JEA®

Building Community®

TEN YEAR SITE PLAN

April 2021-*REVISED*

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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
DFO	No. 2 Fuel Oil
RFO	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, 2021 to December 31, 2030. This power supply strategy maintains a balance of reliability, environmental stewardship, and low cost to the consumers.

1. Description of Existing Facilities

1.1 Power Supply System Description

1.1.1 System Summary

JEA is the eighth 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 more than 450,000 customers.

As of January 1, 2021, JEA consists of two financially separate entities: the JEA Electric System; and the Robert W. Scherer bulk power system. The total projected net capability of JEA's generation system is 3,134 MW for winter and 2,969 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 (CFB) steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); seven dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT7 and GT8, GEC GT1 and GT2 and Brandy Branch GT1, CT2, and CT3); 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).

During the spring of 2019, JEA upgraded Brandy Branch units CT2 and CT3. The upgrade involved the addition of General Electric's Advanced Gas Path (AGP) and 7FA.05 compressor modifications to the existing Brandy Branch CT2 and CT3 7FA.03 units. Refer to Schedule 1 for summer and winter net capability updates.

1.1.1.2 Robert W. Scherer Bulk Power System

Robert W. Scherer Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. Scherer Unit 4 is one of four coal-fired steam units located at the 12,000-acre site near the Ocmulgee River approximately three miles east of Forsyth, Georgia. JEA and Florida Power & Light (FPL) purchased an undivided interest of this unit from Georgia Power Company. JEA has 23.6 percent (200 net MW) and FPL 76.4 percent ownership interest in Unit 4.

In addition to the purchase of undivided ownership interests in Scherer Unit 4, JEA and FPL also purchased proportionate undivided ownership interests in (i) certain common facilities shared by Units 3 and 4 at Plant Scherer, (ii) certain common facilities shared by Units 1, 2, 3 and 4 at Plant Scherer and (iii) an associated coal stockpile under the Scherer Unit 4 Purchase Agreement. Under a separate agreement, JEA also purchased a proportionate undivided ownership interest in substation and switchyard facilities. JEA has firm transmission service for delivering the energy output from this unit to JEA's system.

On June 26, 2020, the Board adopted Resolution 2020-06, which delegated authority to the Interim Managing Director and Chief Executive Officer to enter into a Cooperation Agreement with FPL ("FPL Cooperation Agreement") for the closure of Plant Scherer Unit 4 on or before January 1, 2022 with the capacity and energy to be replaced by a 20-year power purchase agreement (PPA) between JEA and FPL for a natural gas-fired system product with a solar conversion option. The FPL Cooperation Agreement was executed on August 25, 2020 and calls for the parties to cooperate in good faith in a joint effort to consummate the retirement of Plant Scherer Unit 4 and enter into the FPL PPA. On November 24, 2020, JEA executed a retirement agreement with FPL, setting forth the terms and conditions of the Plant Scherer Unit 4 closure as of January 1, 2022.

1.1.2 Power Purchases

1.1.2.1 Trail Ridge Landfill

In 2006, JEA entered into a PPA with Trail Ridge Energy, LLC (TRE) to purchase energy and environmental attributes from 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 facility was one of the largest landfill gas-to-energy facilities in the Southeast when it began commercial operation on December 6, 2008.

JEA and TRE executed an amendment to this PPA on March 9, 2011 that included additional capacity. The "Phase Two Purchase" amendment included up to 9 additional net MW. Landfill Energy Systems (LES) developed the Sarasota County Landfill in Nokomis, Florida (up to 6 net MW) to serve part of this Phase Two agreement. This portion of the Phase Two purchase began in February 2015. These landfill gas projects generated 87,561 MWh during calendar year 2019.

1.1.2.2 Jacksonville Solar

In May 2009, JEA entered into a PPA with Jacksonville Solar, LLC (Jax Solar) to receive up to 12 MW_{AC} 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 was 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 on September 30, 2010. Jax Solar generated 16,287 MWh during calendar year 2020.

1.1.2.3 Solar Power Purchase Agreements

In 2014, JEA's Board approved a Solar Photovoltaic Initiative that supports up to 38 additional MW_{AC}. JEA issued a Solar PV Request for Proposals (RFP) in December 2014 and April 2015 to solicit PPA proposals to satisfy the adopted 2014 policy. JEA awarded a total of 31.5 MW of solar PV power purchase contracts with terms of 20-25 years to various vendors. Of the awarded contracts, only seven agreements were finalized for a total of 27 MW. The last of these seven projects was completed in December 2019.

In October 2017, the JEA Board approved a further solar expansion consisting of five-50 MW_{AC} solar facilities to be constructed on JEA-owned property. These projects, totaling 250 MW_{AC}, are structured as PPAs. A Request for Qualifications (RFQ) to select the vendors was issued and a vendor short list was announced in November 2017. The RFP for the facilities was released to the short listed vendors on January 2, 2018. JEA received and evaluated 50 proposals that conformed to the requirements of the RFP. JEA awarded the contracts to EDF Renewables Distributed Solutions on April 26, 2018. JEA negotiated and executed the contracts with EDF in the first quarter of 2019. JEA will purchase the produced energy and the associated environmental attributes from each facility. Beaver Street Solar Center, Cecil Commerce Solar Center, Deep Creek Solar Center, Forest Trail Solar Center, and Westlake Solar Center are tentatively scheduled for completion by the end of 2022.

1.1.2.4 Nuclear Generation

JEA's Board had established targets to acquire 10 percent of JEA's energy requirements from nuclear sources by 2018 and up to 30 percent carbon-neutral sources by 2030. In March 2008, the JEA Board of Directors approved the pursuit of nuclear energy partnerships as part of a strategy for greater regulatory and fuel diversification. In October 2017, the JEA Board modified this goal by adopting an Energy Mix Policy, which allows the 30 percent target to be met by any carbon-free or carbon-neutral generation. Meeting these targets will result in a smaller carbon footprint for JEA's customers.

In June 2008, JEA entered into a 20-year 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 Vogtle construction schedule makes available to JEA 100 net MW of capacity beginning November 2021 from Unit 3, and an additional 100 net MW beginning November 2022 from Unit 4. Table 1 lists JEA's current power purchase contracts.

1.1.2.5 Florida Power & Light Power Purchase Agreement

On August 25, 2020, JEA and FPL executed a Cooperation Agreement for the retirement of Plant Scherer Unit 4 with the capacity and energy to be replaced by a 20-year 200 MW PPA between JEA and FPL for natural gas-fired system product with a solar conversion option on or after the 10^{th} anniversary from the PPA start date.

1.1.2.6 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.

Table 1: JEA Power Purchase Schedule

Contract		Start Date	End Date	MW_{AC}	Product Type
LES Trail Ridge	**I**	12/06/08	12/31/26	9	Annual
	II	02/01/14	12/31/26	6	Annual
MEAG Plant Vogtle	**Unit 3**	11/01/21	11/01/41	100	Annual
	Unit 4	11/01/22	11/01/42	100	Annual
FPL PPA		01/01/22	01/01/42	200	Annual
Jacksonville Solar		09/30/10	09/30/40	12	Annual
NW Jacksonville Solar		05/30/17	05/30/42	7	Annual
Old Plank Road Solar		10/13/17	10/13/37	3	Annual
Starratt Solar		12/20/17	12/20/37	5	Annual
Simmons Road Solar		01/17/18	01/17/38	2	Annual
Blair Site Solar		01/23/18	01/23/38	4	Annual
Old Kings Solar		10/15/18	10/15/38	1	Annual
SunPort Solar		12/04/19	12/04/39	5	Annual
Cecil Commerce Solar(1)		12/01/22	12/01/47	50	Annual
Westlake Solar(1)		05/01/22	05/01/47	50	Annual
Deep Creek Solar(1)		10/01/22	10/01/47	50	Annual
Beaver Street Solar(1)		07/01/22	07/01/47	50	Annual
Forest Trail Solar(1)		08/01/22	08/01/47	50	Annual

(1) Dates are tentative.

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 (b)	Net MW Capability		Ownership	Status
				Primary	Alt.	Primary	Alt.	Mo/Year	Mo/Year	kW	Summer	Winter		
Kennedy										407,600	357	382		
	7	12-031	GT	NG	DFO	PL	WA	06/2000	(a)	203,800	179	191	Utility	
	8	12-031	GT	NG	DFO	PL	WA	06/2009	(a)	203,800	179	191	Utility	
Northside										1,512,100	1,310	1,356		
	1	12-031	ST	PC	BIT	WA	RR	05/2003	(a)	350,000	293	293	Utility	
	2	12-031	ST	PC	BIT	WA	RR	04/2003	(a)	350,000	293	293	Utility	
	3	12-031	ST	NG	RFO	PL	WA	07/1977	(a)	563,700	524	524	Utility	
	33-36	12-031	GT	DFO		WA,TK		01/1975	(a)	248,400	200	246	Utility	
Brandy Branch										879,800	746	814		
	1	12-031	GT	NG	DFO	PL	TK	05/2001	(a)	203,800	179	191	Utility	
	2	12-031	CT	NG		PL	TK	05/2001	(a)	203,800	190	212	Utility	
	3	12-031	CT	NG		PL	TK	10/2001	(a)	203,800	190	212	Utility	
	4	12-031	CA	WH				01/2005	(a)	268,400	188	200	Utility	
Greenland Energy Center										407,600	357	382		
	1	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	203,800	179	191	Utility	
	2	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	203,800	179	191	Utility	
Scherer														
	4	13-207	ST	BIT		RR		02/1989	01/2022	990,000	198	198	Joint	(c)
JEA System Total											**2,969**	**3,134**		(d)

Notes:

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

(b) Generator Max Nameplate is total unit not ownership.

(c) Net capability reflects JEA's 23.64% ownership in Scherer 4.

(d) Numbers may not add due to rounding.

1.2 Transmission and Distribution

1.2.1 Transmission and Interconnections

JEA's transmission system consists of 744 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV.

The 500 kV transmission lines are jointly owned by JEA and FPL, completing the path from FPL's Duval substation (located in the westerly portion of JEA's system) to the north to interconnect with 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 capacity is 1,228 MW over the 500 kV transmission lines through Duval substation.

The 230 kV and 138 kV transmission systems provide 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; covering the area not covered by the 230 kV and 138 kV transmission backbone.

JEA owns and operates a total of four 230 kV transmission interconnections at FPL's Duval substation in Duval County. JEA has one 230 kV transmission interconnection which terminates at Beaches Energy Services' Sampson substation (FPL metered) in St. Johns County. JEA's ownership of this interconnection ends at State Road 210 which is located just north of the Sampson substation. JEA has one 230 kV transmission interconnection terminating at Seminole Electric Cooperative Incorporated's (SECI) Black Creek substation in Clay County. JEA's ownership of this interconnection ends at the Duval County – Clay County line.

JEA has a 138 kV tie with Beaches Energy Services at JEA's Neptune substation. JEA owns and operates a 138 kV transmission loop that extends from the 138 kV backbone north to JEA's Nassau substation. This substation serves as a 138 kV transmission interconnection point for FPL's O'Neil substation and Florida Public Utilities Company's (FPU) Step Down substation. JEA's ownership of these two 138 kV interconnections end at the first transmission structure outside of the Nassau substation.

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.

Since the FRCC region became the FL-Peninsula sub-region of SERC in July 2019, JEA has been following additional guidelines and actively participating in the SERC activities towards the reliability and security of the bulk electric 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 within the FRCC Region.

FRCC's members include investor owned utilities, municipal utilities, 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 Technical Subcommittee 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

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.

The following existing transmission service contract is set to expire in the future during this Ten Year Site Plan period:

- FPL purchased Cedar Bay plant and retired the generation in December 2016. The transmission service for the delivery of Cedar Bay generation has been converted to JEA's Open Access Transmission service, and will remain with FPL through 2024.

1.2.4 Distribution

The JEA distribution system operates at three primary voltage levels (4.16 kV, 13.2 kV, and 26.4 kV). The 4.16 kV system serves a permanently defined area in older residential neighborhoods. The 13 kV system serves a permanently defined area in the urban downtown area. These two distribution systems serve any new customers that are located within their defined areas, but there are no plans to expand these two systems beyond their present boundaries. The 26.4 kV system serves approximately 88 percent of JEA's load, including 75 percent of the 4.16 kV substations. The current standard is to expand the 26.4 kV system as required to serve all new distribution loads, except loads that are within the boundaries of the 4.16 kV or 13.2 kV systems. JEA has approximately 7,100 miles of distribution circuits of which more than half is underground.

1.3 Demand-Side Management (DSM)

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 100 MW of interruptible peak load for the summer and 102 MW for the winter which remain constant throughout the study period. For 2021, the interruptible load represents 3.4 percent of the forecasted total peak demand in the winter and 4.02 percent of the forecasted total peak demand in the summer.

1.3.2 Demand-Side Management Programs

JEA continues to pursue a greater implementation of demand-side management programs where economically beneficial and continues 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.

Electrification programs include on-road and off-road vehicles, floor scrubbers, forklifts, cranes and other industrial process technologies. JEA's forecast of annual incremental demand and energy reductions due to its current DSM energy efficiency programs is shown in Table 2. JEA's current and planned DSM programs are summarized by commercial and residential programs in Table 3.

Table 2: DSM Portfolio – Energy Efficiency Programs

ANNUAL INCREMENTAL		2021	2022	2023	2024	2026	2026	2027	2028	2029	2030
Annual	Residential	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2
Energy	Commercial	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
(GWh)	***Total***	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**	**34.6**
Summer	Residential	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Peak	Commercial	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
(MW)	***Total***	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**	**7.9**
Winter	Residential	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Peak	Commercial	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
(MW)	***Total***	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**	**6.1**

Table 3: DSM Programs

Commercial Programs	Residential Programs
Commercial Energy Assessment Program	Residential Energy Assessment Program
Commercial Energy Efficient Products	Residential Energy Efficient Products
Commercial Prescriptive Program	Residential New Build
Custom Commercial Program	Residential Solar Water Heating
Commercial Solar Net Metering	Residential Solar Net Metering
Small Business Direct Install Program	Neighborhood Efficiency Program
Off-Road Electrification	Residential Efficiency Upgrade
	Electric Vehicles

1.4 Clean Power and Renewable Energy

JEA continues to investigate economic 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

As established in JEA's "Clean Power Action Plan" and through routine Clean Power Program meetings from 1999-2014, JEA worked with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups as a means of providing guidance and recommendations to JEA in the development and implementation of the Clean Power Programs.

Since the conclusion of this program, JEA has continued to make considerable progress related to clean power initiatives. This progress includes installation of clean power systems, unit efficiency improvements, solar PPAs, legislative and public education activities, and research 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. JEA issued several RFPs for solar energy that resulted in new resources for JEA's portfolio. As discussed below, JEA's existing renewable energy sources include installation of solar photovoltaic (PV), solar thermal, and landfill gas 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 provided 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. The policy has since evolved with several revisions:

- 2009: Tier 1 & 2 Net Metering policy launched to include all customer-owned renewable generation systems less than or equal to 100 kW

- 2011: Tier 3 Net Metering policy established for customer-owned renewable generation systems greater than 100 kW up to 2 MW
- 2014: Policy updated to define Tier 1 as 10 kW or less, Tier 2 as greater than 10 kW – 100 kW, and Tier 3 as 100 kW – 2 MW. This policy was capped at 10 MW for total generation. All customer-owned generation in excess of 2 MW would be addressed in JEA's Distributed Generation (DG) Policy.
- 2017: In October, the JEA Board approved the consolidation of the Net Metering and DG Policies into a single, comprehensive DG Policy.
- 2018: Effective April 1, the comprehensive DG Policy qualified renewable and non-renewable customer-owned generation systems under the following ranges:
  - DG-1 – Less than or equal to 2 MW
  - DG-2D – Over 2 MW with distribution level connection
  - DG-2T – Over 2 MW with transmission level connection

  This DG policy acts in concert with the JEA Battery Incentive Program (see Section 1.4.3.3 Energy Storage) and allows existing customers the option to be grandfathered under the 2014 Net Metering Policy for a period of 20 years.

JEA signed a PPA with Jacksonville Solar, LLC May 2009 to provide energy from a 12 MW_{AC} rated solar farm, which began operation in summer 2010 (see Section 1.1.2.3 Jacksonville Solar).

In December 2014, a Solar Policy was approved by the JEA Board, setting forth the goal of an additional 38 MW of solar photovoltaic (PV) power via power purchase contracts by the end of 2016. JEA issued three Solar PV RFPs and received a total of 73 bids. In 2015, JEA awarded a total of 31.5 MW of solar PV power purchase contracts with terms of 20 to 25 years to various vendors. The PPA, 5 MW on U.S. Navy owned land, awarded to Hecate Energy, LLC in 2016 was cancelled because JEA and the Navy were unable to reach an agreement on the land lease. A 4.5 MW award to SunEdison Utility Solutions, LLC was cancelled due to failure of the contractor to secure site control. The following are the seven PPAs that were finalized for a total of 27 MW in JEA's service territory of which JEA pays for the energy and has rights to the associated environmental attributes produced by the facilities:

- Northwest Jacksonville Solar Partners, LLC: 7 MW_{AC} / 25-year PPA. The NW Jax facility consists of 28,000 single-axis tracking photovoltaic panels on a vendor-leased site, owned by American Electric Power (AEP). The facility became operational on May 30, 2017.
- Old Plank Road Solar Farm, LLC: 3 MW_{AC} / 20-year PPA. The Old Plank Road Solar facility consists of 12,800 single-axis tracking photovoltaic panels on a vendor-leased 40-acre site, owned by Southeast Solar Farm Fund, a partnership between PEC Velo & Cox Communications. The site attained commercial operation on October 13, 2017.

- C2 Starratt Solar, LLC: 5 MW_{AC} / 20-year PPA. The Starratt Solar facility, on a vendor-leased site, is owned by C2 Starratt Solar, LLC and was constructed by Inman Solar, Incorporated. The site attained commercial operation on December 20, 2017.
- Inman Solar Holdings 2, LLC: 2 MW_{AC} /20-year PPA. The Simmons Solar facility, on a vendor-leased site, is owned by Inman Solar Holdings 2, LLC and was constructed by Inman Solar, Inc. The site attained commercial operation on January 17, 2018.
- Hecate Energy Blair Road, LLC: 4 MW_{AC} / 20-year PPA. The Blair Road facility, on a vendor-leased site, is owned by Hecate Energy Blair Road, LLC and was constructed by Hecate Energy, LLC. The site attained commercial operation on January 23, 2018.
- JAX Solar Developers, a wholly-owned subsidiary of Mirasol Fafco Solar, Inc.: 1 MW_{AC} / 20-year PPA. The Old Kings Rd Solar facility is owned by EcoPower Development, LLC and was constructed by Mirasol Fafco Solar, Inc. The site attained commercial operation on October 15, 2018.
- Imeson Solar, LLC: 5 MW_{AC} solar PV / 2 MW, 4 MWh battery energy storage system (BESS) / 20-year PPA. The primary function of the BESS is to smooth the solar generation. It is the first utility scale solar plus storage facility interconnected to the JEA grid. The site, labeled SunPort Solar, was constructed by 174 Power Global and attained commercial operation on December 4, 2019.

In October 2017, the JEA Board approved a further solar expansion consisting of five -50 MW_{AC} solar facilities to be constructed on JEA-owned property. These projects, totaling 250 MW_{AC}, are structured as PPAs. A RFQ to select the vendors was issued and a vendor short list was announced in November 2017. The RFP for the facilities was released to the short listed vendors on January 2, 2018. JEA received and evaluated 50 proposals that conformed to the requirements of the RFP. JEA awarded the contracts to EDF Renewables Distributed Solutions in April 2018 and executed the contracts in the 1st quarter of 2019. JEA will purchase the produced energy, as well as the associated environmental attributes from each facility. Beaver Street Solar Center, Cecil Commerce Solar Center, Deep Creek Solar Center, Forest Trail Solar Center, and Westlake Solar Center contractually have until the end of 2022 to be completed.

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 was 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, methane gas generation has declined and one generator was removed and placed into service at the Buckman Wastewater Treatment facility and the remaining Girvin landfill generation facilities were decommissioned in 2014.

JEA's 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 one 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 the digester heaters.

JEA signed a PPA with TRE in 2006 (Phase One) for 9 net MW of the gas-to-energy facility at the Trail Ridge Landfill in Duval County. In 2011, JEA executed an amendment to the PPA (Phase Two) to purchase 9 additional MW from a gas-to-energy facility. LES has developed the Sarasota County Landfill in Nokomis, Florida (up to 6 net MW) to serve part of the Phase Two agreement. This portion of the Phase Two purchase began February 2015 (see Section 1.1.2.1 Trail Ridge Landfill).

1.4.2.3 Biomass

In 2008, 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 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 and 2.

In 2011, JEA co-fired biomass in the Northside Units 1 and 2, utilizing wood chips from JEA tree trimming activities as a biomass energy source. Northside 1 and 2 produced a total of 2,154 MWh of energy from wood chips during 2011 and 2012. At that time, JEA received bids from local sources to provide biomass for potential use for Northside Units 1 and 2. Currently, no biomass is being co-fired in Northside Units 1 and 2.

1.4.3 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 with UNF, worked to quantify the winter peak reductions of solar hot water systems.
- UNF, in association with the University of Florida, 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 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 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.

Through Florida State University (FSU), JEA participated in The Sunshine State Solar Grid Initiative (SUNGRIN) which was a five-year project (2010-2015) funded under the Department of Energy (DOE) Solar Energy Technologies Program, Systems Integration Subprogram, High Penetration Solar Deployment Projects. The goal of the SUNGRIN project, which started in spring 2010, was to gain significant insight into effects of high-penetration levels of solar PV systems in the power grid, through simulation-assisted research and development involving a technically varied and geographically dispersed set of real-world test cases within the Florida grid. JEA provided FSU with data from the output of the Jacksonville Solar project.

In 2016, JEA pledged its support to the proposed 3-year Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) project. The program is led by Nhu Energy, Inc. and Florida Municipal Electric Association (FMEA) with partial funding from the DOE. FAASSTeR seeks to grow solar capacity in FMEA member utilities to over 10% by 2024, and provide increased value in terms of cost of service, electric infrastructure reliability, security, and resilience, and environmental and broader economic benefits. With assistance from the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory, studies on cost and performance of solar and solar plus storage applications were conducted. The program recently concluded after a no-cost extension, where Nhu Energy, Inc. provided technical assistance on various solar and solar plus storage applications, including proper storage sizing for solar ramp rate mitigation. The study results will aid JEA in making informed decisions regarding its generation strategy.

1.4.3.1 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 GEC significantly reduced CO2 emissions.

During the spring of 2019, JEA upgraded Brandy Branch units CT2 and CT3. The upgrade involved the addition of General Electric's Advanced Gas Path (AGP) and 7FA.05 compressor modifications to the existing Brandy Branch CT2 and CT3 7FA.03 units. These upgrades improved the efficiency of the Brandy Branch units CT2 and CT3 taking them from approximately 48% to 53% on an ISO basis.

1.4.3.2 Renewable Energy Credits (REC)

JEA makes all environmental attributes from renewable facilities available to sell in order to lower rates for JEA customers. JEA has sold environmental credits for specified periods. In 2020, JEA certified approximately 17,000 Solar RECs under the Green-e certification structure and tracked and delivered approximately 80,000 landfill gas RECs through the North America Renewables (NAR) registry.

1.4.3.3 Energy Storage

JEA continues its efforts to demonstrate its commitment to energy efficiency and environmental improvement by researching energy storage applications and methods to efficiently incorporate storage technologies into the JEA system.

JEA welcomed the first utility-scale battery energy storage system to its grid with the addition of the SunPort Solar facility's 4 MWh battery; the storage system levels the solar PV output. JEA is undertaking an Integrated Resource Plan (IRP), scoped to include supply-side and demand-side strategies and recommendations on existing resources and future resource additions/replacements, including battery energy storage and other storage technologies. For more information on JEA's IRP, see Section 3.1.1.

JEA's residential Battery Incentive Program enacted on April 1, 2018 has continued to provide financial incentive towards the cost of an energy storage system, subject to lawfully appropriated funds. The Program, used in concert with the 2018 DG Policy, is intended to assist customers in being efficient energy users. Customers who elect to collect the rebate are able to offset electricity consumption from JEA, up to the limits of their storage devices. Funds allotted to each customer under the Program is subject to review and change to optimize adoption. Since its inception, over 140 residential storage systems have been installed.

1.4.3.4 Potential Hydrokinetic Project for the St. John's River

JEA is working with several parties regarding a potential Hydrokinetic Project for the St. John's River at The City's St. John's Marina. Hydrokinetic Energy Corp is working on a low velocity hydro turbine prototype (in Key West) and is looking to possibly partner with The City and JEA with the St. John's Marina project. Hydrokinetic is working with other parties to possibly make this a DOE project. The current proposal contains four 9kW turbines at the marina. The output of the turbines is variable depending on flow velocity of the river.

2. Forecast of Electric Power Demand and Energy Consumption

Annually, JEA develops forecasts of seasonal peaks demand, net energy for load (NEL), interruptible customer demand, DSM, and the impact of plug-in electric vehicles (PEVs). JEA removes from the total load forecast all seasonal, coincidental non-firm sources and adds sources of additional demand to derive a firm load forecast.

JEA uses National Oceanic and Atmospheric Administration (NOAA) Weather Station - Jacksonville International Airport for the weather parameters, Moody's Analytics (Moody) economic parameters for Duval County, JEA's Data Warehouse to determine the total number of Residential accounts and CBRE Jacksonville for Commercial total inventory square footages. JEA develops its annual forecast using SAS and Microsoft Office Excel.

JEA's Calendar Year 2021 baseline forecast uses 10-years of historical data. Using the shorter period allows JEA to capture the more recent trends in customer behavior, and energy efficiency and conservation, where these trends are captured in the actual data and used to forecast projections.

2.1 Energy Forecast

JEA begins this forecast process by weather normalizing energy for each customer class. JEA uses NOAA Weather Station - Jacksonville International Airport for historical weather data. JEA develops the normal weather using 10-year historical average heating/cooling degree days and maximum/minimum temperatures. Normal months, with heating/cooling degree days and maximum/minimum temperatures that are closest to the averages, are then selected. JEA updates its normal weather every 5 years or more frequently, if needed.

The residential energy forecast was developed using multiple regression analysis of weather normalized historical residential energy, total population, number of households, median household income, total housing starts from Moody's Analytics, JEA's total residential accounts and JEA's residential electric rate.

The commercial energy forecast was developed using multiple regression analysis of weather normalized historical commercial energy, commercial inventory square footage, total commercial employment, gross domestic product from Moody's Analytics, and JEA's commercial electric rate.

The industrial energy forecast was developed using multiple regression analysis of weather normalized historical industrial energy, total industrial employment, and gross domestic product from Moody's Analytics.

The lighting energy forecast was developed using the historical actual energy, number of luminaries and JEA's estimated High Pressure Sodium (HPS) to Light-Emitting Diode (LED) street light conversion schedule. The LEDs are estimated to use 45% less energy than the HPS street lights. JEA developed the forecasted number of luminaries using regression analysis of the number of JEA customers. The forecasted lighting energy was calculated using the forecasted number of luminaries, applied with the remaining HPS to LED street light conversions with all new street light additions as LED only.

JEA's forecasted AAGR for net energy for load during the TYSP period is 0.92 percent.

2.2 Peak Demand Forecast

JEA normalizes historical seasonal peaks using historical maximum and minimum temperatures. JEA uses 25°F as the normal temperature for the winter peak and 97°F for the normal summer peak demands. JEA develops the seasonal peak forecasts using normalized historical and forecasted residential, commercial and industrial energy for winter/summer peak months, and the average load factor based on historical peaks and net energy for winter/summer peak months. JEA's forecasted Average Annual Growth Rate (AAGR) for total peak demand during the TYSP period is 0.92 percent for summer and 0.82 percent for winter.

Figure 1: Net Energy for Load History & Forecast

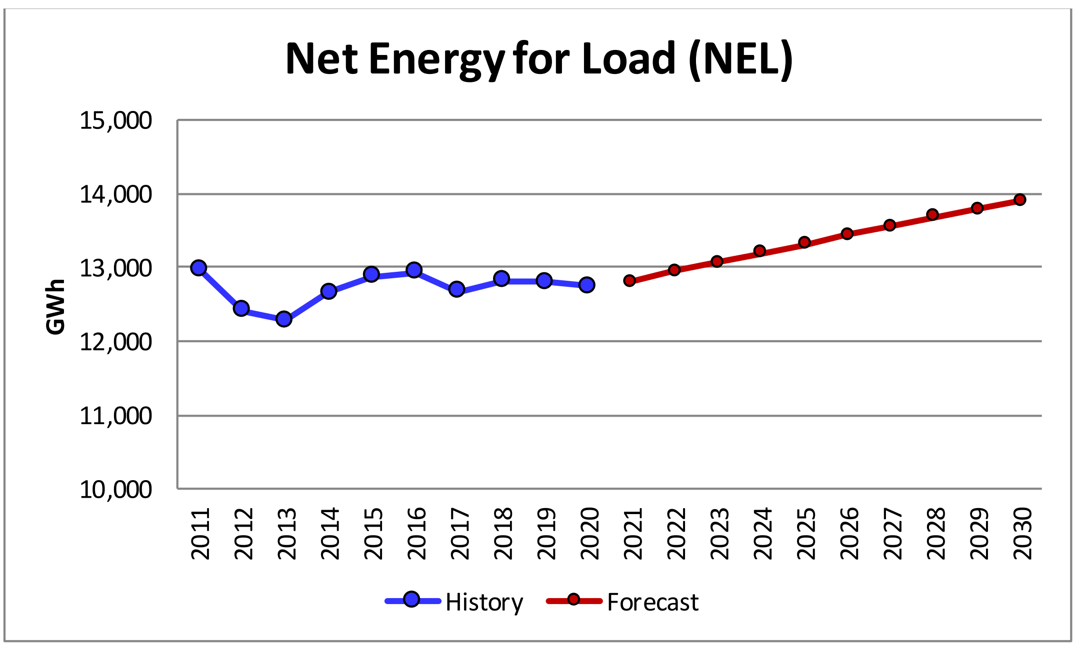


Figure 2: Summer Peak Demand History & Forecast

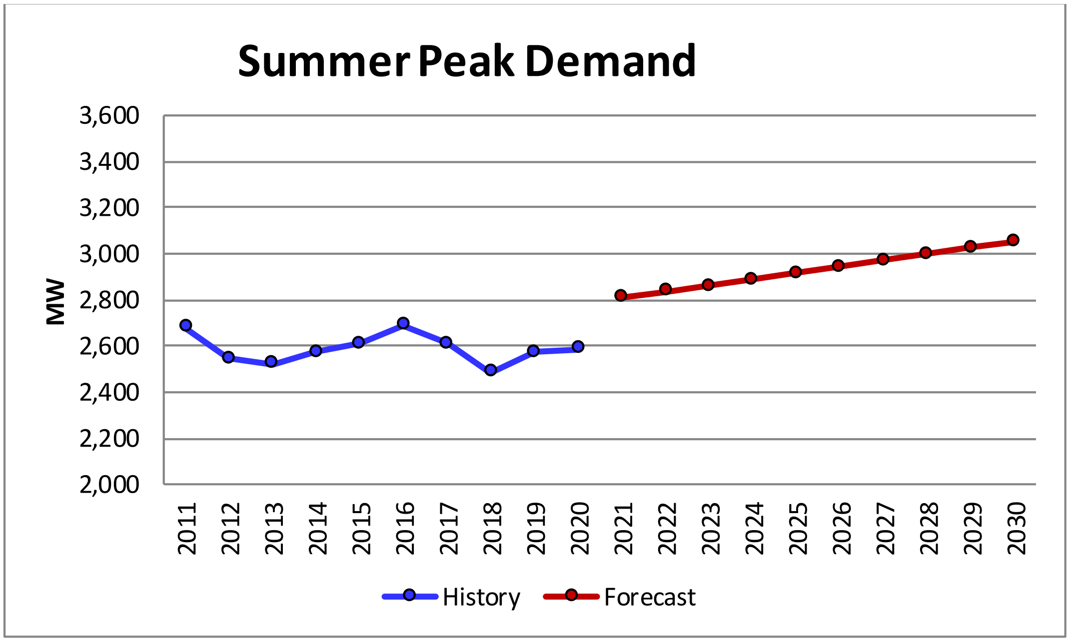
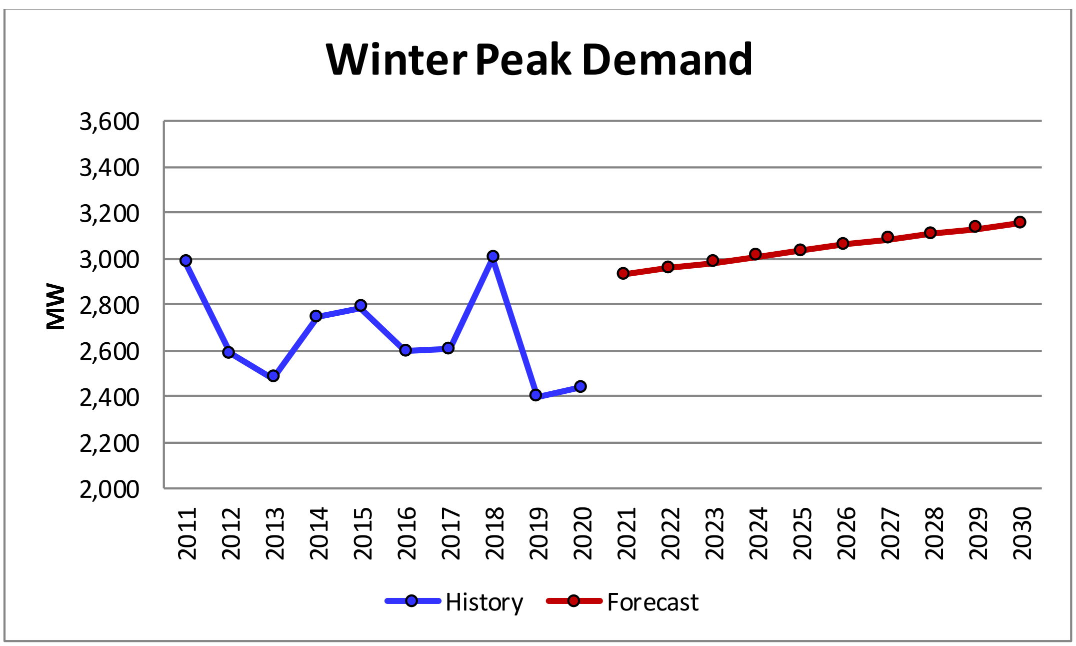


Figure 3: Winter Peak Demand History & Forecast



2.3 Plug-in Electric Vehicles Peak Demand and Energy

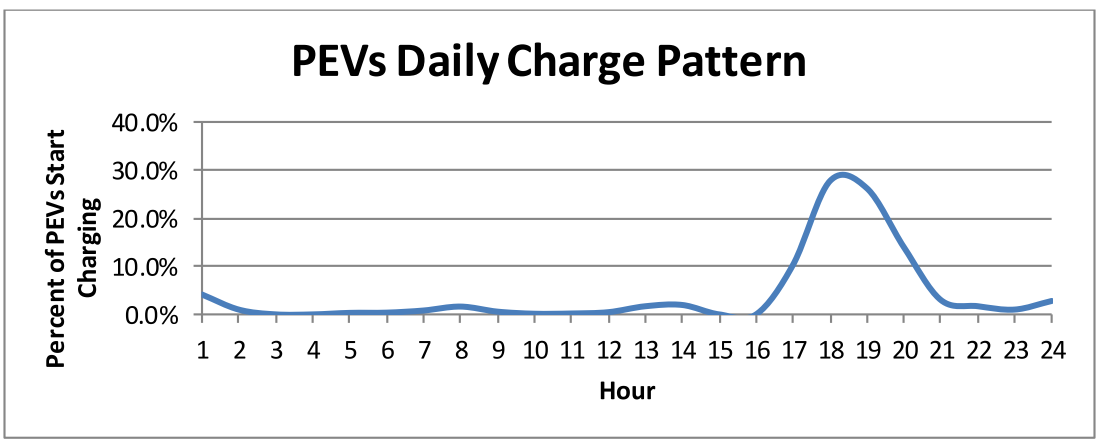
The PEVs demand and energy forecasts are developed using the historical number of PEVs in Duval County obtained from the Florida Department of Highway Safety and Motor Vehicles and the historical number of vehicles in Duval County from the U.S. Census Bureau.

JEA forecasted the number of vehicles in Duval County using multiple regression analysis of historical and forecasted Duval population, median household income and number of households from Moody's Analytics. The forecasted number of PEVs is modeled using multiple regression analysis of the number of vehicles, disposable income from Moody's Analytics, the average motor gasoline price from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO), and JEA's electric rates.

The usable battery capacity (85% of battery capacity) per vehicle was determined based on the current plug-in vehicle models in Duval County, such as Audi, BMW, General Motors' Chevrolet and Cadillac, Honda, Karma, Ford, Mercedes, Mitsubishi, Nissan, Porsche, Tesla, Toyota, Volkswagen and Volvo. The average usable battery capacity per PEV is calculated using the average usable battery capacity of each vehicle brand and then assumes the annual growth of usable battery capacity per PEV by using historical 5 years average growth of 0.01 kWh. Similarly, the peak capacity is determined based on the average on-board charging rate of each vehicle brand and the forecast peak capacity per PEV grows by 0.01 kW per year.

JEA developed the PEVs daily charge pattern based on the U.S. Census 2013 American Community Survey (ACS-13) for time of arrival to work and travel time to work for Duval County. The baseline forecast assumed that charging will be once every two days and uncontrolled; charging starts immediately upon arriving home.

Figure 4: PEVs Daily Charge Pattern



The PEVs peak demand forecast is developed using the on-board charge rate for each model, the PEVs daily charge pattern and the total number of PEVs each year. The PEVs energy forecast is developed simply by summing the hourly peak demand for each year.

JEA forecasts AAGRs for PEVs winter and summer coincidental peak demand of 21 percent and 36 percent, respectively, and total energy of 21 percent during the TYSP period.

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	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
2011	5,237	369,761	14,163	3,927	46,605	84,255	2,682	215	12,469,585
2012	4,880	372,430	13,102	3,852	47,127	81,735	2,598	218	11,908,327
2013	4,852	377,326	12,860	3,777	47,691	79,204	2,589	219	11,812,928
2014	5,162	383,998	13,443	3,882	49,364	78,642	2,564	215	11,951,824
2015	5,197	391,219	13,285	4,001	50,821	78,733	2,579	207	12,438,487
2016	5,351	398,387	13,431	4,064	51,441	78,994	2,457	202	12,159,793
2017	5,199	404,806	12,842	4,011	51,970	77,176	2,532	202	12,510,027
2018	5,460	412,070	13,251	4,042	52,525	76,954	2,524	196	12,853,285
2019	5,479	420,831	13,019	4,060	53,153	76,389	2,733	194	14,085,278
2020	5,679	429,575	13,220	3,886	53,701	72,363	2,698	196	13,759,522
2021	5,544	436,306	12,707	3,979	54,427	73,116	2,700	197	13,707,359
2022	5,622	443,443	12,677	4,004	55,142	72,606	2,701	197	13,710,731
2023	5,700	450,767	12,645	4,026	55,844	72,090	2,702	197	13,715,408
2024	5,782	458,345	12,614	4,040	56,540	71,449	2,713	197	13,771,399
2025	5,863	465,909	12,583	4,050	57,232	70,773	2,731	197	13,865,002
2026	5,936	472,860	12,553	4,061	57,921	70,114	2,753	197	13,976,684
2027	6,002	479,193	12,525	4,072	58,607	69,484	2,779	197	14,104,822
2028	6,063	485,029	12,499	4,084	59,290	68,890	2,805	197	14,240,452
2029	6,120	490,578	12,475	4,097	59,969	68,317	2,830	197	14,367,476
2030	6,175	495,940	12,452	4,109	60,644	67,755	2,855	197	14,490,825

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

Year	(11) Street & Highway Lighting	(12) Other Sales to Ultimate Customers	(13) Total Sales to Ultimate Customers	(14) Sales For Resale	(15) Utility Use & Losses	(16) Net Energy For Load	(17) Other Customers	(18) Total Number of Customers
	GWH	GWH	GWH	GWH	GWH	GWH	(Avg. Number)	
2011	123	0	11,968	589	424	12,980	2	416,583
2012	123	0	11,452	585	374	12,411	2	419,777
2013	122	0	11,340	395	550	12,286	2	425,238
2014	105	0	11,713	472	473	12,658	2	433,578
2015	87	0	11,864	392	612	12,868	2	442,249
2016	77	0	11,949	490	498	12,937	2	450,032
2017	63	0	11,805	288	578	12,672	2	456,981
2018	59	0	12,085	82	646	12,813	0	464,792
2019	57	0	12,328	58	411	12,797	0	474,178
2020	56	0	12,319	7	414	12,740	0	483,471
2021	55	0	12,279	31	498	12,808	0	490,930
2022	56	0	12,382	57	509	12,949	0	498,782
2023	57	0	12,485	57	522	13,064	0	506,808
2024	58	0	12,592	58	537	13,187	0	515,082
2025	59	0	12,703	58	553	13,315	0	523,338
2026	60	0	12,810	58	570	13,438	0	530,978
2027	61	0	12,913	59	587	13,559	0	537,997
2028	61	0	13,014	59	605	13,678	0	544,516
2029	62	0	13,109	60	622	13,791	0	550,743
2030	63	0	13,201	60	641	13,903	0	556,781

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Schedule 3.1: History and Forecast of Summer Peak Demand

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)	
Calendar Year	Total Demand	Interruptible Load	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
2011	2,681	0	0	0	0	0	0	2,681	6	18	1700	102
2012	2,542	0	0	0	0	0	0	2,542	8	11	1700	98
2013	2,523	0	0	0	0	0	0	2,523	7	25	1700	95
2014	2,572	0	0	0	0	0	0	2,572	8	14	1600	93
2015	2,609	0	0	0	0	0	0	2,609	8	22	1600	99
2016	2,688	0	0	0	0	0	0	2,688	6	17	1600	97
2017	2,608	0	0	0	0	0	0	2,608	7	7	1700	98
2018	2,483	0	0	0	0	0	0	2,483	8	16	1700	96
2019	2,571	0	0	0	0	0	0	2,571	8	14	1600	94
2020	2,585	0	0	0	0	0	0	2,585	6	29	1800	93
2021	2,697	113	0	0	0	5	3	2,576	---	---	---	----
2022	2,722	113	0	0	0	9	6	2,593	---	---	---	----
2023	2,747	113	0	0	0	14	10	2,610	---	---	---	----
2024	2,773	113	0	0	0	19	13	2,629	---	---	---	----
2025	2,798	113	0	0	0	21	15	2,650	---	---	---	----
2026	2,826	113	0	0	0	26	18	2,669	---	---	---	----
2027	2,853	113	0	0	0	30	21	2,689	---	---	---	----
2028	2,880	113	0	0	0	34	23	2,709	---	---	---	----
2029	2,906	113	0	0	0	39	26	2,728	---	---	---	----
2030	2,932	113	0	0	0	43	29	2,746	---	---	---	----

Note: All projections coincident at time of peak.

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Schedule 3.2: History and Forecast of Winter Peak Demand

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)	
Calendar Year	Total Demand	Interruptible Load	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
2011	2,983	0	0	0	0	0	0	2,983	1	14	800	23
2012	2,589	0	0	0	0	0	0	2,589	1	4	800	22
2013	2,482	0	0	0	0	0	0	2,482	2	18	800	24
2014	2,746	0	0	0	0	0	0	2,746	1	7	800	22
2015	2,785	0	0	0	0	0	0	2,785	2	20	800	24
2016	2,596	0	0	0	0	0	0	2,596	1	20	800	28
2017	2,605	0	0	0	0	0	0	2,605	1	9	800	30
2018	3,001	0	0	0	0	0	0	3,001	1	8	800	26
2019	2,398	0	0	0	0	0	0	2,398	1	31	800	34
2020	2,438	0	0	0	0	0	0	2,438	1	22	800	33
2021	2,833	100	0	0	0	4	2	2,726	---	---	---	----
2022	2,857	100	0	0	0	7	5	2,745	---	---	---	----
2023	2,882	100	0	0	0	11	7	2,764	---	---	---	----
2024	2,908	100	0	0	0	15	10	2,783	---	---	---	----
2025	2,934	100	0	0	0	19	12	2,803	---	---	---	----
2026	2,959	100	0	0	0	22	14	2,823	---	---	---	----
2027	2,884	100	0	0	0	26	17	2,842	---	---	---	----
2028	3,009	100	0	0	0	30	19	2,860	---	---	---	----
2029	3,032	100	0	0	0	33	22	2,877	---	---	---	----
2030	3,055	100	0	0	0	37	24	2,894	---	---	---	----

Note: All projections coincident at time of peak.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Calendar Year	Total Energy For Load	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Energy For Load	Load Factor
			Residential	Comm/Ind.		Residential	Comm/Ind.		
2011	12,980	0	0	0	0	0	0	12,980	50%
2012	12,411	0	0	0	0	0	0	12,411	55%
2013	12,286	0	0	0	0	0	0	12,286	57%
2014	12,658	0	0	0	0	0	0	12,658	53%
2015	12,868	0	0	0	0	0	0	12,868	53%
2016	12,937	0	0	0	0	0	0	12,937	57%
2017	12,672	0	0	0	0	0	0	12,672	56%
2018	12,813	0	0	0	0	0	0	12,813	49%
2019	12,797	0	0	0	0	0	0	12,797	61%
2020	12,740	0	0	0	0	0	0	12,740	60%
2021	12,843	0	0	0	0	17	17	12,808	52%
2022	13,018	0	0	0	0	34	35	12,949	52%
2023	13,168	0	0	0	0	52	52	13,064	52%
2024	13,325	0	0	0	0	69	70	13,187	52%
2025	13,488	0	0	0	0	86	87	13,315	52%
2026	13,646	0	0	0	0	103	104	13,438	52%
2027	13,802	0	0	0	0	120	122	13,559	53%
2028	13,955	0	0	0	0	138	139	13,678	53%
2029	14,103	0	0	0	0	155	157	13,791	53%
2030	14,249	0	0	0	0	172	174	13,903	53%

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

(1)	(2)	(3)	(2)	(3)	(4)	(5)	(6)	(7)
Month	**Actual**	**2020**	**Forecast**	**2021**	**Forecast**	**2022**	**Forecast**	**2023**
	Firm Peak Demand (MW)	Net Energy For load (GWH)	Firm Peak Demand (MW)	Net Energy For load (GWH)	Firm Peak Demand (MW)	Net Energy For load (GWH)	Firm Peak Demand (MW)	Net Energy For load (GWH)
January	2,438	973	2,726	1,076	2,745	1,095	2,764	1,101
February	2,027	881	2,398	928	2,414	944	2,431	946
March	2,076	977	1,944	929	1,957	938	1,970	946
April	2,108	906	2,061	925	2,075	940	2,088	946
May	2,286	1,050	2,325	1,071	2,341	1,083	2,355	1,094
June	2,585	1,166	2,532	1,207	2,549	1,219	2,565	1,233
July	2,527	1,309	2,534	1,315	2,551	1,329	2,567	1,340
August	2,578	1,290	2,576	1,299	2,593	1,313	2,610	1,324
September	2,487	1,165	2,438	1,142	2,454	1,154	2,469	1,166
October	2,160	1,065	2,159	1,001	2,174	1,010	2,188	1,021
November	1,817	908	1,942	924	1,955	927	1,968	938
December	2,344	1,048	2,306	991	2,322	997	2,337	1,009
Annual Peak/Total Energy	2,585	12,740	2,726	12,808	2,745	12,949	2,764	13,064

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3. Forecast of Facilities Requirements

3.1 Future Resource Needs

3.1.1 Integrated Resource Planning (IRP) Study

3.1.1.1 Prior IRP Study

JEA initiated an IRP study in the spring of 2018. This 2019 IRP was developed to study JEA's electric system over the 2020 through 2050 time period and assist JEA in determining the most cost-effective type of generation to provide firm power in the 2025 to 2030 timeframe with the potential retirement of JEA's Northside 3 due to 316(b) compliance as the primary driver for projected capacity requirements.

A scenario approach was utilized which allowed simultaneous consideration of variations to several inputs. Scenarios were developed to address uncertainties related to:

- Projected load growth (both peak demand and annual energy requirements)
- Penetration of PEVs and increased electrification
- Net metering, energy efficiency, energy conservation, and direct load control
- Future environmental regulations and clean energy standards
- Estimated capital costs for new generating units
- Projected natural gas prices
- Potential future solid-fuel unit retirements

A wide range of natural gas technologies plus solar photovoltaic (PV) technologies and battery storage were considered as potential supply-side options for evaluation. The natural gas options represent various technologies including reciprocating engines, aeroderivatives, and combustion turbines in different simple cycle and combined cycle configurations. Solar PV technologies included utility scale PV with and without battery storage, and reflected projected continuation of decreases in equipment and construction costs.

The economic evaluations performed included an initial screening of the supply-side options as well as detailed generation expansion and production cost modeling. The initial screening, performed as a levelized cost of energy analysis, was utilized to evaluate the various supply-side options and screen out options that were not economic for consideration in the generation expansion planning and subsequent production cost modeling.

Regardless of the scenario or sensitivity evaluated, the expansion plan that included retirement of Northside 3 with the addition of a new 1x1 advanced-class combined cycle was the least cost expansion plan on a cumulative present worth cost (CPWC) basis. When comparing expansion plans including continued operation of Northside 3, retirement of Northside 3, and conversion of the GEC simple cycle units to combined cycle, the CPWCs of expansion plans within each scenario and sensitivity were within approximately 1 percent to 3 percent of one another. The differentials in CPWC were smallest for expansion plans that included replacement of Northside 3 with either a new 1x1 combined cycle or conversion of one or both of the existing GEC simple cycle units to combined cycle.

Because the need for additional capacity is fueled by the potential retirement of Northside Unit 3, and to ensure the unit's safety and reliability in the near term, JEA performed condition assessments on Northside 3 at critical locations that have not identified any latent issues. JEA has plans for additional assessments scheduled for the next outage. JEA continues to develop the scope and estimate the capital investment needed for the unit to remain safe and reliable and to comply with applicable regulations, primarily 316(b).

3.1.1.2 New IRP Study

Given the age of the resource cost data from the prior 2019 IRP, it was necessary to update the IRP with current resource cost data before taking action on the previous IRP's recommendations. In addition, with some changes to the 316(b) compliance timeline and a potential shift in the expected environmental and regulatory outlook, JEA has elected to develop a new IRP to assess the best path forward relative to Northside 3 in the next ten years, as well as other units beyond that term. This IRP will not only refresh resource costs and revisit potential Northside 3 retirement, but will also explore the potential of incremental utility-scale solar to impact JEA system Area Control Error.

Since JEA has not made a definitive decision on the future of Northside 3, the unit is included as a capacity resource for the term of this Ten Year Site Plan period.

3.1.2 Capacity 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 in Table 4 reflects the addition of the PPA with MEAG for Vogtle Units 3 and 4 in 2021 and 2022, respectively, and the planned retirement of Scherer Unit 4 and the replacement with a 200 MW PPA with FPL on January 1, 2022.

Table 4a: Resource Needs after Committed Units - Summer

Summer										
Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Reserve Margin After Maintenance	
		Import	Export							
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	Percent
2021	2,969	15	0	0	2,984	2,576	408	0	408	16%
2022	2,771	315	0	0	3,086	2,593	493	0	493	19%
2023	2,771	415	0	0	3,186	2,610	576	0	576	22%
2024	2,771	415	0	0	3,186	2,629	557	0	557	21%
2025	2,771	415	0	0	3,186	2,650	537	0	537	20%
2026	2,771	415	0	0	3,186	2,669	517	0	517	19%
2027	2,771	400	0	0	3,171	2,689	482	0	482	18%
2028	2,771	400	0	0	3,171	2,709	462	0	462	17%
2029	2,771	400	0	0	3,171	2,728	444	0	444	16%
2030	2,771	400	0	0	3,171	2,746	425	0	425	15%

Note: Committed capacity additions include Vogtle Units 3 & 4 in November 2021 & 2022, respectively.

Table 4b: Resource Needs after Committed Units - Winter

Winter										
Year	Installed Capacity	Firm Capacity		QF	Available Capacity	Firm Peak Demand	Reserve Margin Before Maintenance		Reserve Margin After Maintenance	
		Import	Export							
	MW	MW	MW	MW	MW	MW	MW	Percent	MW	Percent
2020/21	3,134	15	0	0	3,149	2,726	423	15%	423	15%
2021/22	2,936	315	0	0	3,251	2,745	506	18%	506	18%
2022/23	2,936	415	0	0	3,351	2,764	587	21%	587	21%
2023/24	2,936	415	0	0	3,351	2,783	568	20%	568	20%
2024/25	2,936	415	0	0	3,351	2,803	548	20%	548	20%
2025/26	2,936	415	0	0	3,351	2,823	528	19%	528	19%
2026/27	2,936	400	0	0	3,336	2,842	494	17%	494	17%
2027/28	2,936	400	0	0	3,336	2,860	475	17%	475	17%
2028/29	2,936	400	0	0	3,336	2,877	459	16%	459	16%
2029/30	2,936	400	0	0	3,336	2,894	442	15%	442	15%

Note: Committed capacity additions include Vogtle Units 3 & 4 in November 2021 & 2022, respectively.

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 FPSC for municipalities in the consideration of need for additional generation additions.

To meet these Planning Reserve Policy requirements, JEA will acquire the needed capacity and associated energy as identified in Table 4, for those years where the reserve margin is below 15 percent. JEA's Planning Reserve Policy establishes a guideline that provides 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. Where JEA's seasonal needs are greater than 3% of firm peak demand, TEA will acquire short-term seasonal market purchases for JEA no later than the season prior to the need. 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 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, committed unit additions, existing capacity changes and annual and seasonal capacity purchase additions. All of these factors considered collectively provide JEA with sufficient capacity to cover customer demand and reserves during this ten year period. Table 5 presents the ten-year resource plan, which meets JEA's strategic goals. TYSP Schedules 5-10 provide further detail on this plan.

Table 5: Resource Plan

Year	Resource Plan
2021	MEAG Plant Vogtle 3 Purchase (100 MW) (1)
2022	FPL Purchase (200 MW)(2)
	MEAG Plant Vogtle 4 Purchase (100 MW) (1)
2023	
2024	
2025	
2026	Trail Ridge Contract Expires (-15 MW)
2027	
2028	
2029	
2030	

Notes:

(1) After accounting for transmission losses, JEA expects to receive 100 MW in November 2021 and 100 MW in November 2022 for a total of 200 MW of net firm capacity from the Vogtle units under construction.

(2) 20-year PPA with FPL starting in 2022.

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	**Type**	**Units**	**Actual** **2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
(1)	**NUCLEAR**													
		TOTAL	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**													
		TOTAL	**1000 TON**	**1,407**	**2,098**	**1,098**	**990**	**849**	**803**	**880**	**953**	**1,056**	**1,077**	**1,100**
	RESIDUAL													
(3)		STEAM	1000 BBL	2	22	29	82	42	46	51	40	22	33	29
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT/GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		**TOTAL**	**1000 BBL**	**2**	**22**	**29**	**82**	**42**	**46**	**51**	**40**	**22**	**33**	**29**
	DISTILLATE													
(7)		STEAM	1000 BBL	0.5	12.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)		CC	1000 BBL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)		CT/GT	1000 BBL	8.2	13.1	4.5	4.6	5.3	6.6	7.0	5.5	10.2	11.2	9.5
(10)		**TOTAL**	**1000 BBL**	**9**	**26**	**5**	**4.6**	**5**	**7**	**7**	**5**	**10**	**11**	**10**
	NATURAL GAS													
(12)		STEAM	1000 MCF	23,396	20,251	19,667	18,081	18,897	19,843	20,186	20,856	18,272	19,570	19,569
(13)		CC	1000 MCF	32,398	29,373	28,710	27,859	29,375	29,453	29,243	2,192	29,172	29,345	29,455
(14)		CT/GT	1000 MCF	9,317	7,755	5,764	3,531	5,808	7,882	6,464	32,451	7,749	5,991	6,313
(15)		**TOTAL**	**1000 MCF**	**65,111**	**57,379**	**54,141**	**49,471**	**54,080**	**57,177**	**55,893**	**55,499**	**55,192**	**54,906**	**55,336**
(16)	**OTHER (SPECIFY)**													
		TOTAL	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Note: Coal includes JEA's share of Scherer 4, and Northside Coal and Petroleum Coke.

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Schedule 6.1: Energy Sources (GWh)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	Type	Units	Actual 2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
(1)	Firm Inter-Region Intchg. [a]		GWH	1,344	232	2,487	3,097	3,048	2,984	3,028	3,031	2,987	3,058	3,027
(2)	NUCLEAR		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL [b]		GWH	3,020	4,853	2,977	2,659	2,268	2,130	2,345	2,557	2,833	2,903	2,986
(4)	RESIDUAL	STEAM		1.12	0	0	0	0	0	0	0	0	0	0
(5)		CC		0	0	0	0	0	0	0	0	0	0	0
(6)		CT		0	0	0	0	0	0	0	0	0	0	0
(7)		TOTAL	GWH	1	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	STEAM		0	0	0	0	0	0	0	0	0	0	0
(9)		CC		0	0	0	0	0	0	0	0	0	0	0
(10)		CT		2.41	5.20	1.80	1.80	2.00	2.60	2.80	2.10	4.10	4.60	3.90
(11)		TOTAL	GWH	2	5	2	2	2	3	3	2	4	5	4
(12)	NATURAL GAS	STEAM		2,254	2,000	1,878	1,680	1,771	1,884	1,926	2,003	1,744	1,852	1,865
(13)		CC		5,051	4,747	4,621	4,473	4,726	4,745	4,704	4,571	4,688	4,726	4,745
(14)		CT		924	760	562	344	564	765	631	727	755	585	616
(15)		TOTAL	GWH	8,229	7,508	7,061	6,496	7,061	7,394	7,261	7,300	7,187	7,163	7,227
(16)	NUG		GWH	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
(18)		LANDFILL GAS		89.95	130	130	130	130	130	130	0	0	0	0
(19)		SOLAR		54.10	81.00	292.30	679.60	678.50	673.80	671.00	668.60	667.30	662.90	659.90
(20)		TOTAL		144	211	422	810	809	804	801	669	667	663	660
(22)	OTHER (SPECIFY)		GWH	0	0	0	0	0	0	0	0	0	0	0
(23)	NET ENERGY FOR LOAD [c]		GWH	12,740	12,808	12,949	13,064	13,187	13,314	13,438	13,559	13,678	13,791	13,903

Note:

[a] Firm Inter-Regional Interchange includes Wholesale Market purchases, Nuclear PPA from MEAG starting in 2021 and 2022, and FPL PPA starting in 2022.
[b] Coal includes JEA's share of Scherer 4, and Northside Coal and Petroleum Coke.
[c] May not add due to rounding.

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Schedule 6.2: Energy Sources (Percent)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	**Type**	**Units**	**Actual 2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
(1)	**Firm Inter-Region Intchg.** [a]		%	**10.5**	**1.8**	**19.2**	**23.7**	**23.1**	**22.4**	**22.5**	**22.4**	**21.8**	**22.2**	**21.8**
(2)	**NUCLEAR**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(3)	**COAL** [b]		%	**23.7**	**37.9**	**23.0**	**20.4**	**17.2**	**16.0**	**17.5**	**18.9**	**20.7**	**21.0**	**21.5**
(4)	**RESIDUAL**	STEAM		0.01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		CC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CT		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		**TOTAL**	%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(8)	**DISTILLATE**	STEAM		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)		CC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		CT		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		**TOTAL**	%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(12)	**NATURAL GAS**	STEAM		17.7	15.6	14.5	12.9	13.4	14.1	14.3	14.8	12.8	13.4	13.4
(13)		CC		39.6	37.1	35.7	34.2	35.8	35.6	35.0	33.7	34.3	34.3	34.1
(14)		CT		7.3	5.9	4.3	2.6	4.3	5.7	4.7	5.4	5.5	4.2	4.4
(15)		**TOTAL**	%	**64.6**	**58.6**	**54.5**	**49.7**	**53.5**	**55.5**	**54.0**	**53.8**	**52.5**	**51.9**	**52.0**
(16)	**NUG**		%	**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
(18)		**LANDFILL GAS**		0.7	1.0	1.0	1.0	1.0	1.0	1.0	0.0	0.0	0.0	0.0
(19)		**SOLAR**		0.4	0.6	2.3	5.2	5.1	5.1	5.0	4.9	4.9	4.8	4.7
(20)		**TOTAL**	%	**1.1**	**1.6**	**3.3**	**6.2**	**6.1**	**6.0**	**6.0**	**4.9**	**4.9**	**4.8**	**4.7**
(22)	**OTHER (SPECIFY)**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(23)	**NET ENERGY FOR LOAD**		%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Note:

[a] Firm Inter-Regional Interchange includes Wholesale Market purchases, Nuclear PPA from MEAG starting in 2021 and 2022, and FPL PPA starting in 2022.

[b] Coal includes JEA's share of Scherer 4, and Northside Coal and Petroleum Coke.

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
2021	2,969	15	0	0	2,984	2,576	408	0	0	408	16%
2022	2,771	315	0	0	3,086	2,593	493	0	0	493	19%
2023	2,771	415	0	0	3,186	2,610	576	0	0	576	22%
2024	2,771	415	0	0	3,186	2,629	557	0	0	557	21%
2025	2,771	415	0	0	3,186	2,650	537	0	0	537	20%
2026	2,771	415	0	0	3,186	2,669	517	0	0	517	19%
2027	2,771	400	0	0	3,171	2,689	482	0	0	482	18%
2028	2,771	400	0	0	3,171	2,709	462	0	0	462	17%
2029	2,771	400	0	0	3,171	2,728	444	0	0	444	16%
2030	2,771	400	0	0	3,171	2,746	425	0	0	425	15%

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
2021	3,134	15	0	0	3,149	2,726	423	0	0	423	15%
2022	2,936	315	0	0	3,251	2,745	506	0	0	506	18%
2023	2,936	415	0	0	3,351	2,764	587	0	0	587	21%
2024	2,936	415	0	0	3,351	2,783	568	0	0	568	20%
2025	2,936	415	0	0	3,351	2,803	548	0	0	548	20%
2026	2,936	415	0	0	3,351	2,823	528	0	0	528	19%
2027	2,936	400	0	0	3,336	2,842	494	0	0	494	17%
2028	2,936	400	0	0	3,336	2,860	475	0	0	475	17%
2029	2,936	400	0	0	3,336	2,877	459	0	0	459	16%
2030	2,936	400	0	0	3,336	2,894	442	0	0	442	15%

Schedule 8: Planned and Prospective Generating Facility Additions and Changes

Planned and Prospective Generating Facility and Purchased Power 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	
NONE TO REPORT														

Schedule 9: Status Report and Specifications of Proposed Generating Facilities

(2021 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

JEA uses a diverse mix of fuels in its generating units. The fuel price projections include natural gas, coal, petroleum coke, uranium, and diesel fuel.

The fuel price projections used in this forecast were developed based on long-term price forecasts from the Annual Energy Outlook 2021 (AEO2021) issued by the EIA. The AEO2021 presents projections of energy supply, demand, and prices through 2050. AEO2021 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, cost and performance characteristics of energy technologies, and demographics.

Scherer 4 is projected to burn Powder River Basin (PRB) coal until retirement at the end of calendar year 2021. The commodity price and the transportation component for PRB coal are based on existing coal contracts through 2021. After retirement, Scherer 4 will be replaced by a PPA with FPL that will provide 200 MW of natural gas combined cycle power. The natural gas price projection was based on the 1/20/21 settle prices of short-term NYMEX natural gas strip and then escalated using the AEO2021 Henry Hub price forecast. The transportation costs are based on the PPA contract terms and the total cost is escalated by an inflation rate of 2.1% thereafter. The inflation rate of 2.1% originates from the AEO2021.

Northside Units 1 and 2 currently burn a blend of petroleum coke and coal. These units are projected to burn 60 percent petroleum coke and 40 percent coal during the forecast period. The Northside coal price projections are based on 1/20/21 settle prices of short-term NYMEX API2 Argus-McCloskey coal futures and then escalated using AEO2021 projections for Interior coal. Freight rates for waterborne delivery of Colombian coal were based on the historical average over the last five years and escalated using the AEO2021 inflation rate to project transportation costs beyond 2020. A ratio of historical delivered petroleum coke and coal prices over the past year was applied to the delivered Northside coal price projections to derive the projected petroleum coke price.

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 price projection was based on the 1/20/21 settle prices of short-term NYMEX natural gas strip and then escalated using the AEO2021 Henry Hub price forecast. The transportation costs are a combination of historical Florida city gate market costs on Florida Gas Transmission and local distribution fees.

The 1970's-vintage combustion turbine units at Northside (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, GEC GT1 and GT2, and Brandy Branch GT1. Projections for the price of diesel fuel are based on 1/20/21 settle prices of short-term NYMEX ultra-low sulfur diesel futures pricing and then escalated using AEO2021 projections for ultra-low sulfur diesel.

JEA has a PPA with MEAG for 200 MW from Vogtle Units 3 and 4 currently under construction in Georgia with planned in-service dates of 2021 and 2022. 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 2.1 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 4.50 percent. This rate is based on JEA's judgment and expectation that the long-term financial markets will return to historical stable behavior under more stable economic conditions.

4.2.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax-exempt municipal bond interest rate of 4.50 percent.

4.2.4 Interest during Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 4.50 percent.

4.2.5 Levelized Fixed Charge Rate

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

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 4.50 percent tax-exempt municipal bond interest rate, a 1.00 percent bond issuance fee, and a 0.50 percent annual property insurance cost. The resulting 20-year FCR is 8.265 percent and the 25-year FCR is 7.312 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.