State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

110000-OT

DATE: May 4, 2011

TO: Ann Cole, Commission Clerk, Office of Commission Clerk

FROM: Phillip O. Ellis, Engineering Specialist II, Division of Regulatory Analysis POE
Traci L. Matthews, Government Analyst I, Division of Regulatory Analysis

RE: JEA's Response to 2011 Ten-Year Site Plan Supplemental Data Request #1

Attached is JEA's Response to 2011 Ten-Year Site Plan Supplemental Data Request #1, submitted by April 29, 2011. Please place this item in Docket No. 110000 – Undocketed Filings for 2011, as it relates to the annual undocketed staff Ten-Year Site Plan Review project.

If you have any additional questions, please contact me.

POE

Attachment

DOCUMENT NUMBER-DATE
03138 MAY-5 =
FPSC-COMMISSION CLERK

2011 TEN YEAR SITE PLANS : SUPPLEMENTAL DATA REQUEST

Company Name: **JEA**

Renewable Generation Resources

As used in the proceeding questions, the term "renewable energy" has the same meaning as used in Section 377.803, Florida Statutes. Please refer to the tables below when identifying fuel and generator types.

Fuel Types	Shorthand	Examples
Biomass	AB	Agriculture By-Products, Bagasse, Straw, Energy Crops.
	MSW	Municipal Solid Waste
	SLW	Sludge Waste.
	WDS	Wood / Wood Waste Solids
	OBS	Biomass Solids
Landfill Gas	LFG	Landfill gas.
Water	WAT	Hydro
Geothermal	GEO	Geothermal
Biofuels	WDL	Wood / Wood Waste Liquids
	BL	Black Liquor
	OBL	Biomass Liquids
	OBG	Biomass Gases
Solar	SUN	Solar Photovoltaic and Thermal devices
Waste Heat	WH	Waste heat from sulfuric acid manufacture
Wind	WND	Wind Energy.
Other	OTH	Any renewable not covered above. Please describe.

Generation Types	Shorthand
Combined Cycle - Steam Part	CA
Combined Cycle - Combustion Turbine Part	CT
Combined Cycle - Total Unit	CC
Compressed Air Energy Storage	CE
Combined Cycle Single Shaft	CS
Fuel Cell	FC
Combustion Turbine	GT
Hydraulic Turbine	HY
Hydraulic Turbine - Pumped Storage	PS
Internal Combustion Engine	IC
Not Available	NA
Other	OT
Photovoltaic Cells	PV
Steam Turbine	ST
Wind Turbine	WT

GENERAL QUESTIONS

1. Please provide all data requested in the attached forms labeled 'Appendix A,' in electronic (Excel) and hard copy. If any of the requested data is already included in the Company's Ten-Year Site Plan, state so on the appropriate form.

2. Please provide all data requested in the attached forms labeled 'Appendix B,' which consist of Schedules 1 through 10 from the Company's Ten-Year Site Plan, in an electronic copy in Excel (.xls file format).

LOAD & DEMAND FORECASTING

3. **Please provide, on a system-wide basis, an average month of observed peak capacity values for Summer and Winter. From this data, excluding weekends and holidays, generate an average seasonal Daily Loading Curve. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.**

See excel spreadsheet.

4. **Please provide, on a system-wide basis, historical annual heating degree day (HDD) and cooling degree day (CDD) data for the period 2001 through 2010 and forecasted annual HDD and CDD data for the period 2011 through 2020. Describe how the Company derives system-wide temperature if more than one weather station is used. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.**

Only one weather station is used to derive system-wide temperature. HDD data and CDD data are shown in the table below.

Year		HDD	CDD
Actual	2001	1213	2537
	2002	1333	2872
	2003	1432	2616
	2004	1427	2834
	2005	1342	2682
	2006	1170	2742
	2007	1128	2662
	2008	1369	2499
	2009	1347	2797
	2010	1988	2835
Projected	2011	1375	2707
	2012	1375	2707
	2013	1375	2707
	2014	1375	2707
	2015	1375	2707
	2016	1375	2707
	2017	1375	2707
	2018	1375	2707
	2019	1375	2707
	2020	1375	2707

5. **Please provide the following data to support Schedule 4 of the Company 's Ten-Year Site Plan: the 12 monthly peak demands for the years 2008, 2009, and 2010; the date when these monthly peaks occurred; and, the temperature at the time of these monthly peaks. Describe how the Company derives system-wide temperature**

if more than one weather station is used. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Only one weather station is used. Monthly peak demands, date of occurrence, and temperature associated with the peak are shown in the table below.

Year	Month	Peak Demand (MW)	Date	Day of Week	Hour	Temperature (F)
2008	1	2914	3	Thursday	8	25
	2	2484	14	Thursday	8	29
	3	2059	25	Tuesday	8	34
	4	2017	12	Saturday	17	89
	5	2363	21	Wednesday	18	89
	6	2694	9	Monday	17	93
	7	2732	21	Monday	16	95
	8	2866	7	Thursday	16	96
	9	2647	15	Monday	17	92
	10	2263	1	Wednesday	17	87
	11	2310	19	Wednesday	8	28
	12	2473	3	Wednesday	8	29
2009	1	3060	22	Thursday	8	21
	2	3064	6	Friday	8	23
	3	2476	4	Wednesday	8	29
	4	2048	24	Friday	17	89
	5	2451	11	Monday	17	94
	6	2754	22	Monday	16	98
	7	2628	2	Thursday	17	95
	8	2735	12	Wednesday	17	95
	9	2417	25	Friday	17	89
	10	2423	9	Friday	16	93
	11	1710	10	Tuesday	13	82
	12	2151	29	Tuesday	8	31
2010	1	3224	11	Monday	8	20
	2	2667	26	Friday	8	27
	3	2335	4	Thursday	8	32
	4	2016	23	Friday	18	87
	5	2368	3	Monday	17	93
	6	2817	15	Tuesday	17	102
	7	2749	27	Tuesday	16	99
	8	2731	18	Wednesday	17	96
	9	2595	10	Friday	17	95
	10	2199	28	Thursday	17	89
	11	1785	8	Monday	8	33
	12	3053	14	Tuesday	8	20

6. Please discuss any recent trends in customer growth, by customer type (residential, industrial & commercial, etc), and as a whole. Please explain the nature or reason for these trends, and identify what types of customers are most affected by these trends. (For example, is a decline in customers a loss of temporary construction meters or a decline in population?)

During 2003 and 2004, JEA's service territory experienced a level of new development that was significantly higher than average annual development. This fostered a greater amount of construction labor in the area and subsequently greater need for residential and commercial development to support the construction industry employees. Due to the downturn of construction, many construction laborers have migrated out of the area. This has resulted in a decrease in population and thus demand. In addition, home foreclosures have caused a migration of customers from larger demand houses to smaller demand apartments. Within past year, however, there is a significant improvement in the residential sector. Due to the large number of foreclosures, prices for the local homes have been driven down to a more affordable range; hence, emptied larger demand homes are slowly being occupied, both by customers migrating from the smaller demand apartments and new customers from outside JEA's service territory.

As a whole, JEA experienced an average annual growth rate of 2% in sales and 2.29% in customer accounts from 2001-2006. However, the use per customer during the same period decreased 0.28%. From 2007-2009, the overall sales decreased 1.95%, customer accounts increased 0.60%, and use per customer decreased 2.54%. Within the past year, the overall sales increased by 4.81%, customer account increased by 0.43%, and average use per customer increased by 4.36%.

The residential sector experienced an average annual growth rate of approximately 2.91% in sales, 2.26% in customer accounts, and 0.64% in use per customer from 2001-2006. From 2007-2009, residential sales decreased 1.64% and use per customer decreased 2.12%. However, the numbers of customer accounts increased 0.49%. Within the past year, the sales increased by 8.45%, customer account increased by 0.32%, and average use per customer increased by 8.10%.

The commercial and industrial sectors experienced an average annual growth rate of approximately 1.29% in sales, 2.56% in customer accounts, and -1.23% in use per customer from 2001-2006. From 2007-2009, commercial and industrial sales decreased 2.20%, customer accounts increased 1.53%, and use per customer decreased 3.67%. Within the past year, the sales increased by 1.99%, customer account increased by 1.32%, and average use per customer increased by 0.66%.

7. **Please discuss any impacts of "smart" or digital meter installations on forecasting sales and net energy for load. Please explain the nature or reason for these trends, and identify what types of customers are most affected by these trends. (For example, are increased sales due to more accurate measurement of low-load conditions?)**

JEA has formed a Smart Grid Steering committee that will provide direction and oversight for the implementation of Smart Grid initiatives and will insure the success of the DOE Smart Grid program scope. For the next three years, the focus of JEA's Smart Grid program is to deploy a customer facing energy management program. The program will enable JEA residential customers to become partners with JEA in the daily management of their energy consumption. JEA will enhance existing systems and processes, integrate them into a cohesive effort, and provide a measured outcome that will help drive future Smart Grid efforts.

The expectations of the Smart Grid program are to implement or upgrade the Consumer Engagement Software (Energy Portal) system, Meter Data Management System (MDMS), Network Metering Infrastructure (2-way network, NMR), Field Management System (FMS) and Outage Management System (OMS), and Remote Connect and Disconnect and pre-pay function.

The energy portal is the central focus of the Smart Grid effort. This is the customer interface that will allow JEA to interact with their residential customers in a way that will enable them to become partners in managing their energy. The full deployment of the pilot Energy Portal is expected to allow the collection of hourly electric consumption data up dated every two hours and monthly water consumption data up dated monthly.

RENEWABLE GENERATION

8. **Please provide the estimated total capacity of all renewable resources the utility owns or purchases as of January 1, 2011. Include in this value the sum of all utility-owned, and purchased power contracts (firm and non-firm), and purchases from as-available energy producers (net-metering, self-generators, etc.). Please also include the estimated total capacity of all renewable resources (firm and non-firm) the utility is anticipated to own or purchase as of the end of the planning period in 2020.**

Fuel Type	Renewable Resource Capacity (MW)	
	Existing	Planned
Solar	15.6	0.0
Wind	10.0	0.0
Biomass	0.0	0.5
Municipal Solid Waste	0.0	0.0
Waste Heat	0.0	0.0
Landfill Gas	15.1	9.6
Hydro	0.0	0.0
Total	40.7	10.1

9. **Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement as of January 1, 2011. For both utility-owned and purchased resources, please divide them into Firm and Non-Firm categories as shown below. Please also include those renewable resources which provide fuel to conventional facilities, if applicable, with estimates of their capacity and energy contributions. As part of this response, please include the description of the unit's generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. For purchased power agreements, also provide the contract start and end dates. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.**

Solar: JEA has installed 35 solar PV systems, totaling approximately 220 kW, on public high schools, a local college and university in Duval County, as well as many of JEA's facilities, the Jacksonville Zoo and the Jacksonville International Airport (one of the largest solar PV systems in the Southeast).

JEA signed a purchase power agreement with Jacksonville Solar, LLC in May 2009 to provide energy from a 15.0 MW DC rated solar farm which was declared full commercial operation on September 30, 2010. The facility is located in western Duval County and consists of approximately 200,000 photovoltaic panels on a 100 acre site and generates about 22,340 megawatt-hours (MWh) of electricity per year.

Landfill Gas and Biogas: JEA owns three internal combustion engine generators located at the City of Jacksonville's Girvin Road landfill. This facility was placed into service in July 1997, and is fueled by the methane gas produced by the landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, gas generation has declined and one generator was removed and placed into service at the Buckman Wastewater Treatment facility. The JEA Buckman Wastewater Treatment Plant previously dewatered and incinerated the sludge from the treatment process and disposed of the ash in a landfill. The current facility manages the sludge using two anaerobic digesters and a sludge dryer to produce a fertilizer pellet product. The methane gas from the digesters is used, as a fuel, for the sludge dryer and for the relocated on-site 800 kW generator. JEA also receives approximately landfill gas from the City of Jacksonville's closed North Landfill, which is piped to the Northside Generating Station and is used to generate power at Northside Unit 3.

JEA has under contract, through a PPA, energy produced from Landfill Energy System's 9.6 MW Trail Ridge landfill gas-to-energy facility, which is located in west Duval County.

Wind: JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) in 2004 to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive environmental credits associated with this green power project. Under the wind generation agreement, JEA purchases 10 MW of capacity from NPPD's wind generation facility. In turn, NPPD buys back the energy at specified on/off peak charges. JEA retains the rights to the environmental attributes.

Existing Renewables as of January 1, 2011

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
			(MM/YYYY)	Sum	Win	(MWh)	(%)
North *	IC	LFG	1997			1,513	
Girvin	IC	LFG	1999	1200	1200	2,932	28%

* Landfill gas fuel contribution only. LFG burned in an existing conventional unit.

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
			(MM/YYYY)	Sum	Win	(MWh)	(%)
Buckman	IC	OBG	2003	800	800	137	1.95%
Solar	SUN	PV	1999/2000/2001/2002/2003			181	

Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
			(MM/YYYY)	Sum	Win	(MWh)	(%)		(%)
Trail Ridge I	IC	LFG	12/2009	9100	9100	74,915	94%	12/2008	12/2018
Jacksonville Solar	SUN	PV	09/2010			11,812		09/2010	09/2040

Non-Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
			(MM/YYYY)	Sum	Win	(MWh)	(%)	(%)	(%)

10. **Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement planned during the 2011 through 2020 period. For both utility-owned and purchased resources, please divide them into Firm and Non-Firm categories as shown below. Please also include those renewable resources which provide fuel to conventional facilities, if applicable, with estimates of their capacity and energy contributions. As part of this response, please include the description of the unit's generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. For purchased power agreements, also provide the contract start and end dates. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.**

At this time, there is no planned utility-owned renewable resource additions with an in-service date during the 2011 through 2020 period. JEA has under contract, through a PPA, energy produced from Landfill Energy System's 9.6 MW Trail Ridge landfill gas-to-energy facility which is located in west Duval County. An amendment to this PPA was signed in March 2011 to provide for the development and operation of up to 9.6 MWs of additional electric generating capacity at the Trail Ridge Landfill which is anticipated to commence commercial operation in 2011/2012.

Planned Renewables for 2011 through 2020

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
			(MM/YYYY)	Sum	Win	(MWh)	(%)

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
			(MM/YYYY)	Sum	Win	(MWh)	(%)

Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
			(MM/YYYY)	Sum	Win	(MWh)			(%)
Trail Ridge II	IC	LFG	2011/2012	9100	9100	75,490	95%	12/2011	12/2026

Non-Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
			(MM/YYYY)	Sum	Win	(MWh)	(%)	(%)	(%)

11. **Please refer to the list of planned utility-owned renewable resource additions with an in-service date for the renewable generator during the 2011 through 2020 period outlined above. Please discuss the current status of each project.**

    At this time, there is no planned utility-owned renewable resource additions planned with an in-service date during the 2011 through 2020 period.

12. **Please refer to the list of existing or planned renewable PPAs with an in-service date for the renewable generator during the 2011 through 2020 period outlined above. Please discuss the current status of each project.**

    At this time, there is no planned utility-owned renewable resource additions planned with an in-service date during the 2011 through 2020 period. JEA has under contract, through a PPA, energy produced from Landfill Energy System's 9.6 MW Trail Ridge landfill gas-to-energy facility which is located in west Duval County. An amendment to this PPA was signed in March 2011 to provide for the development and operation of up to 9.6 MWs of additional electric generating capacity at the Trail Ridge Landfill which is anticipated to commence commercial operation in 2011/2012.

13. **Please provide a description of each renewable facility in the company's service territory that it does not currently have a PPA with, including self-service facilities. As part of this response, please include the description of the unit's location, generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. Please exclude from this**

response small customer-owned renewable resources, such as rooftop PV, which are more appropriately included in the following question. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.

There are no renewable facilities in the JEA service territory that does not have a PPA with JEA.

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
			(MM/YYYY)	Sum	Win	(MWh)	(%)
None							

14. **Please provide the number of customer-owned renewable resources within the Company's service territory. Please organize by resource type, and include total estimated installed capacity and annual output. Please exclude from this response any customer-owned renewable resources already accounted for under PPAs or other sources. If renewable energy types beyond those listed were utilized, please include an additional row and a description of the renewable fuel and generator. For non-electricity generating renewable energy systems, such as geothermal cooling and solar hot water heaters, please use kilowatt-equivalent and kilowatt-hour-equivalent units. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.**

Customer Class	Renewable Type	# of Connections	Installed Capacity (kW)	Annual Output (kWh)
Residential	Solar Photovoltaic	55.00	257.89	*
Residential	Solar Thermal Water Heating	815.00	2,463.00	*
Residential	Geothermal Heat Pump	0.00	0.00	0.00
Residential	Wind Turbine	0.00	0.00	0.00
Residential	Other (Describe)	0.00	0.00	0.00
Commercial	Solar Photovoltaic	11.00	142.11	*
Commercial	Solar Thermal Water Heating	0.00	0.00	0.00
Commercial	Geothermal Heat Pump	0.00	0.00	0.00
Commercial	Wind Turbine	1.00	3.60	*
Commercial	Other (Describe)	0.00	0.00	0.00

* Net Metered Customers - Customer's system not metered by JEA; data available for kWh sent to JEA from customer

15. Please provide the annual output for the company's renewable resources (owned and purchased through PPA), retail sales, and the net energy for load for the period 2010 through 2020. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

Annual Output (GWh)		Actual	Projected									
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Renewable Generation	Utility	4.8										
	PPA	86.7	158.4	177.8	177.2	177.1	176.9	177.4	176.7	150.4	98.1	98.4
	Total	91.5	158.4	177.8	177.2	177.1	176.9	177.4	176.7	150.4	98.1	98.4
Retail Sales		13,198	13,753	13,945	14,070	14,229	14,388	14,591	14,725	14,892	15,060	15,264
Net Energy for Load		13,842	14,424	14,625	14,757	14,923	15,090	15,303	15,443	15,619	15,795	16,009

16. Provide, on a system-wide basis, the historical annual average as-available energy rate in the Company's service territory for the period 2001 through 2010. Also, provide the forecasted annual average as-available energy rate in the Company's service territory for the period 2011 through 2020. Please use the Consumer Price Index to calculate real as-available energy rates. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year	As-Available Energy ($/MWh)		CPI
	Real	Nominal	
2010	18.90	41.15	218
2011	19.22	42.90	223
2012	21.68	49.60	229
2013	21.02	49.30	235
2014	21.84	52.50	240
2015	25.16	62.00	246
2016			253
2017			259
2018			265
2019			272
2020			279

17. Please discuss any studies conducted or planned regarding the use combinations of renewable and fossil fuels in existing or future fossil units. What potential does the Company identify in this area?

JEA conducted a detailed feasibility study of both self-build stand-alone biomass units and the co-firing of biomass in JEA's Northside 1 and 2 circulating fluidized bed units in

2008. Northside 1 and 2 have historically been two of JEA's least cost units, therefore any decreases in reliability due to the co-firing of alternative for Northside 1 and 2 would result in increases in costs to JEA's customers due to the higher costs of replacement power. The study data have been and will continue to be utilized to evaluate any future biomass PPA proposals.

In 2009 and 2010, JEA conducted analytical and technical evaluations for specific biomass fuel types and the utility's wastewater treatment facility's bio-solids to determine the possibility of conducting a co-firing test in Northside 1 or 2. Based on the evaluation, it was determined not to pursue a test at this time utilizing the utility's wastewater treatment facility's bio-solids.

As part of the assessment, JEA evaluated co-firing of biomass consisting of woodchips from tree trimming activities within the JEA territory in the Northside 1 or 2. JEA is in the process of requesting the authorization to co-fire up to 12 tons of the biomass consisting of woodchips from tree trimming activities.

18. **Please discuss any planned renewable generation or renewable purchased power agreements within the past 5 years that did not materialize. What was the primary reason these generation plans or purchased power contracts were not realized? What, if any, were the secondary reasons?**

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

In 2009, JEA received an unsolicited proposal for a 50 MW developer PPA for renewable energy generated by biomass. JEA and the biomass generation provider signed a "Letter of Intent" to pursue a PPA which expired on December 31, 2009 due to regulatory uncertainties and associated energy costs.

19. Please discuss whether the company purchases or sells Renewable Energy Credits. As part of this response, please discuss whether the company offers the sale of Renewable Energy Credits to its customers through a green pricing or similar program.

At this time, JEA does not have any contracts to sell Renewable Energy Credits (RECs). JEA had a contract through 2008 for the sale of RECs received from a PPA associated with "out –of-state" wind energy. In addition, JEA does not offer a green pricing program or similar program for the sale of RECs to customers.

TRADITIONAL GENERATION

20. **Please provide the cumulative present worth revenue requirement of the Company's Base Case for the 2011 Ten-Year Site Plan. If available, please provide the cumulative present worth revenue requirement for any sensitivities conducted of the Company's generation expansion plan.**

Year	Base Case Resource Plan[1] [2]	Present Worth Rev. Req. 2011 Million $	
		Annual	Cumulative
2011	Build 2 - 7FA CTs at GEC (177 MW each)	734,722	734,722
2012	Trailridge II Purchase (9 MW)	723,944	1,458,666
2013		720,636	2,179,302
2014		749,982	2,929,285
2015		741,706	3,670,991
2016	MEAG Plant Vogtle Purchase (100 MW) [3]	772,384	4,443,375
2017	MEAG Plant Vogtle Purchase (100 MW) [3] SJRPP Sale to FPL Suspended (383 MW) [4]	798,329	5,241,704
2018	Trailridge I Contract Expires (9 MW)	802,268	6,043,973
2019		806,773	6,850,746
2020		829,205	7,679,952

Notes:

(1) Seasonal purchases may be required in operating horizon in years 2013-2016.
(2) Cumulative DSM addition of 89 MW Winter and Summer by 2020.
(3) After accounting for transmission losses, JEA is anticipating to receive a total of 200 MW of net firm capacity from the proposed units.
(4) SJRPP Sales return projected in March 2017.

21. **Please illustrate what the Company's generation expansion plan would be as a result of sensitivities to the base case demand. Include impacts on unit in-service dates for any possible delays, cancellations, accelerated completion, or new additions as a result.**

N/A

22. **Please complete the following table detailing planned unit additions, including information on capacity and in-service dates. Please include only planned conventional units with an in-service date past January 1, 2011, and including nuclear units, nuclear unit up rates, combustion turbines, and combined-cycle units. For each planned unit, provide the date of the Commission's Determination**

of Need and Power Plant Siting Act certification (if applicable), and the anticipated in-service date.

Planned Unit Additions for 2011 through 2020

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions / Uprates				
Combustion Turbine Unit Additions				
Greenland Energy Center CT1	142	N/A	N/A	June 2011
Greenland Energy Center CT2	142	N/A	N/A	June 2011
Combined Cycle Unit Additions				
Steam Turbine Unit Additions				

23. **For each of the generating units contained in the Company's Ten-Year Site Plan, please discuss the 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, and final decision point.**

By the due date of this report both units will have passed their substantial completion date. Both units are scheduled to be released for commercial operation on or before June 1, 2011.

24. **Please complete the following table detailing unit specific information on capacity and fuel consumption for 2010. For each unit on the Company's system, provide the following data based upon historic data from 2010: the unit's capacity; annual generation; resulting capacity factor; estimated annual availability factor; unit average heat rate; quantity of fuel burned; average cost of fuel; and resulting average energy cost for the unit's production. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.**

Plant	Unit #	Unit Type	Fuel Type	Nameplate Capacity	Net Capacity (MW)		Annual Generation	Capacity Factor	Availability Factor	In-Service Date
				(MW)	Sum	Win	(MWh)	(%)	(%)	
Kennedy	CT 7	GT	NG/FO2	203.8	150.0	191.0	36,771	2.3%	99.0%	6/2000
Kennedy	CT 8	GT	NG/FO2	203.8	150.0	191.0	96,089	5.8%	97.9%	6/2009
Northside	1	ST	PC/BIT	350.0	293.0	293.0	1,800,519	73.0%	97.1%	2003
Northside	2	ST	PC/BIT	350.0	293.0	293.0	1,891,526	75.9%	95.3%	2002
Northside	3	ST	NG/FO6	563.7	524.0	524.0	640,163	14.4%	77.4%	7/1977
Northside	CT 3	GT	FO2	248.4	53.0	61.5	1,214	0.3%	85.4%	1/1975
Northside	CT 4	GT	FO2	248.4	53.0	61.5	1,174	0.3%	99.2%	1/1975
Northside	CT 5	GT	FO2	248.4	53.0	61.5	524	0.1%	99.7%	1/1975
Northside	CT 6	GT	FO2	248.4	53.0	61.5	1,108	0.3%	99.7%	1/1975
Brandy Branch	CT 1	GT	NG/FO2	203.8	150.0	191.0	31,335	2.0%	98.9%	5/2001
Brandy Branch	CT 2	CT	NG/FO2	203.8	501.0	605.0	2,248,921	42.1%	90.9%	5/2001
Brandy Branch	CT 3	CT	NG/FO2	203.8				43.9%	91.4%	5/2001
Brandy Branch	4	CA	WH	268.4				54.4%	91.3%	1/2005
Girvin Landfill	1-2	IC	NG	1.2	1.2	1.2	2,892	12.3%		6/1997
St. Johns River Power Park	1	ST	BIT/PC	679.6	313.0	319.0	2,272,185	82.2%	96.0%	3/1987
St. Johns River Power Park	2	ST	BIT/PC	679.6	313.0	319.0	2,092,239	75.7%	88.6%	5/1988
Scherer	4	ST	SUB/BIT	846.0	200.0	200.0	1,288,131	73.5%	78.0%	2/1989

Plant	Unit #	Fuel Type	Heat Rate	Total Fuel Burned	Total Fuel Cost	Unit Fuel Cost	
			(BTU/kWh)	(MMBTU)	($000)	($/MMBTU)	(¢/kWh)
Kennedy	CT 7	GT	12,568	462,123	4,093,862	8.86	11.13
Kennedy	CT 8	GT	11,672	1,121,514	9,682,122	8.63	10.08
Northside	1	ST	9,647	17,370,009	61,609,159	3.55	3.42
Northside	2	ST	9,611	18,179,851	64,723,182	3.56	3.42
Northside	3	ST	11,926	7,634,756	60,833,288	7.97	9.50
Northside	CT 3	GT	19,605	23,805	277,673	11.66	22.87
Northside	CT 4	GT	20,863	24,491	268,449	10.96	22.87
Northside	CT 5	GT	17,632	9,231	119,722	12.97	22.87
Northside	CT 6	GT	20,431	22,642	253,439	11.19	22.87
Brandy Branch	CT 1	GT	12,376	387,817	3,162,022	8.15	10.09
Brandy Branch	CT 2	CT	7,302	16,421,758	147,108,370	8.96	6.54
Brandy Branch	CT 3	CT					
Brandy Branch	4	CA					
Girvin Landfill	1-2	IC	16,129	46,645			
St. Johns River Power Park	1	ST	9,927	22,556,117	75,389,626	3.34	3.32
St. Johns River Power Park	2	ST	9,887	20,685,325	69,419,104	3.36	3.32
Scherer	4	ST	10,151	13,076,248	30,967,837	2.37	2.40

25. **For each unit on the Company's system, provide the following data based upon historic data from 2010 and forecasted capacity factor values for the period 2011 through 2020. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.**

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Kennedy	CT 7	GT	NG/FO2	2.3%	6.5%	4.4%	4.3%	7.6%	4.0%	6.4%	3.4%	1.6%	0.8%	3.6%
Kennedy	CT 8	GT	NG/FO2	5.8%	4.7%	2.9%	2.5%	5.0%	2.3%	4.1%	2.2%	1.0%	0.3%	2.6%
Northside	1	ST	PC/BIT	73.0%	66.4%	75.3%	78.2%	79.7%	68.7%	69.7%	75.3%	76.3%	78.0%	81.4%
Northside	2	ST	PC/BIT	75.9%	73.8%	75.6%	75.1%	78.7%	77.9%	74.5%	74.9%	75.4%	78.9%	80.4%
Northside	3	ST	NG/FO6	14.4%	36.5%	28.1%	30.9%	36.8%	31.0%	29.7%	22.6%	16.0%	17.8%	20.0%
Northside	CT 3	GT	FO2	0.3%	1.8%	1.2%	0.9%	2.2%	0.9%	1.7%	0.6%	0.4%	0.1%	0.9%
Northside	CT 4	GT	FO2	0.3%	1.4%	1.0%	0.7%	2.2%	0.7%	1.4%	0.4%	0.3%	0.1%	0.8%
Northside	CT 5	GT	FO2	0.1%	1.2%	0.9%	0.6%	2.0%	0.6%	1.2%	0.4%	0.2%	0.0%	0.6%
Northside	CT 6	GT	FO2	0.3%	1.0%	0.7%	0.3%	1.7%	0.4%	1.0%	0.2%	0.2%	0.0%	0.4%
Brandy Branch	CT 1	GT	NG/FO2	2.0%	14.1%	11.5%	10.5%	13.6%	12.2%	14.6%	6.8%	4.6%	4.0%	8.1%
Brandy Branch	CT 2	CT	NG/FO2	42.1%										
Brandy Branch	CT 3	CT	NG/FO2	43.9%	80.1%	87.4%	85.8%	76.3%	89.2%	84.3%	60.0%	57.6%	50.3%	48.1%
Brandy Branch	4	CA	WH	54.4%										
SJRPP	1	ST	BIT/PC	82.2%	64.4%	71.7%	61.3%	67.7%	60.6%	63.3%	57.7%	64.0%	60.3%	74.0%
SJRPP	2	ST	BIT/PC	75.7%	62.8%	60.9%	61.5%	55.8%	74.7%	58.4%	44.8%	53.6%	60.9%	51.0%
Scherer	4	ST	SUB/BIT	73.5%	86.3%	75.1%	97.6%	87.6%	96.9%	87.1%	92.8%	83.7%	94.0%	73.1%
GEC	CT 1	GT	NG/FO2	N/A	14.4%	11.4%	10.8%	17.2%	10.6%	14.1%	7.8%	5.1%	4.6%	8.3%
GEC	CT 2	GT	NG/FO2	N/A	8.5%	7.0%	6.6%	11.2%	6.7%	8.3%	5.0%	2.6%	2.0%	5.2%

26. **Please complete the table below, providing a list of all of the Company's steam units or combustion turbines that are candidates for repowering. As part of this response, please provide the unit's fuel and unit type, summer capacity rating, in-service date, and what potential conversion/repowering would be most applicable. Also include a description of any major obstacles that could affect repowering efforts at any of these sites, such as unit age, land availability, or other requirements.**

The 7 FA CTs (Brandy Branch CT 1, Kennedy CT 7, Kennedy CT 8, GEC CT1, and GEC CT 2) and steam units (Northside 3, SJRPP 1, and SJRPP 2) are capable of repowering into combined cycle configurations. Brandy Branch Generating Station currently holds a 2x1 Combined Cycle configuration with CTs 2 and 3. Brandy Branch

CT 1 is capable of a 1x1 conversion. Likewise, Kennedy CTs 7 & 8 and GEC CTs 1 & 2 could each convert to a 1x1 configuration or both CTs at each station convert to a single 2x1 configuration similar to the Brandy Branch Combined Cycle unit.

Some of the obstacles common to CT and steam unit conversions are site space, transmission, switchyard, cooling water, gas supply, and gas infrastructure. An added challenge for steam unit conversions is unit size. The conversion of 524 MWs of Northside 3, for example, would result in a unit greater than 1000 MW of capacity, approximately one-third of the size of JEA. Conversion of an SJRPP unit to combined-cycle would result in a unit size greater than 1400 MW. Either of these would result in significant transmission, reserve margin, and operational issues for JEA.

Plant Name	Fuel & Unit Type	Summer Capacity (MW)	In-Service Date	Potential Conversion Type
Northside 3	NG/FO6 - ST	524	7/1977	Combined Cycle
SJRPP 1	BIT/PC - ST	313	3/1987	Combined Cycle
SJRPP 2	BIT/PC - ST	313	5/1988	Combined Cycle
Kennedy CT 7	NG/FO2 - GT	150	6/2000	Combined Cycle
Brandy Branch CT 1	NG/FO2 - GT	150	5/2001	Combined Cycle
Kennedy CT 8	NG/FO2 - GT	150	6/2009	Combined Cycle
GEC CT 1	NG/FO2 - GT	142	6/2011	Combined Cycle
GEC CT 2	NG/FO2 - GT	142	6/2011	Combined Cycle

27. **Please complete the table below, in electronic (Excel) and hard copy, regarding the Company's generation fleet and the typical use of each unit. Please identify capacity type as either Baseload, Intermediate, or Peaking, and group units by their capacity type. Please use the abbreviations for fuel and generation facilities from the FRCC Load and Resource Plan for the table below. (For example, a combustion turbine that is not part of a combined cycle unit is identified with generator code "GT.") Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.**

Existing Facilities as of January 1, 2011

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor (1)	Capacity Type	Summer Capacity
Northside	1	ST	BIT/PC	72.8%	Baseload	293
Northside	2	ST	BIT/PC	70.3%	Baseload	293
SJRPP	1	ST	BIT	78.0%	Baseload	319
SJRPP	2	ST	BIT	78.4%	Baseload	319
Scherer	4	ST	SUB	81.1%	Baseload	194
				Sub-Total	**Baseload**	**1418**
Brandy Branch	4	CC	NG	41.1%	Intermediate	501
Northside	3	ST	NG/F06	15.5%	Intermediate	524
				Sub-Total	**Intermediate**	**1025**
Brandy Branch	CT 1	GT	NG/FO2	1.3%	Peaking	150
Brandy Branch	CT 2	CT	NG/FO2	31.1%	Peaking	150
Brandy Branch	CT 3	CT	NG/FO2	16.7%	Peaking	150
Kennedy	CT 7	GT	NG/FO2	2.2%	Peaking	150
Kennedy	CT 8	GT	NG/FO2	1.9%	Peaking	150
Northside	CT 3	GT	FO2	0.4%	Peaking	53
Northside	CT 4	GT	FO2	0.4%	Peaking	53
Northside	CT 5	GT	FO2	0.3%	Peaking	53
Northside	CT 6	GT	FO2	0.6%	Peaking	53
				Sub-Total	**Peaking**	**962**
					Total	**3405**

Planned Facilities During 2011 to 2020

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor (2)	Capacity Type	Summer Capacity
				(%)		(MW)
				Sub-Total	**Baseload**	
				Sub-Total	**Intermediate**	
Greenland Energy Center	CT 1	GT	NG/FO2	10.4%	Peaking	142
Greenland Energy Center	CT 2	GT	NG/FO2	6.3%	Peaking	142
				Sub-Total	**Peaking**	**284**
					Total	**284**

Notes:

(1) Historical three year average capacity factor.
(2) Average capacity factor over the years 2011-2020.

28. **Please complete the table below regarding the system's installed capacity, categorized by capacity type, for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.**

Data in the table below represents summer capacity (MW), 50% interest in SJRPP after sale to FPL, and the sale to FPL projected to return to JEA in 2017. The data also does not include any firm power purchases.

Year		Baseload Capacity	Intermediate Capacity	Peaking Capacity	Total Installed Capacity
Actual	2001	823	767	524	2,114
	2002	823	505	1,001	2,329
	2003	1,371	505	1,001	2,877
	2004	1,371	505	1,001	2,877
	2005	1,371	1,038	683	3,092
	2006	1,389	1,038	581	3,008
	2007	1,407	1,025	563	2,995
	2008	1,407	1,025	563	2,995
	2009	1,407	1,025	662	3,094
	2010	1,407	1,025	662	3,094
Projected	2011	1,407	1,025	662	3,094
	2012	1,407	1,025	847	3,280
	2013	1,407	1,025	847	3,280
	2014	1,407	1,025	847	3,280
	2015	1,407	1,025	847	3,280
	2016	1,407	1,025	847	3,280
	2017	1,783	1,025	847	3,656
	2018	1,782	1,025	847	3,654
	2019	1,782	1,025	847	3,654
	2020	1,782	1,025	847	3,654

Notes:

(a) Summer Capacity (MW).

(b) Included in baseload capacity is 50% interest in SJRPP after sale to FPL. Sale from FPL is projected to return to JEA in 2017.

(c) Does not include firm power purchases.

29. Please provide the system average heat rate for the generation fleet for each year for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year		System Average Heat Rate (BTU/kWh)
Actual	2001	9,924
	2002	10,360
	2003	10,103
	2004	10,132
	2005	9,886
	2006	9,727
	2007	9,789
	2008	9,975
	2009	9,735
	2010	9,562
Projected	2011	9,184
	2012	9,125
	2013	9,160
	2014	9,246
	2015	9,169
	2016	9,163
	2017	9,398
	2018	9,395
	2019	9,457
	2020	9,442

30. **Please provide the average cost of a residential customer bill, based upon a monthly usage of 1200 kilowatt-hours, in nominal and real dollars for the period 2001 through 2020. Please use the Consumer Price Index to calculate real residential bill values. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.**

Year		Residential Bill ($/1200-kWh)		CPI
		Real	Nominal	
Actual	2001	45.56	80.68	177
	2002	44.85	80.68	180
	2003	43.86	80.68	184
	2004	42.71	80.68	189
	2005	43.77	85.48	195
	2006	52.52	105.88	202
	2007	50.59	104.90	207
	2008	52.96	114.02	215
	2009	64.59	138.23	214
	2010	60.38	131.45	218
Projected	2011	64.08	143.02	223
	2012	62.51	143.02	229
	2013	60.99	143.02	235
	2014	59.49	143.02	240
	2015	58.04	143.02	246
	2016	56.64	143.02	253
	2017	55.27	143.02	259
	2018	53.93	143.02	265
	2019	52.61	143.02	272
	2020	51.33	143.02	279

POWER PURCHASES / SALES

31. Please identify each of the Company's existing and planned power purchase contracts, including firm capacity imports reflected in Schedule 7 of the Company's Ten-Year Site Plan. Provide the seller, capacity, associated energy, and term of each purchase, and provide unit information if a unit power purchase. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Existing Purchased Power Agreements as of January 1, 2011

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	

Planned Purchased Power Agreements for 2011 through 2020

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
MEAG	1/1/2016	1/1/2036	100	100	821	94%	NUC	PPA
MEAG	1/1/2017	1/1/2037	100	100	821	94%	NUC	PPA

32. Please identify each of the Company's existing and planned power sales, including firm capacity exports reflected in Schedule 7 of the Company's Ten-Year Site Plan. Provide the purchaser, capacity, associated energy, and term of each purchase, and provide unit information if a unit power sale. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Existing Power Sales as of January 1, 2011

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
FPL	1986	2022 *	188	192	1,543	92%	BIT	PPA
FPL	1987	2022 *	188	192	1,459	87%	BIT	PPA

* Not to exceed date. Projected early suspension of 2017.

Planned Power Sales for 2011 through 2020

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	

33. Please discuss and identify the impacts on the Company's capacity needs of all known firm power purchases and sales over the planning horizon. As part of this discussion, please include whether options to extend purchases or sales exist, and the potential effects of expiration of these purchase or sales.

JEA has evaluated future supply capacity needs for the electric system based on the peak demand/energy forecasts and existing/committed supply resources and contracts. Under a base case scenario, seasonal capacity needs occur in the planning horizon.

JEA's Planning Reserve Policy limits the level of market dependency to meet the 15% reserve margin to no more than 3% of Forecasted Firm Demand in any season. This assumes that JEA can obtain, within the operating horizon, resources capable of supplying up to 3% (90 MW for a 3000 MW firm demand level) of JEA's Firm Demand. JEA will utilize the extensive resources of The Energy Authority (TEA), JEA's affiliated energy market services company, to acquire any realized purchased power needs.

The St. Johns River Power Park (SJRPP) is jointly owned by JEA and FP&L. JEA sells to FPL, on a "take-or-pay" basis, 37.5 percent of JEA's 80 percent share of the generating capacity and related energy of SJRPP. This sale will continue until the earlier of the Joint Ownership Agreement expiration in 2022 or the realization of the sale limit. The 37.5% sale to FP&L is projected by JEA to suspend March, 2017.

If this capacity is not returned in 2017, JEA could test the market for short-term power purchases and, given enough lead-time, JEA could exercise the option of adding capacity to Greenland Energy Center (GEC). The GEC site has the capability for future installation of combined cycle and simple cycle units. The site layout and infrastructure supports the future installation of the conversion of GEC CTs 1 and 2 to combined cycle, an identical 2x1 combined cycle power plant, and one additional peaking unit. The ultimate certification capacity for GEC is approximately 1300 MW. All common equipment and facilities at the site were developed for ultimate build out of the future units; retention pond, the reclaimed water pipeline, natural gas supply pipelines, wastewater return lines, and potable waterlines.

ENVIRONMENTAL ISSUES

34. **Please discuss the impact of environmental restrictions, relating to air or water quality or emissions, on the Company's system during the 2010 period, such as unit curtailments. As part of your discussion, please include the potential for environmental restrictions to impact unit dispatch or retirement during the 2011 through 2020 period.**

There were no unit curtailments or other significant events that could be attributed to environmental restrictions on the company's system during 2010. No unit retirements or impacts to unit dispatch are anticipated for 2011 through 2020 as a result of environmental restrictions. JEA continues to monitor the development of legislation and regulations at the federal, state, and local levels in order to evaluate the potential impact to JEA and its customers.

35. **Please provide the rate of emissions, on an annual and per megawatt-hour basis, of regulated materials and carbon dioxide for the generation fleet each year for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.**

	Year	SOX		NOX		Mercury		Particulates		CO2	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	**2001**	7.25	42,935	4.94	29,231	N/A	N/A	N/A	N/A	2,132	12,627,485
	2002	4.96	30,803	3.91	24,308	N/A	N/A	N/A	N/A	2,047	12,711,113
	2003	4.33	27,799	3.72	23,908	N/A	N/A	N/A	N/A	2,109	13,542,657
	2004	4.54	28,189	3.52	21,850	N/A	N/A	N/A	N/A	2,075	12,886,710
	2005	4.03	26,343	2.85	18,595	N/A	N/A	N/A	N/A	2,072	13,537,327
	2006	3.22	21,608	3.04	20,405	N/A	N/A	N/A	N/A	2,056	13,798,041
	2007	2.18	15,174	2.88	20,044	N/A	N/A	N/A	N/A	2,000	13,934,209
	2008	1.58	10,126	2.82	17,999	N/A	N/A	N/A	N/A	2,027	12,952,896
	2009	1.66	10,438	1.32	8,328	N/A	N/A	N/A	N/A	2,019	12,723,344
	2010	1.50	10,560	0.91	6,436	N/A	N/A	N/A	N/A	1,964	13,840,570
Projected	**2011**	1.68	12,087	1.10	7,914	0.0000258	0.19	0.18	1,319	1,603	11,541,264
	2012	1.60	11,711	1.02	7,469	0.0000277	0.20	0.16	1,151	1,604	11,708,379
	2013	1.74	12,794	1.04	7,670	0.0000275	0.20	0.17	1,235	1,611	11,870,979
	2014	1.67	12,431	1.10	8,212	0.0000281	0.21	0.18	1,345	1,620	12,048,927
	2015	1.75	13,209	1.06	7,965	0.0000257	0.19	0.16	1,237	1,616	12,180,591
	2016	1.67	12,009	1.04	7,468	0.0000265	0.19	0.16	1,176	1,597	11,515,928
	2017	1.89	12,979	1.07	7,367	0.0000282	0.19	0.15	1,008	1,685	11,597,834
	2018	2.02	14,131	1.12	7,844	0.0000287	0.20	0.12	827	1,772	12,404,138
	2019	2.08	14,671	1.14	8,022	0.0000289	0.20	0.13	890	1,784	12,589,891
	2020	1.86	13,328	1.12	8,012	0.0000286	0.21	0.13	936	1,745	12,518,998

FUEL

36. **Please provide, on a system-wide basis, the historic average fuel price (in nominal $/MMBTU) for each fuel type for the period 2001 through 2010. Also, provide the forecasted annual average fuel price (in nominal $/MMBTU) for each fuel type for the period 2011 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.**

Nominal Fuel Price ($/MMBTU)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual	2001	N/A	1.60	4.89	3.41	7.10
	2002	N/A	1.48	4.02	3.72	4.65
	2003	N/A	1.60	5.80	4.00	6.98
	2004	N/A	1.50	6.64	4.11	6.76
	2005	N/A	1.79	8.36	6.04	8.95
	2006	N/A	2.10	8.53	7.66	14.44
	2007	N/A	2.20	8.59	8.67	15.63
	2008	N/A	2.33	9.18	7.57	14.95
	2009	N/A	3.30	4.95	8.05	12.59
	2010	N/A	2.82	5.74	11.27	16.88
Projected	2011	N/A	4.26	6.01	11.84	17.18
	2012	N/A	4.26	6.04	13.16	16.41
	2013	N/A	4.35	6.14	13.83	17.32
	2014	N/A	4.40	6.24	14.75	18.17
	2015	N/A	4.61	6.46	15.60	18.93
	2016	N/A	4.65	6.70	16.50	20.32
	2017	N/A	4.80	6.94	17.36	21.75
	2018	N/A	4.90	7.17	18.35	23.06
	2019	N/A	5.03	7.41	19.18	24.33
	2020	N/A	5.17	7.74	20.05	25.45

* Lower priced contract expired.

37. **Please provide, on a system-wide basis, the historic annual fuel usage (in GWh) for each fuel type for the period 2001 through 2010. Also, provide the forecasted annual fuel usage (in GWh) for each fuel type for the period 2011 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.**

Fuel Usage (GWh)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil	Petroleum Coke
Actual	2001	N/A	6,363	1,014	2,626	81	0
	2002	N/A	6,807	1,728	1,020	118	1,016
	2003	N/A	7,028	814	908	82	3,195
	2004	N/A	6,736	607	1,077	35	2,971
	2005	N/A	6,574	1,212	879	34	3,926
	2006	N/A	6,583	1,720	485	15	4,196
	2007	N/A	6,769	2,093	169	11	3,499
	2008	N/A	6,141	1,990	72	12	3,362
	2009	N/A	6,065	2,417	36	17	2,999
	2010	N/A	5,967	2,960	78	13	3,649
Projected	2011	N/A	5,266	5,684	135	27	3,147
	2012	N/A	5,269	5,656	105	19	3,395
	2013	N/A	5,362	5,651	115	13	3,439
	2014	N/A	5,230	5,762	136	40	3,554
	2015	N/A	5,675	5,823	115	13	3,287
	2016	N/A	5,150	5,736	111	26	3,243
	2017	N/A	6,141	4,006	84	8	3,370
	2018	N/A	6,936	3,470	59	5	3,403
	2019	N/A	7,276	3,177	66	1	3,520
	2020	N/A	7,132	3,412	75	14	3,641

38. Please discuss how the Company compares its fuel price forecasts to recognized, authoritative independent forecasts.

JEA compares its forecasts to other independently produced forecasts at the commodity level excluding transportation. Some commodity prices are compared with monthly granularity, while others are compared on an annual basis. Transportation forecasts tend to be too generic for JEA's specific circumstances, but JEA does consider rail, tanker, and dry bulk cargo freight rates and forecasts from various sources to judge general trends within the respective industries.

39. For each fuel type (coal, natural gas, nuclear fuel, etc.), please discuss in detail the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

Using the 2011 Annual Energy Outlook (AEO) from the Energy Information Administration (EIA) as a basis, the price of natural gas is projected in nominal dollars to increase through 2020. Over the forecast horizon, the U.S. is expected to rely on more onshore unconventional natural gas sources which are expected to provide the largest growth in domestic supply. Natural gas is used as a primary fuel at four of JEA's existing electric generation facilities. Over the forecast period, JEA will benefit from the increasing contribution from unconventional gas supplies that will help insure sufficient availability of natural gas in the future as JEA relies more heavily on natural gas for electric generation.

In the 2011 AEO reference case, the price of residual fuel oil is projected in nominal dollars to significantly increase through 2020. Given considerable uncertainty surrounding the future price of residual fuel oil relative to natural gas, JEA's past fuel diversification efforts included allowing Northside Unit 3 to burn natural gas in addition to residual fuel oil. Natural gas is used as primary fuel for this unit when it is priced at or below the price of residual fuel oil.

The 2011 AEO reference case indicates that coal production and coal prices in nominal dollars will increase slightly per year from 2011 to 2020. The majority of the production increase will occur in the west utilizing the vast remaining surface-minable reserves located in the Powder River Basin (PRB). In the east, higher sulfur Illinois Basin and Northern Appalachia production is expected to offset significant production declines in the Central Appalachia region. The overall price of mine mouth coal in real dollars is expected to remain relatively constant through 2020.

JEA has ownership in Scherer Unit 4 which burns PRB coal. The trend of increasing production in the west supports continued operation of Scherer Unit 4 on PRB coal. Additionally JEA has ownership in St. Johns River Power Park which burns bituminous coal from international and domestic sources. Given the eastern production trends described above, SJRPP is likely to burn significant volumes of international coal and domestic coal from the Illinois Basin and Northern Appalachia regions as Central Appalachia production continues to decline during the forecast period.

JEA uses circulating fluidized bed technology in Northside Generating Station Units 1 and 2. This technology allows JEA to use a blend of petroleum coke and bituminous coal in these units. During the 2011 through 2020 period, JEA expects the petroleum coke market to typically trade at a discount to coal.

40. What steps has the Company taken to ensure gas supply availability and transport over the 2011 through 2020 planning period?

JEA has a firm long term agreement for gas volumes delivered to Jacksonville that utilizes both Florida Gas Transmission and Southern Natural Gas pipelines. To support future gas requirements, JEA has additional contracts that provide access to firm transportation on Florida Gas Transmission and Southern Natural Gas pipeline. JEA has long-term contracts with Florida Gas Transmission for firm gas transportation. JEA also has a long-term contract with SeaCoast Gas Transmission, LLC to deliver natural gas to JEA's Greenland Energy Center.

As necessary, JEA continues to add additional firm gas transportation to satisfy incremental needs. The various transportation contracts allow JEA the ability to access natural gas from diverse supply regions.

41. **Regarding existing and planned natural gas pipeline expansion projects, including new pipelines, affecting the Company for the period 2011 through 2020, please identify each project and discuss it in detail.**

To provide natural gas delivery to JEA's Greenland Energy Center (GEC), JEA contracted with Peoples Gas System (PGS) for the construction of the Greenland Energy Center Lateral (GEC Lateral) pipeline. Completed in November 2010, the GEC Lateral extends approximately 27 miles east from an interconnection with the SeaCoast Pipeline to the GEC site. The SeaCoast Pipeline is an intrastate pipeline that extends from, an interconnection with Southern Natural Gas Pipeline (SNG) near the interconnection with Florida Gas Transmission Pipeline (FGT) to the interconnection with the GEC Lateral.

JEA does not have any other natural gas pipeline expansion projects planned at this time.

42. **Please discuss in detail any existing or planned natural gas pipeline expansion project, including new pipelines and off-shore projects, outside the State of Florida that will affect the Company over the period 2011 through 2020.**

At this time, JEA doesn't foresee any new pipeline expansion projects on the horizon.

43. **Regarding unconventional natural gas production (shale gas, tight sands, etc.), please discuss in detail the expected industry factors and trends for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.**

Given the decline in conventional natural gas sources, the incremental production of lower 48 onshore natural gas is projected to come primarily from unconventional resources. As technology advances and new methods of extracting unconventional natural gas are refined, the resource potential is projected to play an increasing role in supplementing the natural gas supply.

Using existing firm natural gas transportation contracts, JEA is positioned to purchase natural gas volumes from unconventional as well as conventional production sources in various supply basins.

44. Regarding liquefied natural gas (LNG) imports to the United States, please discuss in detail the expected industry factors and trends for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

U.S. imports of liquefied natural gas are expected to decline as a result of demand growth from exporting counties increasing faster than production. The inverse is true domestically with unconventional sources quickly outpacing demand. For these reasons LNG is expected to make a much smaller contribution to total natural gas supply than its 13 percent contribution in 2008.

JEA has a long-term natural gas supply contract that allows the natural gas to be sourced from the LNG facilities of SNG at Elba Island in Savannah, GA.

45. Please discuss in detail the Company's plans for the use of firm natural gas storage for the period 2011 through 2020.

At this time, JEA does not plan to utilize firm natural gas storage.

46. Please discuss the actions taken by the Company to promote competition within and among coal transportation modes.

JEA's fuel procurement process insures that potential fuel suppliers compete with one another for the opportunity to deliver coal to JEA facilities. The competitive process results in low delivered costs for JEA.

JEA's Northside Generating Station (NSGS) and St. Johns River Power Park (SJRPP) solid fuel-fired facility owned jointly with Florida Power and Light have water access to accommodate coal deliveries. In addition, SJRPP can also receive fuel from unit trains on the CSX system. JEA's Scherer Unit 4 receives coal deliveries by rail.

Utilizing water deliveries as a direct alternative to rail at SJRPP has encouraged the rail provider to offer SJRPP more competitive transportation rates. Water borne freight (international ocean freight and domestic freight from the US Gulf) has often cost less than rail transportation, and in 2008 SJRPP delivered 100 percent of its solid fuel by water due to a lower transportation cost by water versus rail.

Domestic coal suppliers using rail to barge logistics and international coal suppliers using ocean vessels compete to provide JEA with coal deliveries to NSGS. JEA currently has limited rail access at NSGS.

As a co-owner of Scherer Unit 4, JEA's fuel is delivered from the Powder River Basin in Wyoming to Plant Scherer located near Macon, Georgia by two rail carriers – one in the west and one in the east. Georgia Power Company entered into contracts with the rail carriers on behalf of the Scherer co-owners. Competition between the major rail carriers was insured by including all in the negotiation process.

JEA has and will continue to solicit coal bids in a competitive process and will make fuel selections based on prudent utility evaluations.

47. **Regarding coal transportation by rail, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company. Also include a discussion of any expected changes to terminals and port facilities that could affect coal transportation for the Company.**

A recent trend has been for the major rail carriers to begin to transfer the burden of owning and maintaining rail equipment for the movement of coal to the larger utilities. Although the railroads still own rail cars, the trend is to reduce the railroad owned rolling stock.

The recent surge of export coal through East Coast ports that is expected to continue for the foreseeable future has decreased available supply. If the projected growth continues, any excess rail car supply will disappear both in railroad-owned equipment and leased rail equipment. This shortage of rail equipment doesn't impact JEA which owns enough rail cars to fully operate three 110 car unit trains and has spare equipment available.

Since both NSGS and SJRPP have water terminals for fuel receipts, any changes to terminals and port facilities in Jacksonville will not affect JEA.

48. **Regarding coal transportation by water, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company. Also include a discussion of any expected changes to terminals and port facilities that could affect coal transportation for the Company.**

Driven by global demand, U.S. coal exports by water are expected to expand to meet the demand from countries such as China and India. To accomplish higher exporting capacity additional loading terminals will have to be constructed, but public perception, environmental concerns and permitting could cause delays and ultimately some facility expansion projects canceled.

Publically owned coal companies, pushed by shareholders to sell globally for the highest profit margin, are directly impacting the market of coal that is available by water domestically. As more coal is sold into the international market the price the coal that is sold domestically will increase. JEA has and will continue to solicit coal bids in a competitive process and will make fuel selections based on prudent utility evaluations. Since both of the Jacksonville generating stations have their own terminals for receiving coal, any changes to other terminals and port facilities will not affect JEA.

49. Regarding planned changes and construction projects at coal generating units, please discuss the expected changes for coal handling, blending, unloading, and storage for the period 2011 through 2020.

JEA currently has no coal handling, blending, or storage projects underway or approved.

50. For the period 2011 through 2020, please discuss in detail the Company's plans for the storage and disposal of spent nuclear fuel. As part of this discussion, please include the Company's expectation regarding Yucca Mountain, dry cask storage, and litigation involving spent nuclear fuel, and the future of the Nuclear Waste Disposal Act.

JEA does not have any self-build nuclear units in the ten-year site plan.

51. Regarding uranium production, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

Not Applicable

52. Regarding the transportation of heavy fuel oil and distillate fuel oil, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

The ongoing decline in utility consumption of residual fuel and distillate fuel oil is expected to continue. JEA has followed this industry trend and is consuming much less fuel oil than in past years. Northside Unit 3 is JEA's last generating unit capable of burning residual fuel oil. JEA burns residual fuel oil in Northside Unit 3 when oil is cheaper than gas including environmental considerations. Any industry trends in the transportation of heavy fuel oil and distillate fuel oil will have little impact on JEA as these fuels make up only a small portion of JEA's fuel use.

53. Please discuss the effect of changes in fossil fuel prices on the competitiveness of renewable technologies.

It is difficult to speculate on the effect that changes in fossil fuel prices may have on the competitiveness of renewable technologies. In general, if fossil fuel prices increase for a sustained period of time, the competitiveness of renewable technologies, from purely a cost-effectiveness perspective, would likely improve. Conversely, if fossil fuel prices decrease for a sustained period of time, the competitiveness of renewable technologies, from purely a cost-effectiveness perspective, would likely decline. However, there are other market factors that need to be considered, therefore it may not be feasible to conclude there will be a direct correlation between changes in fossil fuel prices and competitiveness of renewable technologies.

54. Please discuss the effect of renewable resource development (for electric generation and non-generation technologies) on fossil fuel prices.

It is difficult to speculate on the effect that renewable resource (technology) development may have on fossil fuel prices. In general, if the use of renewable resources develop sufficiently to displace significant amounts of fossil fuel consumption, the price of fossil fuel would likely decline. However, there are other market factors that need to be considered, therefore it may not be feasible to conclude that there will be a direct correlation between changes renewable resource (technology) development and fossil fuel prices.

TRANSMISSION

55. Please provide a list of all proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act. Please also include those that have been approved, but are not yet in-service.

There are no transmission lines to report for this period.

Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
None To Report					