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Attached you will find 25 hardcopies of JEA's 2012 Ten Year Site Plan and a disk containing an electronic version of the TYSP Schedules in excel format (2012 TYSP Data Request # 1 – TYSP Schedules.xls) and the report in Adobe Reader format (JEA2012TYSP.pdf). If you have any questions regarding this submittal, please contact me at (904) 665-6216.

Thank You,

Mary Guyton Baker

Mary Guyton Baker, PE
JEA, Electric System Planning

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TEN YEAR SITE PLAN 2012

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List of Abbreviations

Type of Generation Units

CA	Combined Cycle	- Steam Turbine Portion, Waste Heat Boiler (only)
CC	Combined Cycle	
CT	Combined Cycle – Combustion Turbine Portion	
GT	Combustion Turbine	
FC	Fluidized Bed Combustion	
IC	Internal Combustion	
ST	Steam Turbine, Boiler, Non-Nuclear	

Status of Generation Units

FC	Existing generator planned for conversion to another fuel or energy source
M	Generating unit put in deactivated shutdown status
P	Planned, not under construction
RT	Existing generator scheduled to be retired
RP	Proposed for repowering or life extension
TS	Construction complete, not yet in commercial operation
U	Under construction, less than 50% complete
V	Under construction, more than 50% complete

Types of Fuel

BIT	Bituminous Coal
FO2	No. 2 Fuel Oil
FO6	No. 6 Fuel Oil
MTE	Methane
NG	Natural Gas
SUB	Sub-bituminous Coal
PC	Petroleum Coke
WH	Waste Heat

Fuel Transportation Methods

PL	Pipeline
RR	Railroad
TK	Truck
WA	Water

Introduction

The Florida Public Service Commission (FPSC) is responsible for ensuring that Florida's electric utilities plan, develop, and maintain a coordinated electric power grid throughout the state. The FPSC must also ensure that electric system reliability and integrity is maintained, that adequate electricity at a reasonable cost is provided, and that plant additions are cost-effective. In order to carry out these responsibilities the FPSC must have information sufficient to assure that an adequate, reliable, and cost-effective supply of electricity is planned and provided.

The Ten-Year Site Plan (TYSP) provides information and data that will facilitate the FPSC's review. This TYSP provides information related to JEA's power supply strategy to adequately meet the forecasted needs of our customers for the planning period from January 1, 2012 to December 31, 2021. This power supply strategy maintains a balance of reliability, environmental stewardship, and cost to the consumers.

1 Description of Existing Facilities

1.1 Power Supply System Description

1.1.1 System Summary

JEA is the seventh largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers all of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles and serves approximately 420,000 customers.

JEA consists of three financially separate entities: the JEA Electric System, the St. Johns River Power Park bulk power system, and the Robert W. Scherer bulk power system. The total projected net capability of JEA's generation system for 2012 is 4,122 MW for winter and 3,754 MW for summer. Details of the existing facilities are displayed in TYSP Schedule 1.

1.1.1.1 The JEA Electric System

The JEA Electric System consists of generating facilities located on four plant sites within the City; the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), the Brandy Branch Generating Station (Brandy Branch), and the Greenland Energy Center (GEC). Collectively, these plants consist of two dual-fired (petroleum coke/coal) Circulating Fluidized Bed steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); five dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT7 and GT8, and Brandy Branch GT1, CT2, and CT3); two natural gas-fired combustion turbine-generator units (GEC GT1 and GT2); four diesel-fired combustion turbine-generator units (Northside GTs 3, 4, 5, and 6); and one combined cycle heat recovery steam generator unit (Brandy Branch steam Unit 4).

1.1.1.2 The Bulk Power Systems

1.1.1.2.1 St. John's River Power Park

The St. Johns River Power Park (SJRPP) is jointly owned by JEA (80 percent) and FP&L (20 percent). SJRPP consists of two nominal 638 MW bituminous coal fired units located north of the Northside Generating Station in Jacksonville, FL. Unit 1 began commercial operation in March 1987 and Unit 2 followed in May 1988. The two units have operated efficiently since commercial operation.

Although JEA is the majority owner of SJRPP, both owners are entitled to 50 percent of the output of SJRPP. Since FP&L's ownership is only 20 percent, JEA has agreed to sell, and FPL has agreed to purchase, on a "take-or-pay" basis, 37.5 percent of JEA's 80 percent share of the generating capacity and related energy of SJRPP. This sale will continue until the earlier of the Joint Ownership Agreement expiration in October 2021 or the realization of the sale limits. For the purposes of this Ten Year Site Plan, the 37.5% sale to FP&L is forecasted to suspend summer 2019.

1.1.1.2.2 Robert W. Scherer Generating Station

Robert W. Scherer Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. JEA and FP&L have purchased an undivided interest of this unit from Georgia Power Company. JEA has a 23.6 percent ownership interest in Unit 4 (200 net MW) and proportionate ownership interests in associated common facilities and the associated coal stockpile. JEA has firm transmission service for delivering the energy output from this unit to JEA's system.

1.1.2 Purchased Power

1.1.2.1 Trail Ridge Landfill

In 2006, JEA entered into a purchase power agreement (PPA) with Trail Ridge Energy, LLC (TRE) to receive up to 9 net MW of firm renewable generation capacity utilizing the methane gas from the City's Trail Ridge landfill located in western Duval County (the "Phase One Purchase"). The TRE gas-to-energy facility began commercial operation December 6, 2008 for a ten year term ending December 2018.

JEA and TRE executed an amendment to this purchase power agreement March 9, 2011 to include additional capacity. The "Phase Two Purchase" amendment included up to 9 additional net MW. Phase two is expected to achieve commercial operation in December 2012 for a term of 15 years.

1.1.2.2 Jacksonville Solar

In May 2009, JEA entered into a purchase power agreement with Jacksonville Solar, LLC (Jax Solar) to receive up to 15 MW (DC rating) of as-available renewable energy from the solar plant located in western Duval County. The Jacksonville Solar facility consists of approximately 200,000 photovoltaic panels on a 100 acre site and is forecasted to produce an average of 22,340 megawatt-hours (MWh) of electricity per year. The Jacksonville Solar plant began commercial operation at full designed capacity September 30, 2010. For the purpose of this TYSP, it is assumed that the capacity of this variable energy resource is non-firm until valid statistics can be utilized to assign a firm level of contribution to JEA's coincident peak demands. Jax Solar generated 23,125 MWh in calendar year 2011.

1.1.2.3 Nuclear Generation

In March 2008, the JEA Board of Directors approved the pursuit of nuclear energy partnerships with the goal of providing 10 percent of JEA's power from nuclear sources. Adding power from nuclear sources to JEA's portfolio is part of a strategy for greater regulatory and fuel diversification. Meeting this goal will result in a smaller carbon footprint for JEA's customers.

In June 2008, JEA entered into a 20 year purchase power agreement (PPA) with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to Vogtle Units 3 and 4. These two new nuclear units are under construction at the existing Plant Vogtle location in Burke County, GA. Under this PPA, JEA is entitled to a total of 206 MW of firm capacity from these units. After accounting for transmission losses, JEA is anticipating to receive a total of 200 MW of net firm capacity from these units. The current schedule makes available to JEA 100 net MW of capacity beginning November 1, 2016 from Unit 3 and an additional 100 net MW beginning November 1, 2017 from Unit 4. Table 1 lists JEA's current purchased power contracts.

Table 1: JEA Purchased Power Schedule

Contract	Contract Start Date	Contract End Date	MW [1]	Product Type
Trail Ridge	Unit 1			
	December 6, 2008	December 5, 2018	9	Annual
	Unit 2			
	December 1, 2012	November 31, 2027	9	Annual
MEAG	Vogtle Unit 3			
	November 1, 2016	October 31, 2036	100	Annual
	Vogtle 4			
	November 1, 2017	October 31, 2037	100	Annual
Jacksonville Solar	September 30, 2010	September 30, 2040	15 [2]	Annual

[1] Capacity level may vary over contract term.
[2] Direct Current (DC) rating.

1.1.2.4 Cogeneration

Cogeneration facilities help meet the energy needs of JEA's system on an as-available, non-firm basis. Since these facilities are considered energy only resources, their capacity is not forecasted to contribute firm capacity to JEA's reserve requirements.

Currently, JEA has contracts with one customer-owned qualifying facility (QF), as defined in the Public Utilities Regulatory Policy Act of 1978. Anheuser Busch has a total installed summer rated capacity of 8 MW and winter rated capacity of 9 MW.

Schedule 1: Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit Number	Location	Unit Type	Fuel Type		Fuel Transport		Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net MW Capability		Ownership	Status
				Primary	Alt.	Primary	Alt.	Mo/Yr	Mo/Yr	kW	Summer	Winter		
Kennedy										407,600	300	382		
	7	12-031	GT	NG	FO2	PL	WA	6/2000	(a)	203,800	150	191	Utility	
	8	12-031	GT	NG	FO2	PL	WA	6/2009	(a)	203,800	150	191	Utility	
Northside										1,512,100	1,322	1,356		
	1	12-031	ST	PC	BIT	WA	RR	5/2003	(a)	350,000	293	293	Utility	
	2	12-031	ST	PC	BIT	WA	RR	4/2003	(a)	350,000	293	293	Utility	
	3	12-031	ST	NG	FO6	PL	WA	7/1977	12/2021	563,700	524	524	Utility	
	3-6	12-031	GT	FO2		WA	TK	1/1975	(a)	248,400	212	246	Utility	
Brandy Branch										879,800	651	796		
	1	12-031	GT	NG	FO2	PL	TK	5/2001	(a)	203,800	150	191	Utility	
	2	12-031	CT	NG	FO2	PL	TK	5/2001	(a)	203,800	150	191	Utility	
	3	12-031	CT	NG	FO2	PL	TK	10/2001	(a)	203,800	150	191	Utility	
	4	12-031	CA	WH				1/2005	(a)	268,400	201	223	Utility	
Greenland Energy Center										406,600	284	372		
	1	12-031	GT	NG		PL		6/2011	(a)	203,800	142	186	Utility	
	2	12-031	GT	NG		PL		6/2011	(a)	203,800	142	186	Utility	
Girvin Landfill														
	1-2	12-031	IC	NG		PL		7/1997	(a)	1.2	1.2	1.2	Utility	
St. Johns River Power Park										1,359,200	1,002	1,020		
	1	12-031	ST	BIT	PC	RR	WA	3/1987	(a)	679,600	501	510	Joint	(b)
	2	12-031	ST	BIT	PC	RR	WA	5/1988	(a)	679,600	501	510	Joint	(b)
Scherer														
	4	13-207	ST	SUB	BIT	RR	RR	2/1989	(a)	846,000	194	194	Joint	(c)
JEA System Total											**3,754**	**4,122**		(d)

NOTES: (a) Units expected to be maintained throughout the TYSP period.
(b) Net capability reflects JEA's 80% ownership of Power Park.
(c) Net capability reflects JEA's 23.64% ownership in Scherer 4.
(d) Numbers may not add due to rounding.

1.1.3 Power Sales Agreements

1.1.3.1 Florida Public Utilities Company

JEA furnishes wholesale power to Florida Public Utilities Company (FPU) for resale to the City of Fernandina Beach in Nassau County, north of Jacksonville. In September 2006, JEA and FPU entered into a 10 year agreement for JEA to supply FPU all of their system energy requirements which began January 1, 2008 and extends through December 31, 2017. For the purpose of this TYSP it is assumed that JEA will continue to serve FPU throughout this TYSP reporting period. Sales to FPU in calendar year 2011 totaled 405 GWh or 3.1% of JEA's total system energy requirement.

1.2 Transmission and Distribution

1.2.1 Transmission and Interconnections

The JEA transmission system consists of 734 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV (Figure 1).

The 500 kV transmission lines are jointly owned by JEA and FPL and complete the path from FPL's Duval substation (to the west of JEA's system) to the Florida interconnect at the Georgia Integrated Transmission System (ITS). Along with JEA and FPL, Progress Energy Florida, and the City of Tallahassee each own transmission interconnections with the Georgia ITS. JEA's import entitlement over these transmission lines is 1,228 MW out of 3,700 MW.

The 230 kV and 138 kV transmission system provides a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest to fill in the area not covered by the 230 kV and 138 kV transmission backbone.

JEA owns and operates three 230 kV tie-lines terminating at FPL's Duval substation in Duval County, one 230 kV tie-line terminating at Beaches Energy's Sampson substation (FPL metered tie-line) in St. Johns County, one 230 kV tie-line terminating at Seminole Electric Cooperative's Black Creek substation in Clay County, and one 138 kV tie-line terminating at Beaches Energy's Penman Road substation.

JEA also owns and operates a 138 kV transmission loop that extends from the 138 kV backbone north to the Nassau substation, where JEA delivers wholesale power to FPU for resale within the City of Fernandina Beach, Nassau County, Florida.

1.2.2 Transmission System Considerations

JEA continues to evaluate and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. In compliance with North American Electric Reliability Corporation (NERC) and Florida Reliability Coordinating Council's (FRCC) standards, JEA continually assesses the needs and options for increasing the capability of the transmission system.

JEA performs system assessments using JEA's published Transmission Planning Process in conjunction with and as an integral part of the FRCC's published Regional Transmission Planning Process. FRCC's published Regional Transmission Planning Process facilitates coordinated planning by all transmission providers, owners, and stakeholders with the FRCC Region. FRCC's members include investor owned utilities, municipal utilities, a federal power agency, power marketers, and independent power producers. The FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The FRCC Planning Committee, which includes representation by all FRCC members, directs the FRCC Transmission Working Group, in conjunction with the FRCC Staff, to conduct the necessary studies to fully implement the FRCC Regional Transmission Planning Process. The FRCC Regional Transmission Planning Process meets the principles of the Federal Energy Regulatory Commission (FERC) Final Rule in Docket No. RM05-35-000 for: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects.

1.2.3 Transmission Service Requirements

In addition to the obligation to serve native retail territorial load, JEA also has contractual obligations to provide transmission service for:

- the delivery of FPL's share of SJRPP energy output from the plant to FPL's interconnections
- the delivery of Cedar Bay's energy output from the plant to FPL's interconnections
- the delivery of backup, non-firm, as-available tie capability for the Beaches Energy System

JEA also engages in market transmission service obligations via the Open Access Same-time Information System (OASIS) where daily, weekly, monthly, and annual firm and non-firm transmission requests are submitted by potential transmission service subscribers.

1.2.4 Distribution

The JEA distribution system operations at three primary voltage levels; 4.16 kV, 13.2 kV, and 26.4 kV. The 26.4 kV system serves approximately 86% of JEA's load, including 75% of the 4.16 kV substations. The current standard is to serve all new distribution loads, except loads in the downtown network, with 26.4 kV systems. Conversion of the aging 4 kV infrastructure continues to be implemented. JEA has approximately 6500 miles of distribution circuits of which more than half is underground.

1.3 Demand Side Management

1.3.1 Interruptible Load

JEA currently offers Interruptible and Curtailable Service to eligible industrial class customers with peak demands of 750 kW or higher. Customers who subscribe to the Interruptible Service are subject to interruption of their full nominated load during times of system emergencies, including supply shortages. Customers who subscribe to the Curtailable Service may elect to voluntarily curtail portions of their nominated load based on economic incentives. For the purposes of JEA's planning reserve requirements, only customer load nominated for Interruptible Service is treated as non-firm. This non-firm load reduces the need for capacity planning reserves to meet peak demands. JEA forecasts 65 MW and 105 MW of interruptible peak load in the winter and summer, respectively. For 2012, the interruptible load represents approximately 3.0 percent of the total peak demand in the winter and 4.0 percent of the forecasted total peak demand in the summer. JEA's forecasts for interruptible load increases to approximately 3.5 percent of the total peak demand in winter 2013 and 4.5 percent of the forecasted total peak demand in summer 2013; thereafter, remaining constant.

1.3.2 Demand-Side Management Programs

JEA continues to pursue a greater implementation of demand-side management programs where economically beneficial to our customers and to meet JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals. Currently, JEA does not have or plan to have any Direct Load Control (DLC) programs for controlling specific customer loads. However, JEA continues to offer economic incentives to customers that choose to participate in energy efficiency (EE) initiatives. JEA recognizes that EE programs will also result in not only decreased energy consumption, but also decreased coincident annual peak demands further reducing JEA's forecasted need for increased planning reserves. JEA's forecast of annual incremental demand and energy reductions due to DSM programs over the next ten year period is shown in the Table 2. JEA's planned DSM programs are summarized by commercial and residential programs in Table 3.

Figure 1: JEA Transmission/Generation Facilities System Map

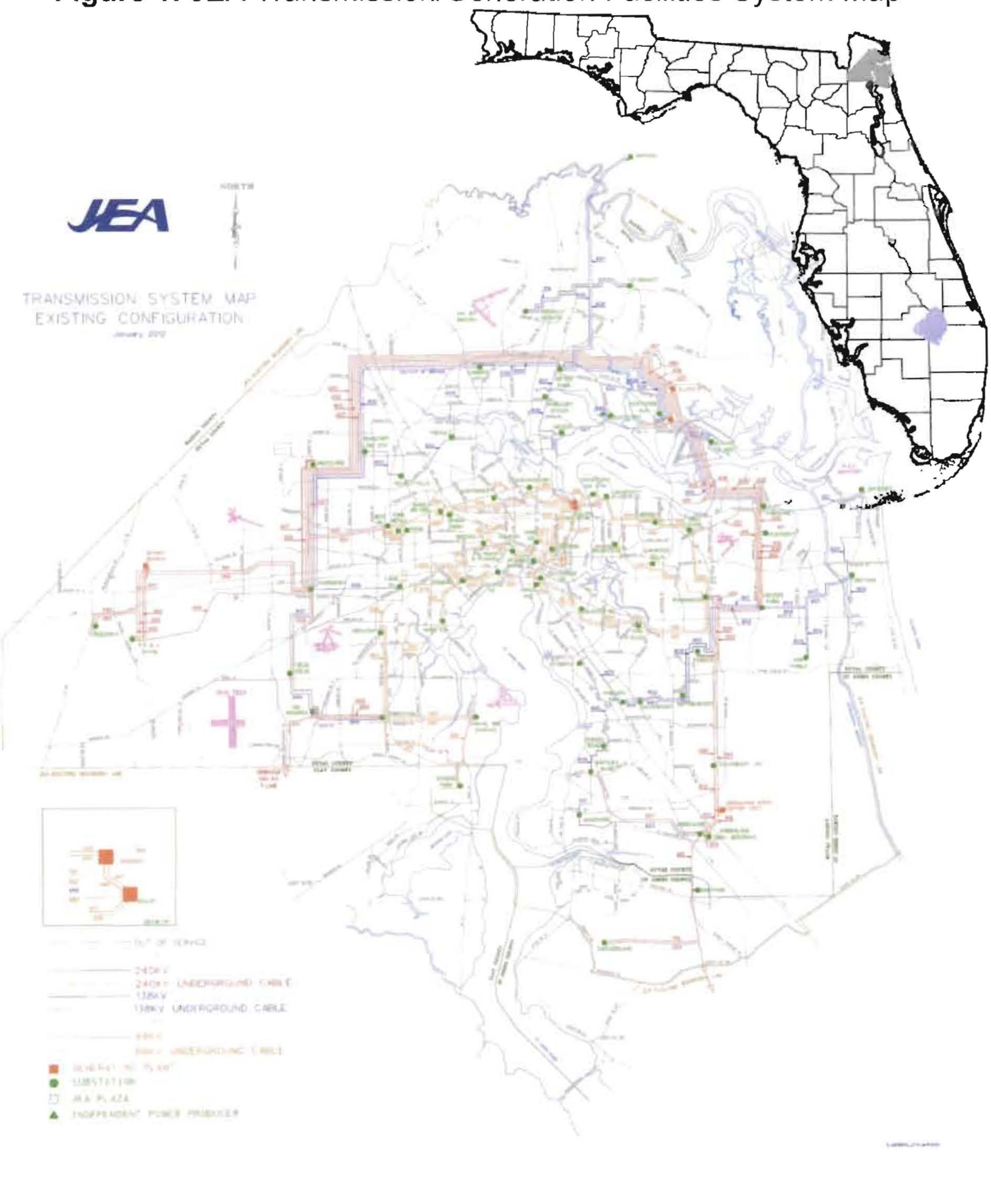


Table 2: DSM Portfolio

ANNUAL INCREMENTAL		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Annual Energy (GWh)	Residential	31.0	28.9	28.9	26.4	23.1	23.1	23.5	23.8	24.1	24.4
	Commercial	31.5	29.4	29.4	26.8	23.5	23.5	23.8	24.2	24.5	24.8
	Total	**62.6**	**58.3**	**58.3**	**53.2**	**46.6**	**46.6**	**47.3**	**47.9**	**48.6**	**49.3**
Summer Peak (MW)	Residential	7.4	6.9	6.9	6.3	5.5	5.5	5.6	5.7	5.7	5.8
	Commercial	5.1	4.8	4.8	4.4	3.8	3.8	3.9	3.9	4.0	4.0
	Total	**12.5**	**11.7**	**11.7**	**10.6**	**9.3**	**9.3**	**9.5**	**9.6**	**9.7**	**9.9**
Winter Peak (MW)	Residential	5.8	5.4	5.4	5.0	4.4	4.4	4.4	4.5	4.5	4.6
	Commercial	3.8	3.5	3.5	3.2	2.8	2.8	2.9	2.9	2.9	3.0
	Total	**9.6**	**9.0**	**9.0**	**8.2**	**7.2**	**7.2**	**7.3**	**7.4**	**7.5**	**7.6**

Table 3: DSM Programs

Commercial Programs	Residential Programs
Commercial Energy Audit Program	Residential Energy Audit Program
Commercial Energy Efficient Products	Residential Energy Efficient Products
District Chilled Water Program	Green Built Homes of Florida
Commercial Solar Net Metering	Residential Solar Water Heating
Commercial Prescriptive Program	Residential Solar Net Metering
Custom Commercial Program	Neighborhood Efficiency Program
Small Business Direct Install Program	Residential Efficiency Upgrade

1.4 Clean Power and Renewable Energy

JEA continues to look for economical opportunities to incorporate clean power and renewable energy into JEA's power supply portfolio. To that end, JEA has implemented several clean power and renewable energy initiatives and continues to evaluate potential new initiatives.

1.4.1 Clean Power Program

Since 1999, JEA has worked with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups through routine JEA Clean Power Program meetings, as established in the JEA "Clean Power Action Plan". The "Clean Power Action Plan" has an Advisory Panel which is comprised of participants from the Jacksonville community. These local members provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program.

JEA has made considerable progress related to clean power initiatives. This progress includes installation of clean power systems, unit efficiency improvements, commitment to purchase power agreements (including nuclear power), legislative and public education activities, and research into and development of clean power technologies.

1.4.2 Renewable Energy

In 2005, JEA received a Sierra Club Clean Power Award for its voluntary commitment to increasing the use of solar, wind and other renewable or green power sources. Since that time, JEA has implemented new renewable energy projects and continues to explore additional opportunities to increase its utilization of renewable energy. In addition, JEA has issued several Request for Proposals (RFPs) for renewable energy resources that have resulted in new resources for JEA's portfolio. As further discussed below, JEA's existing renewable energy sources include installation of solar photovoltaic (PV), solar thermal, and landfill and wastewater treatment biogas capacity.

1.4.2.1 Solar and the Solar Incentive

JEA has installed 35 solar PV systems, totaling 222 kW, on public high schools in Duval County, as well as many of JEA's facilities, and the Jacksonville International Airport. To further promote the acceptance and installation of solar energy systems, JEA implemented the Solar Incentive Program in early 2002. This program continues to provide rebates for the installation of solar thermal systems.

In addition to the solar thermal system incentive program, JEA established a residential net metering program to encourage the use of customer-sited solar PV systems, which was revised as the Tier 1 & 2 Net Metering policy in 2009, to include all customer-owned renewable generation systems up to and equal to 100 kW. In 2011, JEA established the Tier 3 Net Metering Policy for customer-owned renewable generation systems greater than 100 kW up to 2 MW.

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 began operation in summer 2010. (See Section 1.1.2.2 Jacksonville Solar).

1.4.2.2 Landfill Gas and Biogas

JEA owns three internal combustion engine generators located at the 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 to 1.2 MW, 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 pelletized fertilizer product. The methane gas from the digesters is used as a fuel for the sludge dryer and for the on-site 800 kW generator.

JEA signed a Power Purchase Agreement with Trail Ridge Energy, LLC (TRE) in 2006 (Phase One) and executed an amendment to the Power Purchase Agreement in 2011 (Phase Two) to purchase 9 net MW each phase from a gas-to-energy facility at the City's Trail Ridge landfill. (See Section 1.1.2.1 Trail Ridge Landfill).

JEA also receives approximately 1,500 kW of landfill gas from the North Landfill, which is piped to the Northside Generating Station and is used to generate power at Northside Unit 3.

1.4.2.3 Wind

As part of its ongoing effort to utilize more sources of renewable energy, in 2004 JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) 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 (green tags) 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 and off peak charges.

1.4.2.4 Biomass

In a continuing effort to obtain cost-effective biomass generation, JEA completed a detailed feasibility study of both self-build stand-alone biomass units and the co-firing of biomass in Northside 1 and 2. The JEA self-build projects would not have been eligible for the federal tax credits afforded to developers. The co-firing alternative for Northside 1 and 2 considered potential reliability issues associated with both of those units. Even though the price of petroleum coke has been volatile in recent past, petroleum coke prices are still forecasted to be lower than the cost of biomass on an as-fired basis. In addition, JEA conducted an analytical evaluation of specific biomass fuel types to determine the possibility of conducting a co-firing test in Northside 1 or 2.

In 2011, JEA co-fired biomass in the Northside Units 1 and 2, utilizing wood chips from JEA tree trimming activities as a biomass energy source. Northside 1 and 2 produced 1,871 MWh of energy with the wood chips.

JEA has received solicited and unsolicited offers for biomass and other renewable generation. JEA has evaluated the feasible offers, but has been unable to successfully execute a contract for cost-effective biomass generation. One notable example is the 70 MW biomass project burning E-grass that JEA executed in 2002 with Biomass

Investment Group (BIG). Even though JEA executed the purchase power agreement, BIG never implemented the project and subsequently, the contract expired.

Further, an unsolicited offer was received from ADAGE for energy from a proposed 50 MW facility. An exclusive letter of intent to purchase the biomass power expired on December 31, 2009. Due to the premium energy cost, JEA did not enter into a purchase power agreement.

1.4.2.5 Research Efforts

Many of Florida's renewable resources such as offshore wind, tidal, and energy crops require additional research and development before they can be implemented as large-scale power generating technologies. JEA's renewable energy research efforts have focused on the development of these technologies through a partnership with the University of North Florida's (UNF) Engineering Department. UNF and JEA have worked on the following projects:

- JEA has worked with the UNF to quantify the winter peak reductions of solar hot water systems.
- UNF, in association with the University of Florida, has evaluated the effect of biodiesel fuel in a utility-scale combustion turbine. Biodiesel has been extensively tested on diesel engines, but combustion turbine testing has been very limited.
- UNF has evaluated the tidal hydro-electric potential for North Florida, particularly in the Intracoastal Waterway, where small proto-type turbines have been tested.
- JEA, UNF, and other Florida municipal utilities partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for offshore wind development in Florida.
- JEA has also provided solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.
- JEA developed a 15 acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3 year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.

1.4.2.6 Generation Efficiency and New Natural Gas Generation

In the late 1990's, JEA began to modernize its natural gas/oil fleet of generating units by replacing inefficient steam units and inefficient combustion turbine units with more efficient natural gas fired combustion turbines and combined cycle units. The retirement of units and their replacement with an efficient combined cycle unit and efficient simple cycle combustion turbines at Brandy Branch, Kennedy, and Greenland Energy Center significantly reduces CO_2 emissions.

2 Forecast of Electric Power Demand and Energy Consumption

2.1 Peak Demand Forecast

Annually, JEA develops forecasts of seasonal peak demand, net energy for load (NEL), interruptible customer demand, and demand-side management (DSM). This year JEA's forecast includes the impact of plug-in electric vehicles (PEV). JEA subtracts from the total, by season, all coincidental non-firm sources and adds sources of additional demand to derive a firm load forecast.

Over the years JEA has used regression analysis methodology to forecast seasonal peak demand. To address the variability in demand in recent years, JEA has also studied historical average annual growth rates (AAGR) over various periods. JEA observed that the AAGR for the intervals varied little after 20 years. Therefore, JEA's 2012 baseline forecast utilizes the 20 year regression analysis.

The 20 year AAGR from the regression analysis was applied to the season's last historical weather normalized demand to produce future projections. The resulting AAGR for summer is 1.55% and for winter is 1.78% (Figures 2 and 3).

2.2 Energy Forecast

The energy forecast is developed on a monthly and annual basis as a function of time and heating and cooling degree-day data. Inputs into the forecast include historical system energy production, JEA territory sales, off-system sales, and heating and cooling degree-days. The JEA forecast modeling methodology separately accounts for and projects the temperature dependent and non-temperature dependent energy requirements over time, then combines these components to derive the system total energy forecast.

JEA is forecasting a 1% growth in energy for the first 5 years and 1.5%, thereafter (Figure 4). Electric service accounts have grown approximately one half of one percent annually from 2009 through 2011. This energy forecast incorporates the continuation of a slight residential growth and incremental growth in the large industrial class that has been recovering after a 25% reduction in electricity consumption from 2008 levels.

EIA's 2011 Annual Energy Outlook states that U.S. electricity demand is projected to grow an average of 1% a year for at least the next five years. JEA's service territory is assumed to follow this trend. This estimate also reflects the U.S. Census housing start data for years 2007 through 2010. New privately owned houses completed in the South have consistently decreased. This data would indicate no significant projected customer growth. Historical and forecast winter peak demand, summer peak demand, and net energy for load are shown in greater detail in Schedules 2 through 4.

2.3 Plug-in Electric Vehicle Peak Demand and Energy

JEA developed the PEV demand and energy forecast for the service territory using information from the Electric Power Research Institute (EPRI), the Edison Electric Institute (EEI), the U.S. Census Bureau, and the Bureau of Economic and Business Research (BEBR).

JEA's baseline forecast of the number of plug-in vehicles in the area was determined from BEBR's forecasted population growth rate, the U.S. Census Bureau's 2010 estimated number of vehicles, and EPRI's forecasted low scenario PEV penetration rate.

Using the upcoming plug-in vehicle model roll-outs from Toyota, Honda, Ford, and General Motors, the average usable battery capacity per vehicle is projected to be approximately 20 kWh. The size of the battery capacity is projected to grow at 1 kWh per year.

JEA's baseline forecast assumes that charging will initially be uncontrolled and at home until the mid 2020s when public infrastructure is feasible and available. The PEV seasonal peak demand forecast and annual energy forecast are shown on Schedules 3.1, 3.2, and 3.3.

Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers By Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Rural and Residential			Commercial			Industrial		
	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer	GWH Sales	Average Number of Customers	Average kWh/ Customer
2002	5,108	326,362	15,651	1,157	33,841	34,189	5,479	3,475	1,576,691
2003	5,226	332,492	15,718	1,184	33,762	35,069	5,605	3,630	1,544,077
2004	5,400	348,320	15,503	1,185	32,123	36,889	5,396	3,638	1,483,233
2005	5,550	358,770	15,469	1,249	33,087	37,738	5,686	3,747	1,517,473
2006	5,637	357,232	15,780	1,289	37,136	34,704	5,658	4,206	1,345,307
2007	5,478	364,284	15,039	1,328	39,919	33,279	5,832	4,521	1,290,035
2008	5,364	365,632	14,670	1,357	40,608	33,417	5,777	4,599	1,256,240
2009	5,300	367,864	14,408	1,303	41,150	31,660	5,546	4,660	1,190,207
2010	5,748	369,050	15,575	1,329	41,693	31,869	5,657	4,722	1,198,052
2011	5,445	369,566	14,733	1,314	41,958	31,317	5,594	4,752	1,177,321
2012	5,685	384,612	14,781	1,372	43,554	31,501	5,841	4,956	1,178,630
2013	5,719	385,637	14,830	1,380	43,558	31,685	5,876	4,980	1,179,940
2014	5,754	386,711	14,878	1,389	43,567	31,871	5,911	5,004	1,181,252
2015	5,791	387,956	14,927	1,398	43,595	32,057	5,950	5,031	1,182,566
2016	5,842	390,125	14,976	1,410	43,726	32,245	6,003	5,070	1,183,881
2017	5,918	393,884	15,025	1,428	44,034	32,434	6,080	5,130	1,185,197
2018	5,995	397,724	15,074	1,447	44,349	32,624	6,160	5,191	1,186,515
2019	6,074	401,647	15,123	1,466	44,671	32,815	6,241	5,254	1,187,834
2020	6,155	405,648	15,173	1,485	45,000	33,007	6,324	5,318	1,189,155
2021	6,242	410,083	15,222	1,506	45,375	33,200	6,414	5,387	1,190,477

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

Year	(11) Street & Highway Lighting GWH	(12) Other Sales to Ultimate Customers GWH	(13) Total Sales to Ultimate Customers GWH	(14) Sales For Resale GWH	(15) Utility Use & Losses GWH	(16) Net Energy For Load GWH	(17) Other Customers (Avg. Number)	(18) Total Number of Customers
2002	112	0	11,856	446	681	12,983	2	363,698
2003	115	0	12,130	453	595	13,178	2	369,904
2004	76	0	12,057	468	718	13,243	2	384,108
2005	111	0	12,596	486	615	13,696	2	395,606
2006	110	0	12,694	522	595	13,811	7	398,581
2007	113	0	12,751	624	479	13,854	5	408,729
2008	117	0	12,615	451	464	13,530	3	414,418
2009	120	0	12,270	479	406	13,155	3	413,677
2010	122	0	12,855	343	644	13,842	2	415,467
2011	122	0	12,476	100	405	12,980	2	416,278
2012	126	0	13,024	114	415	13,553	2	433,125
2013	127	0	13,102	116	416	13,633	2	434,176
2014	128	0	13,181	119	417	13,716	2	435,285
2015	128	0	13,267	120	418	13,805	2	436,584
2016	130	0	13,385	124	419	13,928	2	438,923
2017	131	0	13,558	129	421	14,108	2	443,050
2018	133	0	13,735	134	423	14,292	2	447,266
2019	135	0	13,916	139	426	14,481	2	451,574
2020	137	0	14,100	144	428	14,672	2	455,967
2021	138	0	14,301	151	430	14,881	2	460,847

Schedule 3.1: History and Forecast of Summer Peak Demand

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	
Calendar Year	Total Demand	Interruptible Load	PEV	Load Management		QF Load Served By QF	Cumulative Conservation		Net Firm Peak Demand	Time Of Peak			
				Residential	Comm/Ind.	Generation	Residential	Comm/Ind.		Month	Day	H.E.	Temp
2002	2,562	0	0	0	0	0	0	0	2,562	7	19	1600	98
2003	2,535	0	0	0	0	0	0	0	2,535	7	10	1600	94
2004	2,539	0	0	0	0	0	0	0	2,539	8	2	1700	94
2005	2,815	0	0	0	0	0	0	0	2,815	8	17	1800	96
2006	2,835	0	0	0	0	0	0	0	2,835	8	4	1700	97
2007	2,897	0	0	0	0	0	0	0	2,897	8	7	1700	97
2008	2,866	0	0	0	0	0	0	0	2,866	8	7	1600	96
2009	2,754	0	0	0	0	0	0	0	2,754	6	22	1600	98
2010	2,817	0	0	0	0	0	0	0	2,817	6	18	1700	102
2011	2,756	0	0	0	0	0	0	0	2,756	8	11	1700	98
2012	2,772	113	0	0	0	0	6	4	2,649	---	---	---	----
2013	2,815	131	0	0	0	0	12	9	2,663	---	---	---	----
2014	2,859	131	0	0	0	0	17	12	2,699	---	---	---	----
2015	2,903	131	0	0	0	0	21	14	2,737	---	---	---	----
2016	2,948	131	0	0	0	0	30	21	2,767	---	---	---	----
2017	2,993	131	1	0	0	0	33	23	2,806	---	---	---	----
2018	3,040	131	1	0	0	0	37	25	2,848	---	---	---	----
2019	3,087	131	1	0	0	0	43	30	2,884	---	---	---	----
2020	3,135	131	1	0	0	0	42	29	2,934	---	---	---	----
2021	3,121	131	85	0	0	0	51	35	2,989	---	---	---	----

Note: (a) All projections coincident at time of peak.

Schedule 3.2: History and Forecast of Winter Peak Demand

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	
Calendar Year	Total Demand	Interruptible Load	PEV	Load Management		QF Load Served By QF	Cumulative Conservation		Net Firm Peak Demand	Time Of Peak			
				Residential	Comm/Ind.	Generation	Residential	Comm/Ind.		Month	Day	H.E.	Temp
2002	2,590	0	0	0	0	0	0	0	2,590	1	4	0800	27
2003	3,083	0	0	0	0	0	0	0	3,083	1	24	0800	19
2004	2,668	0	0	0	0	0	0	0	2,668	1	29	0700	23
2005	2,860	0	0	0	0	0	0	0	2,860	1	24	0800	23
2006	2,919	0	0	0	0	0	0	0	2,919	2	14	0800	26
2007	2,722	0	0	0	0	0	0	0	2,722	1	30	0800	28
2008	2,914	0	0	0	0	0	0	0	2,914	1	3	0800	25
2009	3,064	0	0	0	0	0	0	0	3,064	2	6	0800	23
2010	3,224	0	0	0	0	0	0	0	3,224	1	11	0800	20
2011	3,062	0	0	0	0	0	0	0	3,062	1	14	0800	23
2012	2,665	0	0	0	0	0	0	0	2,665	1	4	0800	22
2013	3,114	107	0	0	0	0	12	8	2,988	---	---	---	----
2014	3,169	107	0	0	0	0	9	6	3,048	---	---	---	----
2015	3,225	107	0	0	0	0	14	9	3,095	---	---	---	----
2016	3,283	107	1	0	0	0	19	13	3,145	---	---	---	----
2017	3,341	107	1	0	0	0	22	14	3,198	---	---	---	----
2018	3,401	107	1	0	0	0	29	19	3,247	---	---	---	----
2019	3,461	107	1	0	0	0	40	26	3,289	---	---	---	----
2020	3,523	107	2	0	0	0	23	15	3,379	---	---	---	----
2021	3,585	107	3	0	0	0	36	23	3,421	---	---	---	----

Note: (a) All projections coincident at time of peak.

Schedule 3.3: History and Forecast of Annual Net Energy For Load

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Calendar Year	Total Energy For Load	Interruptible Load	PEV	Load Management		QF Load Served By QF Generations	Cumulative Conservation		Net Energy For Load	Load Factor(a)
				Residential	Comm/Ind.		Residential	Comm/Ind.		
2002	12,983	0	0	0	0	0	0	0	12,983	57%
2003	13,178	0	0	0	0	0	0	0	13,178	49%
2004	13,243	0	0	0	0	0	0	0	13,243	57%
2005	13,696	0	0	0	0	0	0	0	13,696	55%
2006	13,811	0	0	0	0	0	0	0	13,811	54%
2007	13,854	0	0	0	0	0	0	0	13,854	55%
2008	13,531	0	0	0	0	0	0	0	13,531	53%
2009	13,155	0	0	0	0	0	0	0	13,155	49%
2010	13,842	0	0	0	0	0	0	0	13,842	49%
2011	12,980	0	0	0	0	0	0	0	12,980	48%
2012	13,610	0	5	0	0	0	37	25	13,553	52%
2013	13,746	0	8	0	0	0	72	49	13,633	52%
2014	13,884	0	11	0	0	0	107	72	13,716	51%
2015	14,023	0	14	0	0	0	139	93	13,805	51%
2016	14,180	0	27	0	0	0	167	112	13,928	51%
2017	14,393	0	41	0	0	0	195	131	14,108	50%
2018	14,609	0	56	0	0	0	223	150	14,292	50%
2019	14,828	0	73	0	0	0	252	169	14,480	50%
2020	15,051	0	91	0	0	0	281	189	14,672	50%
2021	15,277	0	123	0	0	0	310	209	14,881	50%

Note: (a) 2012 Load Factor calculation based on forecasted winter peak demand and forecasted energy (see Schedule 4).
(b) All projections are coincident at time of peak.

Schedule 4: Previous Year Actual and Two Year Forecast of Peak Demand and Net Energy for Load By Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Month	Actual 2011		Forecast 2012		Forecast 2013	
	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)
January	3,062	1,147	2,961	1,087	2,988	1,094
February	2,346	901	2,457	974	2,482	980
March	1,746	912	2,090	1,007	2,112	1,013
April	2,251	1,020	1,977	979	1,988	986
May	2,418	1,144	2,376	1,124	2,389	1,131
June	2,668	1,250	2,498	1,261	2,515	1,268
July	2,653	1,307	2,607	1,421	2,618	1,428
August	2,756	1,392	2,649	1,398	2,663	1,405
September	2,359	1,155	2,443	1,201	2,459	1,208
October	2,049	944	2,391	1,049	2,423	1,055
November	1,749	879	2,298	979	2,333	986
December	1,931	929	2,719	1,073	2,766	1,080
Annual Peak/ Total Energy	3,062	12,980	2,961	13,553	2,988	13,633

Figure 2: Summer Peak Demand History & Forecast

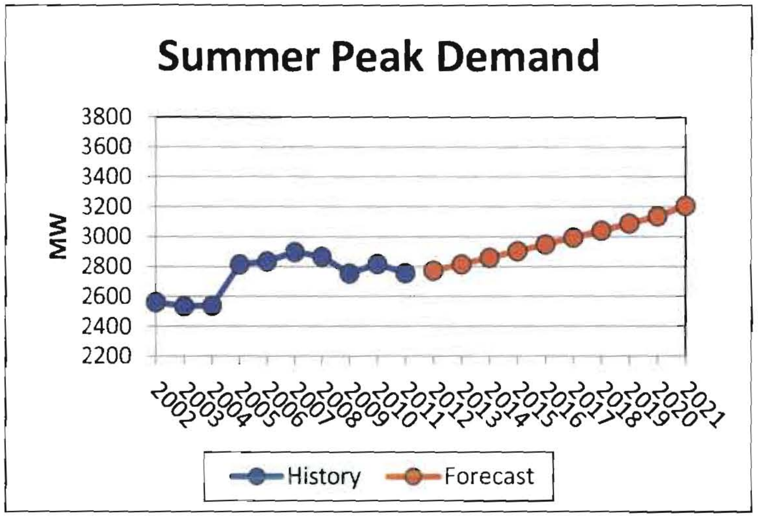


Figure 3: Winter Peak Demand History & Forecast

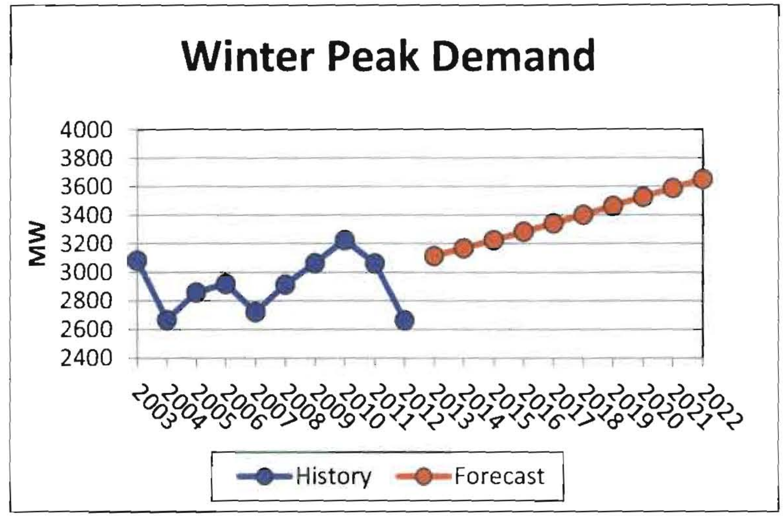
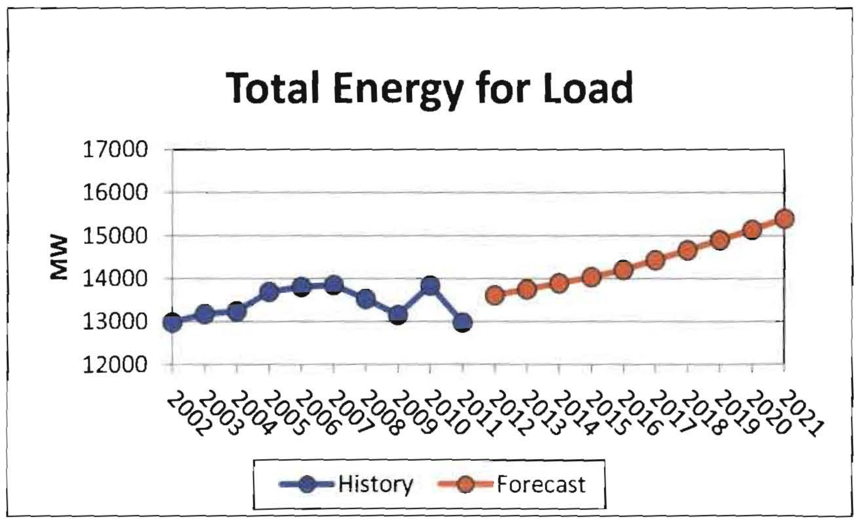


Figure 4: Net Energy for Load History & Forecast



3 Forecast of Facilities Requirements

3.1 Future Resource Needs

JEA evaluates future supply capacity needs for the electric system based on peak demand and energy forecasts, existing supply resources and contracts, transmission considerations, existing unit capacity changes, and future committed resources, as well as other planning assumptions. The base capacity plan includes as committed units the additions of Trail Ridge Phase Two, the purchased power agreement with MEAG for the future Vogtle Nuclear Units 3 and 4, and the return of the SJRPP capacity and energy sale from FPL. With these baseline assumptions, no additional capacity is needed for the term of this TYSP (see Schedules 7.1 and 7.2).

JEA's Planning Reserve Policy defines the planning reserve requirements that are used to develop the resource portfolio through the Integrated Resource Planning process. These guidelines set forth the planning criteria relative to the planning reserve levels and the constraints of the resource portfolio.

JEA's system capacity is planned with a targeted 15% generation reserve level for forecasted wholesale and retail firm customer coincident one hour peak demand, for both winter and summer seasons. This reserve level has been determined to be adequate to meet and exceed the industry standard Loss of Load Probability of 0.1 days per year. This level has been used by the Florida Public Service Commission (FPSC) in the consideration of need for additional generation additions.

JEA's Planning Reserve Policy establishes a guideline that provides for an allowance to meet the 15% reserve margin with up to 3% of forecasted firm peak demand in any season from purchases acquired in the operating horizon. However, no short-term seasonal market purchases are required.

If short-term seasonal market purchases had been needed, The Energy Authority (TEA), JEA's affiliated energy market services company, would have made the purchase. TEA actively trades energy with a large number of counterparties throughout the United States, and is generally able to acquire capacity and energy from other market participants when any of its members, including JEA, require additional resources.

3.2 Resource Plan

To develop the resource plan outlined in this TYSP submittal, JEA included a review of existing electric supply resources, forecasts of customer energy requirements and peak demands, forecasts of fuel prices and fuel availability, and committed unit addition and changes. All these factors considered collectively provided JEA with sufficient capacity to cover customer demand and reserves. Table 4 presents the ten year plan which meets JEA's strategic goals. Schedules 5-10 provide further detail on this plan.

Table 4
Resource Plan

Year	Season	Resource Plan(1) (2)
2012		
2013	Winter	Trail Ridge (Phase Two) Purchase (9 MW)
2014		
2015		
2016		
2017	Winter	MEAG Plant Vogtle 3 Purchase (100 MW) (3)
2018	Winter	MEAG Plant Vogtle 4 Purchase (100 MW) (3) Girvin Road Landfill Expires (1.2 MW)
2019	Winter Summer	Trail Ridge (Phase One) Contract Expires (9 MW) SJRPP Sale to FPL Suspended (383 MW) (4)
2020		
2021		

Notes:

(1) Cumulative DSM addition of 59 MW Winter and 86 MW Summer by 2021.
(2) PEV addition of 3 MW Winter and 85 MW Summer by 2021.
(3) After accounting for transmission losses, JEA is expects to receive 100 MW November 2016 and 100 MW November 2017 for a total of 200 MW of net firm capacity from the proposed units.
(4) SJRPP sales return projected for the Summer 2019.

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	**NUCLEAR**	**TOTAL**	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**[1]	**TOTAL**	**1000 TON**	**2,569**	**2,024**	**2,080**	**1,916**	**2,071**	**1,962**	**1,555**	**1,909**	**2,131**	**2,137**	**2,817**
	RESIDUAL													
(3)		STEAM	1000 BBL	43	200	164	171	151	145	139	169	140	159	98
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT/GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		**TOTAL**	**1000 BBL**	**43**	**200**	**164**	**171**	**151**	**145**	**139**	**169**	**140**	**159**	**98**
	DISTILLATE													
(7)		STEAM	1000 BBL	10	1	1	1	1	1	1	1	2	1	1
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	36	16	9	18	61	3	11	12	4	8	3
(10)		**TOTAL**	**1000 BBL**	**46**	**17**	**10**	**19**	**63**	**4**	**12**	**13**	**6**	**9**	**4**
	NATURAL GAS													
(12)		STEAM	1000 MCF	11,345	14,199	11,621	12,129	10,683	10,252	9,851	11,961	9,952	11,241	6,943
(13)		CC	1000 MCF	22,073	27,022	27,364	27,335	23,875	26,215	24,954	19,423	18,868	17,133	13,514
(14)		CT/GT	1000 MCF	3,248	3,454	2,715	3,059	8,055	2,054	3,345	3,326	2,360	3,198	1,254
(15)		**TOTAL**	**1000 MCF**	**36,666**	**44,675**	**41,700**	**42,523**	**42,612**	**38,521**	**38,150**	**34,711**	**31,180**	**31,572**	**21,711**
(16)	**PETROLEUM COKE**	**TOTAL**	**1000 TON**	**694**	**1,189**	**1,330**	**1,405**	**1,409**	**1,310**	**1,404**	**1,485**	**1,435**	**1,472**	**1,381**
(17)	**OTHER (SPECIFY)**	**TOTAL**	**TRILLION BTU**	**62**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

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

Schedule 6.1: Energy Sources (GWh)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Annual Firm Inter-Region Intchg.		GWH	1,213	0	0	0	0	860	1,705	1,651	1,710	1,656	1,648
(2)	NUCLEAR		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL[1]		GWH	5,129	4,541	4,521	4,291	4,517	4,438	3,634	4,220	4,972	5,139	6,805
(4)	RESIDUAL	STEAM	GWH	24	113	88	94	86	76	76	94	75	86	47
(5)		CC		0	0	0	0	0	0	0	0	0	0	0
(6)		CT		0	0	0	0	0	0	0	0	0	0	0
(7)		TOTAL		24	113	88	94	86	76	76	94	75	86	47
(8)	DISTILLATE	STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0
(9)		CC		0	0	0	0	0	0	0	0	0	0	0
(10)		CT		10	7	4	8	26	1	5	5	2	3	1
(11)		TOTAL		10	7	4	8	26	1	5	5	2	3	1
(12)	NATURAL GAS	STEAM	GWH	976	1,300	1,016	1,085	988	876	871	1,082	861	994	543
(13)		CC		3,220	4,085	4,122	4,125	3,597	3,909	3,681	2,908	2,807	2,560	2,018
(14)		CT		309	307	241	274	739	180	297	298	208	287	109
(15)		TOTAL		4,504	5,692	5,379	5,484	5,324	4,966	4,849	4,288	3,876	3,841	2,670
(16)	NUG		GWH	9	0	0	0	0	0	0	0	0	0	0
(17)	RENEWABLES	HYDRO	GWH	0	0	0	0	0	0	0	0	0	0	0
(18)		LANDFILL GAS		74	79	156	156	156	156	156	130	77	78	77
(19)		SOLAR		23	24	24	24	23	23	23	23	23	23	23
(20)		TOTAL		97	103	179	179	179	180	179	153	100	101	100
(21)	Petroleum Coke		GWH	1,994	3,097	3,461	3,660	3,673	3,408	3,660	3,881	3,745	3,846	3,610
(22)	OTHER (SPECIFY)		GWH	0	0	0	0	0	0	0	0	0	0	0
(23)	NET ENERGY FOR LOAD		GWH	12,980	13,553	13,633	13,716	13,805	13,928	14,108	14,292	14,480	14,672	14,881

Note: [1] Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal. SJRPP sale suspends summer 2019.

Schedule 6.2: Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Annual Firm Inter-Region Intchg.		%	15.3%	0.0%	0.0%	0.0%	0.0%	6.2%	12.1%	11.6%	11.8%	11.3%	11.1%
(2)	NUCLEAR		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL		%	44.5%	33.5%	33.2%	31.3%	32.7%	31.9%	25.8%	29.5%	34.3%	35.0%	45.7%
(4)	RESIDUAL	STEAM	%	0.2%	0.8%	0.6%	0.7%	0.6%	0.5%	0.5%	0.7%	0.5%	0.6%	0.3%
(5)		CC		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CT		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		TOTAL		0.2%	0.8%	0.6%	0.7%	0.6%	0.5%	0.5%	0.7%	0.5%	0.6%	0.3%
(8)	DISTILLATE	STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)		CC		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		CT		0.1%	0.1%	0.0%	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		TOTAL		0.1%	0.1%	0.0%	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)	NATURAL GAS	STEAM	%	4.8%	9.6%	7.5%	7.9%	7.2%	6.3%	6.2%	7.6%	5.9%	6.8%	3.6%
(13)		CC		9.7%	30.1%	30.2%	30.1%	26.1%	28.1%	26.1%	20.3%	19.4%	17.4%	13.6%
(14)		CT		0.5%	2.3%	1.8%	2.0%	5.4%	1.3%	2.1%	2.1%	1.4%	2.0%	0.7%
(15)		TOTAL		15.0%	42.0%	39.5%	40.0%	38.6%	35.7%	34.4%	30.0%	26.8%	26.2%	17.9%
(16)	NUG		%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(17)	RENEWABLES	HYDRO	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(18)		LANDFILL GAS		0.0%	0.6%	1.1%	1.1%	1.1%	1.1%	1.1%	0.9%	0.5%	0.5%	0.5%
(19)		SOLAR		0.0%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
(20)		TOTAL		0.0%	0.8%	1.3%	1.3%	1.3%	1.3%	1.3%	1.1%	0.7%	0.7%	0.7%
(21)	Petroleum Coke		%	24.9%	22.9%	25.4%	26.7%	26.6%	24.5%	25.9%	27.2%	25.9%	26.2%	24.3%
(22)	OTHER (SPECIFY)		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(23)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Note: Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal. SJRPP sales suspension summer 2019.

Schedule 7.1: Summer Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Peak

	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
		Import	Export								
Year	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
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: Winter Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Peak

	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin	
		Import	Export								
Year	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	MW
2012	4,122	9	383	0	3,749	2,961	788	27%	0	788	27%
2013	4,122	18	383	0	3,758	2,988	770	26%	0	770	26%
2014	4,122	18	383	0	3,758	3,048	710	23%	0	710	23%
2015	4,122	18	383	0	3,758	3,095	663	21%	0	663	21%
2016	4,122	18	383	0	3,758	3,145	613	19%	0	613	19%
2017	4,122	118	383	0	3,858	3,198	659	21%	0	659	21%
2018	4,121	218	383	0	3,957	3,247	709	22%	0	709	22%
2019	4,121	209	383	0	3,947	3,289	658	20%	0	658	20%
2020	4,121	209	0	0	4,330	3,379	951	28%	0	951	28%
2021	4,121	209	0	0	4,330	3,421	909	27%	0	909	27%

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)
Plant Name	Unit No.	Location	Unit Type	Fuel Type		Fuel Transport		Construction Start Date	Commercial/ Change In-Service Date	Expected Retirement/ Shutdown	Gen Max Nameplate kW	Net Capability		Status
				Primary	Alternate	Primary	Alternate					Summer MW	Winter MW	
SJRPP	1	SJRPP	ST	Bit/PC		RR	WA		Summer 2019			186	189	Sale To FPL Ends
SJRPP	2	SJRPP	ST	Bit/PC		RR	WA		Summer 2019			186	189	

Schedule 9: Status Report and Specifications of Proposed Generating Facilities 2010 Dollars

1.	**Plant Name and Unit Number:**	None to Report
2.	**Capacity:**	
3.	Summer MW	
4.	Winter MW	
5.	**Technology Type:**	
6.	**Anticipated Construction Timing:**	
7.	Field Construction Start-date:	
8.	Commercial In-Service date:	
9.	**Fuel:**	
10.	Primary	
11.	Alternate	
12.	**Air Pollution Control Strategy:**	
13.	**Cooling Method:**	
14.	**Total Site Area:**	
15.	**Construction Status:**	
16.	**Certification Status:**	
17.	**Status with Federal Agencies:**	
18.	**Projected Unit Performance Data:**	
19.	Planned Outage Factor (POF):	
20.	Forced Outage Factor (FOF):	
21.	Equivalent Availability Factor (EAF):	
22.	Resulting Capacity Factor (%):	
23.	Average Net Operating Heat Rate (ANOHR):	
24.	**Projected Unit Financial Data:**	
25.	Book Life:	
26.	Total Installed Cost (In-Service year $/kW):	
27.	Direct Construction Cost ($/kW):	
28.	AFUDC Amount ($/kW):	
29.	Escalation ($/kW):	
30.	Fixed O&M ($/kW-yr):	
31.	Variable O&M ($/MWh):	

Schedule 10: Status Report and Specification of Proposed Directly Associated Transmission Lines

1.	**Point of Origin and Termination**	None To Report
2.	**Number of Lines**	
3.	**Right of Way**	
4.	**Line Length**	
5.	**Voltage**	
6.	**Anticipated Construction Time**	
7.	**Anticipated Capital Investment**	
8.	**Substations**	
9.	**Participation with Other Utilities**	

4 Other Planning Assumptions and Information

4.1 Fuel Price Forecast

The fuel price forecast is a major input to JEA's TYSP. JEA uses a diverse mix of fuels in its generating units. The forecast includes coal, natural gas, residual fuel oil, diesel fuel, and petroleum coke.

The fuel price projections for natural gas, fuel oil, and coal used in this TYSP were developed using 2011 price projections developed by PIRA Energy Group (PIRA). PIRA is an international energy consulting firm specializing in global energy market analysis and intelligence. PIRA presents integrated projections of energy supply, demand, and prices through 2025. The price projection for petroleum coke and the solid fuel transportation rates are derived from JD Energy's 2011 price projections. JD Energy is an independent energy and environmental price forecasting firm. JD Energy uses proprietary GEMS (Generation and Emissions Modeling System) methodology that integrates independent macroeconomic, energy and emissions pricing projections to deliver forecasts and perspectives on the outlook for fuel, power and emission markets.

Scherer 4 burns Powder River Basin (PRB) coal. The commodity price projections for PRB coal were provided by PIRA, and transportation price projections were provided by Southern Company. The price of PRB coal delivered to Scherer is assumed to undergo two step increases due to expiring rail contracts.

SJRPP has recently begun burning a blend of Illinois Basin (IB) and Colombian coal. For purposes of this study, it has been assumed that a blend of 50 percent IB and 50 percent Colombian coal will be burned by the SJRPP units. Projections of the commodity prices for IB coal and Colombian coal were developed by PIRA, JD Energy provided projected transportation costs for IB coal, which is expected to be delivered by rail, and for waterborne delivery of Colombian coal. SJRPP does have the ability to burn up to 30 percent petroleum coke, but there are currently no plans to reintroduce petroleum coke at SJRPP due to economical considerations.

The CFB units at Northside (Units 1 and 2) are projected to burn a blend of 90 percent petroleum coke and 10 percent IB coal. As with coal price projections for SJRPP, PIRA and JD Energy provided the commodity and transportation components of the IB coal price projections for Northside, respectively, while JD Energy provided both commodity and transportation price projections for petroleum coke. IB coal and petroleum coke are projected to be delivered by barge, as Northside does not have rail delivery capabilities at this time.

JEA currently operates eight units utilizing natural gas as a primary fuel. These units are GEC GT1 and GT2, Brandy Branch GT1, CT2 and CT3, Northside 3, and Kennedy GT7 and GT8. The natural gas prices are interruptible natural gas prices delivered to a

Florida city gate. The interruptible natural gas price projections include consideration of variable transportation costs on Florida Gas Transmission pipeline.

Northside 3 is capable of operating on 1.8 percent sulfur residual fuel oil as an alternative to natural gas. The projected prices for residual fuel oil are based on a discount to PIRA's 2011 WTI Crude price forecast. The discount factor was derived from the Energy Information Administration's (EIA) forecasted differential between crude and residual fuel oil as well as historical trends.

The 1970's-vintage combustion turbine units at Northside Generating Station (GT3, GT4, GT5, and GT6) are permitted to burn high sulfur diesel fuel oil as the primary fuel type. JEA also operates five units which utilize distillate fuel oil as an alternative to natural gas: Kennedy GT7 and GT8 and Brandy Branch GT1, CT2, and CT3. Projections for the price of distillate fuel oil were derived from PIRA's 2011 forecast and historical trends.

4.2 Economic Parameters

This section presents the parameters and methodology used for economic evaluations as part of JEA's least-cost expansion plan to satisfy forecast capacity requirements throughout the TYSP period.

4.2.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed O&M escalation rate, and nonfuel variable O&M escalation rate are each assumed to be 2.5 percent.

4.2.2 Municipal Bond Interest Rate

JEA performs sensitivity assessments of project cost to test the robustness of JEA's resource plan. Project cost includes forecast of direct cost of construction, indirect cost, and financing cost. Financing cost includes the forecast of long term tax exempt municipal bond rates, issuance cost, and insurance cost. For JEA's plan development, the long term tax exempt municipal bond rate is assumed to be 5.50 percent. This rate is based on JEA's judgment and expectation that the long term financial markets will return to historical stable behavior under more stable economic conditions.

4.2.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax exempt municipal bond interest rate of 5.50 percent.

4.2.4 Interest During Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 5.50 percent.

4.2.5 Levelized Fixed Charge Rate

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR (LFCR) that has the same present value as the year-by-year fixed charge rate.

Different generating technologies are assumed to have different economic lives and therefore different financing terms. Simple cycle combustion turbines are assumed to have a 20 year financing term; while natural gas fired combined cycle units are assumed to be financed over 25 years. Given the various economic lives and corresponding financing terms, different LFCRs were developed.

All LFCR calculations assume the 5.50 percent tax exempt municipal bond interest rate, a 2.00 percent bond issuance fee, and a 0.50 percent annual property insurance cost. The resulting 20 year fixed charge rate is 9.322 percent and the 25 year fixed charge rate is 8.281 percent.

5 Environmental and Land Use Information

JEA does not have any capacity build projects underway or planned for the term of this Ten Year Site Plan. Therefore, there are no potential sites in which to report environmental and land use information.