225 N Pearl St.
Jacksonville, Florida 32202

April 1st, 2024

ELECTRIC

WATER

SEWER

Commission Clerk
Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Commission Clerk:

On behalf of JEA, please accept the 2024 Ten Year Site Plan Submission in accordance with Florida Statutes section 186.80.

If you have any questions, please contact me by email at landsg@jea.com.

Sincerely,

Stephany Landaeta Gutierrez
Associate Engineer
JEA

Building Community®

TEN-YEAR SITE PLAN

April 2024

Table of Contents

List of Tables and Figures

List of Schedules

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. The 2024 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 1st, 2024 to December 31st, 2033. This power supply strategy maintains a balance of reliability, environmental stewardship, and low cost to the consumers.

1. Description of Existing Facilities and Resources

1.1 Power Supply System Description

1.1.1 JEA Electric System

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 510,000 customers.

1.1.1.1 Existing Generation 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 multifuel-fired (coal/petroleum coke/natural gas/biomass) 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); five dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT7 and GT8, GEC GT1 and GT2 and Brandy Branch GT1); four diesel-fired combustion turbine-generator units (Northside GTs 3, 4, 5, and 6); and one combined cycle system that comprises of two gas-fired combustion turbine-generator units and one combined cycle heat recovery steam generator unit (Brandy Branch CT2 and CT3 and Brandy Branch steam Unit 4). Details of the existing facilities are displayed in Schedule 1.

Schedule 1: Existing Generating Facilities

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	FYI	(12)	(13)	(14)	(15)
Plant Name	Unit Number	Location	Unit Type	Fuel Type		Fuel Transport		Commercial In-Service	Expected Retirement	Gen Max Nameplate (b)	Gen Max Turbine	Net MW Capability		Ownership	Status
				Primary	Alt.	Primary	Alt.	Mo/Year	Mo/Year	kW	kW	Summer	Winter		
Kennedy										427,800	346,400	357	382		
	7	12-031	GT	NG	DFO	PL	WA	06/2000	(a)	203,800	173,200	179	191	Utility	
	8	12-031	GT	NG	DFO	PL	WA	06/2009	(a)	224,000	173,200	179	191	Utility	
Northside										1,601,856	1,407,100	1,310	1,356		
	1	12-031	ST	PC	BIT	WA		05/2003	(a)	350,000	297,500	293	293	Utility	
	2	12-031	ST	PC	BIT	WA		04/2003	(a)	350,000	297,500	293	293	Utility	
	3	12-031	ST	NG	RFO	PL	WA	07/1977	01/2030	626,300	563,700	524	524	Utility	
	33-36	12-031	GT	DFO		TK		01/1975	(a)	275,556	248,400	200	246	Utility	
Brandy Branch										946,200	745,100	758	831		
	1	12-031	GT	NG	DFO	PL	TK	05/2001	(a)	203,800	173,200	179	191	Utility	
	2	12-031	CT	NG		PL		05/2001	(a)	237,000	173,200	190	212	Utility	
	3	12-031	CT	NG		PL		10/2001	(a)	237,000	173,200	190	212	Utility	
	4	12-031	CA	WH				01/2005	(a)	268,400	225,500	200	216	Utility	
Greenland Energy Center										448,000	346,400	357	382		
	1	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	224,000	173,200	179	191	Utility	
	2	12-031	GT	NG	DFO	PL	TK	06/2011	(a)	224,000	173,200	179	191	Utility	
JEA System Total												**2,782**	**2,952**		(c)

Notes:

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

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

(c) Numbers may not add due to rounding.

1.1.2 Power Purchases

1.1.2.1 FPL Natural Gas Power Purchase Agreement

On August 25, 2020, JEA and Florida Power & Light (FPL) executed a Cooperation Agreement for the retirement of Plant Scherer Unit 4 with the firm capacity and energy to be replaced by a 20-year 200 MW power purchase agreement (PPA) between JEA and FPL for a natural gas-fired system product beginning January 1st, 2022, with a solar conversion option on or after the 10th anniversary from the PPA start date.

1.1.3 Clean Energy Power Purchases

1.1.3.1 Trail Ridge Landfill Power Purchase Agreement

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 6th, 2008.

JEA and TRE executed an amendment to this PPA on March 9th, 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. The contract for Trail Ridge Phase One and Phase Two will expire in December of 2026.

1.1.3.2 Jacksonville Solar Power Purchase Agreement

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. The Jacksonville Solar plant began commercial operation at full designed capacity on September 30th, 2010. The facility was acquired by Rev Renewables, LLC, an LS Power company, on June 15th, 2021. The contract for Jax Solar will expire in September 2040.

1.1.3.3 Small Utility-Scale Solar Power Purchase Agreements

JEA issued two Solar Photovoltaic (PV) Request for Proposals (RFP), one in December 2014 and another in April 2015, and awarded a total of 31.5 MW_{AC} 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_{AC}. The last of these seven projects was completed in December 2019.

The following are the seven PPAs that are installed within 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 30th, 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 13th, 2017.
- C2 Starratt Solar, LLC: 5 MW_{AC} / 20-year PPA. The Starratt Solar facility, on a vendor-leased site, is now owned by EDPR DR (acquired C2 Starratt Solar, LLC) and was constructed by Inman Solar, Incorporated. The site attained commercial operation on December 20th, 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 17th, 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 23rd, 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 15th, 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 4th, 2019.

1.1.3.4 FPL Solar Power Purchase Agreements

On January 24th, 2023, JEA entered into a five-year agreement with The Energy Authority (TEA) to purchase 150 MW_{AC} of electric energy and capacity resources and renewable attributes (Solar) from Florida Power & Light. The contract will expire in April of 2028.

1.1.3.5 Planned Solar Power Purchase Agreements

JEA sought bids for the development of approximately 300 MW_{AC} of solar or solar plus energy storage system on JEA-owned parcels. The solicitation, released on January 31st, 2023 and facilitated through TEA, sourced full attribute solar, or solar plus storage resource solutions formatted in multiple blocks, not to exceed 74.9 MW_{AC} each. Fifteen companies responded to the solicitation, providing an array of options. Responses were evaluated in a two-phase process, narrowing those fifteen respondents down to a shortlist of five, before award. On November 7th, 2023, JEA Board of Directors approved the award for 280 MW_{AC} of solar and energy storage system to Florida Renewable Partners (FRP). Contracts are currently in negotiation for four facilities. One 50 MW_{AC} facility, Forest Trail Solar, and two 74.9 MW_{AC} facilities, Miller Solar and Caldwell Solar, are expected to commission by December 31st, 2026. The final 74.9 MW_{AC} facility, Peterson Solar, is expected to attain commercial operation by September 30th, 2027.

JEA has also entered into a 20-year solar agreement with the Florida Municipal Power Agency (FMPA) to purchase approximately 140 MW_{AC} from two facilities located in Florida, both set to commission by December 31st, 2026.

1.1.3.6 MEAG Nuclear Power Purchase Agreement

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 located at the existing Plant Vogtle in Burke County, GA. Under this PPA, JEA is entitled to a total of 206 MW of firm capacity. After accounting for transmission losses, JEA is anticipating to receive a total of approximately 200 MW of net firm capacity from these units.

Vogtle Unit 3, commissioned on July 31st, 2023, is supplying approximately 100 MW of net firm capacity to JEA. Vogtle Unit 4, currently under construction with a projected commercial operation date of Q2 2024, is anticipated to supply approximately 100 MW of net firm capacity to JEA.

1.1.4 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 towards 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 1a: JEA Existing Power Purchase Agreement 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(1)**	07/31/2023	07/31/2043	100	Annual
	Unit 4(1)	Q2 2024	Q2 2044	100	Annual
FPL PPA		01/01/22	01/01/42	200	Annual
FPL Solar PPA		04/01/23	04/01/28	150	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

(1) After accounting for transmission losses, JEA expects to receive approximately 100 MW from Vogtle Unit 3 and 100 MW from Vogtle Unit 4.

Table 1.1b: JEA Future Solar Power Purchase Agreement Schedule

Contract	Start Date	End Date	MW_{AC}	Product Type
Forest Trail Solar PPA	December 2026	December 2061	50	Annual
Caldwell Solar PPA	December 2026	December 2061	74.9	Annual
Miller Solar PPA	December 2026	December 2061	74.9	Annual
FMPA Solar PPA	December 2026	December 2046	139.8	Annual
Peterson Solar PPA	September 2027	September 2062	74.9	Annual
Two (2) 74.9 MW Solar PPA	Q1 2028	Q1 2053	149.8	Annual
150 MW Solar PPA	Q2 2028	Q2 2053	150	Annual
Seven (7) 74.9 MW Solar PPA	Q1 2030	Q1 2055	524.3	Annual
One (1) 35 MW Solar PPA	Q1 2030	Q1 2055	35	Annual

(1) Refer to section 1.1.3.5 and section 1.3.3 for details about the planned and future solar PPAs.
(2) All dates are subjected to change upon finalization of the agreements.

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 90 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 7,408 miles of distribution circuits of which approximately 60 percent is underground.

1.3 Clean Energy

1.3.1 JEA Clean Energy Goals

On April 25th, 2023, JEA's Clean Energy Goals by 2030 were approved by the JEA Board of Directors. These goals include 35 percent of the total energy mix of the JEA Electric System to be from clean energy, the retirement of the least efficient generating units in JEA's Electric System, 80 percent carbon emissions reductions as compared to 2005 levels, JEA facilities' house load to be served with 100 percent clean energy, and the offset of electrification demand by continuing to create and promote effective energy efficiency programs.

JEA continues to investigate economic opportunities to incorporate clean energy into JEA's power supply portfolio.

1.3.2 Renewable Energy

1.3.2.1 JEA Distributed Energy

JEA has installed 35 solar PV systems, totaling 222 kW, on public high schools in Duval County, some of JEA's facilities and the Jacksonville International Airport.

1.3.2.2 Customer-Owned Distributed Energy

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 of Directors approved the consolidation of the Net Metering and DG Policies into a single, comprehensive DG Policy.
- 2018: Effective April 1st, 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 and allows existing customers the option to be grandfathered under the 2014 Net Metering Policy for a period of 20 years. JEA's residential Battery Incentive Program pilot, enacted on April 1st, 2018, provided financial incentive towards the cost of an energy storage system, subject to lawfully appropriated funds. The pilot, 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 were able to offset electricity consumption from JEA up to the limits of their storage devices. Funds allotted to each customer under the pilot is subject to review and change to optimize adoption. Since its inception until July 2022 when the pilot ended, over 700 residential storage systems have been installed.

1.3.2.3 Renewable Energy Credits (REC)

JEA acquires environmental attributes through its series of renewable PPAs and made those available to sell in order to lower rates for JEA customers. JEA had sold these environmental credits for specified periods. To maximize our clean energy efforts and meet our 2030 goals, a portion of those attributes have been inventoried. In 2023, JEA certified over 150,000 Solar RECs under the Green-e certification structure and tracked over 80,000 landfill gas RECs through the North America Renewables (NAR) registry.

1.3.2.4 SolarSmart and SolarMax

Since 2017, JEA has offered residential and small/mid-sized commercial customers the opportunity to contribute towards funding solar adoption by purchasing renewable energy through its SolarSmart program. Participants pay a premium on their electric bill for solar energy. Customers can select any percent (1% to 100%) of their energy to come from solar resources. The renewable energy is produced by six small utility-scale solar facilities inside JEA’s service territory that were installed between 2017 and 2019. JEA removes RECs from inventory on behalf of the SolarSmart customers.

In addition, SolarMax is a rate offering for JEA’s largest commercial and industrial customers with a minimum consumption of 7 million kWh. The rate was designed around JEA solar farms which are not yet operational and are currently being fulfilled via solar PPAs and associated RECs. The rate allows large business customers to choose to have up to 100 percent of their energy needs met by solar power. Companies select either a five or ten-year contract term. JEA retires the RECs in NAR on behalf of the SolarMax customers. The SolarMax rate replaces the fuel charge with a solar price. The program is currently closed to new customers as JEA continues to explore other innovative programs to offer.

1.3.2.5 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.

1.3.2.6 Biomass

In 2008, to obtain cost-effective biomass generation, JEA completed a detailed feasibility study of building stand-alone biomass units. However, the JEA self-build project would not have been eligible for the federal tax credits afforded to developers, so JEA proceeded with completing a feasibility study of co-firing biomass in Northside units 1 and 2. The co-firing of biomass in Northside 1 and 2 was found to be more cost-effective, but there were concerns with potential operational reliability issues caused by the biomass. Therefore, JEA conducted an analytical evaluation of the specific biomass fuel types to be used, and the percent of biomass co-firing that would be applied, in order to ensure reliable operation of these units could be maintained while co-firing biomass.

In 2011, JEA co-fired biomass in Northside units 1 and 2, utilizing wood chips from JEA tree trimming activities as a biomass energy source. They 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 continued use.

In 2021, JEA began co-firing up to 10 percent of biomass (approximately up to 240 Tons per Day) in Northside Unit 2 due to the high price of petcoke. In early 2022, JEA submitted a request and was granted an air construction permit with the Florida Department of Environment Protection (FDEP), to burn up to 1000 tons per day of biomass in Northside units 1 and 2. At present, the price of petroleum coke continues to be volatile, and biomass is typically co-fired when available and economically beneficial.

1.3.3 Future Utility-Scale Renewable Energy

JEA Clean Energy Goals were approved by the JEA Board of Directors, which calls for 35 percent clean energy by 2030. To achieve the goal, JEA will need a total of 1,275 MW_{AC} of solar generation by 2030. JEA has identified that it can source two 74.9 MW solar facilities on JEA-owned parcels. JEA is expected to seek bids for the two solar facilities in 2024, with anticipated commercial operation in 2028. JEA will continue to plan and identify the addition of the remaining 709 MW_{AC} of solar generation to be in-service between 2028 to 2030. For the purpose of this TYSP, JEA has considered all new solar generation as PPAs, as summarized in Table 1.1b.

1.3.4 Clean Energy Research Efforts

1.3.4.1 Collaboration with University of North Florida

JEA's clean 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 and 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.

On November 28th, 2023, JEA and UNF commemorated the grand opening of the JEA Sustainable Solutions Lab, a collaboration with UNF's College of Computing, Engineering and Construction, that allows undergraduate and graduate students to research clean energy technologies. JEA has committed to $100,000 per year, for five years, for a total contribution of $500,000. The lab will serve as a hub for research to develop sustainable solutions for JEA and a variety of industries.

1.3.4.2 Energy Storage

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

JEA welcomed the first utility-scale BESS to its grid with the addition of the SunPort Solar facility's 4 MWh battery; the storage system levels the solar PV output. The Florida Renewable Partner (FRP) projects will also host BESS alongside the 280 MW_{AC} of solar PV. As JEA continues to seek additional solar generation, JEA will be looking for opportunities to pair the new solar facilities with storage systems.

2. Forecast of Electric Power Demand and Energy Consumption

Annually, JEA develops forecasts of seasonal peak demands, 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 2024 baseline forecast used 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, total commercial employment, gross domestic product from Moody's Analytics, and commercial inventory square footage from the CBRE Market view 2023 Report.

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

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) streetlight conversion schedule. The LEDs are estimated to use 45 percent less energy than the HPS streetlights. 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 streetlight conversions with all new streetlight additions as LED only.

JEA's forecasted Average Annual Growth Rate (AAGR) net energy for load during the TYSP period is 0.82 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 AAGR for net firm peak demand during the TYSP period is 0.58 percent for summer and 0.65 percent for winter.

2.3 Demand-Side Management (DSM)

2.3.1 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 107 MW of interruptible peak load for the summer and 102 MW for the winter which remain constant throughout the study period. For 2024, the interruptible load represents 3.9 percent of the forecasted total peak demand in the summer and 3.6 percent of the forecasted total peak demand in the winter.

2.3.2 Demand-Side Management Programs

JEA continues to implement DSM programs that are economically beneficial and meet JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals. JEA's programs focus on improving the efficiency of customer end use equipment, as well as, improving the system load factor through behavioral education and technology incentives.

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		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Annual Energy	Residential	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2
	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 Peak	Residential	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
	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 Peak	Residential	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
	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 Prescriptive Program	Residential Energy Efficiency Products
Commercial Custom Program	Residential Solar Water Heating
Small Business Direct Install Program	Neighborhood Energy Efficiency Program
	Residential Energy Upgrades

2.4 Customer-Sited Renewables

A customer-sited renewables analysis on rooftop solar PV and battery storage installation was conducted by Black & Veatch Consulting group for JEA. The solar PV analysis accounted for available roof space (including pitched vs. flat roofs, other roof equipment, etc.), PV power density, hourly generation shapes, and AC/DC ratios, among other factors. These technical potential calculations were supplemented by forecasting market adoption of solar PV systems over a 30-year forecast horizon. A rigorous hourly economic analysis calculated the point at which it is cost-effective for customers to install a system as a function of $/kW, discount rates, and other costs using the extensive sensitivity analysis capabilities of the modeling software.

The battery storage analysis focused primarily on technical potential for paired solar + energy storage systems. The modeling software accounted for the complex economics of a storage technology, which can shift load to reduce energy charges (e.g., through on/off peak period arbitration) or reduce peak demand charges, by utilizing an hourly battery storage dispatch optimization module. This analysis simulates the hourly dispatch of stand-alone or solar-paired storage systems, accounting for electric rate structure, system characteristics, customer load profile, and solar PV generation profile.

2.5 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 percent of battery capacity) per vehicle was determined based on the current plug-in electric vehicle models in Duval County. 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 the historical 5-year average of 0.001 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.

The PEVs peak demand forecast is developed using the on-board charging 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 19.02 percent and 19.02 percent, respectively, and total energy of 19.0 percent during the TYSP period.

2.6 Electrification

JEA's electrification load growth assumptions align with the annual program goals for JEA's Electrification Rebates Program (ERP) through CY25 with the final year's goal projected forward to the end of the ten-year period. These goals were established for the program following a market potential study performed by ICF in June 2019. This study determined there were 803,465 MWh of existing convertible load in JEA's service territory at that time and made high/medium/low goal recommendations for the electrification program based on a prescriptive list of electrification measures for each scenario. JEA chose the medium scenario for the program which resulted in the electrification targets used for the program as well as projected load growth from electrification for the TYSP.

ERP is currently contracted through CY25 and will capture 22.5 percent of the market potential above when the contract expires. Following CY25, it is assumed that the program will be renewed resulting in continued load growth at least equal to the final contractual year of the current program. Assuming the goals are achieved, the resulting kWh of new load will be 46.8 percent of the market potential which is reasonable for a program in market for greater than 10 years.

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		
Calendar 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
2014	5,162	383,998	13,443	3,882	49,364	78,642	2,785	215	12,984,365
2015	5,197	391,219	13,285	4,001	50,821	78,733	2,806	207	13,531,924
2016	5,351	398,387	13,431	4,064	51,441	78,994	2,692	202	13,322,934
2017	5,199	404,806	12,842	4,011	51,970	77,176	2,777	202	13,717,349
2018	5,460	412,070	13,251	4,042	52,525	76,954	2,765	196	14,081,384
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	5,551	438,470	12,660	3,848	54,374	70,767	2,612	196	13,348,722
2022	5,723	447,308	12,795	4,005	55,082	72,717	2,708	199	13,641,119
2023	5,658	458,764	12,334	3,968	55,946	70,922	2,614	199	13,151,607
2024	5,738	464,202	12,360	3,976	56,705	70,115	2,702	200	13,508,157
2025	5,824	470,100	12,389	4,004	57,460	69,686	2,718	201	13,521,706
2026	5,904	476,433	12,393	4,040	58,213	69,395	2,722	201	13,542,903
2027	5,972	482,695	12,372	4,078	58,964	69,164	2,742	202	13,574,253
2028	6,032	488,640	12,345	4,118	59,711	68,958	2,748	202	13,604,039
2029	6,091	494,249	12,323	4,155	60,455	68,726	2,766	203	13,627,834
2030	6,146	499,480	12,305	4,190	61,194	68,479	2,769	203	13,641,554
2031	6,196	504,323	12,285	4,226	61,930	68,236	2,785	204	13,650,781
2032	6,240	508,813	12,264	4,262	62,662	68,021	2,785	204	13,654,261
2033	6,280	512,980	12,243	4,297	63,391	67,787	2,785	204	13,652,068

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

Calendar 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)	
2014	105	0	11,934	472	252	12,658	2	433,578
2015	87	0	12,091	392	385	12,868	2	442,249
2016	77	0	12,184	490	263	12,937	2	450,033
2017	63	0	12,050	288	334	12,672	2	456,981
2018	59	0	12,326	82	405	12,813	1	464,793
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	12,066	25	449	12,540	0	493,039
2022	55	0	12,491	30	408	12,930	0	502,588
2023	55	0	12,295	63	376	12,733	0	514,909
2024	55	0	12,470	0	429	12,899	0	521,107
2025	56	0	12,602	0	434	13,036	0	527,761
2026	57	0	12,723	0	438	13,161	0	534,848
2027	57	0	12,849	0	442	13,291	0	541,861
2028	58	0	12,956	0	446	13,401	0	548,554
2029	58	0	13,070	0	450	13,520	0	554,907
2030	59	0	13,165	0	453	13,618	0	560,878
2031	59	0	13,266	0	456	13,722	0	566,458
2032	60	0	13,348	0	459	13,807	0	571,679
2033	60	0	13,423	0	462	13,885	0	576,574

Schedule 3.1: History and Forecast of Summer Peak Demand

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Calendar Year	Total Net Demand (MW)	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Firm Peak Demand (MW)
			Residential	Comm/Ind.		Residential	Comm/Ind.	
2014	2,591	0	0	0	0	0	0	2,591
2015	2,618	0	0	0	0	0	0	2,618
2016	2,689	0	0	0	0	0	0	2,689
2017	2,631	0	0	0	0	0	0	2,631
2018	2,495	0	0	0	0	0	0	2,495
2019	2,591	0	0	0	0	0	0	2,591
2020	2,582	0	0	0	0	0	0	2,582
2021	2,511	0	0	0	0	0	0	2,511
2022	2,728	0	0	0	0	0	0	2,728
2023	2,756	0	0	0	0	0	0	2,756
2024	2,713	107	0	0	0	3	3	2,600
2025	2,742	107	0	0	0	6	5	2,624
2026	2,768	107	0	0	0	13	9	2,639
2027	2,794	107	0	0	0	17	11	2,659
2028	2,817	107	0	0	0	20	13	2,677
2029	2,840	107	0	0	0	23	16	2,694
2030	2,858	107	0	0	0	23	16	2,712
2031	2,879	107	0	0	0	25	17	2,730
2032	2,895	107	0	0	0	37	26	2,725
2033	2,910	107	0	0	0	38	26	2,739

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)
Calendar Year	Total Net Demand (MW)	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Firm Peak Demand (MW)
			Residential	Comm/Ind.		Residential	Comm/Ind.	
2013/14	2,754	0	0	0	0	0	0	2,754
2014/15	2,791	0	0	0	0	0	0	2,791
2015/16	2,600	0	0	0	0	0	0	2,600
2016/17	2,433	0	0	0	0	0	0	2,433
2017/18	3,011	0	0	0	0	0	0	3,011
2018/19	2,410	0	0	0	0	0	0	2,410
2019/20	2,445	0	0	0	0	0	0	2,445
2020/21	2,532	0	0	0	0	0	0	2,532
2021/22	2,529	0	0	0	0	0	0	2,529
2022/23	2,599	0	0	0	0	0	0	2,599
2023/24	2,853	102	0	0	0	2	2	2,747
2024/25	2,883	102	0	0	0	4	3	2,774
2025/26	2,908	102	0	0	0	5	4	2,797
2026/27	2,935	102	0	0	0	8	5	2,820
2027/28	2,957	102	0	0	0	12	8	2,835
2028/29	2,981	102	0	0	0	17	11	2,851
2029/30	3,000	102	0	0	0	19	12	2,867
2030/31	3,021	102	0	0	0	19	12	2,888
2031/32	3,038	102	0	0	0	18	12	2,906
2032/33	3,054	102	0	0	0	24	16	2,912

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)
Calendar Year	Total Energy for Load (GWH)	Interruptible Load	Load Management		QF Load Served by QF Generation	Cumulative Conservation		Net Energy for Load (GWH)
			Residential	Comm/Ind.		Residential	Comm/Ind.	
2014	12,658	0	0	0	0	0	0	12,658
2015	12,868	0	0	0	0	0	0	12,868
2016	12,937	0	0	0	0	0	0	12,937
2017	12,672	0	0	0	0	0	0	12,672
2018	12,813	0	0	0	0	0	0	12,813
2019	12,797	0	0	0	0	0	0	12,797
2020	12,740	0	0	0	0	0	0	12,740
2021	12,540	0	0	0	0	0	0	12,540
2022	12,930	0	0	0	0	0	0	12,930
2023	12,733	0	0	0	0	0	0	12,733
2024	12,933	0	0	0	0	17	17	12,899
2025	13,104	0	0	0	0	34	34	13,036
2026	13,263	0	0	0	0	51	51	13,161
2027	13,427	0	0	0	0	68	68	13,291
2028	13,571	0	0	0	0	85	85	13,401
2029	13,724	0	0	0	0	102	102	13,520
2030	13,856	0	0	0	0	119	119	13,618
2031	13,994	0	0	0	0	136	136	13,722
2032	14,113	0	0	0	0	153	153	13,807
2033	14,225	0	0	0	0	170	170	13,885

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	**Actual 2023**		**Forecast 2024**		**Forecast 2025**		**Forecast 2026**	
	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	2,326	977	2,747	1,043	2,774	1,054	2,797	1,065
February	1,813	844	2,422	906	2,448	916	2,470	925
March	2,049	948	1,963	953	1,984	964	2,002	973
April	2,080	963	2,080	931	2,102	941	2,123	951
May	2,230	1,064	2,346	1,087	2,372	1,098	2,395	1,109
June	2,598	1,168	2,555	1,218	2,583	1,231	2,608	1,242
July	2,699	1,353	2,563	1,317	2,591	1,330	2,617	1,342
August	2,756	1,418	2,600	1,300	2,624	1,312	2,639	1,324
September	2,461	1,149	2,460	1,167	2,486	1,179	2,511	1,190
October	2,057	993	2,180	1,044	2,204	1,055	2,224	1,065
November	2,043	887	1,961	939	1,983	949	2,000	959
December	2,016	969	2,329	995	2,354	1,006	2,375	1,016
Annual Peak/ Total Energy	2,756	12,733	2,747	12,899	2,774	13,036	2,797	13,161

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	**Type**	**Units**	**Actual 2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
(1)	**NUCLEAR**													
		TOTAL	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL[(a)]**													
		TOTAL	**1000 TON**	**515**	**220**	**430**	**489**	**534**	**422**	**389**	**92**	**69**	**46**	**142**
	RESIDUAL													
(3)		STEAM	1000 BBL	20	0	0	0	0	0	0	0	0	0	0
(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**	**20**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	DISTILLATE													
(7)		STEAM	1000 BBL	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
(9)		CT/GT	1000 BBL	9	78	32	46	22	27	33	22	21	22	20
(10)		**TOTAL**	**1000 BBL**	**9**	**78**	**32**	**46**	**22**	**27**	**33**	**22**	**21**	**22**	**20**
	NATURAL GAS													
(12)		STEAM	1000 MCF	20,647	20,199	19,132	18,097	14,593	12,116	12,850	36	48	24	72
(13)		CC	1000 MCF	27,446	30,181	30,221	29,878	27,749	30,673	30,811	46,793	47,948	47,957	47,363
(14)		CT/GT	1000 MCF	12,429	19,435	12,831	14,104	13,994	11,699	11,777	6,824	6,743	7,022	6,876
(15)		**TOTAL**	**1000 MCF**	**60,522**	**69,815**	**62,184**	**62,079**	**56,335**	**54,488**	**55,438**	**53,654**	**54,739**	**55,003**	**54,311**
(17)	**OTHER (BIOMASS)**													
		TOTAL	**TRILLION BTU**	**45**	**88**	**172**	**195**	**213**	**168**	**155**	**37**	**28**	**18**	**57**

Notes:
(a) Coal includes Northside Coal and Petroleum Coke.

Schedule 6.1: Energy Sources (GWh)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	**Type**	**Units**	**Actual 2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
(1)	**Firm Inter-Region Interchange**		GWH	**3,385**	**1,434**	**1,332**	**1,354**	**1,483**	**1,352**	**1,397**	**489**	**474**	**484**	**484**
(2)	**Firm Inter-Region Intchg. - Nuclear**		GWH	**378**	**1,272**	**1,634**	**1,594**	**1,603**	**1,613**	**1,706**	**1,578**	**1,597**	**1,709**	**1,596**
(3)	**NUCLEAR**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(4)	**COAL[(a)]**		GWH	**1,231**	**630**	**1,216**	**1,378**	**1,527**	**1,196**	**1,104**	**254**	**189**	**129**	**397**
(5)	**RESIDUAL**	STEAM	GWH	11	0	0	0	0	0	0	0	0	0	0
(6)		CC		0	0	0	0	0	0	0	0	0	0	0
(7)		CT		0	0	0	0	0	0	0	0	0	0	0
(8)		**TOTAL**		**11**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(9)	**DISTILLATE**	STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0
(10)		CC		0	0	0	0	0	0	0	0	0	0	0
(11)		CT		3	26	9	15	5	7	10	6	5	5	5
(12)		**TOTAL**		**3**	**26**	**9**	**15**	**5**	**7**	**10**	**6**	**5**	**5**	**5**
(13)	**NATURAL GAS**	STEAM	GWH	1,903	2,055	1,920	1,811	1,426	1,159	1,229	0	0	0	0
(14)		CC		4,147	4,887	4,890	4,834	4,494	4,961	4,987	7,421	7,608	7,610	7,518
(15)		CT		1,219	1,909	1,233	1,347	1,380	1,135	1,147	668	661	683	674
(16)		**TOTAL**		**7,268**	**8,851**	**8,043**	**7,992**	**7,300**	**7,254**	**7,362**	**8,088**	**8,269**	**8,293**	**8,192**
(17)	**NUG**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(18)	**RENEWABLES**	LANDFILL GAS	GWH	53	128	129	129	0	0	0	0	0	0	0
(19)		SOLAR PPA		335	432	449	449	1,096	1,759	1,735	3,138	3,134	3,142	3,122
(20)		SOLARSMART/ SOLARMAX[(b)]		24	24	24	24	24	24	24	24	24	24	24
(22)		**TOTAL**		**412**	**584**	**601**	**601**	**1,120**	**1,782**	**1,759**	**3,161**	**3,158**	**3,166**	**3,146**
(23)	**OTHER (BIOMASS)**		GWH	**46**	**104**	**200**	**227**	**252**	**197**	**182**	**42**	**31**	**21**	**65**
(24)	**NET ENERGY FOR LOAD[(c)]**		GWH	**12,733**	**12,899**	**13,036**	**13,161**	**13,291**	**13,401**	**13,520**	**13,618**	**13,722**	**13,807**	**13,885**

Notes:

(a) Coal includes Northside Coal and Petroleum Coke.
(b) Energy from Solar PPAs supplied to SolarSmart and SolarMax participants. JEA retires the Renewable Energy Credits on behalf of the SolarSmart and SolarMax participants.
(c) 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)
	Fuel	**Type**	**Units**	**Actual 2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
(1)	**Inter-Region Interchange**		%	**26.6**	**11.1**	**10.2**	**10.3**	**11.2**	**10.1**	**10.3**	**3.6**	**3.5**	**3.5**	**3.5**
(2)	**Firm Inter-Region Intchg. - Nuclear**		%	**3.0**	**9.9**	**12.5**	**12.1**	**12.1**	**12.0**	**12.6**	**11.6**	**11.6**	**12.4**	**11.5**
(3)	**NUCLEAR**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(4)	**COAL**[(a)]		%	**9.7**	**4.9**	**9.3**	**10.5**	**11.5**	**8.9**	**8.2**	**1.9**	**1.4**	**0.9**	**2.9**
(5)	**RESIDUAL**	STEAM	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		CT		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)		**TOTAL**		**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(9)	**DISTILLATE**	STEAM	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		CC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CT		0.0	0.2	0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.0
(12)		**TOTAL**		**0.0**	**0.2**	**0.1**	**0.1**	**0.0**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**
(13)	**NATURAL GAS**	STEAM	%	14.9	15.9	14.7	13.8	10.7	8.6	9.1	0.0	0.0	0.0	0.0
(14)		CC		32.6	37.9	37.5	36.7	33.8	37.0	36.9	54.5	55.4	55.1	54.1
(15)		CT		9.6	14.8	9.5	10.2	10.4	8.5	8.5	4.9	4.8	4.9	4.9
(16)		**TOTAL**		**57.1**	**68.6**	**61.7**	**60.7**	**54.9**	**54.1**	**54.5**	**59.4**	**60.3**	**60.1**	**59.0**
(17)	**NUG**		%	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(18)	**RENEWABLES**	LANDFILL GAS	%	0.4	1.0	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(19)		SOLAR PPA		2.6	3.3	3.4	3.4	8.2	13.1	12.8	23.0	22.8	22.8	22.5
(20)		SOLARSMART/ SOLARMAX[(b)]		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(22)		**TOTAL**		**3.2**	**4.5**	**4.6**	**4.6**	**8.4**	**13.3**	**13.0**	**23.2**	**23.0**	**22.9**	**22.7**
(23)	**OTHER (BIOMASS)**		%	**0.4**	**0.8**	**1.5**	**1.7**	**1.9**	**1.5**	**1.3**	**0.3**	**0.2**	**0.2**	**0.5**
(24)	**NET ENERGY FOR LOAD**		%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Notes:
(a) Coal includes Northside Coal and Petroleum Coke.
(b) Energy from Solar PPAs supplied to SolarSmart and SolarMax participants. JEA retires the Renewable Energy Credits on behalf of the SolarSmart and SolarMax participants.

3. Forecast of Facilities Requirements

3.1 Future Resource Needs

JEA's system capacity is planned with a targeted 15 percent generation reserve margin above forecasted firm customers coincident one-hour peak demand, for both winter and summer seasons. The reserve margin has been used by the FPSC for municipalities in the consideration of need for additional generation resources.

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.

3.1.1 Integrated Resource Planning Study

JEA completed an Integrated Resource Plan (IRP) at the end of May 2023. The IRP was developed using a multi-scenario and sensitivity approach, which allowed for evaluations of new resource options under different potential futures. The primary variables and considerations that defined these different potential futures included the following:

- Environmental Legislative and Regulatory Action
  - Cost for emissions of CO_2
  - Specific goals or targets for percentages of energy from sources that do not emit carbon dioxide (CO_2)
  - Retirement of solid fuel and/or natural gas-fired generation
  - 316(b) regulations
- Load Growth Forecasts
  - Energy
  - Peak demand
  - Demand-side management and energy efficiency
  - Plug-in electric vehicles
  - Electrification
  - Customer-sited renewables
- Fuel Costs
- Cost of New Generation
- Continued Operation of Existing Generating Units
- Other Considerations
  - Affordability
  - Reliability
  - Environmental
  - Economic development
  - CO_2 emissions reductions

The resource expansion plan included in this TYSP is representative of what is presently indicated by the IRP and consists of the most common/frequent near-term resource additions identified across multiple scenarios and sensitivities within the IRP study. It should be noted that all aspects of the resource expansion plan presented in this TYSP, i.e., schedule and content, are subject to change. JEA will continue to evaluate its resource plan and new resource additions as part of its ongoing resource planning activities.

The IRP was developed reflecting consideration of JEA's existing 524 MW Northside Unit 3 being removed from service in 2030. Removal of this unit from service is influenced by multiple factors, including the need for capital upgrades to remain reliable and as a means of compliance with potential 316(b) surface water withdrawal regulations.

The IRP results consistently identified a 1x1 advanced-class combined cycle combustion turbine (CCCT) configuration in the 2030 timeframe as part of the least-cost resource plan across the majority of scenarios and sensitivities. Modeling results show that the retirement and replacement of JEA's Northside Unit 3 with an efficient, advanced-class CCCT provides JEA with a new cost-effective resource. This new resource will provide reliable dispatchable power, allow for more efficient use of natural gas, reduces system CO_2, NO_x and SO_2 emissions, provides support to reliably integrate more renewable energy into the JEA system and will also avoid costly upgrades that would otherwise be necessary to extend the life of the 46-year-old unit. It should be noted that in order to maintain reliable operation of JEA's system, Northside Unit 3 unit cannot be retired until a replacement unit has achieved commercial operation. Due to permitting requirements associated with the Florida Power Plant Siting Act (PPSA), specifically Determination of Need and Site Certification (environmental permitting) for a CCCT, Northside Unit 3 may need to continue to operate until the earliest commercial operation date of a new CCCT resource, which is estimated to be in the 2030 timeframe. Development considerations, such as permitting delays, supply chain difficulties, or construction delays, could impact the earliest commercial operation date.

The results from the IRP also helped identify that a total of 1,275 MW_{AC} of Solar PV will enable JEA to achieve part of its Clean Energy Goals by 2030. JEA is currently in negotiation for a total of approximately 415 MW_{AC} of solar PPAs. The details on these solar PPAs can be found in section 1.1.3.5. JEA will continue to seek for additions of solar PV and perform studies to determine potential reliability considerations for the JEA system associated with the integration of 1,275 MW_{AC} of solar.

3.1.2 JEA Planning Reserve Policy

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 the forecasted firm peak demand in any season from purchases acquired in the operating horizon. If up to 3 percent of firm peak demand in any season is needed, The Energy Authority (TEA), JEA's affiliated energy market services company, 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.

No short-term seasonal market purchases are required in this TYSP period.

3.2 Resource Plan

To develop the resource plan outlined in this TYSP submittal, JEA included a review of existing electric supply resources, forecast of customer energy requirements and peak demand, forecast 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 4 presents the ten-year resource addition plan, which meets JEA's strategic goals. TYSP Schedules 7-10 provide further detail of this plan.

Table 4: Resource Plan

Year	Resource Plan
2024	MEAG Plant Vogtle 4 Purchase (100 MW) (2)
2025	
2026	Trail Ridge Contract **Expires** (-15 MW) (3) Forest Trail Solar PPA (50 MW_{AC}) (4) Caldwell Solar PPA (~75 MW_{AC}) (4) Miller Solar PPA (~75 MW_{AC}) (4) FMPA Solar PPAs (~140 MW_{AC}) (4)
2027	Peterson Solar PPA (~75 MW_{AC}) (4)
2028	Two (2) 74.9 MW_{AC} Solar PPAs (~150 MW_{AC}) (5) FPL Solar PPA **Expires** (-150 MW) Future Solar PPA (150 MW) (5)
2029	
2030	Future Solar PPAs (~560 MW_{AC}) (5) Northside 3 **Retires** (-524 MW) (6) 1x1 CCCT (669.8 MW) (6)
2031	
2032	
2033	

Notes:

(1) All dates are subjected to change.

(2) After accounting for transmission losses, JEA expects to receive approximately 100 MW from Vogtle Unit 4. Vogtle Unit 4 in-service date is expected to be Q2 2024.

(3) Trail Ridge contract ends December 31, 2026.

(4) Please refer to section 1.1.3.5 for details about the Planned Solar PPAs.

(5) Please refer to section 1.3.3 for details about Future Solar PPAs.

(6) Please refer to section 3.1.1 for more details.

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
2024	2,782	514	0	0	3,296	2,600	695	27%	0	695	27%
2025	2,782	517	0	0	3,299	2,624	675	26%	0	675	26%
2026	2,782	516	0	0	3,298	2,639	659	25%	0	659	25%
2027	2,782	568	0	0	3,350	2,659	692	26%	0	692	26%
2028	2,782	550	0	0	3,332	2,677	656	24%	0	656	24%
2029	2,782	550	0	0	3,332	2,694	638	24%	0	638	24%
2030	2,834	661	0	0	3,495	2,712	783	29%	0	783	29%
2031	2,834	661	0	0	3,495	2,730	765	28%	0	765	28%
2032	2,834	659	0	0	3,493	2,725	768	28%	0	768	28%
2033	2,834	658	0	0	3,492	2,739	753	27%	0	753	27%

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
2023/24	2,952	315	0	0	3,267	2,747	520	19%	0	520	19%
2024/25	2,952	415	0	0	3,367	2,774	593	21%	0	593	21%
2025/26	2,952	415	0	0	3,367	2,797	570	20%	0	570	20%
2026/27	2,952	400	0	0	3,352	2,820	532	19%	0	532	19%
2027/28	2,952	400	0	0	3,352	2,835	517	18%	0	517	18%
2028/29	2,952	400	0	0	3,352	2,851	501	18%	0	501	18%
2029/30	2,952	400	0	0	3,352	2,867	485	17%	0	485	17%
2030/31	3,098	400	0	0	3,498	2,888	610	21%	0	610	21%
2031/32	3,098	400	0	0	3,498	2,906	591	20%	0	591	20%
2032/33	3,098	400	0	0	3,498	2,912	586	20%	0	586	20%

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				kW	Summer MW	Winter MW	
Northside	Unit 3	12-031	ST	NG	RFO	PL	WA	N/A	Jul-77	Jan-30	626,300	-524	-524	RT
Advanced-Class 1x1 CC	TBD	Jacksonville, FL	CCCT	NG	DFO	PL	TK/WA	Apr-27	Jan-30	Unknown	TBD	576	669.8	P

Schedule 9: Status Report and Specifications of Proposed Generating Facilities

1	**Plant Name and Unit Number:**	Advanced-Class 1x1 CC
2	**Capacity:**	
3	Summer MW:	576
4	Winter MW:	669.8
5	**Technology Type:**	CCCT
6	**Anticipated Construction Timing:**	
7	Field Construction Start-date:	Apr-27
8	Commercial In-Service date:	Jan-30
9	**Fuel:**	
10	Primary:	NG
11	Alternate:	DFO
12	**Air Pollution Control Strategy:**	As required by new source Performance Standards
13	**Cooling Method:**	Wet mechanical draft cooling tower
14	**Total Site Area:**	Block approximately 30 acres
15	**Construction Status:**	Not started
16	**Certification Status:**	Not started
17	**Status with Federal Agencies:**	Permitting not started
18	**Projected Unit Performance Data:**	
19	Planned Outage Factor (POF):	6%
20	Forced Outage Factor (FOF):	3%
21	Equivalent Availability Factor (EAF):	91%
22	Resulting Capacity Factor (%):	50%
23	Average Net Operating Heat Rate (ANOHR):	6,702 Btu/kWh
24	**Projected Unit Financial Data:**	
25	Book Life:	25 years
26	Total Installed Cost (In-Service year $/kW)(1):	1,220 $/kW All-in
27	Direct Construction Cost ($/kW):	Included above
28	AFUDC Amount ($/kW):	IDC included above
29	Escalation ($/kW):	Included above
30	Fixed O&M (2023 $/kW-yr)(1):	7.33
31	Variable O&M ($/MWh):	2.68

Note:
(1) Total installed cost and fixed O&M are based on winter capacity.

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 projections used in this forecast were developed based on long-term price forecasts from the Annual Energy Outlook 2023 (AEO2023 issued by the EIA). A new Annual Energy Outlook will not be available in 2024 because the EIA's model requires substantial updates to better model hydrogen, carbon capture, and other emerging technologies. The AEO2023 presents projections of energy supply, demand, and prices through 2050. AEO2023 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.

On January 1st, 2022, JEA began receiving energy from FPL through a PPA that provides 200 MW of natural gas combined cycle power. The natural gas price projection was based on a six-month average of NYMEX natural gas futures over the short-term and then escalated using the AEO2023 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 3 percent thereafter.

Northside Units 1 and 2 burn a blend of petroleum coke, coal, biomass, and natural gas. The blends of these four fuel types vary during the forecast period based on the projected costs of the fuels and other constraints. The Northside coal price projections are based on a six-month average of NYMEX API2 Argus-McCloskey coal futures over the short-term and then escalated using AEO2023 projections for Interior coal. Freight rates for waterborne delivery of Colombian coal were based on the historical average over the last three years and escalated using a 3 percent inflation rate to project transportation costs beyond 2024. A ratio of historical delivered petroleum coke and coal prices over the past ten years 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 a six-month average of NYMEX natural gas futures over the short-term and then escalated using the AEO2023 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 a six-month average of NYMEX ultra-low sulfur diesel futures pricing over the short-term and then escalated using AEO2023 projections for ultra-low sulfur diesel.

JEA has a PPA with MEAG for 200 MW from Vogtle Units 3 and 4. Unit 3 commenced service in July 2023 and Unit 4 is currently under construction with in-service expected in 2024. 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 non-fuel variable O&M escalation rate are each assumed to be 3.00 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 4.00 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 4.00 percent.

4.2.4 Interest during Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 4.00 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 4.00 percent tax-exempt municipal bond interest rate, a 1.00 percent bond issuance fee, and a 0.57 percent annual property insurance cost. The resulting 20-year FCR is 8.00 percent and the 25-year FCR is 7.00 percent.

5. Environmental and Land Use Information

JEA has identified a potential JEA-owned site to build a 1x1 advanced-class CCCT. The site is currently being evaluated. Further updates will be presented in subsequent TYSPs as the site evaluation process is finalized.