	Ash %	Btu/lb
1.0 - 2.0%	2000	9-10%	12,844
	2001	9-10%	12,600
	2002	9-10%	12,585
	2003+	9-10%	12,000

Nominal, Delivered SJRPP Coal Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
History:												
1997	36.930	155.823	0.8	0.6%	44.325	175.718	5.4	4.5%	N/A	N/A	N/A	N/A
1998	34.711	146.125	-6.0	11.5%	43.253	170.113	-2.4	10.2%	N/A	N/A	N/A	N/A
1999	34.720	147.000	0.0	4.5%	41.150	161.41	-4.9	27.4%	35.330	134.68	N/A	100.0%
Forecast:												
2000	35.45	150.078	2.1	0.0%	42.39	165.005	-2.0	27.5%	N/A	N/A	N/A	N/A
2001	36.25	153.488	2.3	0.0%	39.31	155.972	-7.3	68.6%	N/A	N/A	N/A	N/A
2002	37.10	157.071	2.3	0.0%	40.43	160.637	2.9	68.6%	N/A	N/A	N/A	N/A
2003	37.97	160.774	2.4	0.0%	35.20	146.678	-12.9	100.0%	N/A	N/A	N/A	N/A
2004	38.88	164.602	2.4	0.0%	36.01	150.051	2.3	100.0%	N/A	N/A	N/A	N/A
2005	39.81	168.560	2.4	0.0%	36.84	153.502	2.3	100.0%	N/A	N/A	N/A	N/A
2006	N/A	N/A	N/A	N/A	37.69	157.033	2.3	100.0%	N/A	N/A	N/A	N/A
2007	N/A	N/A	N/A	N/A	38.55	160.645	2.3	100.0%	N/A	N/A	N/A	N/A
2008	N/A	N/A	N/A	N/A	39.44	164.339	2.3	100.0%	N/A	N/A	N/A	N/A
2009	N/A	N/A	N/A	N/A	40.35	168.119	2.3	100.0%	N/A	N/A	N/A	N/A

Notes: For projection purposes, as specific SJRPP coal contracts expire, it is assumed that replacement tons are purchased on the spot market. JEA coal price projections for Scherer Unit 4 are provided by Georgia Power Company and are not available in this format.

Nominal, Delivered SJRPP Coal Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
History:												
1997	36.930	155.823	0.8	0.6%	44.325	175.718	5.4	4.5%	N/A	N/A	N/A	N/A
1998	34.711	146.125	-6.0	11.5%	43.253	170.113	-2.4	10.2%	N/A	N/A	N/A	N/A
1999	34.720	147.000	0.0	4.5%	41.150	161.41	-4.9	27.4%	35.330	134.68	N/A	100.0%
Forecast:												
2000	35.45	150.078	2.1	0.0%	42.39	165.005	-2.0	27.5%	N/A	N/A	N/A	N/A
2001	36.25	153.488	2.3	0.0%	39.13	155.274	-7.7	68.6%	N/A	N/A	N/A	N/A
2002	37.10	157.071	2.3	0.0%	40.13	159.433	2.6	68.6%	N/A	N/A	N/A	N/A
2003	37.97	160.774	2.4	0.0%	33.59	139.973	-16.3	100.0%	N/A	N/A	N/A	N/A
2004	38.88	164.602	2.4	0.0%	33.93	141.372	1.0	100.0%	N/A	N/A	N/A	N/A
2005	39.81	168.560	2.4	0.0%	34.27	142.786	1.0	100.0%	N/A	N/A	N/A	N/A
2006	N/A	N/A	N/A	N/A	34.61	144.214	1.0	100.0%	N/A	N/A	N/A	N/A
2007	N/A	N/A	N/A	N/A	34.96	145.656	1.0	100.0%	N/A	N/A	N/A	N/A
2008	N/A	N/A	N/A	N/A	35.31	147.113	1.0	100.0%	N/A	N/A	N/A	N/A
2009	N/A	N/A	N/A	N/A	35.66	148.584	1.0	100.0%	N/A	N/A	N/A	N/A

Notes: For projection purposes, as specific SJRPP coal contracts expire, it is assumed that replacement tons are purchased on the spot market.
JEA coal price projections for Scherer Unit 4 are provided by Georgia Power Company and are not available in this format.

Nominal Delivered Petroleum Coke Prices
Nortside Generating Station
Base Case

(1)	(2)	(3)	(4)
	Petroleum Coke		
Year	$/Ton	c/MBTU	Escalation %
History:			
1997	N/A	N/A	N/A
1998	N/A	N/A	N/A
1999	N/A	N/A	N/A
Forecast:			
2000	N/A	N/A	N/A
2001	N/A	N/A	N/A
2002	19.39	69.266	N/A
2003	19.78	70.651	2.0
2004	20.18	72.064	2.0
2005	20.58	73.505	2.0
2006	20.99	74.975	2.0
2007	21.41	76.475	2.0
2008	21.84	78.004	2.0
2009	22.28	79.564	2.0

Sulfur %	Ash %	Btu/lb
< 8%	< 1%	14,000

Nominal Delivered Petroleum Coke Prices
Nortside Generating Station
High Case

(1)	(2)	(3)	(4)
	Petroleum Coke		
Year	$/Ton	c/MBTU	Escalation %
History:			
1997	N/A	N/A	N/A
1998	N/A	N/A	N/A
1999	N/A	N/A	N/A
Forecast:			
2000	N/A	N/A	N/A
2001	N/A	N/A	N/A
2002	19.91	71.100	N/A
2003	20.35	72.677	2.2
2004	20.80	74.289	2.2
2005	21.26	75.937	2.2
2006	21.73	77.621	2.2
2007	22.22	79.343	2.2
2008	22.71	81.103	2.2
2009	23.21	82.903	2.2

Sulfur %	Ash %	Btu/lb
< 8%	< 1%	14,000

Nominal Delivered Petroleum Coke Prices
Nortside Generating Station
Low Case

(1)	(2)	(3)	(4)
	Petroleum Coke		
Year	$/Ton	c/MBTU	Escalation %
History:			
1997	N/A	N/A	N/A
1998	N/A	N/A	N/A
1999	N/A	N/A	N/A
Forecast:			
2000	N/A	N/A	N/A
2001	N/A	N/A	N/A
2002	18.74	66.946	N/A
2003	18.98	67.778	1.2
2004	19.21	68.622	1.2
2005	19.45	69.477	1.2
2006	19.70	70.344	1.2
2007	19.94	71.224	1.3
2008	20.19	72.115	1.3
2009	20.45	73.020	1.3

Sulfur %	Ash %	Btu/lb
< 8%	< 1%	14,000