21 West Church Street
Jacksonville, Florida 32202-3139

JEA

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April 25, 2012

Ann Cole
Office of Commission Clerk
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

120000-OT

RE: Review of 2012 Ten-Year Site Plans – Staff's Data Request #1

Pursuant to the Commission's authority under section 366.05(7), Florida Statues, attached is JEA's response to Data Request #1 for supplemental information of JEA's 2012 Ten-Year Site Plan filing.

Enclosed is a hardcopy of JEA's response and copies of additional report submittals. Also enclosed is an electronic version of these files on disk. If you have any questions regarding this submittal, please contact me or any of the respondents listed below.

SECTION	NAME	EMAIL	TELEPHONE
General Questions Traditional Generation Power Purchases / Sales	Mary Guyton Baker	GUYTML@JEA.COM	(904) 665-6216
Load & Demand Forecasting	Melinda Fischer	FISCML@JEA.COM	(904) 665-4048
Renewable Generation	Jay Worley	WORLJA@JEA.COM	(904) 665-8729
Environmental Issues	Jay Worley	WORLJA@JEA.COM	(904) 665-8729
Fuel Supply & Reliability	Jim Myers	MYERJT@JEA.COM	(904) 665-6224
Transmission	Rakesh Sharma	SHARR@JEA.COM	(904) 665-6143

Thank You,

Mary Guyton Baker

Mary Guyton Baker, PE
Electric System Planning, JEA

COM _____
APA _____
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TYSP
Schedules

2012 TYSP Data Request #1 - TYSP Schedules.xls

Schedule 1
Existing Generating Facilities
As of December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)		(14)
Plant Name	Unit No.	Location	Unit Type	Fuel Pri	Fuel Alt	Fuel Transport Pri	Fuel Transport Alt	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate KW	Net Capability Summer MW		Winter MW
Kennedy	7	12-031	GT	NG	FO2	PL	WA		6/2000	(a)	203,800	150		191
Kennedy	8	12-031	GT	NG	FO2	PL	WA		6/2009	(a)	203,800	150		191
Northside	1	12-031	ST	PC	BIT	WA	RR		5/2002	(a)	350,000	293		293
Northside	2	12-031	ST	PC	BIT	WA	RR		2/2002	(a)	350,000	293		293
Northside	3	12-031	ST	NG	FO6	PL	WA		7/1977	10/2021	563,700	524		524
Northside	33	12-031	GT	FO2		WA	TK		2/1975	(a)	248,400	53		62
Northside	34	12-031	GT	FO2		WA	TK		1/1975	(a)	248400	53		62
Northside	35	12-031	GT	FO2		WA	TK		12/1974	(a)	248400	53		62
Northside	36	12-031	GT	FO2		WA	TK		12/1974	(a)	248400	53		62
Brandy Branch	1	12-031	GT	NG	FO2	PL	TK		5/2001	(a)	203,800	150		191
Brandy Branch	2	12-031	CT	NG	FO2	PL	TK		5/2001	(a)	203,800	150		191
Brandy Branch	3	12-031	CT	NG	FO2	PL	TK		10/2001	(a)	203,800	150		191
Brandy Branch	4	12-031	CA	WH					1/2005	(a)	268,400	201		223
Greenland Energy Center	1	12-031	GT	NG	FO2	PL	TK		6/2011	(a)	203,800	142		186
Greenland Energy Center	2	12-031	GT	NG	FO2	PL	TK		6/2011	(a)	203,800	142		186
Girvin Landfill	1-2	12-031	IC	NG		PL			7/1997	(a)	1,200	1		1
St. Johns River Power Park	1	12-031	ST	BIT	PC	RR	WA		3/1987	(a)	679,600	501	(b)	510
St. Johns River Power Park	2	12-031	ST	BIT	PC	RR	WA		5/1988	(a)	679,600	501	(b)	510
Scherer	4	13-207	ST	SUB	BIT	RR	RR		2/1989	(a)	846,000	194	(c)	194
Total												3,754	(d)	4,122

(a) Units expected to be maintained throughout the study period.

(b) Net capability reflects the JEA's 80% ownership of Power Park. Nameplate is original nameplate of the unit.

(c) Nameplate and net capability reflects the JEA's 23.64% ownership in Scherer 4.

(d) Numbers may not add due to rounding.

Schedule 2.1

History and Forecast of Energy Consumption and *Number of Customers* by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential					*Commercial*	
Year	Population	Members per Household	GWH	Average No. of Customers	Average KWH Consumption Per Customer	GWH	Average No. of Customers	Average KWH Consumption Per Customer
HISTORY:								
2002			5,108	326,362	15,651	1,157	33,841	34,189
2003			5,226	332,492	15,718	1,184	33,762	35,069
2004			5,400	348,320	15,503	1,185	32,123	36,889
2005			5,550	358,770	15,469	1,249	33,087	37,738
2006			5,637	357,232	15,780	1,289	37,136	34,704
2007			5,478	364,284	15,039	1,328	39,919	33,279
2008			5,364	365,632	14,670	1,357	40,608	33,417
2009			5,300	367,864	14,408	1,303	41,150	31,660
2010			5,748	369,050	15,575	1,329	41,693	31,869
2011			5,445	369,566	14,733	1,314	41,958	31,317
FORECAST:								
2012			5,685	384,612	14,781	1,372	43,554	31,501
2013			5,719	385,637	14,830	1,380	43,558	31,685
2014			5,754	386,711	14,878	1,389	43,567	31,871
2015			5,791	387,956	14,927	1,398	43,595	32,057
2016			5,842	390,125	14,976	1,410	43,726	32,245
2017			5,918	393,884	15,025	1,428	44,034	32,434
2018			5,995	397,724	15,074	1,447	44,349	32,624
2019			6,074	401,647	15,123	1,466	44,671	32,815
2020			6,155	405,648	15,173	1,485	45,000	33,007
2021			6,242	410,083	15,222	1,506	45,375	33,200

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	GWH	Industrial Average No. of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
HISTORY:							
2002	5,479	3,475	1,576,691	0	112	0	11,856
2003	5,605	3,630	1,544,077	0	115	0	12,130
2004	5,396	3,638	1,483,233	0	76	0	12,057
2005	5,686	3,747	1,517,473	0	111	0	12,596
2006	5,658	4,206	1,345,307	0	110	0	12,694
2007	5,832	4,521	1,290,035	0	113	0	12,751
2008	5,777	4,599	1,256,240	0	117	0	12,615
2009	5,546	4,660	1,190,207	0	120	0	12,270
2010	5,657	4,722	1,198,052	0	122	0	12,855
2011	5,594	4,752	1,177,321		122	0	12,476
FORECAST:							
2012	5,841	4,956	1,178,630	0	126	0	13,024
2013	5,876	4,980	1,179,940	0	127	0	13,102
2014	5,911	5,004	1,181,252	0	128	0	13,181
2015	5,950	5,031	1,182,566	0	128	0	13,267
2016	6,003	5,070	1,183,881	0	130	0	13,385
2017	6,080	5,130	1,185,197	0	131	0	13,558
2018	6,160	5,191	1,186,515	0	133	0	13,735
2019	6,241	5,254	1,187,834	0	135	0	13,916
2020	6,324	5,318	1,189,155	0	137	0	14,100
2021	6,414	5,387	1,190,477	0	138	0	14,301

Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1) Year	(2) Sales for Resale GWH	(3) Utility Use & Losses GWH	(4) Net Energy for Load GWH	(5) Other Customers (Average No.)	(6) Total No. of Customers
HISTORY:					
2002	446	681	12,983	2	363,698
2003	453	595	13,178	2	369,904
2004	468	718	13,243	2	384,108
2005	486	615	13,696	2	395,606
2006	522	595	13,811	7	398,581
2007	624	479	13,854	5	408,729
2008	451	464	13,530	3	414,418
2009	479	406	13,155	3	413,677
2010	343	644	13,842	2	415,467
2011	100	405	12,980	2	416,278
FORECAST:					
2012	114	415	13,553	2	433,125
2013	116	416	13,633	2	434,176
2014	119	417	13,716	2	435,285
2015	120	418	13,805	2	436,584
2016	124	419	13,928	2	438,923
2017	129	421	14,108	2	443,050
2018	134	423	14,292	2	447,266
2019	139	426	14,481	2	451,574
2020	144	428	14,672	2	455,967
2021	151	430	14,881	2	460,847

Schedule 3.1
History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
HISTORY:									
2002	2,562	0	0	0	0	0	0	0	2,562
2003	2,535	0	0	0	0	0	0	0	2,535
2004	2,539	0	0	0	0	0	0	0	2,539
2005	2,815	0	0	0	0	0	0	0	2,815
2006	2,835	0	0	0	0	0	0	0	2,835
2007	2,897	0	0	0	0	0	0	0	2,897
2008	2,866	0	0	0	0	0	0	0	2,866
2009	2,754	0	0	0	0	0	0	0	2,754
2010	2,817	0	0	0	0	0	0	0	2,817
2011	2756	0	0	0	0	0	0	0	2756
FORECAST:									
2012	2,772	0	0	113	0	6	0	4	2,649
2013	2,815	0	0	131	0	12	0	9	2,663
2014	2,859	0	0	131	0	17	0	12	2,699
2015	2,903	0	0	131	0	21	0	14	2,737
2016	2,948	0	0	131	0	30	0	21	2,767
2017	2,994	0	0	131	0	33	0	23	2,806
2018	3,041	0	0	131	0	37	0	25	2,848
2019	3,088	0	0	131	0	43	0	30	2,884
2020	3,136	0	0	131	0	42	0	29	2,934
2021	3,206	0	0	131	0	51	0	35	2,989

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
HISTORY:									
2001/02	2,590	0	0	0	0	0	0	0	2,590
2002/03	3,083	0	0	0	0	0	0	0	3,083
2003/04	2,668	0	0	0	0	0	0	0	2,668
2004/05	2,860	0	0	0	0	0	0	0	2,860
2005/06	2,919	0	0	0	0	0	0	0	2,919
2006/07	2,722	0	0	0	0	0	0	0	2,722
2007/08	2,914	0	0	0	0	0	0	0	2,914
2008/09	3,064	0	0	0	0	0	0	0	3,064
2009/10	3,224	0	0	0	0	0	0	0	3,224
2010/11	3,062	0	0	0	0	0	0	0	3,062
FORECAST:									
2011/12	2,665	0	0	0	0	0	0	0	2,665
2012/13	3,114	0	0	107	0	12	0	8	2,988
2013/14	3,169	0	0	107	0	9	0	6	3,048
2014/15	3,225	0	0	107	0	14	0	9	3,095
2015/16	3,284	0	0	107	0	19	0	13	3,145
2016/17	3,342	0	0	107	0	22	0	14	3,198
2017/18	3,402	0	0	107	0	29	0	19	3,247
2018/19	3,462	0	0	107	0	40	0	26	3,289
2019/20	3,525	0	0	107	0	23	0	15	3,379
2020/21	3,588	0	0	107	0	36	0	23	3,421

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
HISTORY:								
2002	12,910	0	0	0	0	0	12,910	57%
2003	13,120	0	0	0	0	0	13,120	49%
2004	13,349	0	0	0	0	0	13,349	57%
2005	13,696	0	0	0	0	0	13,696	55%
2006	13,811	0	0	0	0	0	13,811	54%
2007	13,854	0	0	0	0	0	13,854	55%
2008	13,531	0	0	0	0	0	13,531	53%
2009	13,155	0	0	0	0	0	13,155	49%
2010	13,842	0	0	0	0	0	13,842	49%
2011	12,980	0	0	0	0	0	12,980	48%
FORECAST:								
2012	13,615	37	25	0	0	0	13,553	52% (a)
2013	13,754	72	49	0	0	0	13,633	52%
2014	13,895	107	72	0	0	0	13,716	51%
2015	14,037	139	93	0	0	0	13,805	51%
2016	14,207	167	112	0	0	0	13,928	51%
2017	14,433	195	131	0	0	0	14,108	50%
2018	14,665	223	150	0	0	0	14,292	50%
2019	14,901	252	169	0	0	0	14,480	50%
2020	15,142	281	189	0	0	0	14,672	50%
2021	15,400	310	209	0	0	0	14,881	50%

(a) 2012 Load Factor calculation based on forecasted winter peak demand and forecasted energy (see Schedule 4), not calculated on actual winter 2012 peak.

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Schedule 4
Previous Year and 2-Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2011 Actual		2012 Forecast		2013 Forecast	
Month	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	3,062	1,149	2,961	1,091	2,988	1,102
February	2,346	904	2,457	978	2,482	988
March	1,746	914	2,090	1,011	2,112	1,021
April	2,251	1,022	1,977	983	1,988	993
May	2,418	1,146	2,376	1,129	2,389	1,140
June	2,668	1,252	2,498	1,266	2,515	1,279
July	2,653	1,309	2,607	1,427	2,618	1,441
August	2,756	1,395	2,649	1,404	2,663	1,418
September	2,359	1,157	2,443	1,207	2,459	1,219
October	2,049	946	2,391	1,054	2,423	1,064
November	1,749	881	2,298	983	2,333	993
December	1,931	931	2,719	1,076	2,766	1,087

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2010	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	2847	2,569	2,015	2,080	1,916	2,071	1,962	1,555	1,909	1,998	1,671	2,300
(3)	Residual	Total	1000 BBL	151	43	198	164	171	151	145	139	169	142	204	152
(4)		Steam	1000 BBL	151	43	198	164	171	151	145	139	169	142	204	152
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	40	46	14	10	19	63	4	12	13	12	26	9
(9)		Steam	1000 BBL	3	10	1	1	1	1	1	1	1	2	0	1
(10)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	37	36	13	9	18	61	3	11	12	10	26	8
(12)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	24084	36,666	44,318	41,700	42,523	42,612	38,521	38,150	34,711	33,292	40,341	32,565
(14)		Steam	1000 MCF	6631	11,345	14,013	11,621	12,129	10,683	10,252	9,851	11,961	10,110	14,444	10,749
(15)		CC	1000 MCF	15698	22,073	26,959	27,364	27,335	23,875	26,215	24,954	19,423	20,657	20,907	18,933
(16)		CT	1000 MCF	1755	3,248	3,347	2,715	3,059	8,055	2,054	3,345	3,326	2,525	4,990	2,884
(17)	Other (Specify)		Trillion BTU	1123	756	1,185	1,330	1,405	1,409	1,310	1,404	1,485	1,453	1,455	1,370

Note: Other over the years includes a combination of some or all of the following in a given year: Petroleum Coke, landfill gas, wood chips burned at Northside, and/or sludge burned at Buckman Sewage Treatment Plant.

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Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2010	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Firm Inter-Region Interchange		GWH	1,418	1,202	0	0	0	0	860	1,715	1,654	1,715	1,659	1,654
(2)	Nuclear		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWH	5598	5,129	4,518	4,522	4,291	4,507	4,444	3,634	4,220	4,600	4,065	5,427
(4)	Residual	Total	GWH	90	24	111	88	94	86	76	76	94	76	117	83
(5)		Steam	GWH	90	24	111	88	94	86	76	76	94	76	117	83
(6)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWH	15	10	5	4	8	26	1	5	5	4	11	4
(10)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWH	15	10	5	4	8	26	1	5	5	4	11	4
(13)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	2986	4,504	5,649	5,379	5,484	5,324	4,966	4,848	4,288	4,187	4,918	4,038
(15)		Steam	GWH	592	976	1,278	1,016	1,085	988	876	871	1,082	875	1,339	953
(16)		CC	GWH	2244	3,220	4,074	4,122	4,125	3,597	3,909	3,681	2,908	3,089	3,130	2,831
(17)		CT	GWH	150	309	297	241	274	739	180	297	298	223	449	255
(18)	NUG		GWH	0	9	0	0	0	0	0	0	0	0	0	0
(19)	Renewables	Total	GWH	87	99	180	179	179	179	180	179	153	100	100	100
(20)		Biofuels	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(21)		Biomass	GWH	0	2	0	0	0	0	0	0	0	0	0	0
(22)		Hydro	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(23)		Landfill Gas	GWH	75	74	156	156	156	156	156	156	130	77	78	77
(24)		MSW	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(25)		Solar	GWH	12	23	24	24	24	23	23	23	23	23	23	23
(26)		Wind	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(27)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(28)	Other (Specify)		GWH	3649	1,994	3,089	3,461	3,660	3,683	3,402	3,652	3,879	3,797	3,803	3,576
(29)	Net Energy for Load		GWH	13842	12,971	13,553	13,633	13,716	13,805	13,928	14,108	14,292	14,480	14,672	14,881

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Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2010	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Firm Inter-Region Interchange		%	10%	9%	0%	0%	0%	0%	6%	12%	12%	12%	11%	11%
(2)	Nuclear		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(3)	Coal		%	40%	40%	33%	33%	31%	33%	32%	26%	30%	32%	28%	36%
(4)	Residual	Total	%	1%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
(5)		Steam	%	1%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
(6)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(7)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(8)		Other	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(9)	Distillate	Total	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(10)		Steam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(11)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(12)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(13)		Other	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(14)	Natural Gas	Total	%	22%	35%	42%	39%	40%	39%	36%	34%	30%	29%	34%	27%
(15)		Steam	%	4%	8%	9%	7%	8%	7%	6%	6%	8%	6%	9%	6%
(16)		CC	%	16%	25%	30%	30%	30%	26%	28%	26%	20%	21%	21%	19%
(17)		CT	%	1%	2%	2%	2%	2%	5%	1%	2%	2%	2%	3%	2%
(18)	NUG		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(19)	Renewables	Total	%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
(20)		Biofuels	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(21)		Biomass	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(22)		Hydro	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(23)		Landfill Gas	%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
(24)		MSW	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(25)		Solar	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(26)		Wind	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(27)		Other	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(28)	Other (Specify)		%	26%	15%	23%	25%	27%	27%	24%	26%	27%	26%	26%	24%
(29)	Net Energy for Load		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Schedule 7.1

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
							Reserve Margin before Maintenance			Reserve Margin before Maintenance	
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	MW	% of Peak	Scheduled Maintenance MW	MW	% of Peak
FORECAST:											
2012	3,754	9	376	0	3,388	2,649	739	28%	0	739	28%
2013	3,754	18	376	0	3,397	2,663	733	28%	0	733	28%
2014	3,754	18	376	0	3,397	2,699	697	26%	0	697	26%
2015	3,754	18	376	0	3,397	2,737	660	24%	0	660	24%
2016	3,754	18	376	0	3,397	2,767	630	23%	0	630	23%
2017	3,754	118	376	0	3,497	2,806	690	25%	0	690	25%
2018	3,753	218	376	0	3,595	2,848	748	26%	0	748	26%
2019	3,753	209	0	0	3,962	2,884	1,078	37%	0	1,078	37%
2020	3,753	209	0	0	3,962	2,934	1,028	35%	0	1,028	35%
2021	3,753	209	0	0	3,962	2,989	973	33%	0	973	33%

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin before Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
FORECAST:											
2011/12	4,122	9	383	0	3,749	2,961	788	27%	0	788	27%
2012/13	4,122	18	383	0	3,758	2,988	770	26%	0	770	26%
2013/14	4,122	18	383	0	3,758	3,048	710	23%	0	710	23%
2014/15	4,122	18	383	0	3,758	3,095	663	21%	0	663	21%
2015/16	4,122	18	383	0	3,758	3,145	613	19%	0	613	19%
2016/17	4,122	118	383	0	3,858	3,198	659	21%	0	659	21%
2017/18	4,121	218	383	0	3,957	3,247	709	22%	0	709	22%
2018/19	4,121	209	383	0	3,947	3,289	658	20%	0	658	20%
2019/20	4,121	209	0	0	4,330	3,379	951	28%	0	951	28%
2020/21	4,121	209	0	0	4,330	3,421	909	27%	0	909	27%

2012 TYSP Data Request #1 - TYSP Schedules.xls

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Net Capability		
	Unit		Unit	Fuel		Fuel Transport		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Mo/Yr	Mo/Yr	Mo/Yr	KW	MW	MW	Status
SJRPP	1	12-031	ST	Bit/PC		RR	WA		6/1/2019		679,600	186	189	
SJRPP	2	12-031	ST	Bit/PC		RR	WA		6/1/2019		679,600	186	189	

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) Plant Name and Unit Number:

(2) Capacity
a. Summer:
b. Winter:

(3) Technology Type:

(4) Anticipated Construction Timing
a. Field construction start-date:
b. Commercial in-service date:

(5) Fuel
a. Primary fuel:
b. Alternate fuel:

(6) Air Pollution Control Strategy:

(7) Cooling Method:

(8) Total Site Area:

(9) Construction Status:

None To Report

(10) Certification Status:

(11) Status with Federal Agencies:

(12) Projected Unit Perfomance Data
Planned Outage Factor (POF):
Forced Outage Factor (FOF):
Equivalent Availability Factor (EAF):
Resulting Capacity Factor (%):
Average Net Operating Heat Rate (ANOHR):

(13) Projected Unit Financial Data
Book Life (Years):
Total Installed Cost (In-Service Year $/kW):
Direct Construction Cost ($/kW):
AFUDC Amount ($/kW):
Escalation ($/kW):
Fixed O&M ($/kW-Yr):
Variable O&M ($/MWH):
K Factor:

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1) Point of Origin and Termination:

(2) Number of Lines:

(3) Right-of-Way:

(4) Line Length:

(5) Voltage:

None To Report

(6) Anticipated Construction Timing:

(7) *Anticipated Capital Investment*:

(8) Substations:

(9) *Participation with* Other Utilities:

REVIEW OF THE 2012 TEN-YEAR SITE PLANS: DATA REQUEST #1

Please provide an electronic copy of all responses in Adobe PDF format, with tables to be provided for in an Excel (.xls file format) document, unless otherwise specified in the question.

Please respond to the following question by **April 1, 2012.**

1. Please provide an electronic copy of the Company's 2012 Ten-Year Site Plan (in PDF format) and Schedules 1 through 10 (in Excel format).

Please respond to all remaining questions by **May 1, 2012.**

GENERAL QUESTIONS

2. Please provide all data requested in the attached forms labeled 'Appendix A,' as an electronic copy (in Excel). Please do **not** provide a hardcopy of this response. If any of the requested data is already included in the Company's Ten-Year Site Plan, state so on the appropriate form.

LOAD & DEMAND FORECASTING

3. [Investor-owned Utilities Only] **Please provide, on a system-wide basis, the hourly system load for the period January 1, 2011, through December 31, 2011. Please provide this only as an electronic copy (in Excel). Please do not provide a hardcopy of this response.**

Not applicable for JEA.

4. **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.**

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. In the recent years, however, there is a slight 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.

From the U.S. Bureau of Labor Statistic, prior to 2008, Jacksonville only experience 4.3% unemployment rate. Annual average number of residential customer growth was 1.9% from 2002 to 2008; whereas, annual average number of commercial and industrial growth was 3.3% within the same period. Since then, the unemployment rates were 7.5% in 2008, 10.9% in 2009, 11.4% in 2010 and 9.4% in 2011. The annual average number of residential customer growth is 0.4% from 2008 to 2011, while the annual average number of commercial and industrial growth was 1.1% within the same period.

5. **Please describe the Company's current and planned number of digital and/or "smart" meter installations. As part of this response, please detail the number of installations and penetration level of installations by customer class. If possible, also identify how many digital and/or "smart" meters were installed as part of a DSM or Pilot program.**

Since 2004, all of JEA's residential customers have in operation a 1-way AMR meter. In Fall 2012, as a part of a DOE Smart Grid grant, JEA will install 3,000 two-way AMI electric meters. The installation of the 2-way meters will allow JEA to provide new services for residential customers. These services include Prepay, Real Time Start Service, and a Web Based Energy Management Tool. Additional, 2-way meters will be installed based on customer demand for the new service offerings and to support future JEA business cases. Meters are not installed to solely support DSM programs.

6. **Please describe the meters that are currently considered standard service. Please include at a minimum, the manufacturer, model, the capabilities, if the meter communicates one-way or two-way, and the frequency of meter reads.**

All JEA residential meters currently provide a daily consumption read.

Manufacturer & Model	Form	Phase	Wire	Volts	Class	Amps	Communication Mod.	Communication Protocol	Read Frequency
Itron C1SC	1S	1	2	120	100	15	Radio Mod.	1-Way	Monthly
Elster A1T	2S	1	3	120/480	200	30	Cellnet MFMM with DRR*	1-Way	Daily
L+G Focus	2S	1	3	240	200	30	Cellnet BAMM	1-Way	Daily
L+G Focus	2S	1	3	240	320	50	Cellnet BAMM / Radio Mod.	1-Way	Monthly
L+G Focus	2S	1	3	240	200	30	Radio Mod.	1-Way	Monthly
Elster ABR1	3S	1	2	240	20	2.5	Cellnet BAMM	1-Way	Monthly
Elster A1T	5S	1/3	3	120/480	20	2.5	Cellnet MFMM with DRR / Radio Mod.	1-Way	Daily/Monthly
Elster A1T	6S	3	4	120/480	20	2.5	Cellnet MFMM with DRR / Radio Mod.	1-Way	Daily/Monthly
Elster A1T	9S	3	4	120/480	20	2.5	Cellnet MFMM with DRR / Radio Mod.	1-Way	Daily/Monthly
Sentinel	9S	3	4	120/480	20	2.5	MV90 Modem	1-Way	Monthly
Elster A1T	9S	3	4	120/480	20	2.5	Cellnet MFMM 2-Channel KYZ	1-Way	Monthly
GE KV2	9S	3	4	120/480	20	2.5	Load Profile, kVar, kVA Recording	1-Way	Monthly
Elster A3TL	9S	3	4	120/480	20	2.5	Load Profile Recorder, Metrum Mod.	1-Way	Monthly
Elster A1T	12S	3	3	120/480	200	30	Cellnet MFMM with DRR / Radio Mod.	1-Way	Daily/Monthly
L+G AX	12K	1	3	120/480	200	30	Manual	1-Way	Monthly
L+G Focus	12S	3	3	120	200	30	Cellnet BAMM	1-Way	Daily/Monthly
L+G AX	16K	3	4	120/480	480	50	Cellnet 1-Channel DRR	1-Way	Monthly
Elster A1T	16S	2	4	120/480	200	30	Cellnet MFMM with DRR / Radio Mod.	1-Way	Daily
Elster A1T	16S	3	4	120/480	320	50	Cellnet MFMM with DRR / Radio Mod.	1-Way	Daily
GE KV2	16S	3	3	120/480	200	30	Load Profile, kVar, kVA Recording	1-Way	Monthly
Elster A3TL	16S	3	3	120/480	200	30	Load Profile Recorder, Metrum Mod.	1-Way	Monthly

*DRR = Direct Register Read

7. **Please explain any meter replacement program, including the schedule and estimated cost. Please include at a minimum, the manufacturer, model, the capabilities, if the meter communicates one-way or two-way, and the frequency of meter reads.**

JEA does not have a formal meter replacement program. Two-way meters will be installed to directly support the new customer service offerings and in support of future business cases that requires a 2-way meter. The one-way to two-way meter replacements are currently scheduled as follows at the corresponding cost estimate.

- FY12 –3,000 meters – $500,000
- FY13 – 19,000 meters –$3,000,000
- FY14 –19,000 meters –$3,000,000

The 2-way electric meter JEA is evaluating is manufactured by L+G. The meters include a 200 amp remote controlled service switch and a HAN module capable of supporting the ZigBee protocol. The 2-way electric meters will provide JEA with hourly consumption reads. The table below gives specific information on the meters under consideration.

Manufacturer & Model	Form	Phase	Wire	Volts	Class	Amps	Communication Module	Communication Protocol	Read Frequency
L+G AXR	2S	1	3	240	200	30	Grid Stream RF with ZigBee	2-Way	60 min
L+G AXR	12S	3	3	120	200	30	Grid Stream RF with ZigBee	2-Way	60 min

*DRR = Direct Register Read

8. What new tariffs or programs is the utility planning to offer to customers as smart meters are installed throughout the utility service territory?

JEA is not planning to introduce any new tariffs as a result of installing AMI meters. As part of the JEA's Smart Grid DOE grant, a Prepay billing program will be offered to customers this fall. The Prepay offering will utilize the existing JEA residential rate.

9. Are smart meters currently being used for purposes other than billing, outage reporting, and remote connect/disconnect?

No smart meters at JEA are being used for purposes other than billing, outage reporting, and remote connect/disconnect.

10. Please describe what impacts, if any, the Company identifies from installation of digital and/or "smart" metering installations on peak demand, net energy for load, enhanced identification of outages/faults, and voltage concerns. Please describe the impact these metering installations may have on DSM Programs, such as increasing participation in Time-of-Day rate programs.

JEA is not currently utilizing "advanced" metering for current DSM activities and is not planning any residential programs for peak demand or voltage control.

11. **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 2009, 2010, and 2011; 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).**

Year	Month	Peak Demand (MW)	Date	Hour	Temperature (F)
2009	1	3060	22	8	21
	2	3064	6	8	23
	3	2476	4	8	29
	4	2048	24	17	89
	5	2451	11	17	94
	6	2754	22	16	98
	7	2628	2	17	95
	8	2735	12	17	95
	9	2417	25	17	89
	10	2423	9	16	93
	11	1710	10	13	82
	12	2151	29	8	31
2010	1	3224	11	8	20
	2	2667	26	8	27
	3	2335	4	8	32
	4	2016	23	18	87
	5	2368	3	17	93
	6	2817	15	17	102
	7	2749	27	16	99
	8	2731	18	17	96
	9	2595	10	17	95
	10	2199	28	17	89
	11	1785	8	8	33
	12	3053	14	8	20
2011	1	3062	14	8	23
	2	2346	9	8	32
	3	1746	24	18	87
	4	2251	27	18	93
	5	2418	24	17	94
	6	2668	22	17	96
	7	2653	21	17	96
	8	2756	11	17	98
	9	2359	12	17	93
	10	2049	11	17	87
	11	1749	16	19	63
	12	1931	8	8	35

12. **Please provide the company's historic projections of total retail energy sales for the years 2007 through 2011. Complete the table below by drawing this information from the company's forecasts in Schedule 2.2 in the 2002 through 2011 Ten-Year Site Plans. Please complete the table below and provide an electronic copy (in Excel).**

Total Retail Energy Sales Forecasts (GWh)					
Year	**2007**	**2008**	**2009**	**2010**	**2011**
2011 TYSP					14481
2010 TYSP				13283	13174
2009 TYSP			13838	13809	13936
2008 TYSP		14700	15016	15367	15717
2007 TYSP	14315	14701	15016	15367	15717
2006 TYSP	14441	14532	14876	15258	15642
2005 TYSP	14441	14532	14876	15258	
2004 TYSP	14873	14834	15200		
2003 TYSP	14873	15324			
2002 TYSP	15228				

RENEWABLE GENERATION

13. **Please provide the estimated total capacity of all renewable resources the utility owns or purchases as of January 1, 2012. 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 2021. Please complete the table below and provide an electronic copy (in Excel).**

Fuel Type	**Renewable Resource Capacity (MW)**	
	Existing (2012)	**Planned (2021)**
Solar	15.6	0.0
Wind	10.0	0.0
Biomass	<1.0	15.0
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	41.7	24.6

14. **Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement (PPA) which delivered capacity or energy as of January 1, 2012. 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 type, fuel type, in-service date, net capacity (even if not considered firm capacity), and annual energy generation. For PPAs, also provide the contract start and end dates. For small (less than 100 kW) distributed generating units, please make a single summary entry which includes the total number of distributed generating units of that type. Please complete the tables below and provide an electronic copy (in Excel).**

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.

Biomass: In June 2011, JEA commenced co-firing of wood chips in the Northside Generating Station's Unit 1 & 2 Circulating Fluidized Bed boilers. As of January 1, 2012, up to 33 tons per day (<1% capacity) was authorized to be co-fired as a total amount for both boilers.

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, 2012

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
North*	IC	LFG	1997			998	
Girvin	IC	LFG	1999	1200	1200	2,079	28%

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
Buckman	IC	OBG	2003	800	800	277	1.95%
Solar	SUN	PV	1999/2000/2001/2002/2003			162	

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
Landfill Energy Systems	Trail Ridge I	IC	LFG	12/2009	9100	9100	71,803	94%	12/2008	12/2018
PSEG	Jacksonville Solar	SUN	PV	09/2010			23,126		09/2010	09/2040

Non-Firm Renewable Purchased Power Agreements

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

15. Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement planned during the 2012 through 2021 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 type, fuel type, commercial in-service date, net capacity (even if not considered firm capacity), and average annual energy generation. For purchased power agreements, also provide the contract start and end dates. For small (less than 100 kW) distributed generating units, please make a single summary entry which includes the total number of distributed generating units of that type. Please complete the tables below and provide an electronic copy (in Excel).

At this time, there are no planned utility-owned renewable resource additions with an in-service date during the 2012 through 2021 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 2012/2013.

Planned Renewables for 2012 through 2021

Utility-Owned Firm Renewable Resources

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

Utility-Owned Non-Firm Renewable Resources

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

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
Landfill Energy Systems	Trail Ridge II	IC	LFG	2012/2013	9100	9100	75,490	95%	12/2012	12/2026

Non-Firm Renewable Purchased Power Agreements

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

16. Please provide a description of the costs associated with each utility-owned renewable generation resource, and each renewable purchased power agreement during 2011. Please also include each renewable resource which provides fuel to conventional facilities (co-firing), if applicable, with estimates of its capacity and energy contributions. As part of this response, please include the description of the unit's generator type, fuel type, seasonal net capacity (even if not considered firm capacity), and annual energy generation. For utility-owned resources, also provide the annual capital revenue requirements, operations & maintenance (O&M) costs, fuel costs, and total cost of the facility. For purchased power agreements, also provide the amount of capacity payments, energy payments, and total payments to the facility. Please note if payment information to a renewable provider is confidential, and exclude confidential information from your response. Please complete the tables below and provide an electronic copy (in Excel).

Renewable Costs and/or Payments for the Year Ending December 31, 2011.

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capital Expenses	O&M Expenses	Fuel Expenses	Total Expenses
-	-	-	Sum	Win	(MWh)	($)	($)	($)	($)
North	IC	LFG			998			8,858	8,858
Girvin	IC	LFG	1200	1200	2,079		341,143	40,839	381,982

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capital Expenses	O&M Expenses	Fuel Expenses	Total Expenses
-	-	-	Sum	Win	(MWh)	($)	($)	($)	($)
Buckman	IC	OBG	800	800	277		3,600		3,600
Solar	SUN	PV			162		22584		22584

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capacity Payments	Energy Payments	Total Payments
-	-	-	-	Sum	Win	(MWh)	($)	($)	($)
Landfill Energy Systems	Trail Ridge I	IC	LFG	9100	9100	71,803	0	3,501,508	3,501,508
PSEG	Jacksonville Solar	SUN	PV			23,126	0	2,926,965	2,926,965

Non-Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capacity Payments	Energy Payments	Total Payments
-	-	-	-	Sum	Win	(MWh)	($)	($)	($)

17. 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 name of the facility or owner, description of the unit's location, generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), and annual energy generation. Please exclude from this response net-metering installations or other small distributed generation systems. Please complete the table below and provide an electronic copy (in Excel).

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

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

18. **Please refer to the list of planned utility-owned renewable resource additions and renewable PPAs with an in-service date for the renewable generator during the 2012 through 2021 period outlined above. Please discuss the current status of each project.**

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. The date of commercial operation has been delayed one year and is anticipated to commence commercial operation in 2012/2013.

19. **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 solar hot water heaters, please use kilowatt-equivalent and kilowatt-hour-equivalent units. Please complete the table below and provide an electronic copy (in Excel).**

Customer Class	Residential			Commercial		
Renewable Type	# of Connections	Installed Capacity (kW)	Annual Output (MWh)	# of Connections	Installed Capacity (kW)	Annual Output (MWh)
Solar PV	73	326	*	15	238	*
Solar Thermal (Water)	943	2,832	*	0	0	*
Wind Turbine	0	0	*	1	3.6	*

* Note: Customer's system not metered by JEA. Net metered customer data available for kWh sent to JEA from customer

20. **Please provide the annual output for the company's renewable resources, including utility-owned, firm purchases through a PPA, non-firm purchases (through a PPA or as-available energy contract), or customer-owned generation, for the period 2011**

through 2021. Please complete the table below and provide an electronic copy (in Excel).

Annual Output (GWh)	Actual	Projected								
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Utility	3.077										
Firm PPA	94.929	102.0	179.7	178.7	178.7	178.7	178.7	153.0	100.0	101.0	100.0
Non-Firm	0.439										
Customer	0.200										
Total	98.645	102.0	179.7	178.7	178.7	178.7	178.7	153.0	100.0	101.0	100.0

21. [Investor-owned Utilities Only] **Provide, on a system-wide basis, the historical annual average as-available energy rate in the Company's service territory for the period 2002 through 2011. Also, provide the forecasted annual average as-available energy rate in the Company's service territory for the period 2012 through 2021. Please complete the table below and provide an electronic copy (in Excel).**

Not applicable for JEA.

22. **Please discuss whether the Company uses any renewable fuels in its existing fossil units, or has plans to do so within the planning period. Also, please identify whether the Company has conducted or is planning to conduct any studies relating to co-firing renewable fuels (such as biomass or biogas) in existing or planned fossil units.**

Biomass: In June 2011, JEA commenced co-firing of wood chips in the Northside Generating Station's Unit 1 & 2 Circulating Fluidized Bed boilers. As of January 1, 2012, up to 33 tons per day was authorized to be co-fired as a total amount for both boilers.

23. **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.

24. Please provide a list of all changes from January 1, 2011 to January 1, 2012 to existing or planned utility-owned renewable projects or purchased power agreements, including delays in in-service date, modifications of project size or contract terms, and expirations of purchased power agreements without renewal.

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. The date of commercial operation has been delayed one year and is anticipated to commence commercial operation in 2012/2013.

TRADITIONAL GENERATION

25. Please provide the cumulative present worth revenue requirement of the Company's Base Case for the 2012 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.

System operating cost do not include debt service for capital expenditures.

Year	Base Case Resource Plan System Operating Costs	Present Worth Rev. Req. 2012 Million $	
		Annual	Cumulative
2012		715,655	715,655
2013	Trail Ridge (Phase Two) Purchase (9 MW)	689,309	1,404,964
2014		681,235	2,086,199
2015		690,716	2,776,915
2016		725,728	3,502,643
2017	MEAG Plant Vogtle 3 Purchase (100 MW)	766,121	4,268,765
2018	MEAG Plant Vogtle 4 Purchase (100 MW) Girvin Road Landfill Expires (1.2 MW)	765,177	5,033,942
2019	Trail Ridge (Phase One) Expires (9 MW) SJRPP Sale to FPL Suspended (383 MW)	782,270	5,816,212
2020		797,201	6,613,413
2021		778,154	7,391,567

26. **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.**

None to report

27. **Please complete the following table detailing unit specific information on capacity and fuel consumption for 2011. For each unit on the Company's system, provide the following data based upon historic data from 2011; the unit's capacity, annual generation, capacity factor, estimated annual availability factor, unit average heat rate, and average energy cost for the unit's production. For dual fuel units, please report each fuel separately. Please complete the table below and provide an electronic copy (in Excel).**

Plant	Unit #	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capacity Factor	Availability Factor	In-Service Date	Heat Rate	Unit Fuel Cost
				Sum	Win	(MWh)	(%)	(%)	mm/yyyy	BTU/ kWh	¢/kWh
Kennedy	7	GT	NG/FO2	150	191	19,011	1%	93%	06/2000	12671	$6.53
Kennedy	8	GT	NG/FO2	150	191	95,656	6%	99%	06/2009	11086	$6.53
Northside	1	ST	PC/BIT	293	293	1,023,647	48%	84%	05/2002	10219	$4.64
Northside	2	ST	PC/BIT	293	293	1,174,590	50%	83%	02/2002	10273	$4.64
Northside	3	ST	NG/FO6	524	524	1,000,121	23%	98%	07/1977	10219	$6.23
Northside	33	GT	FO2	53	61.6	629	0.1%	87%	02/1975	18107	$26.15
Northside	34	GT	FO2	53	61.6	641	0.1%	95%	01/1975	22296	$26.15
Northside	35	GT	FO2	53	61.6	537	0.1%	99%	12/1974	24810	$26.15
Northside	36	GT	FO2	53	61.6	380	0.1%	99%	12/1974	31391	$26.15
Brandy Branch	1	GT	NG/FO2	150	191	36,365	2%	94%	05/2001	12004	$7.21
Brandy Branch	2	CT	NG/FO2	150	191	1,005,530	60%	88%	05/2001	10987	$4.34
Brandy Branch	3	CT	NG/FO2	150	191	1,066,138	63%	91%	10/2001	10953	
Brandy Branch	4	CA	WH	201	223	1,147,916	77%	93%	01/2005	N/A	
Brandy Branch	**	CC	NG/FO2	501	605	3,219,584	66%			7,087	
GEC	1	GT	NG/FO2	142	186	76,471	5%	100%	06/2011	11783	$15.13
GEC	2	GT	NG/FO2	142	186	81,158	5%	100%	06/2011	11524	$15.13
Girvin Landfill	1-2	IC	NG	1.2	1.2	2,190	13%		07/1997	17306	
SJRPP	1	ST	BIT/PC	313	319	1,899,995	62%	87%	03/1987	10145	$3.48
SJRPP	2	ST	BIT/PC	313	319	1,746,421	64%	96%	05/1988	10168	$3.48
Scherer	4	ST	SUB/BIT	200	200	1,447,726	79%	91%	02/1989	10058	$3.59

** Brandy Branch 2,3, & 4 Combined is the 2x1 Combined Cycle unit comprised of Brandy Branch CT 2, CT 3, and HRSG 4.

28. For each of the planned 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.

JEA does not have any planned generating unit additions in this TYSP period, only purchased power and sales agreements.

29. 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, 2012, 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. Please complete the table below and provide an electronic copy (in Excel).

JEA does not have any planned generating unit additions in this TYSP period, only purchased power and sales agreements.

Planned Unit Additions for 2012 through 2021

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				
Combined Cycle Unit Additions				
Steam Turbine Unit Additions				

30. **For each existing and planned unit on the Company's system, provide the following data based upon historic data from 2011 and forecasted capacity factor values for the period 2012 through 2021. Please complete the tables below and provide an electronic copy (in Excel).**

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Kennedy	7	GT	NG/FO2	1	8	6	7	14	5	7	6	6	6	3
Kennedy	8	GT	NG/FO2	6	4	3	4	9	2	3	3	3	3	1
Northside	1	ST	PC/BIT	48	70	80	81	80	75	80	86	85	85	80
Northside	2	ST	PC/BIT	50	68	74	82	84	77	83	87	82	86	81
Northside	3	ST	NG/FO6	23	31	24	26	24	21	21	26	20	24	13
Northside	33	GT	FO2	0.1	0.4	0.3	0.5	1.6	0.1	0.4	0.4	0.2	0.3	0.1
Northside	34	GT	FO2	0.1	0.4	0.2	0.4	1.4	0.1	0.3	0.3	0.1	0.2	0.0
Northside	35	GT	FO2	0.1	0.3	0.1	0.3	1.2	0.1	0.2	0.2	0.0	0.1	0.1
Northside	36	GT	FO2	0.1	0.3	0.1	0.3	1.0	0.0	0.1	0.1	0.0	0.1	0.0
Brandy Branch	1	GT	NG/FO2	2	1	1	1	4	1	1	1	1	1	1
Brandy Branch	2,3, & 4	CC	NG/FO2	66	87	88	88	77	83	79	62	60	55	43
GEC	1	GT	NG/FO2	5	5	4	5	14	3	6	6	4	6	2
GEC	2	GT	NG/FO2	5	3	2	3	9	2	3	4	2	4	1
SJRPP	1	ST	BIT/PC	62	61	54	57	51	61	51	41	60	55	65
SJRPP	2	ST	BIT/PC	64	47	42	44	42	52	47	51	64	61	68
Scherer	4	ST	SUB/BIT	81	74	92	68	94	58	32	77	39	25	33

31. **Please complete the table below, providing a list of all of the Company's steam units or combustion turbines that are potential 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. Please complete the table below and provide an electronic copy (in Excel).

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

Some of the obstacles common to GT 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 current size of JEA. Conversion of a 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	Unit Type	Fuel Type	Summer Capacity (MW)	In-Service Date	Potential Conversion Type
Northside 3	ST	NG/FO6	524	7/1977	Combined Cycle
SJRPP 1	ST	BIT/PC	313	3/1987	Combined Cycle
SJRPP 2	ST	BIT/PC	313	5/1988	Combined Cycle
Kennedy CT 7	GT	NG/FO2	150	6/2000	Combined Cycle
Kennedy CT 8	GT	NG/FO2	150	6/2009	Combined Cycle
Brandy Branch CT 1	GT	NG/FO2	150	5/2001	Combined Cycle
GEC CT 1	GT	NG	142	6/2011	Combined Cycle
GEC CT 2	GT	NG	142	6/2011	Combined Cycle

32. [Investor-owned Utilities Only] **Please provide the system average heat rate for the generation fleet for each year for the period 2002 through 2011. Please complete the table below and provide an electronic copy (in Excel).**

Not applicable to JEA

33. **Please provide the average cost of a residential customer bill, based upon a monthly usage of 1200 kilowatt-hours, for the period 2002 through 2011. Please complete the table below and provide an electronic copy (in Excel).**

Year		Residential Bill ($/1200-kWh)
Actual	2002	80.68
	2003	80.68
	2004	80.68
	2005	85.48
	2006	105.88
	2007	104.90
	2008	114.02
	2009	138.23
	2010	131.45
	2011	143.02

34. **Please complete the following table detailing the Company's planned changes to summer capacity. In addition to providing the net change for the current year's Ten-Year Site Plan, please also provide the net change based on last year's Ten-Year Site Plan. Please complete the table below and provide an electronic copy (in Excel).**

The capacity listed in the table below are the change in the MW by category of the specified TYSP reporting year when compared to the previous year's report. Therefore, a positive number indicates an increase in capacity for the given year's report. Included in the interchange are both seasonal and long-term purchases. The seasonal capacity included is the season of highest need across the study period.

Fuel Type	**Unit Type**	**Summer Capacity Changes (MW)**	
		2011 TYSP	**2012 TYSP**
		(2011-2020)	**(2012-2021)**
Natural Gas	Combined Cycle	0.00	0.00
	Combustion Turbine	0.00	0.00
	Steam	0.00	0.00
Coal	Steam	0.00	0.00
	Integrated Coal Gasification	0.00	0.00
Oil	Combustion Turbine & Diesel	0.00	0.00
	Steam	0.00	0.00
Nuclear	Steam	0.00	0.00
Firm Purchases	Independent Power Producer (IPP)	0.00	0.00
	Interchange	40.00	(130.00)
	Non-Utility Generator (NUG)	0.00	0.00
	Renewables	3.00	0.00
NET CAPACITY ADDITIONS		**43.00**	**(130.00)**

35. **Please complete the table below describing the status of the company's generating units during each month's peak demand, for the years 2009 through 2011. As part of this response, include the actual values at monthly peak for installed capacity, scheduled maintenance, forced outages, available capacity, and net firm peak demand. Please complete the table below and provide an electronic copy (in Excel).**

Capacity / Demand at Time of Monthly Peak (MW)						
Year	**Month**	**Installed Capacity**	**Scheduled Maintenance**	**Forced Outages**	**Available Capacity**	**Peak Demand**
2009	**1**	3605	124	0	3481	3060
	2	3605	124	0	3481	3064
	3	3605	315	0	3290	2476
	4	3161	0	0	3161	2048
	5	3161	0	0	3161	2451
	6	3311	0	508	2803	2754
	7	3311	0	0	3311	2628
	8	3311	0	0	3311	2735
	9	3311	293	0	3018	2417
	10	3311	586	0	2725	2423
	11	3584	586	0	2998	1710
	12	3734	0	0	3734	2151
2010	**1**	3734	0	44	3690	3224
	2	3734	200	319	3215	2667
	3	3734	200	191	3343	2335
	4	3311	556	0	2755	1903
	5	3311	0	0	3311	2368
	6	3104	0	191	2913	2817
	7	3104	0	0	3104	2749
	8	3104	0	90	3014	2731
	9	3104	0	231	2873	2595
	10	3104	0	53	3051	2199
	11	3377	524	0	2853	1785
	12	3377	524	524	2329	3053
2011	**1**	3377	0	319	3058	3062
	2	3377	0	387	2990	2346
	3	3377	0	291	3086	1746
	4	3104	524	0	2580	2251
	5	3104	0	236	2868	2418
	6	3388	0	0	3388	2668
	7	3388	0	0	3388	2653
	8	3388	0	0	3388	2756
	9	3388	0	456	2932	2359
	10	3388	178	100	3110	2049
	11	3749	0	0	3749	1749
	12	3749	0	191	3558	1931

POWER PURCHASES / SALES

36. **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).**

Existing Purchased Power Agreements as of January 1, 2012

Seller	Contract Term		Contract Capacity (MW)		Annual Generation (MWh)	Capacity Factor (%)	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter				
None								

Planned Purchased Power Agreements for 2012 through 2021

Seller	Contract Term		Contract Capacity (MW)		Annual Generation (MWh)	Capacity Factor (%)	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter				
MEAG	11/1/2016	10/31/2036	100	100	832	95%	NUC	PPA
MEAG	11/1/2017	10/31/2037	100	100	832	95%	NUC	PPA

37. **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).**

Existing Power Sales as of January 1, 2012

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation (MWh)	Capacity Factor (%)	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter				
FPL	1986	2019 *	188	192	1,007	60%	BIT	PPA
FPL	1987	2019 *	188	192	1,007	60%	BIT	PPA

* Projected early suspension date is summer 2019. Not to exceed date is 10/2021.

Planned Power Sales for 2012 through 2021

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

38. 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.

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 (JOA) expiration in 10/2021 or the realization of the sale limit. Based on JEA's calculation, the 37.5% sale to FP&L is projected suspend summer 2019. If this capacity is not returned in 2019, JEA's current forecast does not result in a capacity short fall until after the expiration of the JOA.

If an unexpected capacity shortfall were to occur, 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

39. Please discuss the impact of existing environmental restrictions, relating to air or water quality or emissions, on the Company's system during the 2011 period, such as unit curtailments. As part of your discussion, please include the potential for existing environmental restrictions to impact unit dispatch or retirement during the 2012 through 2021 period.

There were no unit curtailments or other significant events that could be attributed to environmental restrictions on the company's system during 2011. No unit retirements or impacts to unit dispatch are anticipated for 2012 through 2021 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.

40. **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 2002 through 2021. Please complete the table below and provide an electronic copy (in Excel).**

Year		SOX		NOX		Mercury		Particulates		CO2e	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	**2002**	3.18	24,152	2.31	17,512	-	-	-	-	1,261.96	9,569,813
	2003	4.35	21,555	3.31	16,413	-	-	-	-	2,096.34	10,380,762
	2004	4.50	21,687	3.14	15,150	-	-	-	-	2,051.93	9,886,984
	2005	3.90	20,347	2.50	13,047	-	-	-	-	2,054.21	10,707,532
	2006	3.07	16,214	2.63	13,896	-	-	-	-	2,036.79	10,771,711
	2007	2.01	11,077	2.44	13,434	-	-	-	-	1,966.55	10,830,909
	2008	1.51	7,657	2.40	12,125	-	-	-	-	2,000.43	10,123,298
	2009	1.54	7,713	1.24	6,199	-	-	-	-	1,989.41	9,977,618
	2010	1.56	8,838	1.22	6,872	-	-	-	-	1,919.16	10,849,176
	2011	1.70	8,635	0.99	5,055	-	-	-	-	1,737.21	8,836,999
Projected	**2012**	1.13	7,622	0.89	6,033	-	-	-	-	1,591.59	10,764,180
	2013	1.16	7,865	0.87	5,920	-	-	-	-	1,613.58	10,980,810
	2014	1.13	7,716	0.86	5,879	-	-	-	-	1,605.15	10,990,350
	2015	1.16	7,964	0.88	6,091	-	-	-	-	1,632.37	11,240,440
	2016	1.11	7,756	0.82	5,710	-	-	-	-	1,530.47	10,648,660
	2017	0.98	6,930	0.74	5,179	-	-	-	-	1,423.32	10,029,200
	2018	1.08	7,732	0.81	5,791	-	-	-	-	1,494.12	10,661,560
	2019	1.19	8,614	0.85	6,144	-	-	-	-	1,536.75	11,111,460
	2020	1.20	8,826	0.87	6,392	-	-	-	-	1,551.19	11,363,160
	2021	1.43	10,598	0.95	7,070	-	-	-	-	1,637.88	12,173,740

Table Notes:

1. Total emissions are in short tons.
2. Emission rates are on a lb/ Net MWh basis.
3. Total emissions are shown on a calendar year basis.
4. Emissions for JEA's 200MW share of Georgia Power Scherer Unit 4 are not included in actual or projected emissions totals.
5. Emissions from 200 MW UPS purchase power agreement with Georgia Power (expired on May 31, 2010) are not included in actual totals.
6. Actual emissions include JEA's entitlement of SJRPP Units 1 and 2, (nominally 50%)
7. Projected emissions include JEA's entitlement of SJRPP Units 1 and 2, 50% in 2012. JEA's sales to FPL are projected to suspend summer 2019. JEA's entitlement then increases to 80%.
8. Fleet mercury emissions were not continuously monitored and reported during this period. Mercury emissions were continuously monitored for part of the period in two units only, and data was not quality assured.
9. Projected mercury emissions will be as required for compliance with any finalized EPA regulations.
10. Actual PM Emissions were not continuously monitored and reported, but annual PM stack tests are performed on some of the units in the JEA fleet.
11. Projected PM emissions will be as required for compliance with any finalized EPA regulations.

41. Please identify if your company has developed a compliance strategy for the new or proposed EPA Rules listed below. If so, please provide a copy of the document for each rule and discuss the compliance strategies your company intends to employ. If not, explain the timeline for completion of the compliance strategy, including any regulatory approvals, for each rule.

- **Mercury and Air Toxics Standards (MATS) Rule**
- **Cross-State Air Pollution Rule (CSAPR)**
- **Cooling Water Intake Structures Rule (CWIS)**
- **Coal Combustion Residuals Rule (CCR), both for classification of coal ash as a "Non-Hazardous Waste" and as a "Special Waste"**

Compliance strategies:

- MATS: Solid fuel flexibility and oil usage will have to be evaluated for the JEA fleet.
- CSAPR: The SCRs may have to be utilized to reduce NOx emissions during the ozone season (May-Sep) in addition to held allowances.
- CWIS: Compliance strategy will be developed upon promulgation of final rule.
- CCR: Compliance strategy will be developed upon promulgation of final rule.

42. **Please identity, for each unit impacted by one or more of the EPA's new or proposed rules, what the impact is for each Rule, including unit retirement, curtailment, installation of additional emissions controls, fuel switching, or other impact identified by the Company. As part of this response, please provide the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy (in Excel).**

Air Rules: No retirements, curtailments, or installation of additional controls are anticipated to be required as a results of currently proposed or finalized rules. Some changes in fuel mix could occur, such as purchasing lower sulfur fuel for SJRPP, but no changes are currently anticipated.

Water Rules: CWIS has the potential to require upgrades to intake structures on NGS units depending on the final form of the rule.

Solid Waste Rules: Subtitle D: Only minor impacts are expected at NGS and SJRPP plants. Subtitle C: NS units would not be impacted under current operating conditions. SJRPP would need to close its active cells and send the waste out of state due to current Florida statutory limitations.

43. **Please identify, for each unit impacted by one or more of the EPA's new or proposed rules, what the estimated cost is for implementing each Rule over the course of the planning period. As part of this response, please provide the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy (in Excel).**

Potential costs associated with CWS and CCR rules are unknown at this time and will be determined as rules are finalized and implemented. Capital costs associated with MATS are expected to be approximately $350,000 per unit for additional CEMS for SJRPP Units 1 & 2 and for Northside Units 1 & 2. O&M costs for additional SCR operation are expected to be on the order of $500,000 per year per unit for SJRPP1 & 2, and $750,000 per year per unit for Northside 1 & 2. The potential cost of lower sulfur fuel on SJRPP units (for MATS or CSAPR) has not been estimated.

44. **Please identify, for each unit impacted by one or more of the EPA's new or proposed rules, when and for what duration units would be required to be offline due to retirements, curtailments, installation of additional emissions controls, or additional maintenance related to emissions controls. Please also include important dates relating to each rule. Please complete the table below and provide an electronic copy (in Excel).**

It is expected that no units would be required to be offline due to retirements, curtailments, installation of additional emissions controls, or additional maintenance related to emissions controls.

45. **Please provide a preliminary estimate of the cost required for your company to comply with each EPA Rule over the planning period (2012 – 2021). As part of this response, please detail the amount of capital costs, operations & maintenance (O&M costs, and fuel costs). Please also provide a description of the majority share of each of these costs (such as replacement generation, retrofitting of existing facilities, fuel switching, etc.).**

Potential costs associated with CWS and CCR rules are unknown at this time and will be determined as rules are finalized and implemented. Capital costs associated with MATS are expected to be approximately $350,000 per unit for additional CEMS for SJRPP Units 1 & 2 and for Northside Units 1 & 2. O&M costs for additional SCR operation are expected to be on the order of $500k per year per unit for SJRPP 1 & 2, and $750,000 per year per unit for Northside 1 & 2. The potential cost of lower sulfur fuel on SJRPP units (for MATS or CSAPR) has not been estimated.

46. **From a system-wide perspective, provide a preliminary estimate of the cost associated with each EPA Rule over the planning period, 2012 through 2021. As part of this response, please include the estimated additional capital cost expenditures, O&M costs, and fuel costs associated with each rule. Please complete the table below and provide an electronic copy (in Excel).**

Potential costs associated with CWS and CCR rules are unknown at this time and will be determined as rules are finalized and implemented. Capital costs associated with MATS are expected to be approximately $350,000 per unit for additional CEMS for SJRPP units 1&2 and for Northside units 1 & 2. O&M costs for additional SCR operation are expected to be on the order of $500,000 per year per unit for SJRPP1 & 2, and $750,000 per year per unit for Northside 1 & 2. The potential cost of lower sulfur fuel on SJRPP units (for MATS or CSAPR) has not been estimated.

47. Please discuss any expected reliability impacts resulting from each of the EPA Rules listed below. As part of this discussion, include the impact of transmission constraints and units not modified by the rule, that may be required to maintain reliability if unit retirements, curtailments, additional emissions control upgrades, or longer outage times are impacts of the EPA Rules.

- **Mercury and Air Toxics Standards (MATS) Rule**
- **Cross-State Air Pollution Rule (CSAPR)**
- **Cooling Water Intake Structures Rule (CWIS)**
- **Coal Combustion Residuals Rule (CCR)**

No reliability impacts are expected from any of the EPA Rules.

48. Please describe the process your company employs to develop a compliance strategy for proposed Environmental Protection Agency (EPA) rules.

To develop a compliance strategy, JEA forms ad hoc teams consisting of members from various groups such as fuels management services, legislative affairs, corporate planning, system operations, and environmental services as necessary to assess potential impacts of new regulations and actions necessary to comply with the various aspects of the proposed rules.

49. Please describe the process your company employs to develop a compliance strategy when EPA finalizes a rule.

As EPA rules are finalized, activities identified as being necessary and appropriate for compliance are budgeted and implemented after suitable review and approvals.

50. **Please explain how your company determines its optimum environmental compliance strategy, given that EPA's rules are in various stages of being revised or finalized.**

Various methods can be employed to determine JEA's optimum environmental compliance strategy. Technical evaluations, cost evaluations, production modeling, etc. can be performed to determine cost effective and optimum approaches to compliance.

51. **Please describe and provide the capital costs for any significant environmental compliance investments made by your company in response to environmental regulations within the past five years. How will these investments affect your company's compliance with recently finalized or proposed EPA regulations?**

SCR at SJRPP $282 million (total project), and Scherer (scrubber, SCR, ACI w/ baghouse) $150 million (JEA Percentage).

The above investments are expected to allow JEA to comply with most of the recently finalized or proposed regulations. Additional investment may be needed to comply with 316(b) and CCR

52. **Please provide a copy of any comments your company has filed with EPA during EPA's rule development proceedings for the following:**

- **Mercury and Air Toxics Standards**
- **Cross-State Air Pollution**
- **Cooling Water Intake Structures**
- **Coal Combustion Residuals**
- **Greenhouse Gas Emissions**

JEA's comment letters are included in this submittal. The corresponding filenames are listed below.

- Mercury and Air Toxics Standards: JEA MACT Comments 8-4-11.pdf
- Cross-State Air Pollution: JEA Comments – CATR 10-1-10.pdf and
  JEA Comments –CATR NODA 2-4-11.pdf
- Cooling Water Intake Structures: JEA Comments –316(b) 8-18-11.pdf
- Coal Combustion Residuals: JEA CCR Rule Proposal Comments 11-19-10.pdf
- Greenhouse Gas Emissions: JEA Comments –GHG-ANPR 11-27-08.pdf

53. On December 30, 2011, the U.S. Court of Appeals issued an order to stay the EPA's implementation of the final Cross-State Rule. Has the Court's order to stay implementation of the Cross-State Rule impacted your compliance strategies? If so, how?

Since Florida was not included in the annual SO2 and NOx allowance programs under the Cross-State Air Pollution Rule (CSAPR), JEA had developed possible alternative operating scenarios to comply with the lower level of ozone season allowances provided under that rule. With the stay of CSAPR, JEA's strategy returned to its prior method of operation within the allowance holdings provided by CAIR.

54. Does your company intend to participate in the allowance trading market associated with the rule? If so, do you expect to be a net seller or net buyer of allowances?

JEA expects to have sufficient allowances to operate under either rule without purchasing or selling allowances.

55. Please discuss your company's current coal residue disposal practices for each coal generating facility.

JEA's Northside Generating Station (NGS) consists of one boiler that uses natural gas and residual fuel oil for fuel and two circulating fluidized bed boilers that use primarily petroleum coke for fuel. Consequently, based on the current preamble language in the EPA co-proposal for a hazardous waste listing for CCRs, the NGS is not considered a producer of coal residue.

JEA's SJRPP facility operates several byproduct storage areas for CCRs. Areas I and II have been closed. Phase I of Area B was recently opened and currently accepts the following byproducts: fly ash, bottom ash, emission control wastes, off-specification flue gas desulfurization solids, and other miscellaneous solids from sedimentation basins, wastewater treatment basins, and cooling towers.

56. Please discuss your company's efforts to facilitate the recycling of coal waste into beneficial products. What percentage of your company's coal waste is used for beneficial purposes?

SJRPP has had an aggressive byproduct marketing program in place since it began operations in the late 1980s. SJRPP has pursued the following markets for its byproducts: use of synthetic gypsum in wallboard and agronomic applications, use of fly ash as cement plant feed or fuel, and use of fly and bottom ash in concrete batch plants and other aggregate markets. Since 2004, overall byproduct utilization rates have approached 75%, but recent declines in construction activity in Florida and the Southeast have adversely impacted these markets. Utilization rates for the last several years have declined to approximately 50%.

57. **EPA has proposed two regulatory schemes to regulate coal combustion residuals. Proposal one would regulate coal ash as "special waste" under Subtitle C of the Resource Conservation and Recovery Act; while under the second proposal, coal ash would be considered "non-hazardous waste" under Subtitle D of the Act. Please discuss any modifications that would be required at each of your company's coal facilities to comply with each of these two proposed regulatory schemes. Provide any available compliance strategies and expected costs for each facility and the timing of implementation of these compliance strategies. Provide the generating capacity for each unit that will require modifications.**

JEA has not conducted a detailed compliance strategy for SJRPP. JEA will do so when the regulatory to be undertaken by EPA becomes clarified and its direction more certain. JEA did provide input to the comment letter submitted to EPA by the American Public Power Association (APPA). This comment letter did contain rudimentary estimates of the compliance costs associated with both alternatives. The APPA comment letter can be viewed at the following site: http://publicpower.org/files/PDFs/APPAcommentsEPAHQRCRA20090640.pdf. The generating units themselves are not expected to be subject to requirements that would result in modifications. The ancillary waste management equipment and processes are expected to be subject to modifications.

58. **Please discuss how your company takes the potential for greenhouse gas regulations into account in its resource planning process and environmental compliance planning process.**

JEA's baseline analysis does not include any proposed limitations to greenhouse gas emissions. JEA performs sensitivity analysis at various potential CO2 emissions levels and costs.

FUEL SUPPLY & RELIABILITY

59. Please provide, on a system-wide basis, the historic annual fuel usage (in GWh) and historic average fuel price (in nominal $/MMBTU) for each fuel type utilized by the company in the period 2002 through 2011. Also, provide the forecasted annual fuel usage (in GWh) and forecasted annual average fuel price (in nominal $/MMBTU) for each fuel type forecasted to be used by the Company in the period 2012 through 2021. Please complete the table below and provide an electronic copy (in Excel).

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	2002	N/A	N/A	6,807	1.48	1,728	4.02	1,020	3.72	118	4.65
	2003	N/A	N/A	7,028	1.60	814	5.80	908	4.00	82	6.98
	2004	N/A	N/A	6,736	1.50	607	6.64	1,077	4.11	35	6.76
	2005	N/A	N/A	6,574	1.79	1,212	8.36	879	6.04	34	8.95
	2006	N/A	N/A	6,583	2.10	1,720	8.53	485	7.66	15	14.44
	2007	N/A	N/A	6,769	2.20	2,093	8.59	169	8.67	11	15.63
	2008	N/A	N/A	6,141	2.33	1,990	9.18	72	7.57	12	14.95
	2009	N/A	N/A	6,065	3.30	2,417	4.95	36	8.05	17	12.59
	2010	N/A	N/A	5,967	2.82	2,960	5.74	78	11.27	13	16.88
	2011	N/A	N/A	5,129	4.94	4,504	4.49	24	13.18	10	19.61
Projected	2012	N/A	N/A	4,540	3.23	5,691	4.52	113	13.13	7	18.59
	2013	N/A	N/A	4,522	3.17	5,379	4.80	88	17.09	4	23.85
	2014	N/A	N/A	4,291	3.17	5,484	5.05	94	19.07	8	26.51
	2015	N/A	N/A	4,507	3.28	5,324	5.42	86	20.51	26	28.43
	2016	N/A	N/A	4,444	3.53	4,966	5.91	76	21.36	1	29.60
	2017	N/A	N/A	3,634	3.65	4,848	6.43	76	22.16	5	30.69
	2018	N/A	N/A	4,220	3.76	4,288	6.97	94	22.89	5	31.69
	2019	N/A	N/A	4,972	4.14	3,875	7.40	75	23.56	2	32.60
	2020	N/A	N/A	5,139	4.29	3,841	7.98	86	24.15	3	33.42
	2021	N/A	N/A	6,805	4.41	2,671	8.59	47	24.75	1	34.25

60. 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.

61. For each fuel type (coal, natural gas, nuclear fuel, etc.), please discuss in detail the expected industry trends and factors for the period 2012 through 2021. As part of this discussion, please include how these factors and trends will affect the Company.

Using the PIRA's 2011 price projections developed by PIRA Energy Group as a basis, the price of natural gas is projected in nominal dollars to increase through 2021. 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.

The price of residual fuel oil is projected in nominal dollars to increase through 2021 and remain higher than the price of natural gas. Northside Unit 3 is JEA's only unit capable of operation on residual fuel oil. 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 coal prices in nominal dollars are expected to increase from 2012 to 2021. Coal price increases are due in part to increasing production costs which are a result of moving into reserves that are more costly to mine. 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.

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 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 2012 through 2021 period, JEA expects the petroleum coke market to typically trade at a discount to coal.

62. What steps has the Company taken to ensure gas supply availability and transport over the 2012 through 2021 planning period?

JEA utilizes firm transportation on both Florida Gas Transmission and Southern Natural Gas pipeline. In addition, JEA has entered into a firm long term agreement for gas supply delivered to Jacksonville using Florida Gas Transmission and Southern Natural Gas. To deliver natural gas to JEA's Greenland Energy Center, JEA has a long-term contract with SeaCoast Gas Transmission, LLC.

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.

63. Regarding existing and planned natural gas pipeline expansion projects, including new pipelines, affecting the Company for the period 2012 through 2021, 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.

64. 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 2012 through 2021.

At this time, while no specific projects have been identified consideration is being given to future projects that would deliverer natural gas from the emerging onshore unconventional wells to JEA's service territory.

65. Regarding unconventional natural gas production (shale gas, tight sands, etc.), please discuss in detail the expected industry factors and trends for the period 2012 through 2021. 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.

66. Regarding liquefied natural gas (LNG) imports to the United States, please discuss in detail the expected industry factors and trends for the period 2012 through 2021. 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 remain low as a result of international 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 consumption than its 11 percent contribution in 2010.

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. Given reduced LNG imports, it is likely that domestic supplies will be utilized primarily in support of the agreement.

67. Regarding the potential for liquefied natural gas (LNG) exports from the United States, please discuss in detail the expected industry factors and trends for the period 2012 through 2021. As part of this discussion, please include how these factors and trends will affect the Company.

According to EIA's 2012 Early Release Overview, the United States is projected to become an overall net exporter of LNG gas by 2016. The expected increase in LNG exports is a result of the increased use of LNG in markets outside of North America, strong domestic natural gas production, reduced pipeline imports, increased pipeline exports, and relatively low natural gas prices in the United States compared to other global markets. An increase in U.S. LNG exports may reduce the overall quantity of natural gas that JEA has available to purchase. Despite projected increases in natural gas exports, JEA expects sufficient gas supplies will continue to be available to me JEA's needs.

68. Regarding the potential for liquefied natural gas (LNG) exports from the United States, please discuss the potential impacts for natural gas prices within the US and how this would affect the Company.

As U.S. LNG exports increase, the supply of natural gas available for domestic consumption will decrease, assuming all other factors influencing the natural gas supply are held constant. Using the relationship between supply and demand, a domestic natural gas supply reduction would cause U.S natural gas prices to increase if the demand remained constant. Many factors influence the natural gas market, but taken in isolation, an increase in U.S. LNG export volume would most likely cause JEA to pay more for natural gas.

69. Please discuss in detail the Company's plans for the use of firm natural gas storage for the period 2012 through 2021.

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

70. 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.

71. **Regarding coal transportation by rail, please discuss the expected industry trends and factors for the period 2012 through 2021. 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 that started in 2011 through East Coast ports is expected to continue for the foreseeable future. With this surge in exporting of coal the Eastern railroads elected to purchase new equipment and lease sufficient equipment to guarantee movements of coal to export terminals would not be interrupted and also to not disrupt existing domestic coal movements. Recently, with reductions in coal usage due to low natural gas prices, utility coal inventory has increased resulting in lower rail car utilization. Since JEA has a long term lease for rail cars sufficient to fully operate three 110 car unit trains including spares, any shortage or surplus of rail equipment that might exist will have no impact on JEA for the foreseeable future.

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

72. **Regarding coal transportation by water, please discuss the expected industry trends and factors for the period 2012 through 2021. 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 of 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.

73. **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 2012 through 2021.**

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

74. **For the period 2012 through 2021, 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 short-term and long-term storage, 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.

75. **Regarding uranium production, please discuss the expected industry trends and factors for the period 2012 through 2021. As part of this discussion, please include how these factors and trends will affect the Company.**

Not Applicable

76. **Regarding the transportation of heavy fuel oil and distillate fuel oil, please discuss the expected industry trends and factors for the period 2012 through 2021. 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.

TRANSMISSION

77. 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. Please complete the table below and provide an electronic copy (in Excel).

JEA does not have any proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act.

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

Tables

Year	Month	Peak Demand (MW)	Date	Hour	Temperature (F)
2009	**1**	3060	22	8	21
	2	3064	6	8	23
	3	2476	4	8	29
	4	2048	24	17	89
	5	2451	11	17	94
	6	2754	22	16	98
	7	2628	2	17	95
	8	2735	12	17	95
	9	2417	25	17	89
	10	2423	9	16	93
	11	1710	10	13	82
	12	2151	29	8	31
2010	**1**	3224	11	8	20
	2	2667	26	8	27
	3	2335	4	8	32
	4	2016	23	18	87
	5	2368	3	17	93
	6	2817	15	17	102
	7	2749	27	16	99
	8	2731	18	17	96
	9	2595	10	17	95
	10	2199	28	17	89
	11	1785	8	8	33
	12	3053	14	8	20
2011	**1**	3062	14	8	23
	2	2346	9	8	32
	3	1746	24	18	87
	4	2251	27	18	93
	5	2418	24	17	94
	6	2668	22	17	96
	7	2653	21	17	96
	8	2756	11	17	98
	9	2359	12	17	93
	10	2049	11	17	87
	11	1749	16	19	63
	12	1931	8	8	35

Total Retail Energy Sales Forecasts (GWh)

Year	2007	2008	2009	2010	2011
2011 TYSP					14481
2010 TYSP				13283	13174
2009 TYSP			13838	13809	13936
2008 TYSP		14700	15016	15367	15717
2007 TYSP	14315	14701	15016	15367	15717
2006 TYSP	14441	14532	14876	15258	15642
2005 TYSP	14441	14532	14876	15258	
2004 TYSP	14873	14834	15200		
2003 TYSP	14873	15324			
2002 TYSP	15228				

Fuel Type	Renewable Resource Capacity (MW)	
	Existing (2012)	Planned (2021)
Solar	15.6	0.0
Wind	10.0	0.0
Biomass	<1.0	15.0
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	**41.7**	**24.6**

Existing Renewables as of January 1, 2012

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
North*	IC	LFG	1997			998	
Girvin	IC	LFG	1999	1200	1200	2,079	28%

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
Buckman	IC	OBG	2003	800	800	277	1.95%
Solar	SUN	PV	1999/2000/2001/2002/ 2003			162	

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
Landfill Energy Systems	Trail Ridge I	IC	LFG	Dec-09	9100	9100	71,803	94%	Dec-08	Dec-18
PSEG	Jacksonville Solar	SUN	PV	Sep-10			23,126		Sep-10	Sep-40

Non-Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
None										

Planned Renewables for 2012 through 2021

Utility-Owned Firm Renewable Resources

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

Utility-Owned Non-Firm Renewable Resources

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

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
Landfill Energy Systems	Trail Ridge II	IC	LFG	2012/2013	9100	9100	75,490	95%	Dec-12	Dec-26

Non-Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
None										

Renewable Costs and/or Payments for the Year Ending December 31, 2011.

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capital Expenses	O&M Expenses	Fuel Expenses	Total Expenses
-	-	-	Sum	Win	(MWh)	($)	($)	($)	($)
North	IC	LFG			998			8,858	8,858
Girvin	IC	LFG	1200	1200	2,079		341,143	40,839	381,982

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capital Expenses	O&M Expenses	Fuel Expenses	Total Expenses
-	-	-	Sum	Win	(MWh)	($)	($)	($)	($)
Buckman	IC	OBG	800	800	277		3,600		3,600
Solar	SUN	PV			162		22584		22584

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capacity Payments	Energy Payments	Total Payments
-	-	-	-	Sum	Win	(MWh)	($)	($)	($)
PSEG	Jacksonville Solar	SUN	PV			23,126	0	2,926,965	2,926,965

Non-Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capacity Payments	Energy Payments	Total Payments
-	-	-	-	Sum	Win	(MWh)	($)	($)	($)
None									

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

Customer Class	Residential			Commercial		
Renewable Type	# of Connections	Installed Capacity	Annual Output	# of Connections	Installed Capacity	Annual Output
	(-)	(kW)	(MWh)	(-)	(kW)	(MWh)
Solar PV	73	326	*	15	238	*
Solar Thermal (Water)	943	2,832	*	0	0	*
Wind Turbine	0	0	*	1	3.6	*

* Note: Customer's system not metered by JEA. Net metered customer data available for kWh sent to JEA from customer

Annual Output	Actual	Projected									
(GWh)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Utility	3.077										
Firm PPA	94.929	102.0	179.7	178.7	178.7	178.7	178.7	153.0	100.0	101.0	100.0
Non-Firm	0.439										
Customer	0.2										
Total	98.645	102.0	179.7	178.7	178.7	178.7	178.7	153.0	100.0	101.0	100.0

Year		As-Available Energy
		($/MWh)
Actual	2002	
	2003	
	2004	
	2005	
	2006	
	2007	
	2008	
	2009	
	2010	
	2011	
Projected	2012	
	2013	
	2014	
	2015	
	2016	
	2017	
	2018	
	2019	
	2020	
	2021	

[Investor-owned Utilities Only]

Plant	Unit #	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capacity Factor	Avail. Factor	In-Service Date	Heat Rate	Unit Fuel Cost
				Sum	Win	(MWh)	(%)	(%)	mm/yyyy	(BTU/kWh)	(¢/kWh)
Kennedy	7	GT	NG/FO2	150	191	19,011	1%	93%	06/2000	12,671	$6.53
Kennedy	8	GT	NG/FO2	150	191	95,656	6%	99%	06/2009	11,086	$6.53
Northside	1	ST	PC/BIT	293	293	1,023,647	43%	84%	05/2002	10,224	$4.64
Northside	2	ST	PC/BIT	293	293	1,174,590	48%	83%	02/2002	10,280	$4.64
Northside	3	ST	NG/FO6	524	524	1,000,121	22%	98%	07/1977	11,202	$6.23
Northside	33	GT	FO2	53	61.6	629	0.1%	87%	02/1975	18,107	$26.15
Northside	34	GT	FO2	53	61.6	641	0.1%	95%	01/1975	22,296	$26.15
Northside	35	GT	FO2	53	61.6	537	0.1%	99%	12/1974	24,810	$26.15
Northside	36	GT	FO2	53	61.6	380	0.1%	99%	12/1974	31,391	$26.15
Brandy Branch	1	GT	NG/FO2	150	191	36,365	2%	94%	05/2001	12,004	$7.21
Brandy Branch	2	CT	NG/FO2	150	191	1,005,530	60%	88%	05/2001	10,987	$4.34
Brandy Branch	3	CT	NG/FO2	150	191	1,066,138	63%	91%	10/2001	10,953	
Brandy Branch	4	CA	WH	201	223	1,147,916	77%	93%	01/2005	N/A	
Brandy Branch 2,3, & 4 Combined	2x1	CC		501	605	3,219,584	66%			7,087	
Greenland Energy Center	1	GT	NG/FO2	142	186	76,471	5%	100%	06/2011	11,783	$15.13
Greenland Energy Center	2	GT	NG/FO2	142	186	81,158	5%	100%	06/2011	11,524	$15.13
Girvin Landfill	1-2	IC	NG	1.2	1.2	2,190	13%		07/1997	17,306	
St. Johns River Power Park	1	ST	BIT/PC	313	319	1,899,995	62%	87%	03/1987	10,145	$3.48
St. Johns River Power Park	2	ST	BIT/PC	313	319	1,746,421	64%	96%	05/1988	10,168	$3.48
Scherer	4	ST	SUB/BIT	200	200	1,447,726	79%	91%	02/1989	10,058	$3.59

Brandy Branch 2,3, & 4 Combined is the 2x1 Combined Cycle unit comprised of Brandy Branch CT 2, CT 3, and HRSG 4.

Planned Unit Additions for 2012 through 2021

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		Commercial In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions / Uprates				
Combustion Turbine Unit Additions				
Combined Cycle Unit Additions				
Steam Turbine Unit Additions				

No Self-Build Unit Addtions Planned for 2012 - 2021

Projected Unit Information – Capacity Factor (%)

Plant	Unit	Unit	Fuel	Actual	Projected									
	#	Type	Type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Kennedy	7	GT	NG/FO2	1%	8%	6%	7%	14%	5%	7%	6%	6%	6%	3%
Kennedy	8	GT	NG/FO2	6%	4%	3%	4%	9%	2%	3%	3%	3%	3%	1%
Northside	1	ST	PC/BIT	48%	70%	80%	81%	80%	75%	80%	86%	85%	85%	80%
Northside	2	ST	PC/BIT	50%	68%	74%	82%	84%	77%	83%	87%	82%	86%	81%
Northside	3	ST	NG/FO6	23%	31%	24%	26%	24%	21%	21%	26%	20%	24%	13%
Northside	33	GT	FO2	0.1%	0.4%	0.3%	0.5%	1.6%	0.1%	0.4%	0.4%	0.2%	0.3%	0.1%
Northside	34	GT	FO2	0.1%	0.4%	0.2%	0.4%	1.4%	0.1%	0.3%	0.3%	0.1%	0.2%	0.0%
Northside	35	GT	FO2	0.1%	0.3%	0.1%	0.3%	1.2%	0.1%	0.2%	0.2%	0.0%	0.1%	0.1%
Northside	36	GT	FO2	0.1%	0.3%	0.1%	0.3%	1.0%	0.0%	0.1%	0.1%	0.0%	0.1%	0.0%
Brandy Branch	1	GT	NG/FO2	2%	1%	1%	1%	4%	1%	1%	1%	1%	1%	1%
Brandy Branch 2,3, & 4 Combined	2x1	CC		66%	87%	88%	88%	77%	83%	79%	62%	60%	55%	43%
Greenland Energy Center	1	GT	NG/FO2	5%	5%	4%	5%	14%	3%	6%	6%	4%	6%	2%
Greenland Energy Center	2	GT	NG/FO2	5%	3%	2%	3%	9%	2%	3%	4%	2%	4%	1%
St. Johns River Power Park	1	ST	BIT/PC	62%	61%	54%	57%	51%	61%	51%	41%	60%	55%	65%
St. Johns River Power Park	2	ST	BIT/PC	64%	47%	42%	44%	42%	52%	47%	51%	64%	61%	68%
Scherer	4	ST	SUB/BIT	81%	74%	92%	68%	94%	58%	32%	77%	39%	25%	33%

Plant Name	Unit Type	Fuel Type	Summer Capacity	In-Service Date	Potential Conversion
(-)	(-)	(-)	(MW)	(MM/YY)	
Northside 3	ST	NG/FO6	524	07/77	Combined Cycle
SJRPP 1	ST	BIT/PC	313	03/87	Combined Cycle
SJRPP 2	ST	BIT/PC	313	05/88	Combined Cycle
Kennedy GT 7	GT	NG/FO2	150	06/00	Combined Cycle
Kennedy GT 8	GT	NG/FO2	150	06/09	Combined Cycle
Brandy Branch GT 1	GT	NG/FO2	150	05/01	Combined Cycle
GEC GT 1	GT	NG	142	06/11	Combined Cycle
GEC GT 2	GT	NG	142	06/11	Combined Cycle

Year		System Average Heat Rate
		(BTU/kWh)
Actual	2002	
	2003	
	2004	
	2005	
	2006	
	2007	
	2008	
	2009	
	2010	
	2011	

[Investor-owned Utilities Only]

Year		Residential Bill ($/1200-kWh)
Actual	2002	80.68
	2003	80.68
	2004	80.68
	2005	85.48
	2006	105.88
	2007	104.9
	2008	114.02
	2009	138.23
	2010	131.45
	2011	143.02

Fuel Type	Unit Type	Summer Capacity Changes (MW)	
		2011 TYSP (2011-2020)	2012 TYSP (2012-2021)
Natural Gas	Combined Cycle	0.00	0.00
	Combustion Turbine	0.00	0.00
	Steam	0.00	0.00
Coal	Steam	0.00	0.00
	Integrated Coal Gasification	0.00	0.00
Oil	Combustion Turbine & Diesel	0.00	0.00
	Steam	0.00	0.00
Nuclear	Steam	0.00	0.00
Firm Purchases	Independent Power Producer (IPP)	0.00	0.00
	Interchange	40.00	(130.00)
	Non-Utility Generator (NUG)	0.00	0.00
	Renewables	3.00	0.00
NET CAPACITY ADDITIONS		**43.00**	**(130.00)**

Capacity / Demand at Time of Monthly Peak (MW)

Year	Month	Installed Capacity	Scheduled Maintenance	Forced Outages	Available Capacity	Peak Demand
2009	1	3605	124	0	3481	3060
	2	3605	124	0	3481	3064
	3	3605	315	0	3290	2476
	4	3161	0	0	3161	2048
	5	3161	0	0	3161	2451
	6	3311	0	508	2803	2754
	7	3311	0	0	3311	2628
	8	3311	0	0	3311	2735
	9	3311	293	0	3018	2417
	10	3311	586	0	2725	2423
	11	3584	586	0	2998	1710
	12	3734	0	0	3734	2151
2010	1	3734	0	44	3690	3224
	2	3734	200	319	3215	2667
	3	3734	200	191	3343	2335
	4	3311	556	0	2755	1903
	5	3311	0	0	3311	2368
	6	3104	0	191	2913	2817
	7	3104	0	0	3104	2749
	8	3104	0	90	3014	2731
	9	3104	0	231	2873	2595
	10	3104	0	53	3051	2199
	11	3377	524	0	2853	1785
	12	3377	524	524	2329	3053
2011	1	3377	0	319	3058	3062
	2	3377	0	387	2990	2346
	3	3377	0	291	3086	1746
	4	3104	524	0	2580	2251
	5	3104	0	236	2868	2418
	6	3388	0	0	3388	2668
	7	3388	0	0	3388	2653
	8	3388	0	0	3388	2756
	9	3388	0	456	2932	2359
	10	3388	178	100	3110	2049
	11	3749	0	0	3749	1749
	12	3749	0	191	3558	1931

Existing Purchased Power Agreements as of January 1, 2012

Seller	**Contract Term**		**Contract Capacity (MW)**		**Annual Generation**	**Capacity Factor**	**Primary Fuel**	**Description**
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
NONE								

Planned Purchased Power Agreements for 2012 through 2021

Seller	**Contract Term**		**Contract Capacity (MW)**		**Annual Generation**	**Capacity Factor**	**Primary Fuel**	**Description**
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
MEAG	11/1/2016	10/31/2036	100	100	832	95%	NUC	PPA
MEAG	11/1/2017	10/31/2037	100	100	832	95%	NUC	PPA

Existing Power Sales as of January 1, 2012

Purchaser	**Contract Term**		**Contract Capacity (MW)**		**Annual Generation**	**Capacity Factor**	**Primary Fuel**	**Description**
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
FPL	1986	2019 *	188	192	1,007	60%	BIT	PPA
FPL	1987	2019 *	188	192	1,007	60%	BIT	PPA

* Projected early suspension date is summer 2019. Not to exceed date is 10/2021.

Planned Power Sales for 2012 through 2021

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

Year		SOX		NOX		Mercury		Particulates		CO2e	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	**2002**	3.18	24,152	2.31	17,512	-	-	-	-	1,261.96	9,569,813
	2003	4.35	21,555	3.31	16,413	-	-	-	-	2,096.34	10,380,762
	2004	4.50	21,687	3.14	15,150	-	-	-	-	2,051.93	9,886,984
	2005	3.90	20,347	2.50	13,047	-	-	-	-	2,054.21	10,707,532
	2006	3.07	16,214	2.63	13.896	-	-	-	-	2,036.79	10,771,711
	2007	2.01	11,077	2.44	13,434	-	-	-	-	1,966.55	10,830,909
	2008	1.51	7,657	2.40	12,125	-	-	-	-	2,000.43	10,123,298
	2009	1.54	7,713	1.24	6,199	-	-	-	-	1,989.41	9,977,618
	2010	1.56	8,838	1.22	6,872	-	-	-	-	1,919.16	10,849,176
	2011	1.70	8,635	0.99	5,055	-	-	-	-	1,737.21	8,836,999
Projected	**2012**	1.13	7,622	0.89	6,033	-	-	-	-	1,591.59	10,764,180
	2013	1.16	7,865	0.87	5,920	-	-	-	-	1,613.58	10,980,810
	2014	1.13	7,716	0.86	5,879	-	-	-	-	1,605.15	10,990,350
	2015	1.16	7,964	0.88	6,091	-	-	-	-	1,632.37	11,240,440
	2016	1.11	7,756	0.82	5,710	-	-	-	-	1,530.47	10,648,660
	2017	0.98	6,930	0.74	5,179	-	-	-	-	1,423.32	10,029,200
	2018	1.08	7,732	0.81	5,791	-	-	-	-	1,494.12	10,661,560
	2019	1.19	8,614	0.85	6,144	-	-	-	-	1,536.75	11,111,460
	2020	1.20	8,826	0.87	6,392	-	-	-	-	1,551.19	11,363,160
	2021	1.43	10,598	0.95	7,070	-	-	-	-	1,637.88	12,173,740

Notes:

1. Total emissions are in short tons.
2. Emission rates are on a lb/ Net MWh basis.
3. Total emissions are shown on a calendar year basis.
4. Emissions for JEA's 200MW share of Georgia Power Scherer Unit 4 are not included in actual or projected emissions totals.
5. Emissions from 200 MW UPS purchase power agreement with Georgia Power (expired on May 31, 2010) are not included in actual totals.
6. Actual emissions include JEA's entitlement of SJRPP Units 1 and 2, (nominally 50%)
7. Projected emissions include JEA's entitlement of SJRPP Units 1 and 2, 50% in 2012. JEA's sales to FPL are projected to suspend summer 2019. JEA's
8. Fleet mercury emissions were not continuously monitored and reported during this period. Mercury emissions were continuously monitored for part of the period in two units only, and data was not quality assured.
9. Projected mercury emissions will be as required for compliance with any finalized EPA regulations.
10. Actual PM Emissions were not continuously monitored and reported, but annual PM stack tests are performed on some of the units in the JEA fleet.
11. Projected PM emissions will be as required for compliance with any finalized EPA regulations.

Unit	Unit Type	Fuel Type	Net Summer Capacity (MW)	Type of New or Proposed EPA Rules Impacts				
				MATS	CSAPR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste

See Word Document for Discussion

Unit	Unit Type	Fuel Type	Net Summer Capacity	Estimated Cost of New or Proposed EPA Rules Impacts ($ million)					
			(MW)	MATS	CSAPR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste	Total

Costs to be determined when rules are finalized

Unit	Unit Type	Fuel Type	Net Summer Capacity	Estimated Timing of New or Proposed EPA Rules Impacts (Month/Year – Duration)				
			(MW)	MATS	CSAPR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste
None								

EPA Rule	Capital Costs ($ Millions)	O&M Costs ($ Millions)	Fuel Costs ($ Millions)	Total Costs ($ Millions)
Mercury and Air Toxics Standards (MATS) Rule				
Cross-State Air Pollution Rule (CSAPR)				
Cooling Water Intake Structures Rule (CWIS)				
Coal Combustion Residuals Rule (CCR)				

Costs to be determined when rules are finalized

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	**2002**	N/A	N/A	6,807	1.48	1,728	4.02	1,020	3.72	118	4.65
	2003	N/A	N/A	7,028	1.60	814	5.80	908	4.00	82	6.98
	2004	N/A	N/A	6,736	1.50	607	6.64	1,077	4.11	35	6.76
	2005	N/A	N/A	6,574	1.79	1,212	8.36	879	6.04	34	8.95
	2006	N/A	N/A	6,583	2.10	1,720	8.53	485	7.66	15	14.44
	2007	N/A	N/A	6,769	2.20	2,093	8.59	169	8.67	11	15.63
	2008	N/A	N/A	6,141	2.33	1,990	9.18	72	7.57	12	14.95
	2009	N/A	N/A	6,065	3.30	2,417	4.95	36	8.05	17	12.59
	2010	N/A	N/A	5,967	2.82	2,960	5.74	78	11.27	13	16.88
	2011	N/A	N/A	5,129	4.94	4,504	4.49	24	13.18	10	19.61
Projected	**2012**	N/A	N/A	4,540	3.23	5,691	4.52	113	13.13	7	18.59
	2013	N/A	N/A	4,522	3.17	5,379	4.80	88	17.09	4	23.85
	2014	N/A	N/A	4,291	3.17	5,484	5.05	94	19.07	8	26.51
	2015	N/A	N/A	4,507	3.28	5,324	5.42	86	20.51	26	28.43
	2016	N/A	N/A	4,444	3.53	4,966	5.91	76	21.36	1	29.60
	2017	N/A	N/A	3,634	3.65	4,848	6.43	76	22.16	5	30.69
	2018	N/A	N/A	4,220	3.76	4,288	6.97	94	22.89	5	31.69
	2019	N/A	N/A	4,972	4.14	3,875	7.40	75	23.56	2	32.60
	2020	N/A	N/A	5,139	4.29	3,841	7.98	86	24.15	3	33.42
	2021	N/A	N/A	6,805	4.41	2,671	8.59	47	24.75	1	34.25

Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	Commercial In-Service Date
NONE					

Appendix A

History and Forecast of Summer Peak Demand
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2002	2562	0	0	0	0	0	0	0	2562
2003	2535	0	0	0	0	0	0	0	2535
2004	2539	0	0	0	0	0	0	0	2539
2005	2815	0	0	0	0	0	0	0	2815
2006	2835	0	0	0	0	0	0	0	2835
2007	2897	0	0	0	0	0	0	0	2897
2008	2866	0	0	0	0	0	0	0	2866
2009	2754	0	0	0	0	0	0	0	2754
2010	2817	0	0	0	0	0	0	0	2817
2011	2756	0	0	0	0	0	0	0	2756
FORECAST:									
2012	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2014	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2019	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2020	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2021	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

History and Forecast of Summer Peak Demand
Low Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) C / I Load Management	(9) C / I Conservation	(10) Net Firm Demand
HISTORY:									
2002	2562	0	0	0	0	0	0	0	2562
2003	2535	0	0	0	0	0	0	0	2535
2004	2539	0	0	0	0	0	0	0	2539
2005	2815	0	0	0	0	0	0	0	2815
2006	2835	0	0	0	0	0	0	0	2835
2007	2897	0	0	0	0	0	0	0	2897
2008	2866	0	0	0	0	0	0	0	2866
2009	2754	0	0	0	0	0	0	0	2754
2010	2817	0	0	0	0	0	0	0	2817
2011	2756	0	0	0	0	0	0	0	2756
FORECAST:									
2012	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2014	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2019	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2020	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2021	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

History and Forecast of Winter Peak Demand
High Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) C / I Load Management	(9) C / I Conservation	(10) Net Firm Demand
HISTORY:									
2001/02	2590	0	0	0	0	0	0	0	2590
2002/03	3083	0	0	0	0	0	0	0	3083
2003/04	2668	0	0	0	0	0	0	0	2668
2004/05	2860	0	0	0	0	0	0	0	2860
2005/06	2919	0	0	0	0	0	0	0	2919
2006/07	2722	0	0	0	0	0	0	0	2722
2007/08	2914	0	0	0	0	0	0	0	2914
2008/09	3054	0	0	0	0	0	0	0	3054
2009/10	3224	0	0	0	0	0	0	0	3224
2010/11	3062	0	0	0	0	0	0	0	3062
FORECAST:									
2011/12	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2012/13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013/14	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2014/15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015/16	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016/17	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2017/18	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2018/19	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2019/20	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2020/21	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

History and Forecast of Winter Peak Demand
Low Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) C / I Load Management	(9) C / I Conservation	(10) Net Firm Demand
HISTORY:									
2001/02	2590	0	0	0	0	0	0	0	2590
2002/03	3083	0	0	0	0	0	0	0	3083
2003/04	2668	0	0	0	0	0	0	0	2668
2004/05	2860	0	0	0	0	0	0	0	2860
2005/06	2919	0	0	0	0	0	0	0	2919
2006/07	2722	0	0	0	0	0	0	0	2722
2007/08	2914	0	0	0	0	0	0	0	2914
2008/09	3054	0	0	0	0	0	0	0	3054
2009/10	3224	0	0	0	0	0	0	0	3224
2010/11	3062	0	0	0	0	0	0	0	3062
FORECAST:									
2011/12	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2012/13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013/14	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2014/15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015/16	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016/17	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2017/18	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2018/19	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2019/20	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2020/21	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

History and Forecast of Annual Net Energy for Load - GWH
High Case

(1) 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 (%)
HISTORY:								
2002	12983	0	0	0	0	0	12983	57%
2003	13204	0	0	0	0	0	13204	49%
2004	13243	0	0	0	0	0	13243	57%
2005	13696	0	0	0	0	0	13696	55%
2006	13811	0	0	0	0	0	13811	54%
2007	13854	0	0	0	0	0	13854	55%
2008	13530	0	0	0	0	0	13530	53%
2009	13155	0	0	0	0	0	13155	49%
2010	13842	0	0	0	0	0	13842	49%
2011	12980	0	0	0	0	0	12980	48%
FORECAST:								
2012	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2014	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2019	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2020	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2021	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

History and Forecast of Annual Net Energy for Load - GWH
Low Case

(1) 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 (%)
HISTORY:								
2002	12983	0	0	0	0	0	12983	57%
2003	13204	0	0	0	0	0	13204	49%
2004	13243	0	0	0	0	0	13243	57%
2005	13696	0	0	0	0	0	13696	55%
2006	13811	0	0	0	0	0	13811	54%
2007	13854	0	0	0	0	0	13854	55%
2008	13530	0	0	0	0	0	13530	53%
2009	13155	0	0	0	0	0	13155	49%
2010	13842	0	0	0	0	0	13842	49%
2011	12980	0	0	0	0	0	12980	48%
FORECAST:								
2012	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2014	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2019	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2020	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2021	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Existing Generating Unit Operating Performance

(1)	(2)	(3)		(4)		(5)		(6)	
		Planned Outage Factor (POF)		Forced Outage Factor (FOF)		Equivalent Availability Factor (EAF)		Average Net Operating Heat Rate (ANOHR)	
Plant Name	Unit No.	Historical	Projected	Historical	Projected	Historical	Projected	Historical	Projected
Kennedy GT	7	0%	1%	1%	5%	95%	94%	12,671	11,344
Kennedy GT	8	0%	1%	1%	5%	95%	94%	11,086	11,209
Northside	1	10%	8%	4%	6%	84%	86%	10,224	9,606
Northside	2	12%	8%	3%	6%	83%	86%	10,280	9,412
Northside	3	7%	4%	1%	5%	91%	91%	11,202	11,652
Northside GT	33	8%	3%	8%	5%	80%	92%	18,107	14,088
Northside GT	34	8%	6%	1%	5%	89%	89%	22,296	13,655
Northside GT	35	0%	6%	0%	5%	97%	89%	24,810	13,274
Northside GT	36	0%	6%	0%	5%	100%	89%	31,391	13,120
Brandy Branch GT	1	0%	1%	1%	5%	97%	94%	12,004	11,105

Nominal, Delivered Residual Oil Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
HISTORY:									
2009	N/A	N/A	N/A	50.73	8.05	6.3	N/A	N/A	N/A
2010	N/A	N/A	N/A	71.03	11.27	40.0	N/A	N/A	N/A
2011	N/A	N/A	N/A	98.33	15.61	38.4	N/A	N/A	N/A
FORECAST:									
2012	N/A	N/A	N/A	82.72	13.13	-15.9	N/A	N/A	N/A
2013	N/A	N/A	N/A	107.67	17.09	30.2	N/A	N/A	N/A
2014	N/A	N/A	N/A	120.14	19.07	11.6	N/A	N/A	N/A
2015	N/A	N/A	N/A	129.21	20.51	7.6	N/A	N/A	N/A
2016	N/A	N/A	N/A	134.57	21.36	4.1	N/A	N/A	N/A
2017	N/A	N/A	N/A	139.61	22.16	3.7	N/A	N/A	N/A
2018	N/A	N/A	N/A	144.21	22.89	3.3	N/A	N/A	N/A
2019	N/A	N/A	N/A	148.43	23.56	2.9	N/A	N/A	N/A
2020	N/A	N/A	N/A	152.15	24.15	2.5	N/A	N/A	N/A
2021	N/A	N/A	N/A	155.93	24.75	2.5	N/A	N/A	N/A

ASSUMPTIONS: 6.3 mmBtu/BBL, 0.02% ash, 1.8% sulfur

Nominal, Delivered Residual Oil Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
HISTORY:									
2009	N/A	N/A	N/A	50.73	8.05	6.3	N/A	N/A	N/A
2010	N/A	N/A	N/A	71.03	11.27	40.0	N/A	N/A	N/A
2011	N/A	N/A	N/A	98.33	15.61	38.4	N/A	N/A	N/A
FORECAST:									
2012	N/A	N/A	N/A	103.40	16.41	-19.8	N/A	N/A	N/A
2013	N/A	N/A	N/A	134.58	21.36	37.7	N/A	N/A	N/A
2014	N/A	N/A	N/A	150.18	23.84	14.5	N/A	N/A	N/A
2015	N/A	N/A	N/A	161.52	25.64	9.4	N/A	N/A	N/A
2016	N/A	N/A	N/A	168.21	26.70	5.2	N/A	N/A	N/A
2017	N/A	N/A	N/A	174.51	27.70	4.7	N/A	N/A	N/A
2018	N/A	N/A	N/A	180.26	28.61	4.1	N/A	N/A	N/A
2019	N/A	N/A	N/A	185.54	29.45	3.7	N/A	N/A	N/A
2020	N/A	N/A	N/A	190.18	30.19	3.1	N/A	N/A	N/A
2021	N/A	N/A	N/A	194.91	30.94	3.1	N/A	N/A	N/A

ASSUMPTIONS: 6.3 mmBtu/BBL, 0.02% ash, 1.8% sulfur

Nominal, Delivered Residual Oil Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
HISTORY:									
2009	N/A	N/A	N/A	50.73	8.05	6.3	N/A	N/A	N/A
2010	N/A	N/A	N/A	71.03	11.27	40.0	N/A	N/A	N/A
2011	N/A	N/A	N/A	98.33	15.61	38.4	N/A	N/A	N/A
FORECAST:									
2012	N/A	N/A	N/A	62.04	9.85	-11.9	N/A	N/A	N/A
2013	N/A	N/A	N/A	80.75	12.82	22.6	N/A	N/A	N/A
2014	N/A	N/A	N/A	90.11	14.30	8.7	N/A	N/A	N/A
2015	N/A	N/A	N/A	96.91	15.38	5.7	N/A	N/A	N/A
2016	N/A	N/A	N/A	100.93	16.02	3.1	N/A	N/A	N/A
2017	N/A	N/A	N/A	104.71	16.62	2.8	N/A	N/A	N/A
2018	N/A	N/A	N/A	108.16	17.17	2.5	N/A	N/A	N/A
2019	N/A	N/A	N/A	111.32	17.67	2.2	N/A	N/A	N/A
2020	N/A	N/A	N/A	114.11	18.11	1.9	N/A	N/A	N/A
2021	N/A	N/A	N/A	116.94	18.56	1.9	N/A	N/A	N/A

ASSUMPTIONS: 6.3 mmBtu/BBL, 0.02% ash, 1.8% sulfur

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:						
2009	73.40	12.59	-15.8	4.95	5.23	-46.1
2010	98.41	16.88	34.1	5.74	6.07	16.1
2011	114.35	19.61	16.2	4.49	4.75	-21.8
FORECAST:						
2012	108.38	18.59	-5.2	4.52	4.78	0.7
2013	139.05	23.85	28.3	4.80	5.08	6.2
2014	154.55	26.51	11.2	5.05	5.34	5.2
2015	165.75	28.43	7.2	5.42	5.73	7.3
2016	172.57	29.60	4.1	5.91	6.25	9.0
2017	178.92	30.69	3.7	6.43	6.80	8.8
2018	184.75	31.69	3.3	6.97	7.37	8.4
2019	190.06	32.60	2.9	7.40	7.83	6.2
2020	194.84	33.42	2.5	7.98	8.44	7.8
2021	199.68	34.25	2.5	8.59	9.09	7.6

ASSUMPTIONS FOR DISTILLATE OIL: 5.83 mmBtu/BBL, 0.01% ash, 0.25% sulfur

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:						
2009	73.40	12.59	-15.8	4.95	5.23	-46.1
2010	98.41	16.88	34.1	5.74	6.07	16.1
2011	114.35	19.61	16.2	4.49	4.75	-21.8
FORECAST:						
2012	135.47	23.24	-6.5	5.65	5.98	0.9
2013	173.81	29.81	35.4	6.00	6.35	7.7
2014	193.19	33.14	13.9	6.31	6.68	6.5
2015	207.18	35.54	9.1	6.78	7.17	9.2
2016	215.71	37.00	5.1	7.39	7.82	11.3
2017	223.65	38.36	4.6	8.04	8.50	11.0
2018	230.94	39.61	4.1	8.71	9.22	10.5
2019	237.57	40.75	3.6	9.25	9.79	7.7
2020	243.55	41.78	3.1	9.98	10.55	9.8
2021	249.60	42.81	3.1	10.74	11.36	9.6

ASSUMPTIONS FOR DISTILLATE OIL: 5.83 mmBtu/BBL, 0.01% ash, 0.25% sulfur

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:						
2009	73.40	12.59	-15.8	4.95	5.23	-46.1
2010	98.41	16.88	34.1	5.74	6.07	16.1
2011	114.35	19.61	16.2	4.49	4.75	-21.8
FORECAST:						
2012	81.28	13.94	-3.9	3.39	3.59	0.5
2013	104.28	17.89	21.2	3.60	3.81	4.6
2014	115.91	19.88	8.4	3.79	4.01	3.9
2015	124.31	21.32	5.4	4.07	4.30	5.5
2016	129.43	22.20	3.1	4.43	4.69	6.8
2017	134.19	23.02	2.8	4.82	5.10	6.6
2018	138.56	23.77	2.4	5.23	5.53	6.3
2019	142.54	24.45	2.2	5.55	5.87	4.6
2020	146.13	25.07	1.9	5.99	6.33	5.9
2021	149.76	25.69	1.9	6.44	6.82	5.7

ASSUMPTIONS FOR DISTILLATE OIL: 5.83 mmBtu/BBL, 0.01% ash, 0.25% sulfur

Nominal, Delivered 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:												
2009	74.47	3.30	43.6	19.70%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2010	63.34	2.82	-14.9	10.70%	N/A	N/A	N/A	N/A	145.44	5.58	N/A	100%
2011	104.78	4.94	65.4	0%	N/A	N/A	N/A	N/A	73.53	3.22	-49.4	100%
FORECAST:												
2012	117.04	5.04	11.7	0%	N/A	N/A	N/A	N/A	84.87	3.69	15.4	0%
2013	105.72	4.56	-9.7	0%	N/A	N/A	N/A	N/A	86.39	3.76	1.8	0%
2014	100.46	4.33	-5.0	100%	N/A	N/A	N/A	N/A	86.95	3.78	0.6	100%
2015	101.75	4.39	1.3	100%	N/A	N/A	N/A	N/A	87.59	3.81	0.7	100%
2016	102.67	4.43	0.9	100%	N/A	N/A	N/A	N/A	88.38	3.84	0.9	100%
2017	103.25	4.45	0.6	100%	N/A	N/A	N/A	N/A	88.81	3.86	0.5	100%
2018	103.78	4.47	0.5	100%	N/A	N/A	N/A	N/A	89.22	3.88	0.5	100%
2019	104.15	4.49	0.4	100%	N/A	N/A	N/A	N/A	89.63	3.90	0.5	100%
2020	105.36	4.54	1.2	100%	N/A	N/A	N/A	N/A	90.02	3.91	0.4	100%
2021	105.38	4.54	0.0	100%	N/A	N/A	N/A	N/A	90.16	3.92	0.2	100%

Colombia - 11,600 Btu/lb, 0.8 lbs. SO2/MMBtu

Illinois Basin - 11,500 Btu/lb, 5.0 lbs. SO2/MMBtu

Nominal, Delivered 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:												
2009	74.47	3.30	43.6	19.70%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2010	63.34	2.82	-14.9	10.70%	N/A	N/A	N/A	N/A	145.44	5.58	N/A	100%
2011	104.78	4.94	65.4	0	N/A	N/A	N/A	N/A	73.53	3.22	-49.4	1
FORECAST:												
2012	146.29	6.31	14.6	0	N/A	N/A	N/A	N/A	106.09	4.61	19.3	0
2013	132.15	5.70	-12.1	0	N/A	N/A	N/A	N/A	107.99	4.70	2.2	0
2014	125.57	5.41	-6.2	1.25	N/A	N/A	N/A	N/A	108.69	4.73	0.8	1.25
2015	127.19	5.48	1.6	1.25	N/A	N/A	N/A	N/A	109.49	4.76	0.9	1.25
2016	128.34	5.53	1.1	1.25	N/A	N/A	N/A	N/A	110.48	4.80	1.1	1.25
2017	129.06	5.56	0.7	1.25	N/A	N/A	N/A	N/A	111.01	4.83	0.6	1.25
2018	129.73	5.59	0.6	1.25	N/A	N/A	N/A	N/A	111.52	4.85	0.6	1.25
2019	130.19	5.61	0.4	1.25	N/A	N/A	N/A	N/A	112.03	4.87	0.6	1.25
2020	131.70	5.68	1.5	1.25	N/A	N/A	N/A	N/A	112.52	4.89	0.5	1.25
2021	131.72	5.68	0.0	1.25	N/A	N/A	N/A	N/A	112.71	4.90	0.2	1.25

Colombia - 11,600 Btu/lb, 0.8 lbs. SO2/MMBtu

Illinois Basin - 11,500 Btu/lb, 5.0 lbs. SO2/MMBtu

Nominal, Delivered 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:												
2009	74.47	3.30	43.6	19.70%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2010	63.34	2.82	-14.9	10.70%	N/A	N/A	N/A	N/A	145.44	5.58	N/A	100%
2011	104.78	4.94	65.4	0	N/A	N/A	N/A	N/A	73.53	3.22	-49.4	1
FORECAST:												
2012	87.78	3.78	8.8	0	N/A	N/A	N/A	N/A	63.65	2.77	11.6	0
2013	79.29	3.42	-7.3	0	N/A	N/A	N/A	N/A	64.80	2.82	1.3	0
2014	75.34	3.25	-3.7	0.75	N/A	N/A	N/A	N/A	65.21	2.84	0.5	0.75
2015	76.31	3.29	1.0	0.75	N/A	N/A	N/A	N/A	65.70	2.86	0.6	0.75
2016	77.00	3.32	0.7	0.75	N/A	N/A	N/A	N/A	66.29	2.88	0.7	0.75
2017	77.43	3.34	0.4	0.75	N/A	N/A	N/A	N/A	66.61	2.90	0.4	0.75
2018	77.84	3.36	0.4	0.75	N/A	N/A	N/A	N/A	66.91	2.91	0.3	0.75
2019	78.12	3.37	0.3	0.75	N/A	N/A	N/A	N/A	67.22	2.92	0.3	0.75
2020	79.02	3.41	0.9	0.75	N/A	N/A	N/A	N/A	67.51	2.94	0.3	0.75
2021	79.03	3.41	0.0	0.75	N/A	N/A	N/A	N/A	67.62	2.94	0.1	0.75

Colombia - 11,600 Btu/lb, 0.8 lbs. SO2/MMBtu

Illinois Basin - 11,500 Btu/lb, 5.0 lbs. SO2/MMBtu

Nominal, Delivered Nuclear Fuel and Firm Purchases

(1)	(2)	(3)	(4)	(5)
	Nuclear		Firm Purchases	
Year	c/MBTU	Escalation %	$/MWh	Escalation %
HISTORY:				
2009	N/A	N/A	49.69	29.7%
2010	N/A	N/A	53.47	7.6%
2011	N/A	N/A	61.02	14.1%
FORECAST:				
2012	N/A	N/A	92.00	50.8%
2013	N/A	N/A	78.37	-14.8%
2014	N/A	N/A	79.56	1.5%
2015	N/A	N/A	80.77	1.5%
2016	N/A	N/A	80.99	0.3%
2017	N/A	N/A	82.87	2.3%
2018	N/A	N/A	85.44	3.1%
2019	N/A	N/A	86.31	1.0%
2020	N/A	N/A	86.04	-0.3%
2021	N/A	N/A	86.52	0.6%

Financial Assumptions
Base Case

AFUDC RATE ______________ %

CAPITALIZATION RATIOS:

DEBT ______________ %
PREFERRED ______________ %
EQUITY ______________ %

RATE OF RETURN

DEBT ______________ %
PREFERRED ______________ %
EQUITY ______________ %

INCOME TAX RATE:

STATE ______________ %
FEDERAL ______________ %
EFFECTIVE ______________ %

OTHER TAX RATE: ______________ %

DISCOUNT RATE: ______________ %

TAX
DEPRECIATION RATE: %

Financial Escalation Assumptions

(1) Year	(2) General Inflation %	(3) Plant Construction Cost %	(4) Fixed O&M Cost %	(5) Variable O&M Cost %
2012	2.5	2.5	2.5	2.5
2013	2.5	2.5	2.5	2.5
2014	2.5	2.5	2.5	2.5
2015	2.5	2.5	2.5	2.5
2016	2.5	2.5	2.5	2.5
2017	2.5	2.5	2.5	2.5
2018	2.5	2.5	2.5	2.5
2019	2.5	2.5	2.5	2.5
2020	2.5	2.5	2.5	2.5
2021	2.5	2.5	2.5	2.5

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/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)
2012	0.0007377	27%	2500			
2013	0.0005006	26%	1400			
2014	0.0005933	23%	2000			
2015	0.0054028	21%	10500			
2016	0.0004776	19%	0			
2017	0.0004433	21%	800			
2018	0.0004257	22%	800			
2019	0.0008641	20%	400			
2020	0.0002978	28%	300			
2021	0.0002292	27%	100			

Additional Documents

(Question #52)

August 4, 2011

Attention Docket ID No. EPA-HQ-OAR-2009-00234
Attention Docket ID No. EPA-HQ-OAR-2011-00044
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW., Mailcode: 2822T
Washington, DC 20460

Submitted Electronically and via First Class U.S. Mail

Dear Sir or Madame:

JEA takes this method and opportunity to submit the following comments in reference to the proposed National Emissions Standards for Hazardous Air Pollutants and New Source Performance Standards for Electric Generating Units (NESHAP/NSPS for EGUs).

COMMENTS OF JEA

ON THEPROPOSED NATIONAL EMISIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS AND NEW SOURCE PERFORMANCE STANDARDS FOR ELECTRIC GENERATING UNITS

EPA Docket No. EPA-HQ-OAR-2009-00234
EPA Docket No. EPA-HQ-OAR-2009-00044

BACKGROUND

JEA is a municipally owned Electric, Water and Waste Water Utility serving over 1,100,000 people in Northeast Florida. JEA has 3,095 MWs of generating capacity employing coal, petroleum coke, residual oil, #2 oil and gas-fired generation as well as one of the largest solar generation systems in the state. All of the coal-fired electric generating units (EGUs) operated by JEA employ the applicable BACT air pollution control systems[1]. JEA's newest coal-fired EGUs at the Northside Generating Station (NGS) were built under a DOE Clean Coal Technology grant and are two of the largest circulating fluidized bed (CFB) boilers in operation

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[1] JEA operates 4 generating stations in northeast Florida and is a co-owner of Plant Scherer Unit 4 in Georgia along with Florida Power and Light Company. Unit 4 is operated by Georgia Power Company and FPL acts as JEA's agent in day-to-day plant operations.

and have some of the lowest emission rates for coal-fired EGUs in the world. JEA spent $282 million for Selective Catalytic Reduction (SCR) at the St. Johns River Power Park (SJRPP) Units #1 and #2 which are now in operation.

GENERAL COMMENTS

Although all of JEA's Florida coal EGUs are equipped with air pollution control systems meeting BACT, it will be difficult, in some cases, to meet the emission cap requirements provided for in the EPA's proposed NESHAP rule. JEA is a member of the Large Public Power Council (LPPC), the American Public Power Association (APPA), the Florida Electric Utility Coordinating Group (FCG), the Florida Municipal Electric Association (FMEA) and the Class of '85 Regulatory Response Group and fully supports the comments of all of those groups on this rule making. JEA's specific comments should be considered as additional comments to those provided by those groups.

Specific Comments:

EPA should designate flexible fuel units that burn coal as belonging under the subcategory for coal-fired EGUs >8, 300 Btu

The proposed rule has some ambiguity regarding under which subcategory flexible fuel units belong (units that can burn a wide array of combinations of coal and petroleum coke). JEA operates two circulating fluidized bed (CFB) boiler that are approximately 300 MW each. The units were designed to burn bituminous coal (>8,300 Btu). The units are also able to fire with petroleum coke. Current operation has them burning approximately 10 -20% coal and 80-90% petroleum coke. Fuel mix varies with fuel cost and availability.

JEA considered three separate rule references within the proposed rule to ascertain the proper subcategory designation for the JEA CFBs. The first reference comes from the proposed rule's preamble, Section IV. Summary of this proposed NESHAP, paragraph B, (page 250) wherein it states *"If an EGU burns coal (either as a primary fuel or as a supplementary fuel), or any combination of coal with another fuel (except as noted below), the unit is considered to be coal-fired under the proposed rule"*. The next two references were found within the definitions of the proposed subcategories (page 288): ... *"an EGU is considered to be a "coal-fired unit designed for coal greater than or equal to 8,300 Btu/lb" if the EGU: 1)combusts coal; 2) meets the proposed definition for "fossil fuel fired"; and 3) burns any coal in an EGU... "* . The last of the references (page 289) states "*We are proposing that the EGU is considered to be "solid oil-derived fuel-fired" if the EGU burns any solid oil-derived fuel (e.g., petroleum coke) and meets the definition of "fossil fuel fired"*.

The first two references cited above gives clear indication that the JEA CFBs are appropriately subcategorized as being *"coal-fired unit designed for coal greater than or equal to 8,300 Btu/lb.* However, an ambiguity and conflict comes from the last reference cited wherein the proposed rule designates the JEA CFBs as *"solid oil-derived fuel-fired*" on the basis that they burned some amount of petroleum coke. JEA encourages EPA to clarify this ambiguity while recognizing that a unit combusting coal, in combination with any other boiler fuel, will have an emissions profile vastly different from combusting the respective boiler fuel alone. JEA supports EPA's premise, expressed in the proposed rule's preamble, "that any unit burning any coal is a coal unit". Accordingly, JEA suggests eliminating the conflicting and ambiguous provision by either removing the entire provision, as cited in the reference above or revise to read as follows: "*We are proposing that the EGU is considered to be "solid oil-derived fuel-fired" if the EGU burns ~~any~~ solid oil-derived fuel (e.g., petroleum coke)* not blended with coal *and meets the definition of "fossil fuel fired".*

EPA should provide additional time to provide additional clarification, receive comments and develop the rule

JEA understands the substantial effort that EPA has undertaken in developing its proposal, and urges EPA to take the time necessary – beyond this November – to increase the credibility and defensibility of the final rule. EPA set a very aggressive schedule for companies to respond to the ICR in 2010 and then finalized the proposal less than 6 months after receiving this information. EPA has already recognized that material mistakes occurred in the proposal, and JEA is concerned that further errors will occur should EPA attempt to evaluate, compile and integrate revisions to the proposal between the August 4 comment deadline and the November 16, 2011 date which EPA has signaled to sign the final rule. This is an important complicated and potentially burdensome rule, and EPA should take the necessary time to carefully consider the public comments and integrate necessary revisions.

EPA Has Not Established A Sufficient Basis For Regulating Oil-Fired EGUs Under Section 112

The Group urges EPA to reconsider its determination that it is appropriate and necessary to regulate oil-fired EGUs under Section 112. EPA's determination is based almost entirely on its outdated risk assessment completed in 1998, which contained significant uncertainties and unproven assumptions. This resulted in an overestimation of the risks posed by oil-fired EGUs, particularly from nickel emissions, which was the ultimate basis on which EPA determined that it was appropriate and necessary to regulate oil-fired EGUs under Section 112. Even based on EPA's outdated risk assessment, the risks posed by nickel emissions from oil-fired EGUs are very low and do not justify a finding that the regulation of such units is appropriate and necessary. EPA has received more recent and realistic data regarding the risks posed by nickel emissions from oil-fired units on two occasions: (1) in 2004, industry groups submitted data on nickel speciation in response to EPA's initial proposal to establish MACT standards for EGUs [cite]; and (2) in 2011, industry members submitted data on nickel speciation after completing testing required by EPA's 2010 ICR. These more recent analyses show that the risks posed by oil-fired EGUs are even less than EPA previously estimated. As a result, EPA should rescind its finding that oil-fired EGUs should be regulated under Section 112. If EPA does not rectify the Proposal and allows it to become final, EPA will impose burdensome and unnecessary regulation on EGUs that pose minimal risk, if any, to public health from their HAP emissions at a cost that could force many of them to shut down. Such a result must be avoided.

Oil-fired EGUs do not warrant regulation and EPA should rescind the regulatory determination for oil-fired EGUs.

The Utility RTC and Non-Hg Risk Assessment provide insufficient bases for regulating oil-fired EGUs under Section 112. Both studies raised substantial uncertainties regarding the species of nickel being emitted and the risk of such emissions from oil-fired EGUs. This lack of data made it impossible for EPA to give an accurate assessment of the risk to human health from nickel emissions from oil-fired EGUs. In the face of such uncertainty, EPA made ultraconservative assumptions aimed at overestimating the risk. While this strategy may have been appropriate for the Utility RTC, it should not have formed the basis for determining whether to regulate oil-fired units under Section 112(n).

EPA recognized in the Utility RTC that it had inadequate information when it stated "[r]esearch would be useful to determine the emissions quantities of various nickel forms and the health effects of various nickel forms." Utility RTC at p. ES-28. The additional scientific evidence that has become available since the Utility RTC indicates that the risks from oil-fired units are significantly lower than those predicted by EPA. In addition to the new scientific evidence, the fuel mix of several of the 11 plants identified as high risk by EPA has changed significantly since 1990, such that, based on new data, there likely would be fewer units posing one in a million cancer risk even using the rest of EPA's flawed and overly conservative assumptions. EPA failed to address this in the Non-Hg Risk Assessment, instead deciding to rely on emissions from only one oil-fired EGU. Non-HG Risk Assessment at 12-13. Consequently, it is clear that EPA has not progressed beyond the limited knowledge available to the Agency in 1998 when it issued the Utility RTC and has continued to base its decisions on faulty assumptions.
EPA has ignored substantial scientific questions bearing on the regulation of oil-fired units. EPA has an inadequate basis for continuing to propose regulating this source category in the face of evidence that the risks are insignificant. EPA should rescind the December 2000 Regulatory Determination with respect to oil-fired EGUs.

EPA should preserve the ability to use reasonable surrogates as measurements in monitoring the HAPs of concern

JEA supports the proposed alternative of using SO2 as a surrogate for acid gases. Utilities already monitor SO_2 emissions continuously under the Acid Rain program, and the control technology that removes SO_2 also is effective at removing acid gas emissions. Under this approach, facilities may choose to monitor either HCl or SO_2 as the indicator of acid gas emissions. However, to qualify for the SO_2 surrogate option, wet or dry flue gas desulfurization technology must be operated "at all times." EPA should clarify that this requirement is not intended to disqualify EGUs that experience SO_2 control device malfunctions or that must turn off controls to perform maintenance. The higher SO_2 recorded by the CEMS during such periods will reflect the potential for higher HCl as well. EPA should also make clear that the existence of a bypass stack does not disqualify an EGU from complying with the SO_2 standard.

EPA should establish MACT standards based on a 12-month rolling average

emission rate

The Class of '85 recommends that EPA establish MACT standards based on a 12-month rolling average emissions rate. For single units that are not part of a multi-unit plant's averaging plan, the averaging period for the relevant standard is highly important in dealing with non-steady state operations, including start-up, shutdown, malfunctions, and load-following operations. Because EPA is proposing to include emissions from these events in the propose emission standards, the averaging period should be lengthened from a 30-day average to a 12-month rolling average, calculated monthly.

Typical EGU operations demonstrate that a 30-day averaging period is insufficient to account for variable emissions resulting from multiple startups and shutdowns. The proposed emission standards are both unrealistic and unreasonable. A 12-month rolling average for all HAPs would achieve the required environmental protection yet provide much needed operational flexibility and accommodate real-world operating conditions for EGUs.

EPA should preserve all reasonable means of demonstrating compliance

JEA supports the ability to use alternatives to CEMS. , Sources should be allowed to select CEMs, but alternatives such as stack testing should be retained and CAM provisions developed.

JEA supports EPA's proposal to handle reporting for PM, HCl, and mercury through the Emissions Collection and Monitoring Plan System ("ECMPS"). The ECMPS system simplifies the reporting process by evaluating continuous monitoring data and other information in an electronic format in preparation for submittal to the Agency. ECMPS is used by Part 75 and emissions trading programs and is a well-established data reporting tool.

EPA Should Establish Filterable PM, not Total PM, as the Surrogate for Non-Mercury Metals

EPA's approach to establish a Total PM limit as a surrogate for metals is flawed. The proposed EGU MACT sets a Total PM limit (filterable & condensable) at 0.030 lb/MMBTU. EPA's assertion that the condensable PM fraction must be included based on a correlation with selenium is refuted by data analyses by EPRI and others. Specifically, filterable PM is an adequate surrogate for all non-mercury metals – there is a statistically significant correlation with particulate-phase metals (e.g., chromium) and with metals that are volatile at stack gas temperatures, particularly selenium. Further, the extent to which selenium is captured in sampling apparatus for condensable PM is not known, and EPARI's review of the ICR data shows that selenium emissions do not have a strong correlation with condensable PM emissions. Accordingly, JEA requests that EPA utilize filterable PM as a surrogate for all non-mercury metals.

Further, EPA established the limit based on the ICR data during steady-state, full-load conditions, which does not account for emissions variability resulting from startup, shutdown, soot blowing and malfunction. EPA needs to either propose a separate work practice standard or exempt any operational mode not included in the establishment of the MACT floor for demonstration of compliance with the PM limit.

In addition, EPA's approach to compliance is also flawed in requiring PM CEMs for compliance. PM monitoring systems have not been proven reliable for the electric utility industry, are very expensive, and measure only filterable PM. The standard as proposed requires an initial Total PM (filterable & condensable) stack test to establish compliance, plus sets a 30-day filterable limit based on this stack test, and requires continuous compliance based on PM CEMs. This methodology does not take into consideration any variability of the reference test method, fuel supply, the CEMs itself or unit operations. Due to this flawed approach in the EGU MACT proposal, JEA requests that EPA require compliance for metals based on an annual filterable PM Test. EGUs are accustomed to conducting annual PM stack tests for SIP and NSPS compliance. Should additional monitoring be necessary, JEA recommends that EPA develop a Compliance Assurance Monitoring (CAM) approach. CAM has been successful in providing reasonable assurance of compliance under the Title V Program and JEA supports its use in the EGU MACT rule.

CONCLUSION

JEA appreciates the opportunity to comment on the proposed National Emissions Standards for Hazardous Air Pollutants and New Source Performance Standards for Electric Generating Units. Appropriately addressing the issues raised above will help assure that we plan and maintain a robust, reliable and economically viable electric energy supply system. We feel that this approach achieves a balance between U.S. energy and environmental objectives without diminishing either.

Respectfully submitted,

Berdell Knowles

Berdell Knowles,

Legislative Advocate, JEA

October 1, 2010

Attention Docket ID No. EPA-HQ-OAR-2009-00491
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW., Mailcode: 2822T
Washington, DC 20460

Submitted Electronically and via First Class U.S. Mail

Dear Sir or Madame:

JEA takes this method and opportunity to submit the following comments in reference to the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone.

COMMENTS OF JEA

ON THE FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE: PROPOSED TRANSPORT RULE

EPA Docket No. OAR-2009-00491

BACKGROUND

JEA is a municipally owned Electric, Water and Waste Water Utility serving over 1,100,000 people in Northeast Florida. JEA has 3,095 MWs of generating capacity employing coal, petroleum coke, residual oil, #2 oil and gas-fired generation as well as one of the largest solar generation systems in the state. All of the coal-fired electric generating units (EGUs) operated by JEA employ the applicable BACT air pollution control systems[1]. JEA's newest coal-fired EGUs at the Northside Generating Station (NGS) were built under a DOE Clean Coal Technology grant and are two of the largest circulating fluidized bed (CFB) boilers in operation and have some of the lowest emission rates for coal-fired EGUs in the world. JEA spent $282 million for Selective Catalytic Reduction (SCR) at the St. Johns River Power Park (SJRPP) Units #1 and #2 which are now in operation. With the recent installation and operation of SCRs at SJRPP, JEA's current pollution control systems were sufficient to meet or exceed the emission requirements associated with the EPA's Clean Air Interstate Rule (CAIR).

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[1] JEA operates 4 generating stations in northeast Florida and is a co-owner of Plant Scherer Unit 4 in Georgia along with Florida Power and Light Company. Unit 4 is operated by Georgia Power Company and FPL acts as JEA's agent in day-to-day plant operations.

GENERAL COMMENTS

Although all of JEA's Florida coal EGUs are equipped with air pollution control systems meeting BACT, it will not be possible in some cases to meet the emission cap requirements provided for in the EPA's proposed Transport Rule. JEA is a member of the Large Public Power Council (LPPC), the American Public Power Association (APPA), the Florida Electric Utility Coordinating Group (FCG), the Florida Municipal Electric Association (FMEA) and the Class of '85 Regulatory Response Group and fully supports the comments of all of those groups on this rule making. JEA's specific comments should be considered as additional comments to those provided by those groups.

Specific Comments:

EPA appears to be relying on data that are incorrect and result in unrealistic expectations for future emission rates

Specifically, the EPA assumed seasonal NOx emission rates of 0.043 lb/mmBtu for the CFBs at NGS Units 1 and 2 are unrealistic and may be unachievable even though both units are equipped with non-selective catalytic reduction (NSCR) technology. An ozone season NOx emission rate closer to the permitted value of 0.09 lb/mmBtu should be applied to these units.

NGS Unit 3, equipped with low-NOx burners, cannot possibly meet the EPA assumed annual NOx emission rate of 0.142 lb/mmBtu during normal operation and cannot meet the ozone season NOx rate of 0.069 lb/mmBtu even during natural gas operation at low load. A more reasonable projected emission rate for this unit would be 0.2 lb/mmBtu or higher for both annual and seasonal NOx since there are no NOx controls on this unit that can be adjusted to meet these low NOx emission rates regardless of the season.

In EPA's posted "Projected Data" spreadsheet which was published with the proposed rule, it appears that EPA had not allotted SO2 allowances for those units which burn fuel oil and natural gas. JEA believes this reasoning is fatally flawed and does not have realistic assumptions related to the availability of natural gas in the state of Florida and in our service area. No SO_2 allowances were allocated to NGS Unit3. It appears that EPA assumed that this unit can and will switch to lower sulfur fuels such as natural gas in order to meet SO2 reduction requirements. This is not practical for JEA because JEA is a winter peaking utility and relies on this oil fired unit (capable of firing natural gas) to meet demand and maintain system reliability. Not having the ability to fire oil would reduce the availability of this unit during this critical time when natural gas is subject to curtailment due to higher priority uses in the state.

Achieving the EPA assumed SO_2 emission rates of 0.137 and 0.167 lb/mmBtu, respectively, for SJRPP Units 1 and 2 would require the use of low sulfur fuel, which may not be available, as well as the excessive and non-conventional use of dibasic acid, which already has limited availability and high cost. Assumptions that coal units can and will switch to lower sulfur burning coals in order to meet SO_2 reduction requirements is invalid. Many of the same questions apply to coal as with natural gas, those being what appears to be a lack of EPA's analysis on current burned coal sulfur limits and the capacity of rail lines to meet EPA assumed fuel switching requirements.

JEA is open to and willing to work with EPA to develop more realistic and achievable emission rates for all its units.

EPA's Choice of 2008 and 2009 for the Baseline is Inappropriate

EPA has chosen 2008 and 2009 as baseline years for NOx and SO_2 emissions, respectively. These two years do not represent normal operating conditions for JEA and many other EGUs regulated under this rulemaking. Therefore, EPA should allow for the selection of a more representative time period. The units regulated by this rulemaking are also regulated under the Clean Air Interstate Rule (CAIR). JEA did indeed have extended outages in 2008 and 2009 to install NOx control equipment at SJRPP. Additionally, in 2008 and further into 2009, the U.S. economy plunged into an economic "crisis," and electricity demand dropped significantly. Therefore, 2008 and 2009 are not representative years for JEA and many other EGUs regulated by this rulemaking. JEA suggests that EPA utilize an approach similar to CAIR, and use an average capacity of the past five years, or some other period that would more accurately represent past performance.

EPA Did Not Provide Sufficient Time to Develop Comments

The Transport Rule was published in the Federal Register on August 2, 2010 with a comment deadline of October 1, 2010, leaving interested parties 60 days to review the proposed regulation (75 FR 45210), albeit the announcement and initial text of the proposed rule came out on July 6, 2010, this is precisely the timeframe that many of the entities regulated by this proposal were performing Part Three Emissions Testing for EPA's Utility MACT Information Collection Request (ICR). Subsequently, multiple regulated entities were entering the ICR data into EPA's database spreadsheets during this proposal period and were not afforded the luxury of the full proposal time period to analyze the rule and its technical support documents. EPA should recognize the burden that they have placed on certain regulated entities' staff and acknowledge this burden by extending the initial comment period or allowing for an additional notice and comment period.

EPA did not allow sufficient participation by the state of Florida to promulgate a state-specific solution

Contrary to those previous interstate emission provisions of CAIR, the proposed Transport Rule would impose a FIP approximately six to nine months after promulgation – providing no meaningful opportunity to the states to first address their interstate emissions through the SIP process. As EPA acknowledges in the preamble to the Transport Rule, SIP revisions typically take on the order of three years to prepare and approximately six months to approve. Since the Transport Rule is likely to be finalized in mid-2011 and FIPs would take effect in 2012, there is almost no chance that states subject to the Transport Rule could revise and approve their SIPs in time to avoid the imposition of the FIP. EPA must respect the rights of individual states to develop and implement their own SIPs if they so choose. EPA does not have the authority to promulgate a FIP without first giving the states this opportunity. The ability to replace federal requirements at some point in the future does not satisfy the requirement that EPA allow states the opportunity to craft their own plans, at the outset of the program, to address interstate transport.

Uninhibited trading is necessary to take of advantage of market forces

JEA supports EPA's proposal to permit at least some degree of allowance trading. Permitting interstate allowance trading would provide for increased flexibility and permit more cost-effective compliance options. Increased flexibility will be particularly important in the early years of the program, especially if EPA does not change the proposed rule's unreasonably accelerated compliance schedule. However, JEA urges EPA to eliminate the 3-year variability limit in the final Transport Rule. Unlike CAIR, the proposed Transport Rule sets individual state emission budgets that are based on each state's estimated significant contributions to nonattainment or interference with maintenance in downwind states. Sources within the state would be permitted to submit allowances in excess of the annual budget (either by procuring them through interstate trading or by using banked allowances) only to the extent necessary to accommodate anticipated year-to-year variability in emissions within each state. EPA views these variability limits – which inherently restrict the volume of interstate emissions trading – as necessary to comply with *North Carolina*'s holding that each state's emission reduction requirements must be tied to its actual level of significant contribution or interference with maintenance.

JEA does not object to this general approach. However, JEA recognizes that variability limits inherently constrain cost-effective use of banking and trading, and could also have adverse impacts on reliability if not carefully designed – both key policy considerations for public power customers. Accordingly, JEA believes that the variability limits should be as flexible, generous, and straightforward as possible while remaining consistent with *North Carolina*. EPA's decision to establish *two* independent variability limits – an annual "1-year" limit and a "3-year" limit which restricts the *average* use of allowances over a rolling three-year period – fails these criteria. In particular, the 3-year limit will be impracticable, costly, and unnecessary.

The threat of moving Group 2 states to Group 1 creates uncertainty

While Florida is currently in Group 2 with no additional reductions required in 2014, EPA makes it clear that it is going to reevaluate the Group placement of states in light of the revised NAAQS in 2011 and 2012 meaning some states may be moved to Group 1. However, EPA is considering only the 1997 Ozone NAAQS in the current Transport Rule proposal even though a revised Ozone NAAQS is in effect. JEA believes that such a piecemeal approach to dealing with current and future NAAQS revisions creates confusion and makes compliance planning by state regulators and industries nearly impossible. EPA should only fix the CAIR remanded issues in this Transport Rule and initiate new interstate rulemaking once all current NAAQS reviews are completed.

EPA's Proposal, if Finalized, Would Violate N.C. v EPA, Constitute a Taking and Violate Due Process

The Proposed Transport Rule properly recognizes the important environmental and economic benefits of allowance banking and that allowance banking as an element of EPA's program was in no way undermined by the court's decision in *North Carolina v. EPA*. Additionally, JEA supports approaches that would permit the use of banked CAIR NOx allowances for compliance with the Proposed Transport Rule. Such provisions should allow for unlimited banking along with no "expiration period" attached to the allowances accrued each year. Because CAIR allowances would not be transferrable into the new program, all CAIR allowances for calendar years 2012 and on would become worthless.

JEA expended hundreds of millions of dollars installing and operating SCR on two of its coal units with the reasonable expectation that banked CAIR allowances would continue to have value in the future. EPA's proposed action would clearly interfere with these distinct investment backed expectations, yet the proposed rule does not appear to compensate CAIR allowance holders (or otherwise account) for the loss of their assets.

CONCLUSION

JEA appreciates the opportunity to comment on the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone. Appropriately addressing the issues raised above will help assure that we plan and maintain a robust, reliable and economically viable electric energy supply system. We feel that this approach achieves a balance between U.S. energy and environmental objectives without diminishing either.

Respectfully submitted,

Kevin Holbrooks

JEA Director of Environmental Compliance

February 4, 2011

U.S. Environmental Protection Agency
EPA Docket Center, EPA West
Attention Docket No. EPA-HQ-OAR-2009-00491
1200 Pennsylvania Avenue, NW, Mailcode: 2822T
Washington, DC 20460

Submitted Electronically and via First Class U.S. Mail

Dear Sir or Madame:

JEA takes this method and opportunity to submit the following comments in reference to the Notice of Data Availability (NODA), Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone.

COMMENTS OF JEA

IN RESPONSE TO THE NOTICE OF DATA AVAILABILITY FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE: PROPOSED TRANSPORT RULE

EPA Docket No. OAR-2009-00491

BACKGROUND

JEA is a municipally owned Electric, Water and Waste Water Utility serving over 1,100,000 people in Northeast Florida. JEA has 3,095 MWs of generating capacity employing coal, petroleum coke, residual oil, #2 oil and gas-fired generation as well as one of the largest solar generation systems in the state. All of the coal-fired electric generating units (EGUs) operated by JEA employ the applicable BACT air pollution control systems[1]. JEA's newest coal-fired EGUs at the Northside Generating Station (NGS) were built under a DOE Clean Coal Technology grant and are two of the largest circulating fluidized bed (CFB) boilers in operation and have some of the lowest emission rates for coal-fired EGUs in the world. JEA spent $282 million for Selective Catalytic Reduction (SCR) at the St. Johns River Power Park (SJRPP) Units

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[1] JEA operates 4 generating stations in northeast Florida and is a co-owner of Plant Scherer Unit 4 in Georgia along with Florida Power and Light Company. Unit 4 is operated by Georgia Power Company and FPL acts as JEA's agent in day-to-day plant operations.

#1 and #2 which are now in operation. With the recent installation and operation of SCRs at SJRPP, JEA's current pollution control systems were sufficient to meet or exceed the emission requirements associated with the EPA's Clean Air Interstate Rule (CAIR).

GENERAL COMMENTS

Although all of JEA's Florida coal EGUs are equipped with air pollution control systems meeting BACT, it would not have been possible, in some cases, for JEA to meet the emission requirements initially provided in the EPA's proposed Clean Air Transport Rule (CATR) and submitted comments to that effect. JEA is encouraged to see a deliberate effort, on the part of EPA, to address the inequities that were delineated in the initial CATR proposal. JEA strongly supports the use of historic heat input data as the basis for allowance allocations under CATR. JEA believes this approach is considerably fairer than the allocation scheme initially purposed. JEA also supports the alternative of implementing the proposed assurance on a Designated Representative (DR) basis, as opposed to owner-by-owner. Additionally, JEA believes a provision to allow states to participate in the CATR trading program, by submitting a State Implementation Plan (SIP), will result in a more optimal implementation of CATR. JEA is a member of the Florida Electric Utility Coordinating Group (FCG) and the Florida Municipal Electric Association (FMEA) and fully supports the comments of all of those groups on this rule making. JEA's specific comments should be considered complimentary to comments provided by those groups.

Specific Comments:

JEA strongly supports the use of historic heat input data as the basis for allowance allocations.

JEA believes that the alternative allowance allocation methods (heat input-based, with a more representative baseline) proposed in the NODA is inherently fairer and is better policy than initially proposed because the alternative allocation methods do not allocate more allowances to units than they currently or would ever prospectively need. Similarly, Option 2 does not disadvantage utilities like JEA that have made significant investment in emission controls in anticipation of the emission limits posed by the Clean Air Interstate Rule.

JEA also supports the use of the 2005-2009 time period as the baseline for determining historic heat input for covered units, as opposed to the initial approach that only used 2008 and 2009 for NOx and SO_2 emissions. The two-year period did not represent normal operating conditions for JEA and many other EGUs regulated under this rulemaking. EPA should allow a time period that is more representative of the covered units' operations. JEA had extended outages in 2008 and 2009 to install NOx control equipment at SJRPP. Additionally, in 2008 and further into 2009, the U.S. economy plunged into an economic "crisis" and electricity demand dropped significantly. The years 2008 and 2009 were not representative years for JEA and for many other EGUs regulated by this rulemaking. Consequently, the alternatively proposed 5-year baseline is more representative.

JEA supports the alternative of implementing the proposed assurance provisions on a Designated Representative basis.

JEA has joint ownership in multiple fossil fueled EGUs covered by this rule. JEA believes that having a duly designated representative be responsible for each its EGU's allowance surrender and assurance is less burdensome and confounding than having that responsibility be with the respective EGU owners. Consequently, having the EGU's DR be responsible for assurance and allowance surrender requirements makes sense from an administrative standpoint.

JEA supports provisions for the state to participate in the CATR trading programs through submission of a State Implementation Plan (SIP).

Contrary to provisions of CAIR, the proposed Transport Rule would impose a FIP approximately six to nine months after promulgation – providing no meaningful opportunity to the states to first address their interstate emissions through the SIP process. As EPA previously acknowledged in the preamble to the CATR, there was almost no chance that states subject to the rule could revise and approve their SIPs in time to avoid the imposition of the FIP. JEA believes that imposition of a FIP abrogates the states' rights and abilities to develop equitable remedies, respective of regional or local circumstances, and does not satisfy EPA's own objective to allow states the opportunity to craft their own plans to address the interstate transport of emissions. JEA believes that EPA should only use a FIP in cases where states fail to develop a SIP due to direct state inaction.

CONCLUSION

JEA appreciates the opportunity to comment on the Notice of Data Availability, Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone. Appropriately addressing the issues raised above will help assure that we plan and maintain a robust, reliable and economically viable electric energy supply system. We feel that our suggested revision achieves a balance between U.S. energy supply and environmental objectives, without diminishing either.

Respectfully submitted,

Berdell Knowles

Berdell Knowles

JEA Government Relations

cc Office of Management and Budget, Desk Officer for EPA

August 18, 2011

U.S. Environmental Protection Agency
Water Docket
1200 Pennsylvania Avenue, NW, Mailcode: 4203M
Washington, DC 20460

Attention Docket No. EPA-HQ-OW-2008-0667

Submitted Electronically and via First Class U.S. Mail

Dear Sir or Madame:

JEA takes this method and opportunity to submit the following comments in reference to the Environmental Protection Agency's (EPA) proposed Clean Water Act (CWA), Section 316(b), Standards for Cooling Water Intake Structures at Existing Facilities.

JEA COMMENTS

ON EPA'S PROPOSED STANDARDS FOR COOLING WATER INTAKE STRUCTURES AT EXISTING FACILITIES AND PHASE I FACILITIES ("SECTION 316(b) STANDARDS")

EPA Docket No. OW-2008-0667

BACKGROUND

JEA is a municipally owned Electric, Water and Waste Water Utility serving over 1,100,000 people in Northeast Florida. JEA has 3,095 MWs of generating capacity employing coal, petroleum coke, residual oil, #2 oil and gas-fired generation as well as one of the largest solar generation systems in the state[1]. JEA's newest coal-fired EGUs at the Northside Generating Station (NGS) were built under a DOE Clean Coal Technology grant and are two of the largest circulating fluidized bed (CFB) boilers in operation in the U.S. JEA owns and operates facilities that will be affected by the proposed section 316(b) standards, and has decades of expertise in designing and operating cooling water intake structures that are protective of aquatic biota and compliant with requirements established by local permitting authorities.

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[1] JEA operates 4 generating stations in northeast Florida and is a co-owner of Plant Scherer Unit 4 in Georgia along with Florida Power and Light Company. Unit 4 is operated by Georgia Power Company and FPL acts as JEA's agent in day-to-day plant operations.

GENERAL COMMENTS

JEA appreciates the opportunity to acknowledge and support key aspects of proposed provisions, as well as to request additional consideration of aspects of the proposed rule where such changes will result in a final rule that is less costly and easier to comply with while remaining protective of the biota of concern. JEA is a member of the American Public Power Association (APPA), Florida Electric Utility Coordinating Group (FCG), the Florida Municipal Electric Association (FMEA) and the Large Public Power Council (LPPC) and fully supports the comments of all of those groups on this rule making. JEA's specific comments should be considered complementary to comments provided by those groups.

Specific Comments:

JEA strongly supports EPA's proposed decision not to require closed-loop cooling systems at all existing facilities.

JEA supports the EPA's determination that closed-cycle cooling is not an appropriate Best Technology Available (BTA) standard for all facilities. EPA correctly recognized that it "could identify no single technology that represented BTA for all facilities"[2] and further explained that it made such a finding because different facility types have diverse needs and requirements regarding "local energy reliability, air emissions permits, land availability, and remaining useful plant life."[3]

JEA also believes it to be beneficial for local permitting authorities to be engaged in making such determinations of BTA because they have the best understanding of the array of local issues that should be taken into account when determining BTA. Accordingly, JEA believes that these provisions should be maintained in the final rule.

JEA supports EPA's proposed reliance on site-specific determinations for entrainment Best Technology Available (BTA).

EPA has correctly proposed to retain a site-specific process for determining BTA for entrainment at existing facilities, which allows local permitting authorities to individually weigh cooling water intake structure requirements on a facility-by-facility basis in light of environmental, economic, and other relevant factors. Site-specific BTA determinations are the best way to implement section 316(b)'s requirement that cooling water intake structures "reflect the best technology available for minimizing adverse environmental impact".[4]

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[2] 76 Fed. Reg. at 22,197.

[3] *Id.*

[4] Clean Water Act, Section 316(b).

Proposed impingement mortality standard is unreasonable and lacks adequate empirical basis.

EPA readily acknowledges the significant degree of site-to-site variability in waterbody characteristics and species nationwide and the associated variability in the attendant costs and benefits of various types of regulation in these different contexts. In spite of this recognition, EPA has proposed a rigid national numerical compliance scheme for impingement reduction that completely ignores crucial distinctions between facilities and the waterbodies on which they are located. Without explanation, EPA departed from its reasoning with respect to the entrainment rule, and took a diametrically opposite and unsupported approach with respect to impingement and completely ignored those site-specific factors. The proposed rule lacks any variance mechanism to address critical site-specific considerations in permitting, rendering the proposed national numeric mortality limitation unrealistic and unsupportable. This omission represents an unwarranted departure from the 2004 Phase II Rule, which contained five compliance alternatives.

EPA has also erred in arriving at a numeric impingement mortality limitation based upon outdated and unrepresentative data, consisting of studies from ***only three*** facilities, all located within the state of New York. For these reasons, JEA believes that EPA should reconsider impingement reduction standards. The 0.5 ft/sec intake velocity criteria for impingement monitoring is too restrictive and too rigid. EPA should provide a mechanism in the rule for modifying these criteria, if the applicant can demonstrate that a less restrictive velocity criteria is protective.

The final rule should provide some avenue by which a facility can obtain a cost-based waiver or relaxation of impingement requirements if costs are wholly disproportionate to benefits.

EPA's proposed section 316(b) standards give permitting authorities no discretion to issue appropriate alternative BTA requirements in cases where the impingement standards would produce no benefit or are unreasonably costly. By contrast, the "Phase I" section 316(b) standards for new facilities allow facilities to petition for alternative BTA requirements where implementing BTA would "result in compliance costs wholly out of proportion" to the cost estimates that were used as the basis for the rule, or would cause adverse impacts on local air quality, water resources, or energy markets. In addition, EPA's original section 316(b) standards for existing electric generating units (the "Phase II" standards) permitted variances from BTA where an applicant could demonstrate that the costs of implementing BTA would be "significantly greater" than the benefits.[5]

Both of these cost-based variances sensibly acknowledged that in individual cases, the costs of meeting BTA requirements may be so high as to justify a departure from the otherwise

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[5] Phase II standards at 41,686 (proposed 40 CFR § 125.94(a)(ii)).

applicable standards. In the case of impingement, flexibility to grant cost-based variances is particularly necessary in cases where a facility is withdrawing from a water body that has very low abundance of aquatic life (for example, stagnant water bodies with very low dissolved oxygen, or manmade irrigation canals) and where the benefits of implementing BTA for impingement would accordingly be negligible. JEA encourages EPA to revise the section 316(b) standards for impingement to provide flexibility to give cost-based variances from BTA, similar to the authority provided to permitting authorities under the Phase I standards and the remanded Phase II standards.

New "entrapment" concept is unnecessary and overly burdensome.

Live fish entrapment should not be treated as impingement mortality in determining compliance with the limitations. Most entrapped fish live their natural life spans within the intake structure. Thus, they should not categorically be considered impingement mortality. Such entrapment is in some cases unavoidable and the numbers are insignificant.

Monitoring requirements are excessive, costly and perhaps unachievable.

The proposed rule generally requires monthly aquatic monitoring. The rule provisions are not clear on monitoring protocols and, in some cases, frequency. Monitoring seems to even be required after there have been infrastructure improvements made and mortality limits demonstrated. JEA believes this level of monitoring is excessive. Because of its extensive experience and long history of operations in a marine life-sensitive environment, JEA is insightful to the amounts and kinds of resources that will be necessary to comply with these proposed monitoring requirements. EPA should work with stakeholders and permitting authorities to identify more cost-effective and reasonable means to reliably measure and report marine life mortality.

JEA is concerned about the availability of technical resources to support compliance.

JEA is also aware of the limited availability of skilled scientists capable of performing and supporting a lot of the scientific research required by the proposed rule. There are already a limited number of qualified state regulators to review industry standards. The large number of facilities covered by this rule and the, as of now, finite resources available to support the aquatic research and, in most cases, design infrastructure improvements, will likely compromise industry's ability to locate and engage the requisitely skilled resources to do the work. For this reason, EPA should not impose any deadlines for collecting data and completing studies within a period that is less than one year. EPA should also be more flexible in establishing absolute timetables for compliance, when infrastructure construction is necessary to achieve compliance.

The Entrainment Characterization Study needs improvement.

EPA has chosen to use an "Entrainment Characterization Study" (ECS) as the central device for determining entrainment BTA. The ECS is required for facilities with an actual intake flow

(AIF) of greater than 125 MGD. JEA will be required to undertake ECS studies, and is therefore concerned about the potentially burdensome nature of the requirements.

The ECS requirements will be quite onerous for regulated facilities. The ECS must include an "Entrainment Mortality Data Collection Plan," which is required to go through a review and comment period prior to implementation. The Entrainment Mortality Data Collection Plan is also required to include a large amount of data, some of which is not otherwise collected by the facilities. Significant time and cost will go into collecting and analyzing such data. If the EPA maintains the ECS process in the final rule, it should simplify the requirements of the ECS and streamline the analysis. In particular, EPA should issue specific guidance on the role of peer review throughout the ECS, and outline a dispute resolution procedure to address formal disagreement with peer review comments. The peer reviewers will have to come from the same pool of scientists that the industry and regulators will be tapping to accomplish their responsibilities. The peer review process could become a bottleneck in accomplishing the goals of the rule.

CONCLUSION

JEA appreciates the opportunity to comment on EPA's proposed standards for Cooling Water Intake Structures at existing facilities and Phase I facilities._Appropriately addressing the issues raised above will help assure that JEA can plan and maintain a robust, reliable and economically viable electric energy supply system. We feel that our suggested revisions achieve a balance between U.S. energy supply and environmental objectives, without diminishing either.

Respectfully submitted,

Berdell Knowles

Berdell Knowles

JEA Legislative Advocate

21 West Church Street
Jacksonville, Florida 32202-3139

November 19, 2010

JEA
ELECTRIC
WATER
SEWER

Ms. Lisa Jackson
Administrator, U.S. Environmental Protection Agency
Hazardous and Solid Waste Management System
Identification and Listing of Special Wastes
Disposal of Coal Combustion Residuals from Electric Utilities Docket
Attention Docket ID No., EPA-HQ-RCRA-2009-0640
Environmental Protection Agency
Mailcode: 28221T
1200 Pennsylvania Ave., N.W.
Washington, DC 20460

Re: Comments on the Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities; Proposed Rule; 75 Fed. Reg. 35128 (June 21, 2010); Docket ID#: **EPA-HQ-RCRA-2009-0640**

Dear Ms. Jackson:

I am submitting comments on behalf of JEA regarding the Environmental Protection Agency's (EPA) co-proposal for regulating Coal Combustion Residuals (CCRs), as referenced above. JEA is a non-profit independent agency of the City of Jacksonville, Florida that provides water, sewer, and electric services for a number of counties in northeast Florida. In the course of providing electric service, JEA has an ownership interest in three power generation facilities that utilize solid fuels.

JEA is a member of the American Public Power Association (APPA), The Large Public Power Council (LPPC), and The Florida Electric Power Coordinating Group (FCG) and endorses the written comments of those organizations in response to this EPA rulemaking. JEA also endorses the comments of the Utility Solid Waste Activity Group (USWAG) even though it is not a member of that organization.

In addition to the regulatory options presented in the co-proposals, JEA urges EPA to more carefully consider a path forward where EPA seeks and obtains the statutory authority needed to approve State programs that meet EPA parameters, allowing States like Florida to manage CCRs in a way that best serves its citizens, while retaining enforcement authority over States that are unable to regulate them in an effective manner.

Of the regulatory options being given consideration at this time, JEA urges EPA to pursue the Subtitle D Prime approach. JEA believes that CCRs do not rise to the level of hazardous waste and that regulating them as such would provide marginal environmental benefit at a great cost. As a utility in Florida, a Subtitle C regulatory framework would not be practicable. Florida has a statutory prohibition against the permitting of hazardous waste landfills, as well as a prohibition against considering byproducts for reuse if they are otherwise hazardous wastes. JEA would be forced to send its CCRs to other states for disposal as hazardous waste, and EPA has already highlighted the lack of disposal capacity associated with such an outcome in its preamble. State statutory changes needed to accommodate the hazardous waste listing for CCRs would be a difficult task and would likely be opposed by a number of environmental groups active in Florida.

The cost to JEA of managing its CCRs as hazardous waste would be prohibitive and would come at a time when it has already been forced to enact a series of rate hikes due to adverse business conditions. A Subtitle C approach, combined with the multitude of other environmental initiatives simultaneously being pursued by EPA would place JEA and its owners, the citizens of northeast Florida, in an unnecessarily burdened situation.

JEA supports the case made by the FCG that Subtitle C regulation is inappropriate for CCRs for the following reasons:

- The decisive factors in EPA's two previous regulatory determinations remain valid today;
- The factors identified by EPA as the basis for its listing determination are more than adequately addressed under a Subtitle D option;
- Due to their variability, CCRs do not lend themselves to a categorical listing;
- A Subtitle C listing poses unnecessary compliance challenges; and
- A Subtitle C listing will adversely impact beneficial use and disposal in Florida.

However, should EPA ultimately decide to pursue a Subtitle C approach, JEA encourages the agency to make certain modifications to its proposal. EPA should establish a point of generation for CCRs as the point where a decision is made to dispose of the CCRs, as opposed to beneficially using them, rather than potentially have the listing apply at the boiler, precipitator, or scrubber module, etc. The EPA has not made a case that there is a concern regarding on-site conveyance and processing of CCRs, and its focus appears to be on landfills and surface impoundments. Allowing the point of generation to be applied at the point where a disposal decision is made will reduce the burden of some of the myriad of hazardous waste regulations that would otherwise unnecessarily apply to a common power plant facility generating CCRs. This will also eliminate the confusion and difficulty some facilities will otherwise encounter regarding third parties that have procured CCRs from the facility but further process them on-site, generating some material that is beneficially used and some that is returned to the facility for disposal.

JEA also requests that EPA limit the reach of the definition of surface impoundments, possibly by using a capacity or size threshold, so that impoundments and ancillary process components containing *de minimis* amounts of CCRs are not subject to the hazardous waste regulations. These units are frequently regulated under NPDES, industrial wastewater, or other permits or authorizations and duplicative and conflicting management of them will not be productive. Furthermore, EPA should address and eliminate the attachment of the waste listing to waste streams such as leachate, run-off, etc. that may contain CCRs and that are already managed in accordance with other permits and authorizations. Finally, EPA should revisit its list of uniquely associated wastes to include items from prior determinations that appear to have been omitted, thereby limiting the reach of the Subtitle C proposal.

Regarding the Subtitle D or D Prime proposals, JEA urges the EPA to expound on its definition of CCRs, thereby limiting its scope or applicability and achieving consistency with the Subtitle C proposal and historical interpretations and regulatory determinations. JEA suggests that the definition of CCRs under the Subtitle D regulatory options be modified as follows:

> Coal Combustion Residuals (CCRs) means fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated primarily from the combustion of coal for the purpose of generating electricity by the electric power sector. CCRs do not include fly ash, bottom ash, boiler slag and flue gas emission control waste generated primarily from the combustion of fossil fuels other than coal, or Uniquely Associated Wastes. CCRs are also known as coal combustion wastes (CCWs) and fossil fuel combustion (FFC) wastes.

Addititonally, JEA urges EPA to adopt a definition of uniquely associated wastes under the Subtitle D approaches that is more consistent with historical interpretations and regulatory determinations and provides the following suggested language in support of this position:

> Uniquely associated wastes are low-volume wastes other than those defined as coal combustion residuals that are related to the coal combustion process. Examples of uniquely associated wastes are precipitation runoff from coal storage piles at the facility, waste coal or coal mill rejects that are not of sufficient quality to burn as fuel, wastes from cleaning the boilers used to generate steam, air heater and precipitator washes, floor and yard drains and sumps, wastewater treatment sludges, and boiler fireside chemical cleaning wastes.

Furthermore, JEA requests modification of the definition of CCR Surface Impoundment under the Subtitle D approach as follows, limiting the applicability to those impoundments identified by EPA as being an issue:

> A facility or part of a facility which is a natural topographic depression, man-made excavation, or diked area formed

> primarily of earthen materials (although it may be lined with man-made materials), which has a storage capacity of 20 acre-feet or more and is designed for the primary purpose of holding and accumulati~~o~~ng ~~of~~ CCRs that have been sluiced (mixed with water to facilitate movement)~~containing free liquids~~ and which is not a landfill or an injection well. Examples of CCR surface impoundments are holding, storage, settling, and aeration pits, ponds, and lagoons that ~~CCR surface impoundments are used to~~ receive CCRs that have been sluiced ~~(flushed or mixed with water to facilitate movement)~~, or wastes from wet air pollution control devices, often in addition to other solid wastes. This definition does not include ponds or impoundments whose primary purpose is to receive industrial wastewaters, including boiler blowdown, boiler drains (chemical cleanings), air pre-heater wash drains, blowdown from Flue Gas Desulfurization, precipitator washes, boiler washes, cooling water blowdown, process water, treated wastewater, contact stormwater and other waters that may contain de minimis amounts of CCRs.

Absent these modifications, JEA's Northside Generating Station (NGS), a facility which utilizes Circulating Fluidized Bed (CFB) technology and which is already regulated under a Subtitle D equivalent State permit, may be subject to an unnecessary and duplicative set of standards and may have to alter its conveyance process. This facility makes use of a high-density slurry system to transfer its fly and bed ash to the permitted landfill cell. The slurry typically contains greater than 50% solids, and undergoes an exothermic chemical reaction during hydration that results in solidification in a series of pits located on top of the landfill, typically achieving solid form within 1 to 2 days. The size of a typical hydration pit is 20 feet wide by 100 feet in length by 20 feet in depth. EPA, represented by Alexander Livnat, Ph.D and James Kohler, P. E., visited this facility in June 2010, and was favorably impressed with the process and operation. JEA contends that this facility should continue to operate as a landfill, without having the slurry pits regulated as surface impoundments, and that its unique hydration and solidification process makes conveyance from the ash silos to the landfill using a high-density slurry acceptable.

Under the Subtitle D approach, EPA notes in its preamble that facilities accepting CCRs that are shipped off site for disposal must also meet the 40 CFR 257 standards. JEA requests that EPA allow those off-site facilities to accept CCRs for disposal without complying with the proposed 40 CFR 257 standards, provided that they are permitted or authorized to operate under the municipal solid waste regulations specified in 40 CFR 258. Otherwise, some of these facilities that are currently permitted under 40 CFR 258 standards may decide not to accept CCRs, should they also have to comply with the standards specified in 40 CFR 257.

Regarding the Subtitle D or D Prime approaches, JEA would point out that the one-size fits all national standards being proposed do not allow enough flexibility for utilities to operate efficiently, and using corporate web sites as an enforcement tool would seem to be a path toward unproductive litigation. More flexibility is needed in the framework of the regulations to allow for equally protective but different liner systems, such as dual geomembrane systems, and to consider State-approved site-specific groundwater monitoring programs that may deviate from the proposed standards.

Regarding beneficial use, JEA supports EPA's current proposals, both of which retain the Bevill exemption for CCRs that are beneficially used. JEA urges EPA to maintain this status for unencapsulated uses as well as those encapsulated issues which are specified in the preamble. The JEA NGS facility markets its hydrated byproduct as EZBase or EZBase Plus, and it is sold and applied in various road construction applications. JEA sought authorization from the State of Florida Department of Environmental Protection (FDEP) for these applications, some of which may be construed to be unencapsulated, and has submitted a variety of beneficial use demonstrations to support the application of the byproducts in a manner that minimizes the impact to human health and the environment. JEA is also initiating a similar demonstration process for the State of Georgia Environmental Protection Department. Consequently, EPA should continue to allow unencapsulated beneficial use of CCRs, provided that a State environmental agency has reviewed and approved a demonstration of acceptability.

Ultimately, JEA believes that additional regulation of CCRs in the State of Florida is unnecessary and that neither a Subtitle C nor D approach is appropriate. Given the need for the EPA to act in response to various incidents and cases, JEA requests that EPA seek and obtain the statutory authority necessary to require permits, approve State programs, and enforce acceptable criteria so that it can implement a separate regulatory framework for CCRs, patterned after the existing Subtitle D, but one that avoids the cumbersome and awkward regulatory framework currently proposed.

Thank you for consideration of our comments on the co-proposals.

Sincerely,

AJ Mann

Athena Mann
Vice President
Environmental Services

November 27, 2008

The Honorable Stephen Johnson
Administrator
U. S. Environmental Protection Agency
EPA West Building, Room 3334
Mail Code: 2822T
1301 Constitution Avenue, N.W.
Washington, D.C. 20004

Re: Docket No. EPA-HQ-OAR-2008-0318

**Regulating Greenhouse Gas Emissions under the Clean Air Act
Advanced Notice of Proposed Rulemaking**

Dear Mr. Johnson:

I am writing on behalf of JEA (formerly the Jacksonville Electric Authority) located in Jacksonville, Florida. Our community owns and operates a municipal electric utility, providing electricity to nearly 350,000 households and 45,000 commercial and industrial customers who provide essential jobs to our community. Our utility's electric generating capacity includes fossil fuel generation for essential base-load electric generating capacity, which is principally fueled by solid fuels, with some reliance on natural gas also. Over 40% of our generating capacity has come online since 2001 and represents some of the best-controlled and lowest emitting coal and gas-fired generating units in the country.

I write to express our community's concern about possible plans by EPA to regulate CO_2 and other greenhouse gases before Congress can review and deliberate on a broad national framework for addressing climate change. We are particularly concerned that the existing Clean Air Act is ill suited to deal with such a complex issue as regulating carbon dioxide and other greenhouse gases.

Using the National Ambient Air Quality Standards (NAAQS) process, the New Source Review (NSR) process, and other regulatory programs under the existing Clean Air Act to regulate greenhouse gases has the potential to be a regulatory nightmare that could overtake other national Clean Air Act program priorities. Regulation in this manner also could significantly increase the cost of electricity and negatively affect our customers in this community. Our utility must be able to assure our customers that the community's electricity is reliable and that the price is reasonable. Thus, we are particularly concerned about reliance on natural gas pricing swings if this were ultimately to be required as a GHG reduction strategy, and we are similarly concerned that EPA officials may presume that carbon capture and geo-sequestration technology is "available" or "achievable" before it is commercially demonstrated and commercially deployable.

Our trade groups, the American Public Power Association (APPA), the Large Public Power Council (LPPC) and the Florida Municipal Electric Association are submitting comments on these issues, and we incorporate those comments by reference.

Addressing climate change is one of the most significant national and international issues that we will address in the first half of the 21st Century. We encourage EPA to work with Congress to adopt a new law that addresses climate change, in a manner which our national economy and our local community can handle.

Thank you,

Sincerely,

P.G. Para, JEA Director of Government Relations