Building Community®

TEN YEAR SITE PLAN

April 2014

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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, 2014 to December 31, 2023. 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 425,000 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 2014 is 4,110 MW for winter and 3,769 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. LES is developing the New River Solid Waste Association Landfill in Raiford, Florida (3 net MW) and the Sarasota County Landfill in Nokomis, Florida (6 net MW) to serve this Phase Two agreement. The Phase Two purchase is expected to begin in the fourth quarter of 2014.

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 2014.

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 December 1, 2017 from Unit 3 and an additional 100 net MW beginning December 1, 2018 from Unit 4. Table 1 lists JEA's current purchased power contracts.

Table 1: JEA Purchased Power Schedule

<table>
<tr><th colspan="2">Contract</th><th>Start Date</th><th>End Date</th><th>MW (1)</th><th>Product Type</th></tr>
<tr><td rowspan="2">LES Trail Ridge</td><td>I</td><td>December 6, 2008</td><td>December 5, 2018</td><td>9</td><td>Annual</td></tr>
<tr><td>II</td><td>December 31, 2014</td><td>November 30, 2026</td><td>9</td><td>Annual</td></tr>
<tr><td rowspan="2">MEAG Vogtle</td><td>Unit 3</td><td>December 1, 2017</td><td>November 30, 2037</td><td>100</td><td>Annual</td></tr>
<tr><td>Unit 4</td><td>December 1, 2018</td><td>November 30, 2038</td><td>100</td><td>Annual</td></tr>
<tr><td colspan="2">Jacksonville Solar</td><td>September 30, 2010</td><td>September 30, 2040</td><td>15 (2)</td><td>Annual</td></tr>
</table>

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	06/2019	563,700	524	524	Utility	(b)
	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	186	Utility	
	3	12-031	CT	NG	FO2	PL	TK	10/2001	(a)	203,800	150	186	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	150	186	Utility	
	2	12-031	GT	NG		PL		6/2011	(a)	203,800	150	186	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	(c)
	2	12-031	ST	BIT	PC	RR	WA	5/1988	(a)	679,600	501	510	Joint	(c)
Scherer														
	4	13-207	ST	BIT		RR		2/1989	(a)	846,000	194	194	Joint	(d)
JEA System Total											**3,769**	**4,110**		(e)

NOTES:
(a) Units expected to be maintained throughout the TYSP period.
(b) Scheduled for long-term reserve, summer 2019.
(e) Numbers may not add due to rounding.
(c) Net capability reflects JEA's 80% ownership of Power Park.
(d) Net capability reflects JEA's 23.64% ownership in Scherer 4.

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 2014 totaled 324 GWh or 2.6 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 745 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, Duke 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 four 230 kV tie-lines terminating at FPL's Duval substation in Duval County, one 230 kV tie-line with FPL terminating at the Sampson substation in St. Johns County, one 230 kV tie-line with Seminole Electric Cooperative terminating at the Black Creek substation in Clay County, and one 138 kV interconnection with Beaches Energy Services' JB Penman Substation located at JEA's Neptune 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 125 MW and 83 MW of interruptible peak load in the summer and winter, respectively. For 2014, the interruptible load represents 3.1 percent of the total peak demand in the winter and 4.8 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 and to meet JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals. JEA's demand-side management programs focus on improving the efficiency of customer end uses as well as improving the system load factor. To encourage efficient customer usage, JEA offers customers both education and economic incentives on more efficient end use technologies. For load factor improvement, JEA is in initial planning of a peak reducing Direct Load Control (DLC) program and a valley filling electrification program. Electrification technologies under consideration include on-road and off-road vehicles, forklifts, cranes and other industrial process equipment. JEA's forecast of annual incremental demand and energy reductions due to its current DSM programs are shown in the Table 2. Both DLC and electrification programs are in early development, and as such their impacts are not reflected in Table 2. JEA's current and planned DSM programs are summarized by commercial and residential programs in Table 3.

Figure 1: JEA Transmission/Generation Facilities System Map

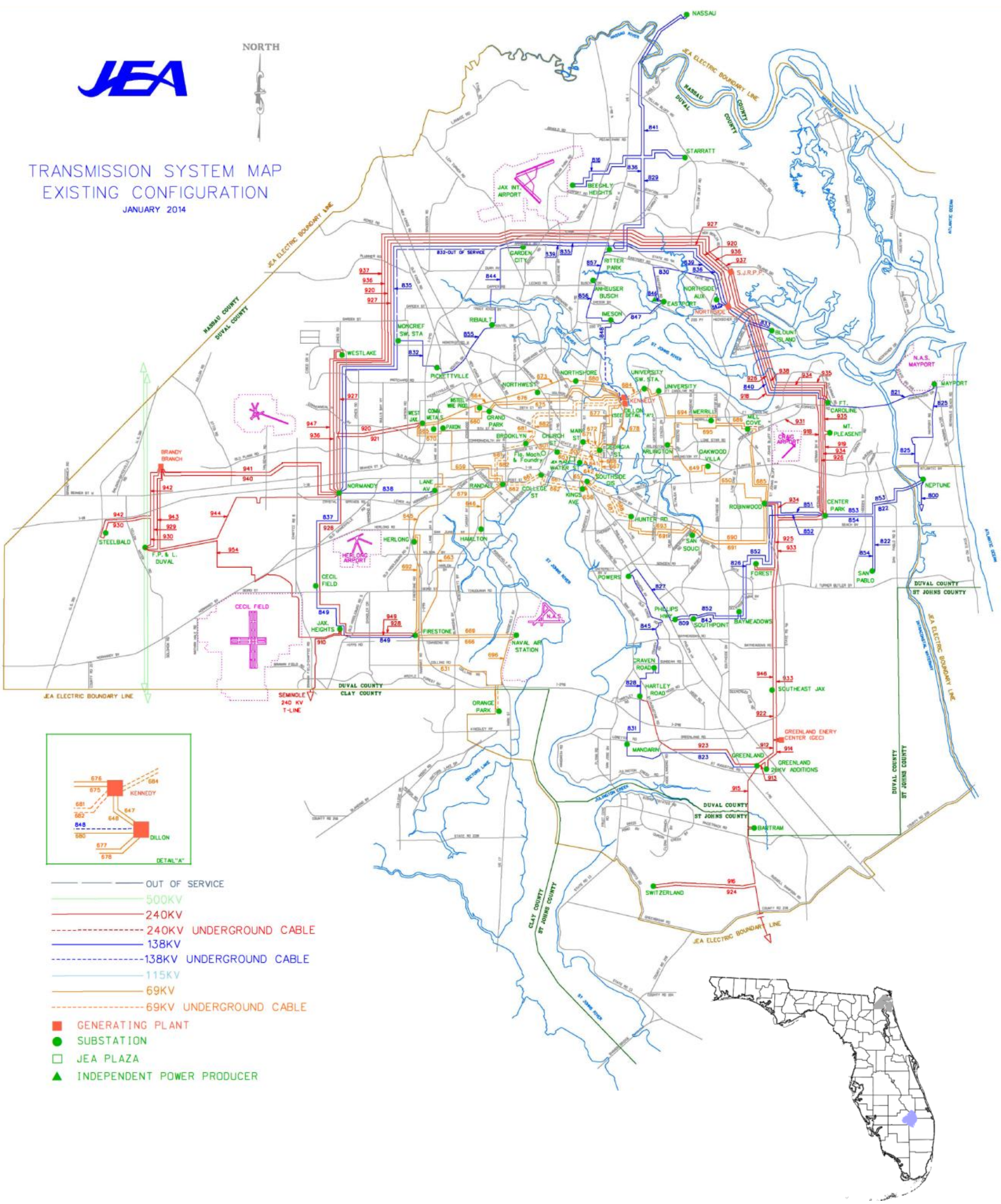


Table 2: DSM Portfolio

ANNUAL INCREMENTAL		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Annual Energy (GWh)	Residential	16.9	15.9	14.7	14.8	14.9	14.9	15.0	15.1	15.2	15.2
	Commercial	17.2	16.1	15.0	15.0	15.1	15.2	15.3	15.3	15.4	15.5
	Total	**34.1**	**32.0**	**29.7**	**29.9**	**30.0**	**30.1**	**30.3**	**30.4**	**30.6**	**30.7**
Summer Peak (MW)	Residential	4.0	3.8	3.5	3.5	3.5	3.6	3.6	3.6	3.6	3.6
	Commercial	2.8	2.6	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5
	Total	**6.8**	**6.4**	**5.9**	**6.0**	**6.0**	**6.0**	**6.1**	**6.1**	**6.1**	**6.1**
Winter Peak (MW)	Residential	3.2	3.0	2.8	2.8	2.8	2.8	2.8	2.8	2.9	2.9
	Commercial	2.1	1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9
	Total	**5.3**	**4.9**	**4.6**	**4.6**	**4.6**	**4.6**	**4.7**	**4.7**	**4.7**	**4.7**

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	Residential New Build
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
Off-Road Electrification (Planned)	Electric Vehicles (Planned)
Direct Load Control (Planned)	Direct Load Control (Planned)

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 owned three internal combustion engine generators located at the Girvin Road landfill. This facility was placed into service in July 1997, and has been fueled by the methane gas produced by the landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, gas generation has declined and one generator was removed and placed into service at the Buckman Wastewater Treatment facility and Girvin has been decommissioned as of 2014.

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 three anaerobic digesters and a sludge dryer to produce a pelletized fertilizer product. The methane gas from the digesters can be 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 (see Section 1.1.2.1 Trail Ridge Landfill).

JEA also has the ability to receive up to 1,500 kW of landfill gas from the North Landfill, which can be piped to the Northside Generating Station 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 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. In the past, 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.

  In addition,
- 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 had used traditional regression analysis methodology to forecast seasonal peak demands and total energy as a whole system. This methodology, however, failed to accurately capture the effect of the housing market meltdown that occurred over recent years. Therefore, JEA developed separate peak demand and energy forecasts for residential, commercial & industrial (C&I) and PEVs, each using different economic parameters.

The forecasted annual average growth rates (AAGR) for residential and C&I peak demands were developed using multiple regression analysis of eight years historical normalized historical seasonal peaks, residential and C&I historical and forecast energy, vacancy rates, last three days heating degree days leading to winter peak and last two days cooling degree day leading to summer peak.

Historical eight year average load factors for winter and summer peaks were used to calculate 2014 winter and summer peak demands. The seasonal AAGRs from the regression analysis were applied to the 2014 seasonal peak demands, escalated forward, to produce the future projections. Overall, JEA’s forecasted AAGR for total peak demand during the TYSP period is 0.87 percent for summer and 1.03 percent for winter (Figures 2 and 3).

2.2 Energy Forecast

The residential energy forecast was modeled using multiple regression analysis of eight years historical weather-adjusted historical residential energy consumption per residential customer, population, average household income, unemployment rate for Duval County, residential vacancy rate and residential electric rate.

Similarly, the C&I energy forecast was modeled using multiple regression analysis of weather-adjusted historical C&I energy consumption, state tax revenue for Jacksonville metropolitan, C&I vacancy rate, unemployment rate for Jacksonville metropolitan and C&I electric rates. Overall, JEA’s forecasted AAGR for total energy during the TYSP period is 0.72 percent.

2.3 Plug-in Electric Vehicle Peak Demand and Energy

PEVs demand and energy forecast for Duval County were developed using information from Electric Power Research Institute (EPRI), Duke Energy through Edison Electric Institute (EEI) webinar, U.S. Census Bureau and State of Florida Bureau of Economic and Business Research (BEBR).

The forecasted numbers of vehicles in Duval County were determined by using the BEBR's forecasted population growth rate and applied it to the U.S. Census Bureau's 2010 estimated number of vehicles. EPRI's forecasted medium scenario PEVs penetration rate was then applied to the forecasted number of vehicle sales to produce the forecasted number of PEVs for Duval County.

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

The PEVs peak demand forecast was developed by applying the average usable battery capacity per PEVs with the charge shape and the peak of the daily charge pattern. Whereas, the PEVs energy forecast was developed by applying the PEVs peak demand to the daily charging pattern.

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
2004	5,424	343,092	15,810	1,396	35,065	39,826	5,381	3,688	1,459,101
2005	5,576	351,705	15,853	1,433	35,757	40,090	5,556	3,607	1,540,233
2006	5,596	358,918	15,591	1,510	38,284	39,454	5,582	4,057	1,375,865
2007	5,507	365,363	15,072	1,581	40,564	38,974	5,643	4,150	1,360,010
2008	5,315	365,872	14,526	1,520	41,016	37,052	5,656	4,307	1,313,135
2009	5,319	368,111	14,448	1,488	41,553	35,811	5,372	4,421	1,215,217
2010	5,748	369,051	15,575	1,524	41,994	36,291	5,461	4,421	1,235,348
2011	5,237	369,761	14,163	1,447	42,393	34,138	5,369	4,428	1,212,633
2012	4,880	372,430	13,102	1,411	42,878	32,899	5,250	4,467	1,175,472
2013	4,852	377,326	12,860	1,394	43,459	32,075	5,188	4,451	1,165,462
2014	4,924	381,391	12,911	1,382	44,249	31,241	5,407	4,456	1,213,544
2015	4,960	384,008	12,917	1,390	44,709	31,091	5,435	4,460	1,218,631
2016	5,004	387,569	12,912	1,396	45,170	30,916	5,459	4,465	1,222,708
2017	5,048	391,162	12,906	1,402	45,630	30,733	5,481	4,469	1,226,354
2018	5,090	394,789	12,894	1,406	46,091	30,500	5,493	4,474	1,227,960
2019	5,134	398,449	12,884	1,410	46,552	30,297	5,510	4,478	1,230,495
2020	5,170	402,144	12,855	1,415	47,012	30,091	5,526	4,483	1,232,805
2021	5,185	405,595	12,785	1,419	47,473	29,885	5,541	4,487	1,234,975
2022	5,219	409,077	12,757	1,422	47,933	29,675	5,557	4,491	1,237,235
2023	5,253	412,588	12,732	1,426	48,394	29,459	5,571	4,496	1,239,114

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
2004	110	0	12,311	475	562	13,349	2	381,846
2005	108	0	12,673	495	528	13,696	2	391,071
2006	111	0	12,800	517	494	13,811	6	401,265
2007	113	0	12,844	478	531	13,854	5	410,082
2008	117	0	12,608	424	499	13,531	2	411,197
2009	120	0	12,299	398	458	13,155	2	414,086
2010	122	0	12,855	421	569	13,846	2	415,468
2011	123	0	12,176	381	424	12,980	2	416,583
2012	123	0	11,663	374	374	12,411	2	419,777
2013	122	0	11,556	324	406	12,286	2	425,238
2014	123	0	11,837	336	520	12,693	2	430,098
2015	123	0	11,909	336	524	12,769	2	433,180
2016	124	0	11,983	338	528	12,849	2	437,205
2017	124	0	12,055	341	532	12,928	2	441,264
2018	124	0	12,113	342	536	12,992	2	445,356
2019	124	0	12,178	344	541	13,063	2	449,481
2020	124	0	12,234	345	546	13,126	2	453,640
2021	124	0	12,270	347	551	13,168	2	457,557
2022	124	0	12,322	349	556	13,227	2	461,504
2023	124	0	12,374	350	562	13,286	2	465,480

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
2004	2,539	0	0.00	0	0	0	0	0	2,539	8	2	1700	94
2005	2,815	0	0.00	0	0	0	0	0	2,815	8	17	1800	96
2006	2,835	0	0.00	0	0	0	0	0	2,835	8	4	1700	97
2007	2,897	0	0.00	0	0	0	0	0	2,897	8	7	1700	97
2008	2,866	0	0.00	0	0	0	0	0	2,866	8	7	1600	96
2009	2,754	0	0.00	0	0	0	0	0	2,754	6	22	1600	98
2010	2,817	0	0.00	0	0	0	0	0	2,817	6	18	1700	102
2011	2,756	0	0.00	0	0	0	0	0	2,756	8	11	1700	98
2012	2,616	0	0.00	0	0	0	0	0	2,616	7	25	1700	95
2013	2,596	0	0.01	0	0	0	0	0	2,596	8	14	1600	93
2014	2,618	125	0.03	0	0	0	3	2	2,488	---	---	---	----
2015	2,647	125	0.04	0	0	0	6	4	2,512	---	---	---	----
2016	2,679	125	0.03	0	0	0	10	7	2,537	---	---	---	----
2017	2,710	125	0.05	0	0	0	13	9	2,563	---	---	---	----
2018	2,732	125	0.07	0	0	0	15	11	2,581	---	---	---	----
2019	2,743	125	0.10	0	0	0	20	14	2,584	---	---	---	----
2020	2,771	125	0.20	0	0	0	19	14	2,613	---	---	---	----
2021	2,786	125	0.27	0	0	0	25	17	2,618	---	---	---	----
2022	2,808	125	0.24	0	0	0	30	21	2,633	---	---	---	----
2023	2,831	125	0.37	0	0	0	32	22	2,653	---	---	---	----

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
2004	2,668	0	0.00	0	0	0	0	0	2,668	1	29	700	23
2005	2,860	0	0.00	0	0	0	0	0	2,860	1	24	800	23
2006	2,919	0	0.00	0	0	0	0	0	2,919	2	14	800	26
2007	2,722	0	0.00	0	0	0	0	0	2,722	1	30	800	28
2008	2,914	0	0.00	0	0	0	0	0	2,914	1	3	800	25
2009	3,064	0	0.00	0	0	0	0	0	3,064	2	6	800	23
2010	3,224	0	0.00	0	0	0	0	0	3,224	1	11	800	20
2011	3,062	0	0.00	0	0	0	0	0	3,062	1	14	800	23
2012	2,665	0	0.00	0	0	0	0	0	2,665	1	4	800	22
2013	2,559	0	0.02	0	0	0	0	0	2,559	2	18	800	24
2014	2,690	83	0.03	0	0	0	3	2	2,603	---	---	---	----
2015	2,726	83	0.04	0	0	0	5	3	2,635	---	---	---	----
2016	2,763	83	0.05	0	0	0	6	4	2,670	---	---	---	----
2017	2,799	83	0.07	0	0	0	9	6	2,702	---	---	---	----
2018	2,827	83	0.10	0	0	0	11	7	2,726	---	---	---	----
2019	2,843	83	0.14	0	0	0	15	10	2,735	---	---	---	----
2020	2,877	83	0.20	0	0	0	17	11	2,766	---	---	---	----
2021	2,896	83	0.27	0	0	0	14	9	2,789	---	---	---	----
2022	2,924	83	0.36	0	0	0	15	10	2,816	---	---	---	----
2023	2,952	83	0.58	0	0	0	22	14	2,832	---	---	---	----

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
				Residential	Comm/Ind.		Residential	Comm/Ind.		
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	12,286	0	1	0	0	0	0	0	12,286	54%
2014	12,727	0	1	0	0	0	17	17	12,693	56%
2015	12,835	0	2	0	0	0	33	33	12,769	55%
2016	12,945	0	2	0	0	0	47	48	12,849	55%
2017	13,053	0	4	0	0	0	62	63	12,928	54%
2018	13,147	0	5	0	0	0	77	78	12,992	54%
2019	13,249	0	7	0	0	0	92	94	13,063	54%
2020	13,342	0	10	0	0	0	107	109	13,126	54%
2021	13,414	0	13	0	0	0	122	124	13,168	53%
2022	13,504	0	18	0	0	0	138	139	13,227	53%
2023	13,594	0	23	0	0	0	152	155	13,286	53%

Note: 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 2012		Actual 2013		Forecast 2014		Forecast 2015	
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	2,665	978	2,126	944	2,603	1,031	2,636	1,038
February	2,638	848	2,559	879	2,362	887	2,391	892
March	1,838	920	2,447	969	1,838	941	1,861	947
April	2,072	953	1,951	902	1,857	927	1,877	933
May	2,293	1,096	2,139	1,017	2,228	1,072	2,251	1,079
June	2,435	1,113	2,567	1,182	2,348	1,166	2,369	1,173
July	2,616	1,313	2,479	1,204	2,449	1,286	2,472	1,293
August	2,539	1,219	2,596	1,265	2,488	1,262	2,512	1,269
September	2,384	1,127	2,500	1,122	2,295	1,123	2,317	1,130
October	2,130	995	2,106	987	2,105	1,031	2,131	1,037
November	1,964	890	1,965	882	2,021	948	2,046	954
December	2,123	957	1,997	933	2,190	1,018	2,217	1,024
Annual Peak/Total Energy	2,665	12,409	2,596	12,286	2,603	12,693	2,636	12,769

Figure 2: Summer Peak Demand History & Forecast

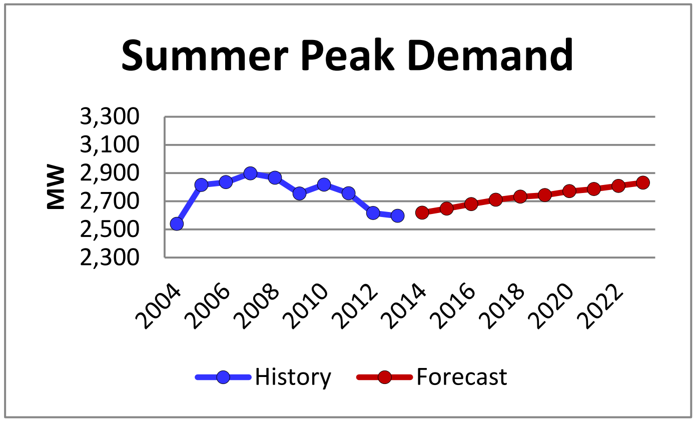


Figure 3: Winter Peak Demand History & Forecast

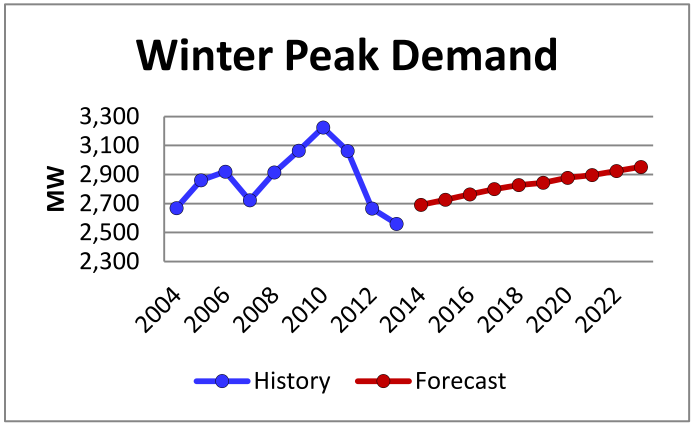
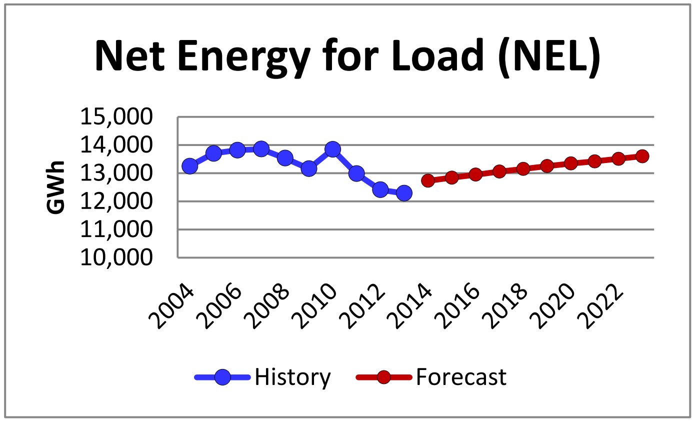


Figure 4: Net Energy for Load History & Forecast



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. Additionally, Northside Unit 3 is currently planned to be placed in long-term reserve the summer of 2019. With these baseline assumptions, no additional capacity is needed for the term of this TYSP (see Table 4).

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 additions and capacity 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 Needs after Committed Units

Summer

Year	Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Available Capacity	Firm Peak Demand	For Peak: Capacity Surplus/ (Deficit)	For Peak: Reserve Margin	For 15% Reserves: Capacity Required	For 15% Reserves: Capacity Surplus/ (Deficit)
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW
2014	3,769	9	376	0	3,402	2,488	914	37%	0	541
2015	3,769	18	376	0	3,411	2,512	899	36%	0	522
2016	3,769	18	376	0	3,411	2,537	875	34%	0	494
2017	3,769	18	376	0	3,411	2,563	849	33%	0	464
2018	3,769	118	376	0	3,511	2,581	930	36%	0	543
2019	3,245	209	0	0	3,454	2,585	869	34%	0	481
2020	3,245	209	0	0	3,454	2,613	841	32%	0	449
2021	3,245	209	0	0	3,454	2,618	836	32%	0	443
2022	3,245	209	0	0	3,454	2,633	821	31%	0	426
2023	3,245	209	0	0	3,454	2,653	801	30%	0	403

Winter

Year	Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Available Capacity	Firm Peak Demand	For Peak: Capacity Surplus/ (Deficit)	For Peak: Reserve Margin	For 15% Reserves: Capacity Required	For 15% Reserves: Capacity Surplus/ (Deficit)
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW
2014	4,110	9	383	0	3,737	2,603	1,134	44%	0	743
2015	4,110	18	383	0	3,746	2,635	1,111	42%	0	715
2016	4,110	18	383	0	3,746	2,670	1,076	40%	0	675
2017	4,110	18	383	0	3,746	2,702	1,044	39%	0	639
2018	4,110	118	383	0	3,846	2,726	1,120	41%	0	711
2019	4,110	209	383	0	3,937	2,735	1,202	44%	0	792
2020	3,586	209	0	0	3,795	2,766	1,030	37%	0	615
2021	3,586	209	0	0	3,795	2,789	1,006	36%	0	588
2022	3,586	209	0	0	3,795	2,816	979	35%	0	557
2023	3,586	209	0	0	3,795	2,833	962	34%	0	537

Notes:

Committed Capacity Additions:

a. 9 MW Trailridge II - December 2014
b. Vogtle Units 3 - December 2017
c. Vogtle Units 4 - December 2018

Table 5: Resource Plan

Year	Season	Resource Plan(1) (2)
2014		
2015	Winter	Trail Ridge II Purchase (9 MW)
2016		
2017		
2018	Winter	MEAG Plant Vogtle 3 Purchase (100 MW) (3)
2019	Winter	MEAG Plant Vogtle 4 Purchase (100 MW) (3) Trail Ridge Contract Expires (- 9 MW)
	Summer	SJRPP Sale to FPL Suspended (383 MW) (4) Northside Unit 3 Long-Term Reserve (-524 MW)
2020		
2021		
2022		
2023		

Notes:

(1) Cumulative DSM addition of 36 MW Winter and 54 MW Summer at time of peak by 2023.
(2) PEV addition of 0.58 MW Winter and 0.37 MW Summer by 2023.
(3) After accounting for transmission losses, JEA is expects to receive 100 MW December 2017 and 100 MW December 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)
	Fuel	**Type**	**Units**	**Actual 2012**	**Actual 2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	NUCLEAR														
(1)		**TOTAL**	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	COAL[1]														
(2)		**TOTAL**	**1000 TON**	**2,257**	**2,710**	**3,282**	**4,100**	**4,198**	**4,174**	**3,981**	**3,381**	**2,587**	**2,742**	**2,582**	**2,825**
	RESIDUAL														
(3)		STEAM	1000 BBL	15	0	83	59	83	76	72	39	0	0	0	0
(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**	**15**	**0**	**83**	**59**	**83**	**76**	**72**	**39**	**0**	**0**	**0**	**0**
	DISTILLATE														
(7)		STEAM	1000 BBL	1	1	2	1	1	1	1	1	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	2	10	2	8	10	8	4	0	7	1	8	4
(10)		**TOTAL**	**1000 BBL**	**3**	**11**	**4**	**9**	**11**	**9**	**5**	**1**	**8**	**2**	**9**	**5**
	NATURAL GAS														
(12)		STEAM	1000 MCF	17,768	4,842	9,735	6,989	9,777	8,923	8,452	4,594	53	52	40	42
(13)		CC	1000 MCF	26,836	23,002	20,237	19,579	17,881	18,567	16,367	8,821	8,741	7,050	8,672	6,977
(14)		CT/GT	1000 MCF	3,018	1,894	1,158	2,681	1,398	1,721	1,210	1,422	1,340	1,529	2,614	1,450
(15)		**TOTAL**	**1000 MCF**	**47,622**	**29,738**	**31,130**	**29,248**	**29,055**	**29,211**	**26,028**	**14,836**	**10,134**	**8,631**	**11,326**	**8,470**
	PETROLEUM COKE														
(16)		**TOTAL**	**1000 TON**	**246**	**761**	**547**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	OTHER (SPECIFY)														
(17)		**TOTAL**	**TRILLION BTU**	**0**	**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**											
				2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
(1)	**Firm Inter-Region Intchg.** (1)		GWH	**1,434**	**841**	**0**	**0**	**0**	**73**	**930**	**1,715**	**1,659**	**1,654**	**1,715**	**1,654**
(2)	**NUCLEAR**(1)		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(3)	**COAL**(2)		GWH	**4,434**	**5,376**	**6,997**	**8,855**	**9,061**	**9,030**	**8,705**	**9,456**	**10,018**	**10,291**	**9,959**	**10,440**
(4)	**RESIDUAL**	STEAM		0	45	33	46	41	39	21	0	0	0	0	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	**0**	**45**	**33**	**46**	**41**	**39**	**21**	**0**	**0**	**0**	**0**	**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		3	1	3	4	3	2	0	3	0	3	2	4
(11)		**TOTAL**	GWH	**3**	**1**	**3**	**4**	**3**	**2**	**0**	**3**	**0**	**3**	**2**	**4**
(12)	**NATURAL GAS**	STEAM		383	851	626	874	785	731	398	0	0	0	0	745
(13)		CC		3,357	2,917	2,825	2,562	2,661	2,324	1,246	1,228	986	1,213	962	1,540
(14)		CT		150	101	246	122	153	107	126	117	135	235	128	90
(15)		**TOTAL**	GWH	**3,890**	**3,869**	**3,698**	**3,558**	**3,600**	**3,163**	**1,770**	**1,345**	**1,121**	**1,449**	**1,090**	**2,376**
(16)	**NUG**		GWH	**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
(18)		**LANDFILL GAS**		71	78	157	157	157	131	78	79	78	78	78	0
(19)		**SOLAR**		21	24	23	23	23	23	23	23	23	23	23	23
(20)		**TOTAL**	GWH	**92**	**102**	**180**	**181**	**180**	**154**	**101**	**101**	**101**	**101**	**101**	**23**
(21)	**Petroleum Coke**		GWH	**618**	**2,084**	**1,679**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(22)	**OTHER (SPECIFY)**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(23)	**NET ENERGY FOR LOAD**(3)		GWH	**12,409**	**12,286**	**12,693**	**12,769**	**12,849**	**12,928**	**12,992**	**13,063**	**13,126**	**13,168**	**13,227**	**13,286**

Note: (1) Nuclear PPA with MEAG beginning 2017 included in Firm Inter-Regional Interchange.
(2) Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal. SJRPP sale suspends summer 2019.
(3) 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	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	Firm Inter-Region Intchg. (1)		%	11.6	6.8	0.0	0.0	0.0	0.6	7.2	13.1	12.6	12.6	13.0	12.4
(2)	NUCLEAR(1)		%	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(2)		%	35.7	43.8	55.1	69.3	70.5	69.9	67.0	72.4	76.3	78.2	75.3	78.6
(4)		STEAM		0.0	0.4	0.3	0.4	0.3	0.3	0.2	0.0	0.0	0.0	0.0	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	%	0.0	0.4	0.3	0.4	0.3	0.3	0.2	0.0	0.0	0.0	0.0	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		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)	DISTILLATE	TOTAL	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		STEAM		3.1	6.7	4.9	6.8	6.1	5.6	3.0	0.0	0.0	0.0	0.0	5.4
(13)		CC		27.3	23.0	22.1	19.9	20.6	17.9	9.5	9.4	7.5	9.2	7.2	11.1
(14)		CT		1.2	0.8	1.9	1.0	1.2	0.8	1.0	0.9	1.0	1.8	1.0	0.7
(15)	NATURAL GAS	TOTAL	%	31.7	30.5	29.0	27.7	27.8	24.3	13.5	10.2	8.5	11.0	8.2	17.1
(16)	NUG		%	0.0	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	1.2	1.2	1.2	1.0	0.6	0.6	0.6	0.6	0.6	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	1.4	1.4	1.4	1.2	0.8	0.8	0.8	0.8	0.8	0.2
(21)	Petroleum Coke		%	5.0	17.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(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(3)		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Note: (1) Nuclear PPA with MEAG beginning 2017 included in Firm Inter-Regional Interchange.
(2) Coal includes JEA's share of SJRPP, Scherer 4 and Northside Coal. SJRPP sale suspends summer 2019.
(3) 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		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
		Import	Export								
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2014	3,769	9	376	0	3,402	2,488	914	37%	0	914	37%
2015	3,769	18	376	0	3,411	2,512	899	36%	0	899	36%
2016	3,769	18	376	0	3,411	2,537	875	34%	0	875	34%
2017	3,769	18	376	0	3,411	2,563	849	33%	0	849	33%
2018	3,769	118	376	0	3,511	2,581	930	36%	0	930	36%
2019	3,245	209	0	0	3,454	2,585	869	34%	0	869	34%
2020	3,245	209	0	0	3,454	2,613	841	32%	0	841	32%
2021	3,245	209	0	0	3,454	2,618	836	32%	0	836	32%
2022	3,245	209	0	0	3,454	2,633	821	31%	0	821	31%
2023	3,245	209	0	0	3,454	2,653	801	30%	0	801	30%

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

Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
		Import	Export								
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	MW	Percent
2014	4,110	9	383	0	3,737	2,603	1,134	44%	0	1,134	44%
2015	4,110	18	383	0	3,746	2,635	1,111	42%	0	1,111	42%
2016	4,110	18	383	0	3,746	2,670	1,076	40%	0	1,076	40%
2017	4,110	18	383	0	3,746	2,702	1,044	39%	0	1,044	39%
2018	4,110	118	383	0	3,846	2,726	1,120	41%	0	1,120	41%
2019	4,110	209	383	0	3,937	2,735	1,202	44%	0	1,202	44%
2020	3,586	209	0	0	3,795	2,766	1,030	37%	0	1,030	37%
2021	3,586	209	0	0	3,795	2,789	1,006	36%	0	1,006	36%
2022	3,586	209	0	0	3,795	2,816	979	35%	0	979	35%
2023	3,586	209	0	0	3,795	2,833	962	34%	0	962	34%

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					Summer	Winter	
											kW	MW	MW	
SJRPP	1	12-031	ST	BIT	PC	RR	WA		06/2019	(a)	679,600	188	191	Sale To FPL Ends
SJRPP	2	12-031	ST	BIT	PC	RR	WA		06/2019	(a)	679,600	188	191	
Northside	3	12-031	ST	NG	FO6	PL	WA			06/2019	563,700	- 524	- 524	Long-Term Reserve

Notes:

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

Schedule 9: Status Report and Specifications of Proposed Generating Facilities 2014 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 natural gas, coal, petroleum coke, uranium, residual fuel oil and diesel fuel.

The fuel price projections for natural gas, residual oil and diesel fuel used in this TYSP were developed based on those included in the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2014 Early Release (AEO2014). AEO2014 presents projections of energy supply, demand, and prices through 2040. The AEO2014 projections 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 fuel price projections for coal and petroleum coke used in this TYSP were developed based on long-term price forecasts from PIRA Energy Group. PIRA is an international consulting firm that specializes in global energy market research and intelligence. PIRA provides long-term price projections for fuels, power, freight and emissions in its Energy Price Portal though 2030.

The price projections for emissions allowances are derived from JD Energy's most recent outlook. JD Energy is an independent energy and environmental price forecasting firm. JD Energy uses a 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 emissions markets.

Scherer 4 burns Powder River Basin (PRB) coal. The commodity price projection for PRB coal was developed by escalating current contract prices by the PIRA forecasted growth rate for PRB coal. The transportation price projection was derived from existing contracts.

SJRPP currently burns a blend of Illinois Basin (IB) and Colombian coal. For the purposes of this study, it has been assumed that 100 percent Colombian coal will be burned by the SJRPP units during the forecast period. Projections of the commodity price for Colombian coal were based on current Intercontinental Exchange (ICE) market prices and PIRA's forecasted growth rate for Colombian coal. Current freight rates for 2014 - 2016 waterborne delivery of Colombian coal were escalated using the assumed inflation rate to project transportation costs beyond 2016. 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.

Northside units 1 and 2 currently burn a blend of petroleum coke and coal. These units are projected to burn 100 percent coal during the forecast period. The coal price projection was developed by using current market prices escalated by PIRA's long-term Colombian coal forecast. The same methodology was used to project transportation costs to Northside Generating Station with additional price consideration given to the shallower draft available at its offloading facility.

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 AEO2014 Henry Hub 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 on the AEO2014 price forecast for residual fuel oil delivered to the Florida Reliability Coordinating Council Region (FRCC).

The 1970's-vintage combustion turbine units at Northside Generating Station (GT3, GT4, GT5, and GT6) burn diesel fuel as the primary fuel type. Five JEA units utilize diesel fuel as an alternative to natural gas: Kennedy GT7 and GT8 and Brandy Branch GT1, CT2, and CT3. GEC GT1 and GEC GT2 are capable of using diesel fuel as a backup fuel. Projections for the price of diesel fuel were based on the AEO2014 price forecast for diesel fuel delivered to the FRCC region.

JEA has purchased shares of Vogtle Units 3 and 4 currently under construction in Georgia with planned in-service dates of 2017 and 2018. The fuel price forecast accounts for the costs of mine-mouth uranium, enrichment and fabrication.

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.