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Attached you will find 25 hardcopies of JEA's 2013 Ten Year Site Plan and a disk containing an electronic version of the TYSP Schedules in excel format (JEA2013TYSPSchedules.xlsx) and the report in Adobe Reader format (JEA2013TYSP.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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Building Community®

TEN YEAR SITE PLAN

April 2013

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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, 2013 to December 31, 2022. 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 most 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 2013 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 of Jacksonville (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 Florida Power and Light (FPL) (20 percent). SJRPP consists of two nominal 638 MW bituminous coal fired units located north of the Northside Generating Station in Jacksonville, Florida. 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 percent sale to FPL 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 FPL 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 on March 9, 2011 to include additional capacity. The "Phase Two Purchase" amendment included up to 9 additional net MW. Due to declining methane levels in the Trail Ridge landfill, Phase Two has not achieved commercial operation and does not have a proposed commercial date at this time. Therefore, Phase Two capacity is not included in this TYSP filing.

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 21,283 MWh in calendar year 2012.

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, 2017 from Unit 3 and an additional 100 net MW beginning November 1, 2018 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	December 6, 2008	December 5, 2018	9	Annual
MEAG	**Vogtle Unit 3**			
	November 1, 2017	October 31, 2037	100	Annual
	Vogtle Unit 4			
	November 1, 2018	October 31, 2038	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, they are not forecasted to contribute firm capacity to JEA's reserve margin 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	(a)	563,700	524	524	Utility	
	33-36	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	1/2018	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	BIT		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 2012 totaled 374 GWh or 3.0 percent 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 percent of JEA's load, including 75 percent 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. 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 126 MW and 97 MW of interruptible peak load in the summer and winter, respectively. For 2013, the interruptible load represents 3.2 percent of the total peak demand in the winter and 4.6 percent of the forecasted total peak demand in the summer; 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

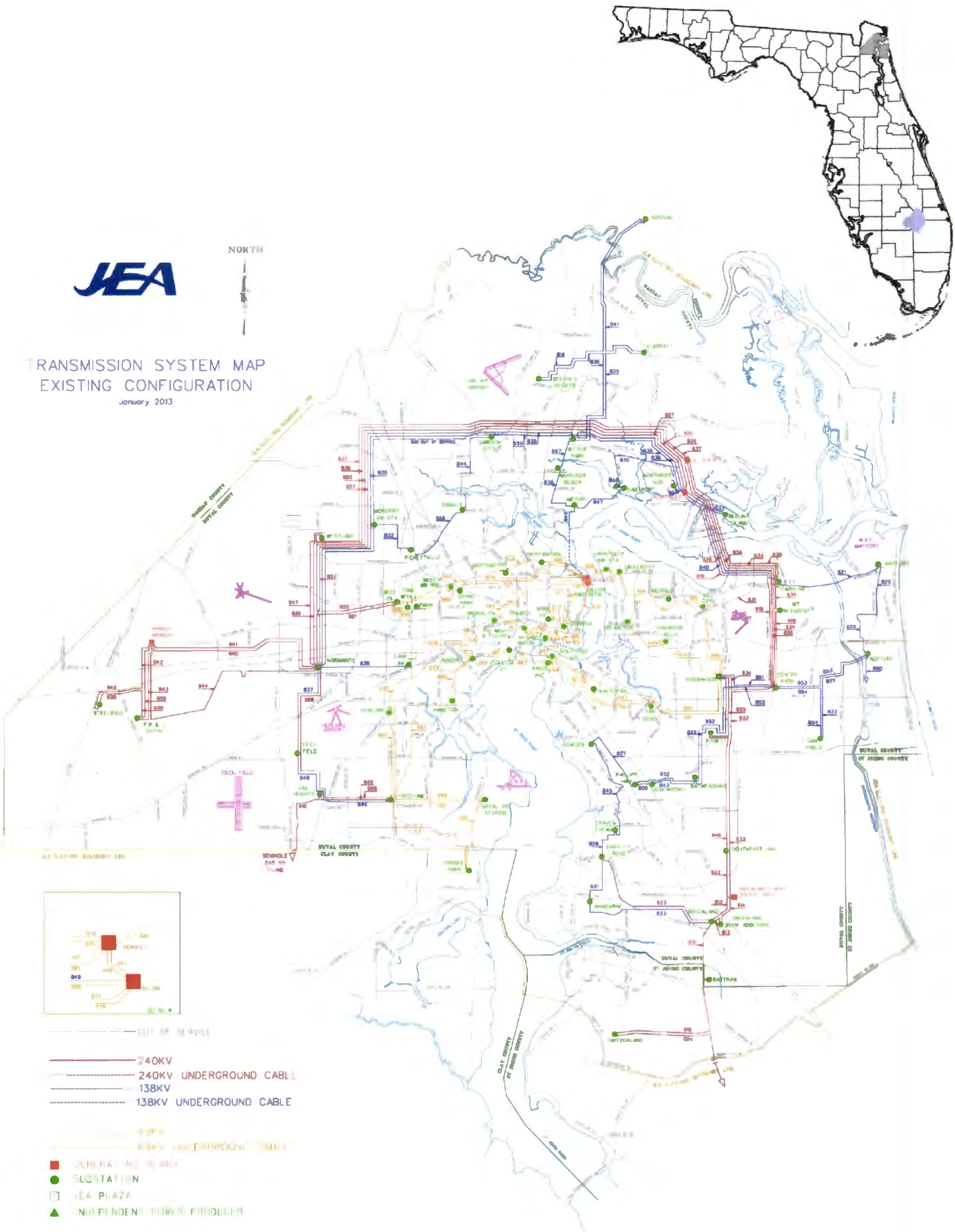


Table 2: DSM Portfolio

ANNUAL INCREMENTAL		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Annual Energy (GWh)	Residential	27.7	22.3	18.7	18.7	18.8	18.9	19.0	19.1	19.2	19.3
	Commercial	28.1	22.7	19.0	19.0	19.1	19.2	19.3	19.4	19.5	19.6
	Total	**55.8**	**45.0**	**37.8**	**37.8**	**37.9**	**38.1**	**38.3**	**38.5**	**38.7**	**38.9**
Summer Peak (MW)	Residential	6.6	5.3	4.5	4.5	4.5	4.5	4.5	4.5	4.6	4.6
	Commercial	4.6	3.7	3.1	3.1	3.1	3.1	3.1	3.2	3.2	3.2
	Total	**11.2**	**9.0**	**7.6**	**7.6**	**7.6**	**7.6**	**7.7**	**7.7**	**7.7**	**7.8**
Winter Peak (MW)	Residential	5.2	4.2	3.5	3.5	3.5	3.6	3.6	3.6	3.6	3.6
	Commercial	3.4	2.7	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4
	Total	**8.6**	**6.9**	**5.8**	**5.8**	**5.8**	**5.9**	**5.9**	**5.9**	**6.0**	**6.0**

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 produce up 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 can also receive up to 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 commenced co-firing 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 has produced a total of 2,154 MWh of energy from wood chips during 2011 and 2012. JEA has received bids from local sources to provide sized biomass for potential use for Northside Units 1 and 2.

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, demand-side management (DSM), and the impact of plug-in electric vehicles (PEV). JEA subtracts from the total load forecast all seasonal, 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's 2013 baseline forecast utilizes the 13 year regression analysis which captures periods of economic downturn and prerecession periods.

This 13 year regression's historical period spans 1999-2011. Until future data indicates otherwise, JEA views the demand decline in 2012 as a weather abnormality or outlier. Therefore, the 13 year AAGR from the regression analysis was applied to the 2011 weather normalized demand, escalated forward, to produce future projections. The resulting AAGR for total peak demand during the TYSP period is 0.90 percent for summer and 0.86 percent for winter (Figures 2 and 3).

2.2 Energy Forecast

In developing the energy forecast, several methods were incorporated; causal modeling (regression), time-series analysis, and "Monte Carlo Simulation". The causal model was developed using the "General Regression" tool in Minitab 16; statistical software for analyzing data in Six Sigma quality and process improvement projects, which allows modeling of factor interactions. A broad range of potential causal factors (degree days, precipitation, unemployment, average wages, and business days) were put into the initial model. Factors that were not statistically significant (highest p-value) were removed one at a time until only statistically significant factors remained. The model's residuals were tested for normality and stability. What remained was the basis for the causal model.

In building the forecast model, two groups of factors were modeled that were expected to vary over time. The total employment and total wages, subject to unemployment compensation insurance, were modeled using time-series techniques. The monthly distributions of weather variables (Heating and Cooling Degree Days) were identified using Crystal Ball; a spreadsheet-based application for predictive modeling, forecasting, simulation, and optimization.

These factors and techniques resulted in a forecast model variation within 2 percent of the 80 percent confidence level and where degree days (temperature) accounted for 38 percent of the overall model variation. This model was deemed sufficient for short-term forecasting of 2013.

Two scenarios were established for long term forecasting, no growth and ten year recovery. In the no growth scenario, improvement is not realized in unemployment and wages and the 5 and 10 year forecasts are equal to the short-term forecast. In the "ten year recovery" scenario, modest gains are realized in wages and unemployment reaches prerecession levels by 2022.

JEA adopted the short-term forecast for 2013 with the "ten year recovery" scenario as the basecase energy forecast for the 2013 planning cycle. In this basecase, the average annual growth rate for total energy escalates at 0.73 percent and 0.49 percent for net energy for load.

2.3 Plug-in Electric Vehicle Peak Demand and Energy

In 2012, JEA developed the PEV demand and energy forecast for the service territory using the 2011 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.

JEA forecasted the average usable battery capacity per vehicle using the upcoming plug-in vehicle model roll-outs from Toyota, Honda, Ford, and General Motors, and grew the capacity by 1 kWh per year. The baseline forecast assumed that charging will initially be uncontrolled at home until the mid 2020s when public infrastructure became feasible and available.

In October 2012 Pike Research, a part of Navigant Consulting, Inc., released its Electric Vehicle Market Forecasts of Light Duty Hybrid, Plug-in Hybrid, and Battery Electric Vehicles: 2012-2020. This market data report provides updated Pike Research forecasts for these vehicles based on several key assumptions, including vehicle availability, economic growth, petroleum fuel prices, government influence on the market, and the overall vehicle market. Annual vehicle sales by electric vehicle segment and market share for key manufacturers were forecast through 2020. These assumptions point to robust growth worldwide for electric vehicles, with hybrids growing at a compound annual growth rate (CAGR) of 6 percent, and PEVs (combined plug-in hybrid and battery electric) growing at a CAGR of 39 percent between 2012 and 2020.

When comparing Pike's 2012 PEV forecasted vehicle sales with JEA's 2012 forecast, JEA's baseline projections were 63 percent higher than Pike. Because of this difference, JEA shifted the start of its PEV forecast back 5 years to 2017. Because Pike did not provide forecast data for Duval County, JEA maintained the previously forecasted annual increases.

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)
	Rural and Residential			Commercial			Industrial		
Year	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
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	15,470	1,249	33,087	37,749	5,686	3,747	1,517,481
2006	5,637	357,232	15,780	1,289	37,136	34,710	5,658	4,206	1,345,221
2007	5,478	364,284	15,038	1,328	39,919	33,267	5,832	4,521	1,289,980
2008	5,364	365,632	14,670	1,357	40,608	33,417	5,777	4,599	1,256,143
2009	5,300	367,864	14,407	1,303	41,150	31,665	5,546	4,660	1,190,129
2010	5,748	369,050	15,575	1,329	41,693	31,876	5,657	4,722	1,198,009
2011	5,445	369,566	14,733	1,314	41,958	31,317	5,594	4,752	1,177,189
2012	4,880	373,160	13,076	1,267	42,651	29,707	5,394	4,830	1,116,651
2013	5,221	375,583	13,900	1,356	42,927	31,579	5,771	4,862	1,187,022
2014	5,245	378,005	13,874	1,362	43,204	31,520	5,797	4,893	1,184,803
2015	5,275	380,428	13,865	1,370	43,481	31,499	5,831	4,925	1,184,031
2016	5,287	383,935	13,770	1,373	43,882	31,283	5,844	4,970	1,175,920
2017	5,315	387,443	13,718	1,380	44,283	31,164	5,875	5,015	1,171,451
2018	5,353	390,950	13,692	1,390	44,684	31,104	5,917	5,061	1,169,191
2019	5,383	394,458	13,647	1,398	45,085	31,002	5,950	5,106	1,165,355
2020	5,404	397,966	13,578	1,403	45,486	30,846	5,973	5,152	1,159,479
2021	5,430	401,353	13,530	1,410	45,873	30,736	6,003	5,195	1,155,364
2022	5,455	404,741	13,477	1,416	46,260	30,618	6,030	5,239	1,150,896

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
2003	115	0	12,130	453	595	13,178	2	369,886
2004	76	0	12,057	468	718	13,243	2	384,083
2005	111	0	12,596	486	615	13,697	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	410,842
2009	120	0	12,269	479	406	13,154	3	413,677
2010	122	0	12,856	343	644	13,843	2	415,467
2011	122	0	12,475	100	405	12,980	2	416,278
2012	123	0	11,663	423	323	12,409	2	420,643
2013	131	0	12,479	452	346	13,277	2	423,374
2014	132	0	12,536	454	347	13,338	2	426,105
2015	133	0	12,608	457	349	13,414	2	428,836
2016	133	0	12,637	458	350	13,445	2	432,789
2017	134	0	12,704	461	352	13,516	2	436,743
2018	135	0	12,794	464	354	13,612	2	440,697
2019	136	0	12,867	466	356	13,690	2	444,651
2020	136	0	12,916	468	358	13,742	1	448,604
2021	137	0	12,979	470	359	13,809	1	452,422
2022	137	0	13,038	473	361	13,872	1	456,241

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 Generation	Cumulative Conservation		Net Firm Peak Demand	Time Of Peak			
				Residential	Comm/Ind.		Residential	Comm/Ind.		Month	Day	H.E.	Temp
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	2,616	0	0	0	0	0	0	0	2,616	7	25	1700	95
2013	2,756	126	0	0	0	0	5	3	2,622	---	---	---	----
2014	2,781	126	0	0	0	0	8	6	2,641	---	---	---	----
2015	2,806	126	0	0	0	0	12	8	2,660	---	---	---	----
2016	2,831	126	0	0	0	0	16	11	2,679	---	---	---	----
2017	2,857	126	0	0	0	0	19	13	2,699	---	---	---	----
2018	2,882	126	0	0	0	0	23	16	2,717	---	---	---	----
2019	2,908	126	0	0	0	0	27	18	2,737	---	---	---	----
2020	2,934	126	0	0	0	0	30	21	2,757	---	---	---	----
2021	2,961	126	0	0	0	0	34	24	2,778	---	---	---	----
2022	2,987	126	1	0	0	0	38	26	2,798	---	---	---	----

Note: 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 Generation	Cumulative Conservation		Net Firm Peak Demand	Time Of Peak			
				Residential	Comm/Ind.		Residential	Comm/Ind.		Month	Day	H.E.	Temp
2003	3,083	0	0	0	0	0	0	0	3,083	1	24	800	19
2004	2,668	0	0	0	0	0	0	0	2,668	1	29	700	23
2005	2,860	0	0	0	0	0	0	0	2,860	1	24	800	23
2006	2,919	0	0	0	0	0	0	0	2,919	2	14	800	26
2007	2,722	0	0	0	0	0	0	0	2,722	1	30	800	28
2008	2,914	0	0	0	0	0	0	0	2,914	1	3	800	25
2009	3,064	0	0	0	0	0	0	0	3,064	2	6	800	23
2010	3,224	0	0	0	0	0	0	0	3,224	1	11	800	20
2011	3,062	0	0	0	0	0	0	0	3,062	1	14	800	23
2012	2,665	0	0	0	0	0	0	0	2,665	1	4	800	22
2013	3,058	97	0	0	0	0	4	3	2,954	---	---	---	----
2014	3,084	97	0	0	0	0	7	4	2,976	---	---	---	----
2015	3,110	97	0	0	0	0	9	6	2,999	---	---	---	----
2016	3,137	97	0	0	0	0	11	7	3,022	---	---	---	----
2017	3,164	97	0	0	0	0	14	9	3,044	---	---	---	----
2018	3,191	97	0	0	0	0	16	11	3,067	---	---	---	----
2019	3,219	97	0	0	0	0	19	12	3,091	---	---	---	----
2020	3,246	97	0	0	0	0	21	13	3,115	---	---	---	----
2021	3,274	97	1	0	0	0	23	15	3,140	---	---	---	----
2022	3,303	97	1	0	0	0	25	16	3,165	---	---	---	----

Note: 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.		
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	58%
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	12,409	0	0	0	0	0	0	0	12,409	53%
2013	13,333	0	0	0	0	0	28	28	13,277	51%
2014	13,438	0	0	0	0	0	50	51	13,338	51%
2015	13,553	0	0	0	0	0	69	70	13,414	51%
2016	13,621	0	0	0	0	0	87	89	13,445	51%
2017	13,731	0	0	0	0	0	106	108	13,517	51%
2018	13,857	0	8	0	0	0	125	127	13,613	51%
2019	13,969	0	11	0	0	0	144	146	13,690	51%
2020	14,057	0	14	0	0	0	163	166	13,742	50%
2021	14,150	0	27	0	0	0	182	185	13,810	50%
2022	14,238	0	41	0	0	0	202	205	13,872	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)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual 2011		Actual 2012		Forecast 2013		Forecast 2014	
Month	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)
January	3,062	1,147	2,665	978	2,954	1,066	2,976	1,070
February	2,346	901	2,638	848	2,450	955	2,467	959
March	1,746	912	1,838	920	2,086	987	2,097	991
April	2,251	1,020	2,072	953	1,962	960	1,976	964
May	2,418	1,144	2,293	1,096	2,355	1,102	2,369	1,106
June	2,668	1,250	2,435	1,113	2,478	1,236	2,494	1,241
July	2,653	1,307	2,616	1,313	2,579	1,393	2,599	1,398
August	2,756	1,392	2,539	1,219	2,622	1,370	2,641	1,375
September	2,359	1,155	2,384	1,127	2,423	1,178	2,436	1,182
October	2,049	944	2,130	995	2,384	1,026	2,398	1,032
November	1,749	879	1,964	890	2,283	957	2,299	964
December	1,931	929	2,123	957	2,706	1,049	2,723	1,056
Annual Peak/Total Energy	3,062	12,980	2,665	12,409	2,954	13,277	2,976	13,338

Figure 2: Summer Peak Demand History & Forecast

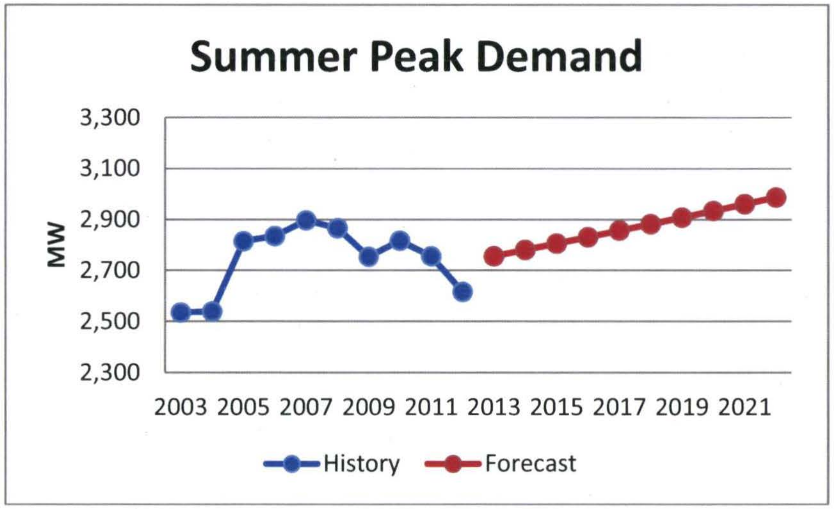


Figure 3: Winter Peak Demand History & Forecast

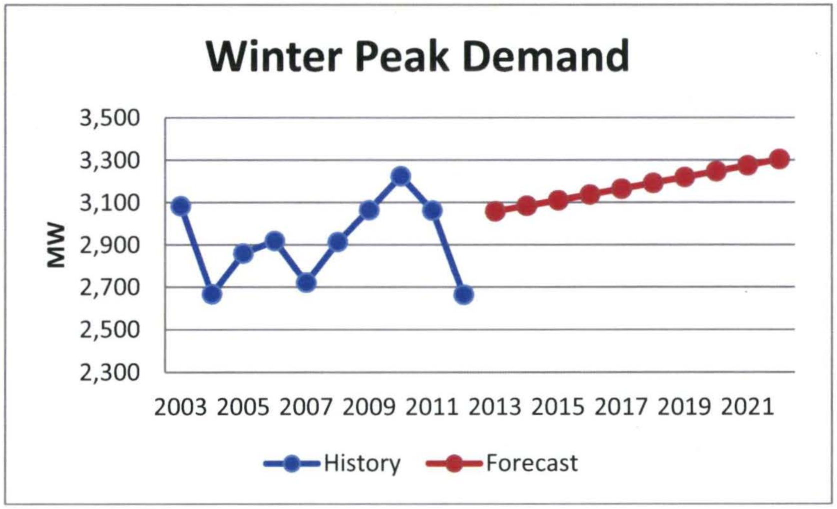
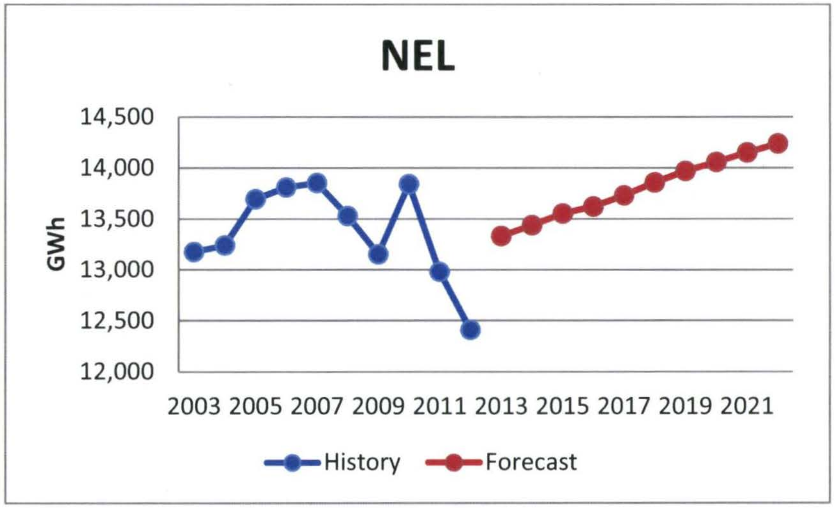


Figure 4: Net Energy for Load History & Forecast



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 addition of 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 percent 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 percent reserve margin with up to 3 percent of forecasted firm peak demand in any season from purchases acquired in the operating horizon. However, no short-term seasonal market purchases are required in this TYSP period.

If short-term seasonal market purchases had been needed, The Energy Authority (TEA), JEA's affiliated energy market services company, would have acquired 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 during this ten year period. 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]
2013		
2014		
2015		
2016		
2017	Winter	
2018	Winter	MEAG Plant Vogtle 3 Purchase (100 MW)[3] Girvin Road Landfill Expires (1.2 MW)
2019	Winter Summer	MEAG Plant Vogtle 4 Purchase (100 MW)[3] Trail Ridge Contract Expires (9 MW) SJRPP Sale to FPL Suspended (383 MW)[4]
2020		
2021		
2022		

Notes:

(1) Cumulative DSM addition of 63 MW Winter and 82 MW Summer by 2022.

(2) PEV addition of 1 MW Winter and 1 MW Summer by 2022.

(3) After accounting for transmission losses, JEA is expects to receive 100 MW November 2017 and 100 MW November 2018 for a total of 200 MW of net firm capacity from the units under construction.

(4) SJRPP sales return based on JEA's forecast estimates.

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actual	Actual										
	Fuel	Type	Units	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	NUCLEAR														
(1)		TOTAL	TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0	0
	COAL[1]														
(2)		TOTAL	1000 TON	2,569	2,257	2,370	2,265	2,329	2,533	2,343	2,310	2,527	2,590	3,040	2,882
	RESIDUAL														
(3)		STEAM	1000 BBL	43	15	95	114	89	114	98	104	81	89	63	79
(4)		CC	1000 BBL	0	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	0
(6)		TOTAL	1000 BBL	43	15	95	114	89	114	98	104	81	89	63	79
	DISTILLATE														
(7)		STEAM	1000 BBL	10	1	1	1	1	1	1	2	1	1	1	1
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(9)		CT/GT	1000 BBL	36	2	10	9	24	4	8	0	2	12	1	9
(10)		TOTAL	1000 BBL	46	3	11	10	25	5	9	3	3	12	2	10
	NATURAL GAS														
(12)		STEAM	1000 MCF	11,345	17,768	11,056	13,198	10,292	13,230	11,355	12,013	9,370	10,325	7,335	9,196
(13)		CC	1000 MCF	22,073	26,836	24,276	24,856	25,360	22,636	21,852	17,780	14,373	14,304	9,908	10,281
(14)		CT/GT	1000 MCF	3,248	3,018	3,874	2,584	3,924	2,824	3,471	2,175	1,824	1,656	1,090	1,022
(15)		TOTAL	1000 MCF	36,666	47,622	39,207	40,639	39,576	38,689	36,678	31,967	25,566	26,285	18,333	20,499
	PETROLEUM COKE														
(16)		TOTAL	1000 TON	694	246	1,165	1,178	1,186	1,115	1,246	1,279	1,223	1,146	1,219	1,231
	OTHER (SPECIFY)														
(17)		TOTAL	TRILLION BTU	62	0	0	0	0	0	0	0	0	0	0	0

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

Schedule 6.1: Energy Sources (GWh)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel	**Type**	**Units**	**Actual**											
				2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
(1)	**Firm Inter-Region Intchg.**		GWH	**1,213**	**1,434**	**0**	**0**	**0**	**0**	**216**	**1,013**	**1,715**	**1,659**	**1,654**	**1,715**
(2)	**NUCLEAR**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(3)	**COAL**[1]		GWH	**5,137**	**4,434**	**4,598**	**4,467**	**4,559**	**5,110**	**4,749**	**4,679**	**5,134**	**5,444**	**6,238**	**5,988**
(4)	**RESIDUAL**	STEAM		24	9	51	60	47	61	52	54	42	44	31	39
(5)		CC		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
(7)		**TOTAL**	GWH	**24**	**9**	**51**	**60**	**47**	**61**	**52**	**54**	**42**	**44**	**31**	**39**
(8)	**DISTILLATE**	STEAM		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
(10)		CT		10	1	4	4	10	2	3	0	1	5	0	4
(11)		**TOTAL**	GWH	**10**	**1**	**4**	**4**	**10**	**2**	**3**	**0**	**1**	**5**	**0**	**4**
(12)	**NATURAL GAS**	STEAM		976	1,608	969	1,136	890	1,151	987	1,032	797	844	593	745
(13)		CC		3,220	3,939	3,681	3,776	3,867	3,395	3,321	2,692	2,116	2,101	1,481	1,540
(14)		CT		309	272	342	223	347	242	303	187	156	148	93	90
(15)		**TOTAL**	GWH	**4,505**	**5,819**	**4,991**	**5,135**	**5,104**	**4,788**	**4,612**	**3,911**	**3,069**	**3,093**	**2,167**	**2,376**
(16)	**NUG**		GWH	**9**	**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
(18)		**LANDFILL GAS**		74	74	78	78	78	79	78	52	0	0	0	0
(19)		**SOLAR**		23	21	24	24	23	23	23	23	23	23	23	23
(20)		**TOTAL**	GWH	**97**	**96**	**102**	**102**	**102**	**102**	**102**	**75**	**23**	**23**	**23**	**23**
(21)	**Petroleum Coke**		GWH	**1,994**	**618**	**3,530**	**3,571**	**3,592**	**3,383**	**3,782**	**3,880**	**3,706**	**3,475**	**3,697**	**3,728**
(22)	**OTHER (SPECIFY)**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(23)	**NET ENERGY FOR LOAD**[2]		GWH	**12,980**	**12,409**	**13,277**	**13,338**	**13,414**	**13,445**	**13,517**	**13,613**	**13,690**	**13,742**	**13,810**	**13,872**

Note: [1] Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal. SJRPP sale suspends summer 2019.
[2] May not add due to rounding.

Schedule 6.2: Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actual											
	Fuel	Type	Units	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	Firm Inter-Region Intchg.		%	9.3	11.6	0.0	0.0	0.0	0.0	1.6	7.4	12.5	12.1	12.0	12.4
(2)	NUCLEAR		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	COAL[1]		%	39.6	35.7	34.6	33.5	34.0	38.0	35.1	34.4	37.5	39.6	45.2	43.2
(4)		STEAM		0.2	0.1	0.4	0.4	0.3	0.5	0.4	0.4	0.3	0.3	0.2	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	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	0.0
(7)	RESIDUAL	TOTAL	%	0.2	0.1	0.4	0.4	0.3	0.5	0.4	0.4	0.3	0.3	0.2	0.3
(8)		STEAM		0.0	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	0.0
(10)		CT		0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)	DISTILLATE	TOTAL	%	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		STEAM		7.5	13.0	7.3	8.5	6.6	8.6	7.3	7.6	5.8	6.1	4.3	5.4
(13)		CC		24.8	31.7	27.7	28.3	28.8	25.2	24.6	19.8	15.5	15.3	10.7	11.1
(14)		CT		2.4	2.2	2.6	1.7	2.6	1.8	2.2	1.4	1.1	1.1	0.7	0.7
(15)	NATURAL GAS	TOTAL	%	34.7	46.9	37.6	38.5	38.1	35.6	34.1	28.7	22.4	22.5	15.7	17.1
(16)	NUG		%	0.1	0.0	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	0.0
(18)		LANDFILL GAS		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.4	0.0	0.0	0.0	0.0
(19)		SOLAR		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(20)		TOTAL	%	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.6	0.2	0.2	0.2	0.2
(21)	Petroleum Coke		%	15.4	5.0	26.6	26.8	26.8	25.2	28.0	28.5	27.1	25.3	26.8	26.9
(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	0.0
(23)	NET ENERGY FOR LOAD		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Note: [1] Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal. SJRPP sale suspends summer 2019.
[2] May not add due to rounding.

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

Year	Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2013	3,754	9	376	0	3,387	2,622	766	29%	0	766	29%
2014	3,754	9	376	0	3,387	2,641	746	28%	0	746	28%
2015	3,754	9	376	0	3,387	2,660	727	27%	0	727	27%
2016	3,754	9	376	0	3,387	2,679	708	26%	0	708	26%
2017	3,754	9	376	0	3,387	2,699	688	26%	0	688	26%
2018	3,754	109	376	0	3,487	2,717	770	28%	0	770	28%
2019	3,753	200	0	0	3,953	2,737	1,216	44%	0	1,216	44%
2020	3,753	200	0	0	3,953	2,757	1,196	43%	0	1,196	43%
2021	3,753	200	0	0	3,953	2,778	1,175	42%	0	1,175	42%
2022	3,753	200	0	0	3,953	2,798	1,155	41%	0	1,155	41%

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

Year	Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2013	4,122	9	383	0	3,749	2,954	795	27%	0	795	27%
2014	4,122	9	383	0	3,749	2,976	773	26%	0	773	26%
2015	4,122	9	383	0	3,749	2,999	750	25%	0	750	25%
2016	4,122	9	383	0	3,749	3,022	727	24%	0	727	24%
2017	4,122	9	383	0	3,749	3,044	704	23%	0	704	23%
2018	4,122	109	383	0	3,849	3,067	781	25%	0	781	25%
2019	4,121	200	383	0	3,939	3,091	847	27%	0	847	27%
2020	4,121	200	0	0	4,321	3,115	1,206	39%	0	1,206	39%
2021	4,121	200	0	0	4,321	3,140	1,181	38%	0	1,181	38%
2022	4,121	200	0	0	4,321	3,165	1,156	37%	0	1,156	37%

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/ In-Service or Change Date	Expected Retirement/ Shutdown Date	Gen Max Nameplate	Net Capability		Status
				Primary	Alternate	Primary	Alternate				kW	Summer MW	Winter MW	
SJRPP	1	12-031	ST	BIT	PC	RR	WA	03/1987	06/2019	(a)	679,600	188	191	Sale To FPL Ends
SJRPP	2	12-031	ST	BIT	PC	RR	WA	05/1988	06/2019	(a)	679,600	188	191	
												376	383	Total

Notes:
(a) Units expected to be maintained throughout the TYSP period.

Schedule 9: Status Report and Specifications of Proposed Generating Facilities 2013 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, coal, and petroleum coke used in this TYSP were developed based on those included in the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2013 Early Release (AEO2013). AEO2013 presents projections of energy supply, demand, and prices through 2040. The projections presented within AEO2013 are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer based, energy-economy modeling system of U.S. energy markets. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics.

The price projection for emission allowances and the solid fuel transportation rates are derived from JD Energy's 2013 price projections. JD Energy is an independent energy and environmental price forecasting firm. JD Energy uses proprietary Generation and Emissions Modeling System (GEMS) 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 projection for PRB coal was developed by escalating current market prices by the AEO2013 forecasted growth rate for PRB coal. The transportation price projection was 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 currently burns a blend of Illinois Basin (IB) and Colombian coal. For purposes of this study, it has been assumed that a blend of 33 percent IB and 67 percent Colombian coal will be burned by the SJRPP units, until 2016. In 2017, it is assumed that SJRPP will burn 100 percent Colombian coal due to environmental legislation. Projections of the commodity prices for IB coal and Colombian coal were developed by escalating current market prices by AEO2013 forecasted growth rate for IB coal. 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 has the ability to burn up to 30 percent petroleum coke, but there are currently no plans to reintroduce petroleum coke at SJRPP at this time.

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, the coal and petroleum coke prices were developed by escalating current market prices by AEO2013 forecasted growth rate for IB coal while JD Energy provided the transportation component. 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 based on interruptible natural gas delivered to a Florida city gate. The interruptible natural gas price projections are based on the AEO2013 forecast for natural gas and include consideration of variable transportation costs on Florida Gas Transmission pipeline.

Northside 3 is capable of operating on residual fuel oil as an alternative to natural gas. The projected prices for residual fuel oil are based the AEO2013 forecast for residual fuel oil.

The 1970's-vintage combustion turbine units at Northside Generating Station (GT3, GT4, GT5, and GT6) burn diesel fuel as the primary fuel type. JEA also operates five units which utilize diesel fuel as an alternative to natural gas: Kennedy GT7 and GT8 and Brandy Branch GT1, CT2, and CT3. Projections for the price of diesel fuel were based on the AEO2013 forecast for diesel fuel.

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 4.75 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 4.75 percent.

4.2.4 Interest During Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 4.75 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 4.75 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 8.515 percent and the 25 year fixed charge rate is 7.560 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.