STEARNS WEAVER MILLER
WEISSLER ALHADEFF & SITTERSON, P.A.

Brooke Humphrey
106 East College Avenue, Suite 700
Tallahassee, FL 32301
Direct: (850) 329-4871
Email: bhumphrey@stearnsweaver.com

July 27, 2026

VIA ELECTRONIC FILING

Adam Teitzman, Director
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399

Re: Petition of JEA for Determination of Need for St. Johns River Power Park Unit 3 for JEA Combined Cycle Generating Unit; Docket No. 2026-0087-EM

Dear. Mr. Teitzman:

Enclosed for filing is a revised version of pre-filed Exhibit JB-2 (JEA's Need Study) reflecting the revisions made to same via the Errata Sheet of Jody B. Brooks filed July 17, 2026.

If you have any questions concerning the filing, please contact me at (850) 829-4871.

Thank you for your assistance with this matter.

Very truly yours,

Stearns Weaver Miller
Weissler Alhadeff & Sitterson, P.A.

By: *<u>/s/ Brooke E. Humphrey</u>*
Counsel for JEA

BEH/rje
Enclosures
cc: Alisha Hixon, PSC
Shaw Stiller, PSC

JEA NEED STUDY

Need for the SJRPP Unit 3

BLACK & VEATCH PROJECT NO. 410163

PREPARED FOR

JEA

22 JULY 2026

BLACK & VEATCH

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1.0 Executive Summary

JEA submits this Need Study in support of a proposed 678 MW (winter net rating) advanced class one-on-one (1x1) natural gas-fired, combined cycle electric generating unit to be constructed at JEA's existing St. John's River Power Park site and to be known as St. John's River Power Park Unit 3 (SJRPP Unit 3 or Project). The analyses discussed throughout this Need Study demonstrate that the Project is the most cost-effective, system-beneficial alternative to meet JEA's capacity needs in the 2031 timeframe and beyond.

1.1 The Primarily Affected Utility

JEA is a municipal electric utility under section 366.02, Florida Statutes, with an approximately 905 square mile electric service area. JEA provides electricity for approximately 537,000 customers in the City of Jacksonville and portions of Clay and St. Johns Counties, making it the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA is governed by a Board of Directors consisting of four members appointed by the City Council and three members appointed by the Mayor of the City of Jacksonville, all of whom are approved by the City Council.

1.2 The Power Plant Siting Act and Need Determination Process

The Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes, provides a "centrally coordinated, one-stop licensing process" for power plant projects. The PPSA provides a centralized process to ensure that all affected state and local agencies review a project before the Siting Board, consisting of the Governor and Cabinet, or the Florida Department of Environmental Protection (FDEP) in cases where all parties stipulate there are no disputed issues of law or fact, takes final action on the site certification application. The Commission's need determination is a critical step in the PPSA certification process. Along with the reports submitted by FDEP and other agencies, the Commission's need determination allows the Siting Board or FDEP Secretary to balance "the increasing demand for electrical power plant location and operation with the broad interests of the public." § 403.502, Fla. Stat. Section 403.519(3), Florida Statutes, sets forth the following criteria which the Commission must consider in making need determinations:

- The need for electric system reliability and integrity;
- The need for adequate electricity at a reasonable cost;
- The need for fuel diversity and supply reliability;
- Whether the proposed plant is the most cost-effective alternative available;
- Whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available; and
- Whether there are conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant.

1.3 The Proposed New Facilities

JEA has determined that the most cost-effective and system-beneficial way to meet its capacity needs is the construction of a 678 MW (winter net rating) dual-fuel, advanced class 1x1 combined cycle unit at its existing SJRPP site. The Project will be located on an approximately 194-acre site that was part of the larger approximately 1,600-acre parcel upon which JEA owned and operated SJRPP Units 1 & 2—two 612 MW coal-fired steam electric generating units certified under the PPSA in 1982. SJRPP Units 1 & 2 were decommissioned and demolished in 2018 and 2019; although some facilities, including a substation, byproduct storage areas, and electrical transmission lines remain certified under the PPSA.

The Project will be primarily natural gas-fired, but capable of operating on ultra-low sulfur diesel (ULSD) as a back-up in the event natural gas is unavailable or uneconomic for JEA's customers, and will also be capable of operating on up to 50 percent hydrogen if available in the future. Location of SJRPP Unit 3 on the SJRPP property will allow utilization of existing infrastructure, including the existing substation, existing 230 kV electrical transmission lines, existing reclaimed water lines, existing water discharge pipelines, and an existing discharge structure. Natural gas will be delivered via pipeline to be permitted, constructed, owned, operated, and maintained by Peoples Gas System (PGS). SJRPP Unit 3 will primarily utilize reclaimed water from JEA's nearby District II Water Reclamation Facility (WRF) for cooling.

1.4 JEA's Need for Generation Capacity

Based on an evaluation of its resource portfolio against its load forecast and reliability criteria, JEA projects a need for 72 MW in the winter of 2031, increasing to 222 MW in 2033 and 802 MW in 2035. The need is primarily driven by increased demand during the summer and winter peaks, along with significant load growth in the residential and industrial sectors. JEA anticipates placing its existing less efficient Northside Generating Station (Northside or NGS) Unit 3 in limited use, operating at or below 8% capacity factor, as a back-up for peak demand periods, emergencies, and unexpected outages coincident with commercial operation of SJRPP Unit 3; JEA currently anticipates retiring NGS Unit 3 in 2035.

1.5 Generating Alternatives

JEA's Board selected moving forward with construction and operation of SJRPP Unit 3 based on the results of a multi-stage resource planning process. That process considered various generating resource options, including multiple configurations of solar photovoltaic (PV) and energy storage options, numerous different natural gas options (including a range of sizes, types, simple and combined cycle configurations, and the conversion of existing simple cycle units to combined cycle configuration), biomass technologies, and nuclear. JEA also considered multiple power purchase alternatives identified during a robust Request for Proposal (RFP) process that was overseen by an independent evaluator, as well as careful consideration of economic and non-economic attributes and risk factors. JEA's analyses demonstrate that SJRPP Unit 3 is the most cost-effective and system-beneficial alternative to meet JEA's capacity needs. SJRPP Unit 3, becoming operational in 2031, would result in projected cumulative present worth cost (CPWC) savings of approximately $92 million to JEA's customers compared to the next most economical plan and the lowest long-term cost per MWh. It is important to note that even the next lowest cost resource plan would include a 1x1 advanced class combined cycle (similar to SJRPP Unit 3) in 2035. SJRPP Unit 3 will also increase operational flexibility, grid reliability, and fuel diversity while decreasing per MWh natural gas consumption and system carbon dioxide (CO_2) emissions. Finally, SJRPP Unit 3 will have the significant benefit of providing JEA with full control over dispatch and operations, enabling JEA to adapt to changing demand, ensure economic efficiency, and optimize resources in the face of sustained load growth.

1.6 Non-Generating Alternatives

JEA is subject to the Florida Energy Efficiency and Conservation Act (FEECA), section 366.82, Florida Statutes, which requires the Commission to adopt and periodically review goals to increase the efficiency of energy consumption, increase the development of demand side renewable energy systems, reduce and control the growth rate of electric consumption and weather sensitive peak demand, and encourage the development of demand side management (DSM) goals. The Florida Public Service Commission (Commission) established JEA's current DSM goals in 2024 based on the detailed analysis of DSM potential and economic analysis.[1] JEA's annual combined residential and commercial/industrial DSM goals for the 2025 to 2034 timeframe are less than 3 MW. The Commission found that these goals were "based on an adequate assessment of the full technical potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems."[2] JEA recently updated the analysis of DSM potential to confirm that cost-effective, reasonably available conservation measures would not mitigate the need for SJRPP Unit 3.

1.7 Adverse Consequences of Denial

Non-approval of the requested need determination would deny JEA's customers the most cost-effective option to meet JEA's need. The additional CPWC to JEA's customers resulting from denial of SJRPP Unit 3 is approximately $92 million. A delay to the in-service date of SJRPP Unit 3 of even one year would cost JEA's customers approximately $20 million in CPWC. Denial would also prevent JEA from placing NGS Unit 3 in limited use status, triggering extremely costly upgrades conservatively estimated at more than $834 million. Denial of SJRPP Unit 3 would also prevent JEA and its customers from realizing numerous non-economic system benefits such as increased flexibility and grid reliability, reduction in natural gas consumption, increased fuel diversity, and decreased system emissions. JEA will begin to fall below its minimum reserve margin level in 2028. While additional off-system purchases can be made to maintain the target reserve margin until commercial operation of SJRPP Unit 3, absent the new unit, JEA would be required to import increasingly large volumes of power (72 MW by 2031, increasing to 222 MW by 2033 and 802 MW by 2035). The current configuration of JEA's transmission system cannot support importing this amount of power and would require substantial and costly upgrades, the completion of which is not feasible by the time the increased import capability is needed.

1.8 Conclusion

The analyses and other information described herein demonstrate that an affirmative need determination is warranted for SJRPP Unit 3 based on consideration of the relevant factors set forth in section 403.519, Florida Statutes. Due primarily to significant load growth and demand, and anticipated retirement of NGS Unit 3 in 2035, JEA will have a need for 72 MW of additional capacity by 2031, increasing to 222 MW by 2033 and 802 MW by 2035. JEA's Board selected SJRPP Unit 3 based on the results of a rigorous, multi-stage planning process that involved extensive economic analyses of generation alternatives, including power purchase alternatives identified during the RFP process, as well as careful consideration of non-economic attributes and risk factors. There are no reasonably available, cost-effective additional DSM/conservation measures that could mitigate JEA's projected need for SJRPP Unit 3.

[1] *In re: Commission review of numeric conservation goals (JEA),* Docket No. 20240016-EG, Order No. PSC-2024-0432-FOF-EG (Sept. 20, 2024) (FEECA Order).

[2] FEECA Order at 5 (recognizing approval of all proposed stipulations in Attachment A, including ¶ 6).

2.0 Purpose and Overview of Need Study

JEA is submitting this Need Study in support of its petition for determination of need for SJRPP Unit 3 pursuant to section 403.519, Florida Statutes. Rule 25-22.081, Florida Administrative Code, sets forth specific information that each petition for need determination must include to allow the Commission to address the statutory factors. This Need Study is organized as follows to provide the information required for such need determinations by Rule 25-22.081:

- Section 3 provides a general description of the utility primarily affected, including the load and electrical characteristics, generating capability, and interconnections;
- Section 4 provides a general description of the proposed electrical power plant, including the size, number of units, fuel type and supply modes, the approximate costs, and projected in-service date;
- Section 5 provides a statement of the specific conditions, contingencies or other factors which indicate a need for the proposed electrical power plant including the general time within which the generating unit will be needed;
- Section 6 provides a discussion of the major available generating alternatives (including renewable energy sources) which were examined and evaluated in arriving at the decision to pursue the proposed generating unit;
- Section 7 provides a discussion of non-generating alternatives; and
- Section 8 provides an evaluation of the adverse consequences which will result if the proposed electrical power plant is not added in the approximate size sought or in the approximate time sought.

3.0 Primarily Affected Utilities

3.1 JEA

JEA is a municipal electric utility under section 366.02, Florida Statutes, with an approximately 905 square mile electric service area. JEA provides electricity for approximately 537,000 customers in the City of Jacksonville and portions of Clay and St. Johns Counties, making it the eighth largest municipally owned electric utility in the United States in terms of number of customers. Figure 3-1 shows JEA's service territory.

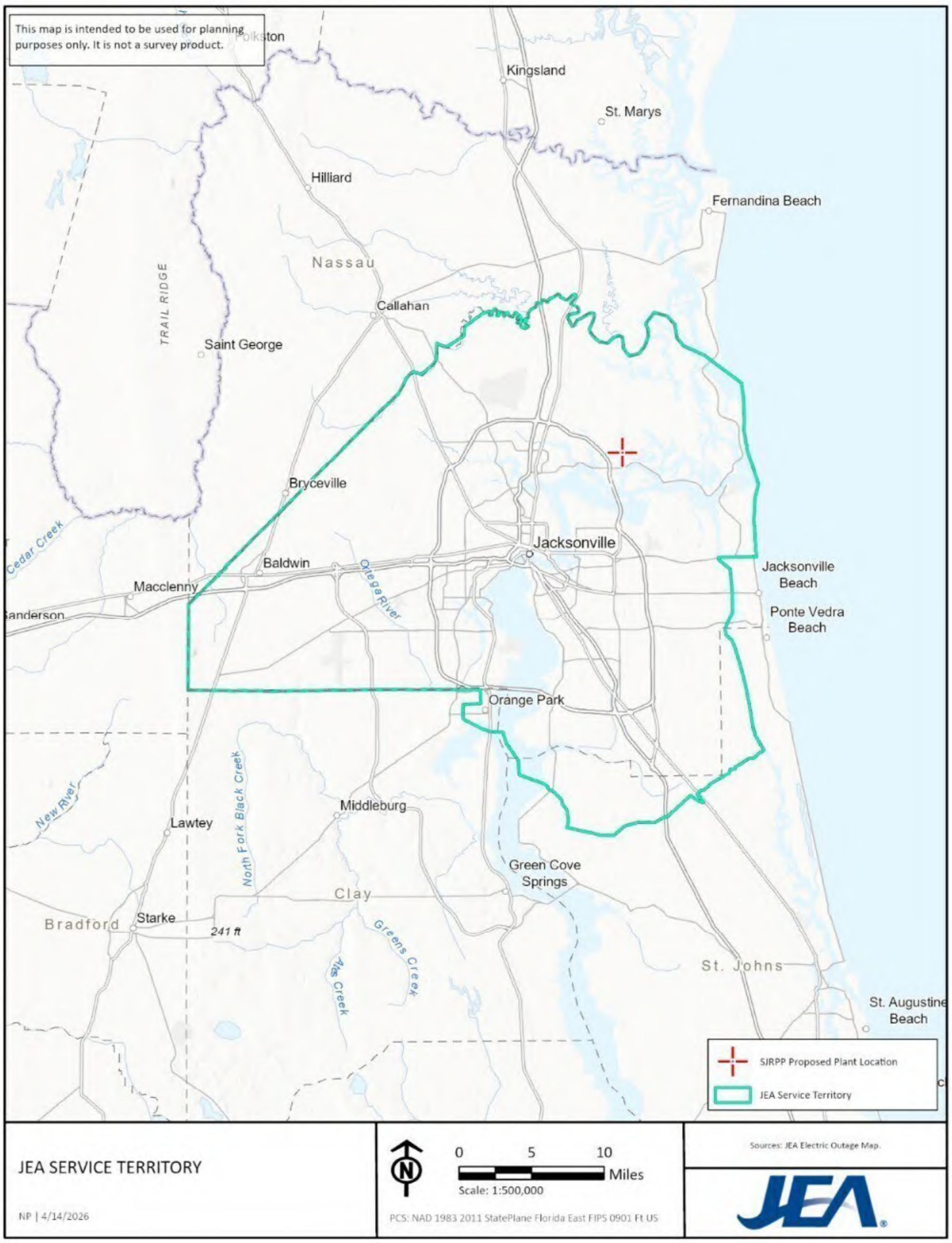

Figure 3-1 JEA Service Territory

JEA is governed by a Board of Directors consisting of four members appointed by the City Council and three members appointed by the Mayor of the City of Jacksonville, all of whom are approved by the City Council. JEA's headquarters is located at 225 N. Pearl Street, Jacksonville, Florida 32202.

3.2 Load and Electrical Characteristics

JEA meets the power supply needs of its customers with JEA-owned generation, power purchase agreements (PPAs) with independent power producers and utilities, and energy purchases on the spot market through The Energy Authority (TEA) when economical. JEA's portfolio has changed greatly over the last 25 years. The 2000s included multiple additions to JEA's generating fleet to meet the growing energy needs in the Jacksonville area. At that time, energy sales were consistently growing year over year. Beginning in the late 2010s and through the early 2020s, slow economic recovery following the housing market crash and financial crisis drove a drastic drop in MWh sales to customers, resulting in less need for resources than was original forecasted. The lower demand for energy led to the ultimate decision to retire SJRPP Units 1 & 2 and Scherer Unit 4 in 2022. Since 2011, JEA has only entered into PPAs for additional energy and capacity needs.

JEA's current load is more unpredictable. JEA remains a winter peaking utility but is becoming more bi-modal. In 2025, a hot summer and cold winter drove the load increasing demand from JEA resources, including an all-time summer peak of 2,980 MW, exceeding the previous summer high of 2,937 MW in 2007. Six of the top 40 peaking days since 2007 occurred in 2025, four in January and two in July. JEA's 2026 Ten-Year Site Plan (TYSP, included as Attachment A hereto) forecast shows a 6.8% increase in summer peak demand and a 5.6% increase in winter peak demand in 2031 over the 2025 forecast. It is this increased demand that requires JEA to maintain NGS Unit 3 in limited use status upon commercial operation of SJRPP Unit 3 rather than full retirement as initially contemplated.

In addition to anticipated organic residential growth, JEA has confirmed a total of 347 MW of new load since the 2025 forecast in projects in design and construction phases. The growth is generally split 50% residential and 50% commercial. This growth trend is being seen industry-wide as a result of reindustrialization, AI, data centers, and electrification. This has led to sustained industry growth for the first time in nearly two decades.

3.3 Generating Capability

JEA's generation portfolio is comprised of a mix of owned assets and PPAs that together aim to ensure affordable, reliable and sustainable energy supply for JEA's customers. JEA's goal is to maintain a portfolio that balances operational flexibility, financial stability, and alignment with regulatory and sustainability objectives while positioning the system to meet both current and future energy demands. JEA meets the demands of its customers with generating facilities located on four plant sites within the City of Jacksonville. Together, these generating facilities total 2,952 MW of net winter capacity, and 2,782 MW of net summer capacity. JEA also has a variety of PPAs, including solar and other renewable facilities, totaling approximately 661 MW of firm winter capacity and 601 MW of firm summer power as of June 1, 2026.

3.3.1 JEA's Owned Generation Facilities

JEA's existing owned generating resources are located at four generating facilities and are summarized in Table 3-1.

- J. Dillon Kennedy Generating Station (Kennedy) uses natural gas with diesel fuel as back-up, in two large combustion turbines (commissioned 2000 and 2009). Total site capacity is 357 MW summer and 382 MW winter.

- NGS uses natural gas, fuel oil, biomass, coal and petroleum coke in three large steam units and four small diesel-powered peaking units. Toal site capacity is approximately 1,310 MW summer and 1,356 MW winter.
  - Unit 1 (coal, petroleum coke, and biomass) commissioned in 1966; repowered in 2000.
  - Unit 2 (coal, petroleum coke, and biomass) commissioned in 1972; decommissioned in 1984; repowered in 2000.
  - Unit 3 (natural gas and fuel oil) commissioned in 1977; anticipated placing in limited use limited to oil-firing coincident with commercial operation of SJRPP Unit 3.
- Brandy Branch Generating Station (Brandy Branch) houses three natural gas combustion turbines with a heat recovery steam generator to recover excess heat from two of the turbines. Total site capacity is 758 MW summer and 851 MW winter.
- Greenland Energy Center (GEC) uses natural gas with diesel fuel as back up in two large combustion turbines. Total site capacity is 357 MW summer and 382 MW winter.

Table 3-1 Summary of JEA's Existing Generating Units

Plant Name	Unit Number	Unit Type	Fuel Type		Commercial In-Service	Net MW Capability	
			Primary	Alt.	Mo/Year	Summer	Winter
Kennedy	7	GT	NG	DFO	06/2000	179	191
	8	GT	NG	DFO	06/2009	179	191
NGS	1	ST	PC	BIT	05/2003	293	293
	2	ST	PC	BIT	04/2003	293	293
	3	ST	NG	RFO	07/1977	524	524
	33-36	GT	DFO		01/1975	200	246
Brandy Branch	1	GT	NG	DFO	05/2001	179	191
	2	CT	NG		05/2001	190	212
	3	CT	NG		10/2001	190	212
	4	CA	WH		01/2005	200	216
Greenland Energy Center	1	GT	NG	DFO	06/2011	179	191
	2	GT	NG	DFO	06/2011	179	191

NG: Natural Gas; DFO: Distillate Fuel Oil; PC: Petroleum Coke; BIT: Bituminous Coal; WH: Waste Heat
GT: Gas Turbine; ST: Steam Turbine; CT: Combustion Turbine portion of Combined Cycle;
CA: Steam Turbine portion of Combined Cycle

3.3.2 Power Purchase Agreements

In the last 15 years, JEA has only added new PPAs to its portfolio; it has not added a new generating facility into its system since 2011. JEA currently has firm PPAs for 601 MW (summer of 2026) with independent power producers and utilities. These PPAs include nuclear power (206 MW), natural gas (280 MW), landfill gas energy (15 MW), and solar (100 MW). JEA's existing PPAs are summarized in Table 3-2, which states capacity on a nameplate basis, and are described in more detail below.

Table 3-2 Summary of JEA's Existing Power Purchase Agreements

Contract	Start Date	End Date	MW(AC)	Energy Source
LES Trail Ridge I	12/06/08	12/31/26	9	Landfill Gas
LES Trail Ridge II	02/01/14	12/31/26	6	Landfill Gas
MEAG Plant Vogtle Unit 3	07/31/2023	07/31/2043	103	Nuclear
MEAG Plant Vogtle Unit 4	04/29/2024	04/29/2044	103	Nuclear
FPL PPA	01/01/22	01/01/42	280	Natural Gas
FPL Solar PPA	04/01/23	04/01/28	150	Solar
Jacksonville Solar	09/30/10	09/30/40	12	Solar
NW Jacksonville Solar	05/30/17	05/30/42	7	Solar
Old Plank Road Solar	10/13/17	10/13/37	3	Solar
Starratt Solar	12/20/17	12/20/37	5	Solar
Simmons Road Solar	01/17/18	01/17/38	2	Solar
Blair Site Solar	01/23/18	01/23/38	4	Solar
Old Kings Solar	10/15/18	10/15/38	1	Solar
SunPort Solar	12/04/19	12/04/39	5	Solar (w/Storage)
Forest Trail Solar PPA	12/31/26	12/31/61	50	Solar
Miller Solar PPA	12/31/26	12/31/61	74.9	Solar (w/Storage)

3.3.2.1 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 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. An increase of up to 100 MW in capacity and transmission service for the Cooperation Agreement was approved by the JEA Board to help meet JEA's growing demand. JEA and FPL agreed to an increase to the natural gas PPA to a total of 280 MW which began on June 1, 2026.

3.3.2.2 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 2026.

3.3.2.3 Jacksonville Solar Power Purchase Agreement

In May 2009, JEA entered into a PPA with Jacksonville Solar, LLC (Jax Solar) to receive up to 12 MWAC 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 contract for Jax Solar will expire in September 2040.

3.3.2.4 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: 7 MW_{AC} / 25-year PPA. The NW Jax facility began commercial operations on May 30th, 2017.
- Old Plank Road Solar: 3 MW_{AC} / 20-year PPA. The Old Plank Road Solar facility began commercial operations on October 13th, 2017.
- Starratt Solar: 5 MW_{AC} / 20-year PPA. The Starratt Solar facility began commercial operations on December 20th, 2017.
- Simmons Road: 2 MW_{AC} / 20-year PPA. The Simmons Road Solar facility began commercial operations on January 17th, 2018.
- Blair Site Solar: 4 MW_{AC} / 20-year PPA. The Blair Site Solar facility began commercial operations on January 23rd, 2018.
- Old Kings Solar.: 1 MW_{AC} / 20-year PPA. The Old Kings Solar facility began commercial operation on October 15th, 2018.
- SunPort Solar: 5 MW_{AC} solar PV / 2 MW, 4 MWh battery energy storage system (BESS) / 20-year PPA. The BESS began commercial operations on December 4th, 2019.

3.3.2.5 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 2028.

3.3.2.6 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 of four facilities, totaling 280 MW_{AC} of solar and energy storage systems, to Florida Renewable Partners (FRP). Contracts for four facilities were originally in negotiations, and due to costly wetland impacts at the proposed Peterson Solar Energy Center, the scope was narrowed to the following: Forest Trail Solar Energy Center, 50 MW_{AC}; Caldwell Solar Energy Center, 74.9 MW_{AC}, and Miller Solar Energy Center, 74.9 MW_{AC}, with the Caldwell and Miller Solar Energy Centers each paired with a 50 MW, 4-hour battery energy storage system. As the projects phased through development, the evolving macroeconomic climate for renewables resulted in the termination of the Caldwell Solar Energy Center and battery energy storage system as of November 13, 2025. The project scope has now been optimized to a total of two renewable energy facilities: Miller Solar Energy Center, 74.9 MW_{AC}, paired with 50 MW, 4-hour battery energy storage system, and Forest Trail Solar Center, 50 MW_{AC}. JEA and FRP have executed power purchase agreements, lease option contracts, and energy storage agreements for the projects. Both facilities are expected to be commissioned by December 31st, 2026.

JEA entered into a 20-year solar agreement with the Florida Municipal Power Agency (FMPA) to purchase approximately 150 MW_{AC} from two facilities located in Florida. The projects were scheduled to commission in December 2026, but were delayed to October 2028, due to longer network upgrade timelines and other nationwide challenges with solar project development. Resultantly, in June 2025, the FMPA Board of Directors approved the termination of the solar agreement and JEA was released of its obligations.

3.3.2.7 MEAG Nuclear Power Purchase Agreements

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.

Vogtle Units 3 and 4 were commissioned on July 31st, 2023 and April 29th, 2024, respectively. Each unit is supplying approximately 103 MW of net firm capacity to JEA. In May 2026, the JEA Board approved the sale of 103 MW of Vogtle capacity and energy to Dalton Utilities in 2028; increasing to 123 MW in 2029, and decreasing to 111 MW in 2030 and 103 MW in 2031 and 2032.

3.3.3 Renewable Resources

JEA currently receives or has contracts in place for a total of approximately 329 MW from renewable energy sources, including 15 MW from landfill gas-to-energy via a PPA and 314 MW from solar via PPAs and 50 MW battery energy storage. JEA co-fires more than 10% biomass in NGS Units 1 and 2 and has also installed solar PV systems at various customer sites in the community, including the Chamber of Commerce, Jacksonville International Airport, Jacksonville University, a fire station, and multiple Duval County public school locations totaling approximately 100 kW. JEA also established a residential net material program to encourage the use of customer-sited solar PV systems and has partnered with the University of North Florida Engineering Department to focus on the development of clean energy technologies.

JEA's Board of Directors approved aspirational clean energy goals in 2023. JEA has incorporated a significant amount of clean energy into its power supply portfolio, including numerous solar PPAs, and continues to explore opportunities to incorporate additional clean energy while ensuring alignment with system reliability, affordability, and adaptability. These efforts have not, however, been without challenges. Many factors have impacted JEA's ability to achieve the aspirational goals on the proposed timeline -- several planned and/or proposed clean energy projects in which JEA intended to participate were cancelled; transmission/interconnection equipment supply chain issues persist and continue to impact project costs and schedule; and finding appropriately sized, environmentally suitable land to support utility-scale solar in Duval County is prohibitively expensive such that extensive transmission upgrades would be necessary to import solar power to JEA's system. In addition, regulatory changes have fundamentally impacted the economics and affordability of clean energy projects and timeline for retirement of existing generating units, including the elimination of subsidies on utility-scale solar projects, EPA's proposed repeal of Greenhouse Gas (GHG) standards for electric generating units (GHG Rule), and EPA's repeal of the 2009 Endangerment Finding. Finally, JEA is experiencing significant load growth, warranting careful reevaluation of the timing of retirement of existing generating units.

JEA utilizes its Integrated Resource Planning (IRP) process to evaluate and inform long-term resource decisions, including scenarios and sensitivities to consider environmental legislative and regulatory action, load growth forecasts, fuel costs, costs of new generation, continued operation of existing generating units, and other factors. JEA has used the IRP process for decades, with the most recent IRP conducted in 2023 and another planned in the 2026/2027 timeframe. The assumptions and information utilized in JEA's IRPs are continually updated to fully inform JEA leadership decisions relative to resource additions. Given regulatory changes and other factors affecting practicality and affordability, as well as significant load growth, JEA continues to evaluate the current cost and practical ability to meet the aspirational clean energy goals and will utilize information from its ongoing IRP process to inform leadership decisions moving forward.

3.4 Transmission Interconnections

JEA's existing transmission facilities consist 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). JEA's import capacity is 1,228 MW over the 500 kV lines through the Duval substation. Prior to the decommissioning of SJRPP Units 1 & 2, JEA was a net exporter of power and JEA's transmission system was developed accordingly to export power out of JEA's service territory. JEA is now a net power importer. The majority of any power purchase – whether from the north (Georgia) or the south (FPL), enters JEA's transmission system through FPL's Duval substation.

The 230 kV and 138 kV transmission lines 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. Four 230 kV transmission lines exit the SJRPP site. 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 lines.

4.0 Description of the Proposed Generating Units

4.1 Proposed Project

The Project involves construction and operation of a new, state-of-the-art, dual-fuel natural gas- and ULSD-fired 1x1 advanced class combined cycle generating facility and onsite associated facilities on an approximately 194-acre site, wholly contained within JEA's existing 1,600-acre SJRPP parcel adjacent to JEA's existing NGS in Jacksonville, Duval County, Florida (Figure 4-1).

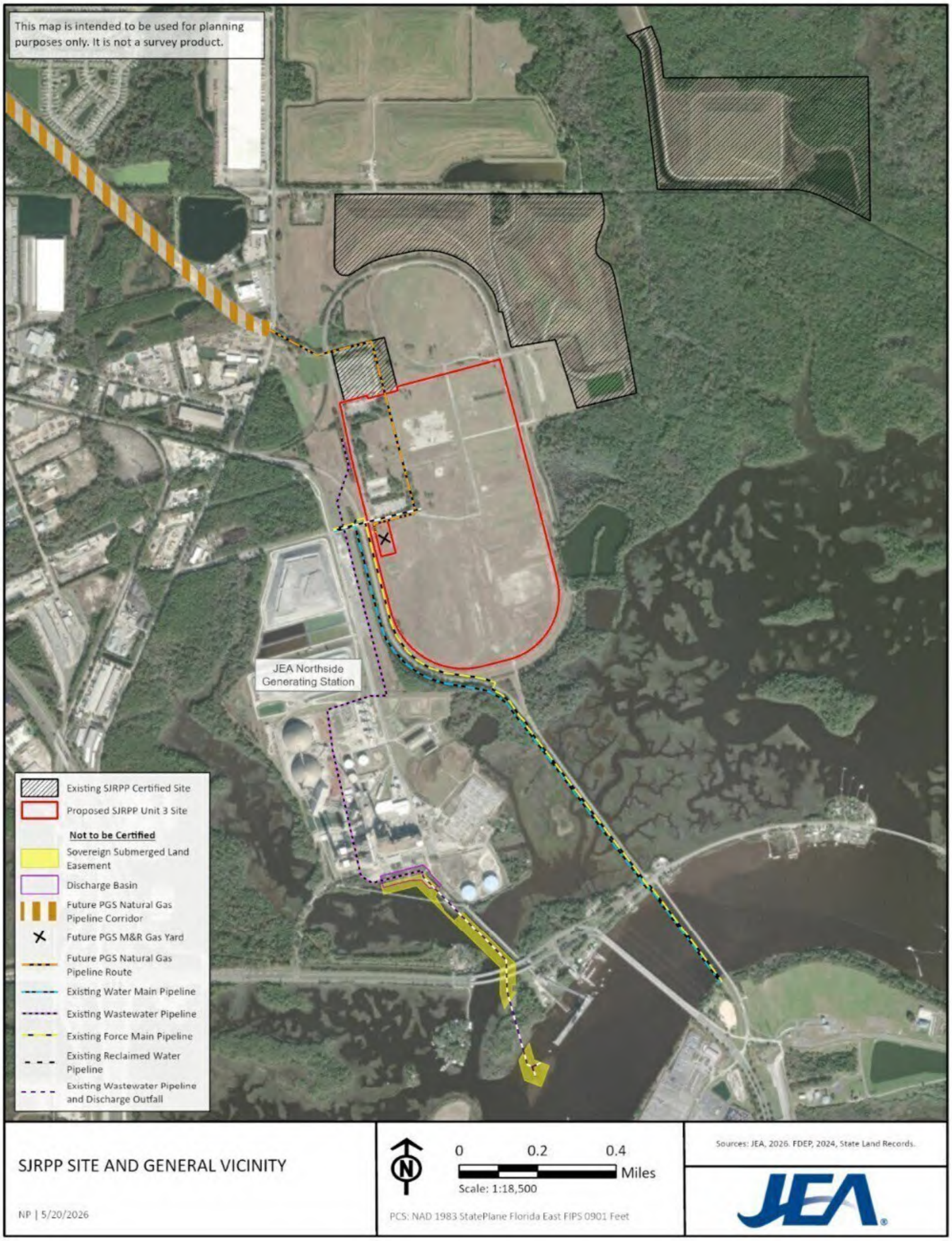

Figure 4-1 Proposed Project Certified Site

SJRPP Unit 3 consists of one combustion turbine generator (CTG), one heat recovery steam generator (HRSG) and one steam turbine generator (STG). SJRPP Unit 3 will have a maximum nameplate capacity of 706 MW with a net capacity (winter) of 678 MW and will be capable of firing natural gas or ULSD fuel oil. The primary fuel source will be natural gas provided via a PGS-owned and -operated lateral, with USLD fuel oil as a back-up fuel source. JEA anticipates placing its existing, less efficient, NGS Unit 3 into limited use, operating at or below an 8% capacity factor as a back-up during peak demand periods, emergencies, and unexpected outages coincident with commercial operation of SJRPP Unit 3. Existing natural gas capacity supply for NGS Unit 3 will be diverted to SJRPP to support operation of SJRPP Unit 3, with a relatively small amount of additional firm natural gas capacity (18,000 MMBtu/day) needed to support full operation of SJRPP Unit 3 during winter peak. Figure 4-2 provides a conceptual rendering of SJRPP Unit 3.

Figure 4-2 Conceptual Project Rendering

4.1.1 Project Site

SJRPP Unit 3 is proposed to be located at JEA's existing SJRPP site in the City of Jacksonville, Duval County, Florida (Figure 4-3). The SJRPP site is approximately 9.3 miles northeast of downtown Jacksonville, east of Interstate I-95, north of State Highway 105 (Heckscher Road), and south of Cedar Point Road. SJRPP is contiguous to NGS to the south. SJRPP Unit 3 will be located on the southern portion of the larger SJRPP parcel. Areas surrounding the parcel are largely used for industrial and commercial purposes.

Figure 4-3 Proposed Project Site Location

4.1.2 Power Generation Technology

SJRPP Unit 3 will consist of one CTG, one HRSG, and one STG. When operated in combined cycle mode, large advanced-class CTGs, like that selected for this Project, are the most efficient electric generating technology currently available for utility-scale power plants. These combined cycle plants can achieve efficiencies greater than 60 percent, compared to CTGs alone in simple-cycle mode at 42 to 43 percent and coal-fired steam plants at 33 to 45 percent. When a CTG is operated alone in simple-cycle mode, combustion exhaust energy is released directly to the atmosphere. In a combined cycle configuration, a portion of the combustion exhaust energy is recovered in an HRSG to produce steam, which is used to drive an STG to generate additional electricity. Therefore, a combined cycle power plant can generate more electricity without burning additional fuel or producing additional air emissions. Figure 4-4 presents a conceptual schematic of a one-on-one combined cycle unit.

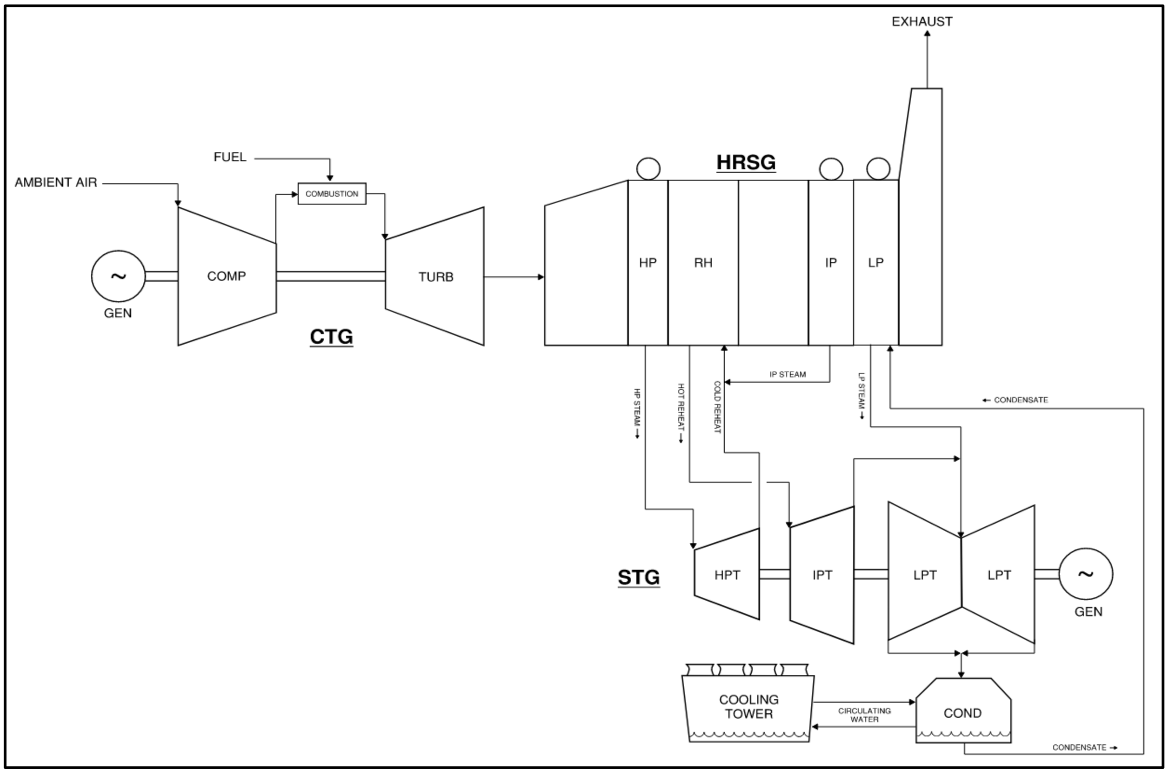

Figure 4-4 Conceptual Schematic of a 1-on-1 Combined Cycle Plant

SJRPP Unit 3 is expected to have a nameplate or gross output of 706 MW and a "net nominal" output of 678 MW (winter) and 582 MW (summer). During peak load periods, SJRPP Unit 3 will be able to fire supplemental natural gas in the HRSG duct burners to provide an increase of ~12% to 15% in STG electrical output. The 7HA.03 gas turbine has an extended "turndown" capability which will allow it to meet emissions compliance levels while operating as low as ~20% - 25% of full-load. This low turn-down capability is valuable as it will allow the facility to remain operational during low-load periods typically experienced at night and avoid the thermal stresses, wear, and additional emissions associated with a shut-down/start-up cycle. SJRPP Unit 3 will be primarily natural gas-fired, but capable of operating on ULSD fuel oil as a back-up. SJRPP Unit 3 will also be capable of operating on up to 50 percent hydrogen if available in the future. The combination of low turndown capabilities, as well as fuel diversity, provides the facility with significant flexibility in terms of operational characteristics.

The SJRPP site arrangement is depicted on Figure 4-5. The Power Island Equipment (PIE) will include one GE Vernova (GEV) 7HA.03 advanced class CTG, one GEV triple-pressure HRSG, and one GEV STF-D650 STG. The CTG will be equipped with a Dry Low NOx (DLN) combustion system designed for firing natural gas fuel and back-up ULSD fuel oil. The triple pressure HRSG will be a horizontal natural circulation design with supplemental duct-firing capabilities and equipment for emissions reductions. The STG will be configured as a tandem compound reheat unit with a side exhaust, dual flow LP cylinder. Cycle heat rejection will consist of a surface condenser and mechanical draft cooling tower. Control systems for the CTG, STG and HRSG will be integrated into the plant Distributed Control System (DCS). The facility will be operated primarily from the DCS.

4.1.3 Existing Infrastructure

SJRPP Unit 3 will utilize existing infrastructure, including the existing substation on the SJRPP property, four existing 230 kV electrical transmission lines exiting the property, existing reclaim water lines from JEA's District II Water Reclamation Facility, existing potable water lines from JEA's Major Grid Water Treatment Plant, existing sanitary sewer lines to District II Water Treatment Plant, conveyance channels for a portion of the stormwater management system design, existing SJRPP cooling tower blowdown water discharge pipeline which discharges to an existing basin located at NGS, an existing discharge pipe from the NGS basin to the St. Johns River, and the existing discharge structure. Use of existing transmission line infrastructure alone reduces the cost of the Project by approximately $100 million In necessary transmission line upgrades compared to alternatives that would require importing power to JEA's system.

4.1.4 Associated Facilities

SJRPP Unit 3 also includes other onsite associated facilities, such as an administration building with the DCS, a warehouse/maintenance building, roadways, parking and laydown areas, a temporary spoils area, a demineralized water treatment building, an open-frame turbine structure, electrical equipment and enclosures, step-up and auxiliary transformers, a natural gas metering and regulation station with gas-fired heaters, a mechanical draft cooling tower, HRSG exhaust stack, natural gas-fired auxiliary boiler with exhaust stack, emissions monitoring and reduction equipment, fire water pumps (electric primary with diesel back-up), diesel-fired emergency generator, above-ground service water storage tank, fire water storage tank, reclaim water storage tank, fuel oil storage tank, aqueous ammonia tank, wells, oil/water separators, a stormwater management system with stormwater ponds, piping tie-ins with existing infrastructure, and other ancillary equipment.

SJRPP Unit 3 will utilize existing on and off-site infrastructure. Natural gas will be delivered to a Metering & Regulation (M&R) yard onsite via an approximately 25-mile pipeline lateral. The M&R yard and pipeline lateral will be permitted, constructed, owned, operated, and maintained by PGS. Reclaimed water from JEA's nearby District II Water Reclamation Facility will be used for makeup to the cooling tower utilizing existing reclaimed water pipelines. Use of the existing piping system will require installation of an off-site booster pump station. The booster pump station will be located on a 0.38-acre property owned by JEA's separately owned and operated Water and Sewer System approximately 2 miles northwest of SJRPP, adjacent to I-295 to the south. These off-site facilities are not "associated facilities" proposed for certification under the PPSA. § 403.503(7), (14), Fla. Stat.

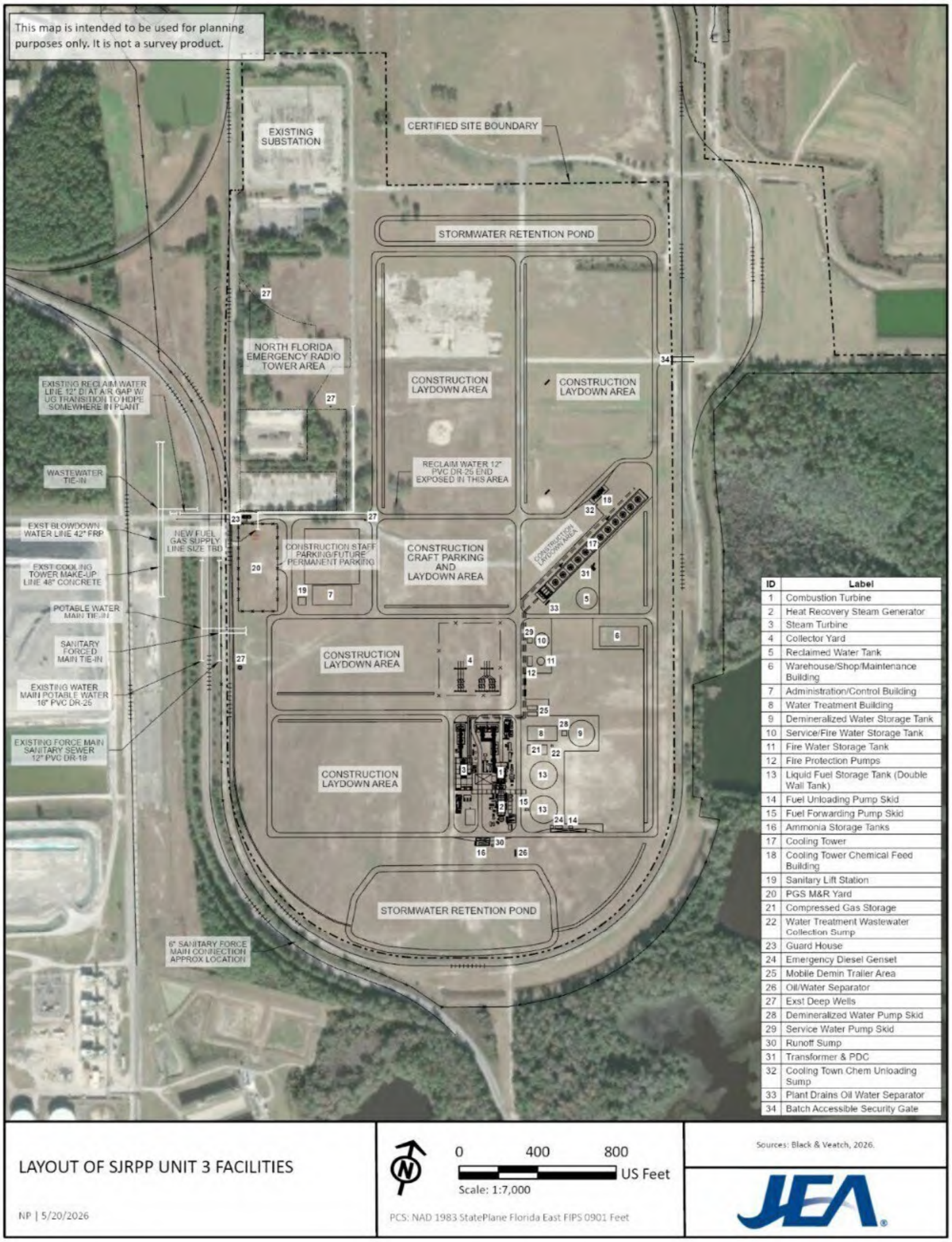

Figure 4-5 Proposed Project Site Arrangement

4.1.5 Air Emission Controls

SJRPP Unit 3 will be designed with technologies to minimize air emissions. The CTG will be equipped with DLN combustors to limit the formation of nitrous oxides (NOx) during combustion. The HRSG will be equipped with an SCR system to further reduce NOx emissions. Water injection will be implemented to reduce NOx emissions when operating on ULSD fuel oil. Emissions of carbon monoxide (CO) and volatile organic compounds (VOCs) will be limited through use of an oxidation catalyst system. Emissions of other regulated air pollutants, such as sulfur dioxide (SO_2) and particulate matter (PM), will be controlled through use of pipeline-quality natural gas and good combustion practices. In addition, SJRPP Unit 3 will minimize GHG emissions through the primary use of clean-burning natural gas along with the highly efficient combined cycle electric generating technology.

4.1.6 Water Use and Supply

SJRPP Unit 3 is designed to minimize the use of water. The condenser cooling system will consist of a 12-cell mechanical draft cooling tower and large pumps/pipes that circulate water between the cooling tower and a condenser located next to the steam turbine. Water is lost from the system at the cooling tower through drift, evaporation, and blowdown. Makeup for these losses will be predominately supplied by reclaimed water. Tie-in will take place with an existing pipeline previously used by SJRPP Units 1 & 2 and currently utilized by NGS. Reclaimed water will be cycled up to four times in the cooling tower (4 cycles of concentration) before blowdown is directed to an existing blowdown line which remains from the decommissioning of SJRPP Units 1 & 2. The existing blowdown line routes from SJRPP to the southwest through NGS where it discharges to an existing mixing basin at NGS. Wastewater from SJRPP mixes with wastewater from NGS in the mixing basin then passes through an existing pipe where it finally discharges through an existing structure to the St. Johns River.

Higher quality freshwater needs for general services and process water uses in the facility will be provided through groundwater withdrawals from new onsite wells. General plant service water will pass through a basic filtration stage to eliminate any sedimentation in the stream that could damage downstream equipment. Service water uses include equipment wash water, emergency fire water for fire protection, HRSG blowdown quench, and pump mechanical seal water. Process water goes through an additional filtration process to yield high-quality demineralized water which is required for steam-cycle makeup, NOx injection water when firing ULSD and closed cycle cooling makeup water. The volume of groundwater needed will be significantly less than the current groundwater allocation in the SJRPP Unit 3 Conditions of Certification. Potable water for drinking, safety showers, eyewash stations, and other sanitary uses will be provided by JEA's Highlands Water Treatment Facility. Tie-in will take place with an existing line which currently routes along the western boundary of the Site. Sanitary sewer from restrooms and domestic facility drains will be routed to JEA's District II Water Treatment Facility. Tie-in will take place with an existing line which currently routes parallel to potable water along the western boundary of the site.

General facility wastewater will be combined with cooling tower blowdown in the existing blowdown line and routed through the mixing basin at NGS before being released through an existing structure in the St. Johns River. Potential oil-contaminated drains will be routed through an oil-water separator prior to discharging to the existing blowdown line. Other potentially contaminated wastewater (e.g. chemical contamination) will be contained and treated in place or removed for off-site treatment.

4.1.7 Stormwater Management

The stormwater management system for SJRPP Unit 3 is designed to handle and treat the 25-year, 24-hour storm event and is designed to meet all federal, state, regional, and local requirements. Potential contact stormwater runoff from the power block and equipment areas will be collected and treated through an oil/water separator and routed to a stormwater retention pond prior to discharge to the St. Johns River. Noncontact stormwater runoff from the facility area will be collected and routed directly to a stormwater retention pond through a network of catch basins, culverts, and conveyance channels. During construction, stormwater runoff from the construction laydown and parking areas will also be collected through a series of culverts and conveyance channels and treated in swales and ponds in dry retention ponds. Best Management Practices (BMPs) will be utilized to minimize erosion from the disturbed areas during construction activities.

4.1.8 Fuel Type & Supply

SJRPP Unit 3 will burn natural gas as the primary fuel. At peak operation, including duct-firing, the facility will require approximately 104,200 million British thermal units (MMBtu) of natural gas per day on a higher-heating value (HHV) basis. In the event that natural gas is unavailable or uneconomic for JEA's customers, SJRPP Unit 3 will be capable of operating on ULSD distillate fuel as a back-up. When ULSD is used as fuel, the consumption rate will be approximately 93,500 MMBtu per day.

Natural gas will be supplied to SJRPP Unit 3 via a new approximately 25-mile lateral from the JEA Brandy Branch Generating Station area to a new M&R yard on the SJRPP property. The pipeline lateral and gas yard will be permitted, constructed, owned, operated, and maintained PGS. Gas will be supplied to the region via existing interstate gas pipelines owned and operated by Florida Gas Transmission (FGT) and Southern Natural Gas (SNG). JEA currently owns firm interstate transmission on each of these lines.

The efficiency of SJRPP Unit 3 over NGS Unit 3 represents a significant improvement in the utilization of existing natural gas supplies. At full load operation, SJRPP Unit 3 will use 37% less gas per MWh produced than NGS Unit 3. The existing interstate capacity made available from placing NGS Unit 3 in limited use on liquid fuel will be adequate to supply natural gas for normal operation of SJRPP Unit 3. JEA will, however, require a relatively small amount of additional firm natural gas capacity (18,000 MMBtu/day) to support full operation of SJRPP Unit 3 during winter peak.

With regard to back-up fuel, ULSD adequate in quantity to supply SJRPP Unit 3 for five (5) days at full load will be stored onsite. The fuel will be stored in double-walled above-ground storage tanks, in compliance with all applicable regulations. JEA anticipates that the fuel will primarily be delivered to the site by tanker truck.

As outlined above, the dual-fuel capability of SJRPP Unit 3 will enhance fuel diversity and reliability of fuel supply to the Project, which will support increased plant availability during operation.

4.1.9 Transmission Interconnections

Prior to the decommissioning of SJRPP Units 1 & 2 in 2018, JEA was a net exporter of power and JEA's transmission system was developed accordingly -- to export power out of JEA's service territory. Following the decommissioning, and with JEA's load growth in recent years, JEA is now a net power importer. The majority of any power purchased – whether from the north (Georgia) or the south (FPL), enters JEA's transmission system through FPL's Duval substation. During normal system operations, the swing of over 900 MW in power interchange (from 428 MW net export in 2017 to over 500 MW net import currently) does not create significant issues. However, when JEA makes additional power purchases for economic reasons or unplanned events (e.g., unscheduled generation outages), the JEA transmission system undergoes significant stress due to the increased import of power through the tie lines. Operation planning becomes more challenging during these times, especially when transmission contingencies are considered as required by NERC Reliability Standards.

The addition of the proposed SJRPP Unit 3 will help reduce this stress on the tie lines by making the power available closer to the load within JEA's system. This will also result in lower overall system loss as the load and generation are much closer and the system is better balanced. Finally, the addition of SJRPP Unit 3 will increase reliability under normal and probable contingency conditions and help insulate JEA from transmission contingencies outside of the JEA system that could negatively impact power import. Conversely, if SJRPP Unit 3 is denied, the current configuration of JEA's transmission system could not support importing the amount of power needed to maintain JEA's target reserve margin (72 MW by 2031, 222 MW by 2033, 802 MW by 2035) without substantial and costly transmission upgrades. These upgrades are not feasible in the timeframe to meet JEA's need in 2031.

There are currently four 230 kV transmission lines exiting the existing substation on the SJRPP property. SJRPP Unit 3 will connect to this existing substation via two new 230 kV generator tie (gen-tie) lines. Beyond the gen-ties, no additional transmission upgrades will be needed to integrate the new unit into JEA's system. If JEA did not construct new generation within its geographic footprint to serve its need for additional power, the construction of additional transmission lines would be required to reliably import power under both planned normal and contingency transmission events.

JEA performed a System Impact Study to assess the impact of the proposed SJRPP Unit 3 on JEA's transmission system. The base cases for steady state (thermal and voltage analysis), short circuit, and transient stability were developed by the Florida Reliability Coordinating Council (FRCC) Planning staff and consisted of all the existing transmission system information (including the generation units) in Florida. Those cases also included the future transmission and generation projects proposed by other FRCC members. The SJRPP Unit 3 data was then included in the base cases to create the study cases. Probable transmission contingencies within JEA were simulated simultaneously in the base and study cases, and the results were compared to ensure compliance with NERC Reliability Standards. The results showed no adverse impacts to JEA's transmission system.

Additionally, JEA coordinated with FRCC members to assess the transmission system in the FRCC region following the interconnection of SJRPP Unit 3 in accordance with the *FRCC Reliability Evaluation Process for Generator and Transmission Service Requests*. All the base cases, study cases, contingency files, the results, and the Reliability Evaluation Report were made available to all FRCC members for their review and comment. JEA also shared the findings with the members during scheduled FRCC meetings. Based on the comments and feedback, JEA analyzed additional scenarios and shared the results with the members. Two technical subcommittees of FRCC recommended acceptance of the Reliability Evaluation Report to the FRCC Planning Committee, which accepted the Report.

Based on JEA's System Impact Study, and FRCC's reliability evaluation, the interconnection of SJRPP Unit 3 will have no adverse impact on JEA's transmission system or any transmission system outside of JEA within the FRCC footprint.

4.1.10 Estimated Capital Costs

The estimated total in-service capital cost of SJRPP Unit 3 in 2031 is $1.57 billion. As summarized in Table 4-1, this estimate includes plant structures and equipment, equipment for interconnection, construction and development costs, interest during construction, insurance, and other owner's costs.

Table 4-1 SJRPP Unit 3 1x1 CCGT Capital Cost Estimate

Equipment and Interconnection, Development, and EPC Contract*	$ 1,277,246,973
Other Owner's Costs and Contingency	$ 119,929,576
Interest During Construction	$ 136,925,018
Insurance	$ 35,898,433
TOTAL	**$ 1,570,000,000**
*Cost component information is confidential and cannot be further broken down absent confidentiality protections.	

4.1.11 Construction Schedule & Projected In-Service Date

Subject to receipt of all regulatory approvals, construction activities for SJRPP Unit 3 are scheduled to begin in early 2028, with targeted commercial operation approximately 36 months later. JEA currently projects an in-service date of January 2031.

5.0 The Need for Proposed Generating Units

5.1 Overview of Need Assessment

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 remainder of this section discusses JEA's load forecast, reserve margin criteria, capacity resources, and the resulting projected need for capacity that underpins the economic analysis demonstrating the proposed SJRPP Unit 3 is part of JEA's least-cost resource plan to meet projected capacity requirements.

5.2 The Load Forecast

Annually, JEA develops forecasts of seasonal peak demands, net energy for load (NEL), interruptible customer demand, demand-side management (DSM), and the impact of plug-in electric vehicles (PEVs). JEA's baseline forecast used 10 years of historical data. Using the shorter period allows JEA to capture the most recent trends in customer behavior, and energy efficiency and conservation, where these trends are captured in the actual data and used to forecast projections. JEA's load forecast methodology is discussed in the following subsections.

5.2.1 Energy Forecast

JEA begins this forecast process by weather normalizing energy for each customer class using National Oceanic and Atmospheric Administration (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. The methodologies used to develop the various components of JEA's load forecast are summarized as follows.

- The residential energy forecast was developed using multiple regression analysis of weather normalized historical residential energy sales, total population, number of households, median household income and 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 sales, total commercial employment and gross domestic product from Moody's Analytics, JEA's total commercial accounts, and commercial inventory square footage from the CBRE Jacksonville Office Figures Q3 2025 Report.
- The industrial energy forecast was developed using multiple regression analysis of weather normalized historical industrial energy sales, gross domestic product, total industrial employment, and total proprietors' profits from Moody's Analytics, and JEA's total industrial accounts. The first 7 years of the forecast also incorporate confirmed new development projects and their expected demand, as well as increase consumption from existing industrial customers due to expansion.
- The lighting energy forecast was developed using the historical actual energy and number of luminaries. 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.

5.2.2 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.

5.2.3 Demand-Side Management (DSM)

5.2.3.1 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 120 MW of interruptible peak load for the summer through 2027, increasing to 124 MW beginning in the summer of 2028, and 107 MW for the winter through 2027, increasing to 111 MW beginning in the winter of 2028.

5.2.3.2 Demand-Side Management Programs

JEA's forecast of annual incremental demand and energy reductions associated with its current DSM programs (as discussed in Section 7 herein) are summarized as follows for 2026; demand and energy reductions associated with DSM are forecast to increase annually thereafter.

- Annual Energy Reductions
  - Residential: 12.04 GWh
  - Commercial/Industrial: 11.36 GWh
  - Total: 23.40 GWh
- Summer Peak Demand Reductions
  - Residential: 2.26 MW
  - Commercial/Industrial: 2.08 MW
  - Total: 4.34 MW
- Winter Peak Demand Reductions
  - Residential: 3.28 MW
  - Commercial/Industrial: 1.01 MW
  - Total: 4.29 MW

5.2.4 Customer-Sited Renewables

JEA's forecast of customer-sited renewables takes into account available roof space, power density of rooftop solar systems, hourly solar generation patterns, AC/DC ratios, and other factors. The potential peak demand and energy reductions associated with customer-sited renewables are reflected in JEA's load forecast.

5.2.5 Plug-in Electric Vehicles Peak Demand and Energy

JEA develops forecasts of demand and energy associated with PEVs based on a number of factors, including historical and forecast PEVs and population, median household income and number of households.

5.2.6 Electrification

JEA's electrification load forecast reflects the most current approved program goals and actual performance for the Electrification Rebate Program (ERP) and Fleet Electrification Program (FEP). The forecast aligns with updated annual targets through fiscal year 2027 for FEP and fiscal year 2028 for ERP, with the final year levels extended through the remainder of the planning horizon.

5.2.7 Historical Data and Forecast Net Peak Demand and Net Energy for Load

Tables 5-1 through 5-5 illustrate JEA's number of customers and energy usage by customer class; system-wide annual energy, summer and winter peak demands; load factors for the previous 10 years (2016 through 2025); and forecasts for the 2026 through 2035 period. Table 5-6 illustrates JEA's forecast system-wide, annual summer and winter firm peak demand, annual NEL, and load factors over the 2026 through 2060 period reflected in this Need Study.

Table 5-1 JEA Rural and Residential Customers and Energy Usage

Calendar Year	Average Number of Customers	% Growth	GWh Sales	% Growth	Average kWh/Customer	% Growth
History						
2016	398,387	--	5,351	--	13,431	--
2017	404,806	1.6%	5,199	-2.8%	12,842	-4.4%
2018	412,070	1.8%	5,460	5.0%	13,251	3.2%
2019	420,831	2.1%	5,479	0.3%	13,019	-1.8%
2020	429,575	2.1%	5,679	3.7%	13,220	1.5%
2021	438,470	2.1%	5,551	-2.3%	12,660	-4.2%
2022	447,308	2.0%	5,723	3.1%	12,795	1.1%
2023	458,764	2.6%	5,658	-1.1%	12,334	-3.6%
2024	470,564	2.6%	6,022	6.4%	12,797	3.8%
2025	479,288	1.9%	6,081	1.0%	12,641	-1.2%
Forecast						
2026	485,840	1.4%	6,075	-0.1%	12,504	-1.1%
2027	492,159	1.3%	6,174	1.6%	12,546	0.3%
2028	498,274	1.2%	6,262	1.4%	12,568	0.2%
2029	504,171	1.2%	6,351	1.4%	12,597	0.2%
2030	509,869	1.1%	6,441	1.4%	12,633	0.3%
2031	515,323	1.1%	6,531	1.4%	12,674	0.3%
2032	520,487	1.0%	6,620	1.4%	12,719	0.4%
2033	525,330	0.9%	6,707	1.3%	12,766	0.4%
2034	529,885	0.9%	6,794	1.3%	12,822	0.4%
2035	534,234	0.8%	6,892	1.4%	12,901	0.6%
Average Annual Growth Rate (2016 - 2025)		2.1%		1.4%		-0.7%
Average Annual Growth Rate (2026 - 2035)		1.1%		1.4%		0.3%

Table 5-2 JEA Commercial Customers and Energy Usage

Calendar Year	Average Number of Customers	% Growth	GWh Sales	% Growth	Average kWh/Customer	% Growth
History						
2016	51,441	--	4,064	--	78,994	--
2017	51,970	1.0%	4,011	-1.3%	77,176	-2.3%
2018	52,525	1.1%	4,042	0.8%	76,954	-0.3%
2019	53,153	1.2%	4,060	0.4%	76,389	-0.7%
2020	53,701	1.0%	3,886	-4.3%	72,363	-5.3%
2021	54,374	1.3%	3,848	-1.0%	70,767	-2.2%
2022	55,082	1.3%	4,005	4.1%	72,717	2.8%
2023	55,946	1.6%	3,968	-0.9%	70,922	-2.5%
2024	56,724	1.4%	4,104	3.4%	72,359	2.0%
2025	57,376	1.1%	4,194	2.2%	73,096	1.0%
Forecast						
2026	58,168	1.4%	4,022	-4.1%	69,136	-5.4%
2027	58,935	1.3%	4,027	0.1%	68,335	-1.2%
2028	59,713	1.3%	4,035	0.2%	67,577	-1.1%
2029	60,504	1.3%	4,046	0.3%	66,865	-1.1%
2030	61,311	1.3%	4,057	0.3%	66,176	-1.0%
2031	62,134	1.3%	4,070	0.3%	65,498	-1.0%
2032	62,969	1.3%	4,082	0.3%	64,829	-1.0%
2033	63,813	1.3%	4,097	0.4%	64,196	-1.0%
2034	64,666	1.3%	4,109	0.3%	63,548	-1.0%
2035	65,527	1.3%	4,122	0.3%	62,901	-1.0%
Average Annual Growth Rate (2016 - 2025)		1.2%		0.4%		-0.9%
Average Annual Growth Rate (2026 - 2035)		1.3%		0.3%		-1.0%

Table 5-3 JEA Industrial Customers and Energy Usage

Calendar Year	Average Number of Customers	% Growth	GWh Sales	% Growth	Average kWh/Customer	% Growth
History						
2016	202	--	2,692	--	13,322,934	--
2017	202	0.0%	2,777	3.2%	13,717,349	3.0%
2018	196	-3.0%	2,765	-0.4%	14,081,384	2.7%
2019	194	-1.0%	2,733	-1.2%	14,085,278	0.0%
2020	196	1.0%	2,698	-1.3%	13,759,522	-2.3%
2021	196	0.0%	2,612	-3.2%	13,348,772	-3.0%
2022	199	1.5%	2,708	3.7%	13,641,119	2.2%
2023	199	0.0%	2,614	-3.5%	13,151,607	-3.6%
2024	203	2.0%	2,691	2.9%	13,254,576	0.8%
2025	198	-2.5%	2,648	-1.6%	13,389,674	1.0%
Forecast						
2026	211	6.6%	2,754	4.0%	13,054,071	-2.5%
2027	215	1.9%	3,033	10.1%	14,107,857	8.1%
2028	219	1.9%	3,285	8.3%	15,001,436	6.3%
2029	222	1.4%	3,357	2.2%	15,120,763	0.8%
2030	224	0.9%	3,427	2.1%	15,297,656	1.2%
2031	227	1.3%	3,475	1.4%	15,307,034	0.1%
2032	230	1.3%	3,526	1.5%	15,329,031	0.1%
2033	233	1.3%	3,544	0.5%	15,209,228	-0.8%
2034	236	1.3%	3,567	0.6%	15,114,511	-0.6%
2035	240	1.7%	3,600	0.9%	14,999,094	-0.8%
Average Annual Growth Rate (2016 - 2025)		-0.2%		-0.2%		0.1%
Average Annual Growth Rate (2026 - 2035)		1.4%		3.0%		1.6%

Table 5-4 JEA Other and Total Customers and Energy Usage

Calendar Year	Street & Highway Lighting (GWh)	Other Sales to Ultimate Customers (GWh)	Total Sales to Ultimate Customers (GWh)	Sales for Resale (GWh)	Utility Use & Losses (GWh)	Net Energy for Load (GWh)	Other Customers	Total Number of Customers
History								
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	56	0	12,873	60	321	13,255	0	527,491
2025	57	0	12,980	69	431	13,479	0	536,862
Forecast								
2026	57	0	12,908	0	479	13,386	0	544,219
2027	58	0	13,293	0	493	13,785	0	551,309
2028	58	0	13,641	0	506	14,147	0	558,206
2029	59	0	13,812	0	512	14,324	0	564,897
2030	59	0	13,984	0	518	14,503	0	571,404
2031	59	0	14,135	0	524	14,659	0	577,684
2032	60	0	14,288	0	530	14,817	0	583,686
2033	60	0	14,407	0	534	14,941	0	589,376
2034	61	0	14,531	0	539	15,070	0	594,787
2035	61	0	14,675	0	544	15,219	0	600,001

Table 5-5 JEA System Total Net Energy for Load, Peak Demand, and Load Factor

Calendar Year	Net Energy for Load (GWh)	% Growth	Net Firm Summer Peak Demand (MW)	% Growth	Net Firm Winter Peak Demand (MW)	% Growth	Load Factor	% Growth
History								
2016	12,937	--	2,689	--	2,600	--	54.9%	--
2017	12,672	-2.0%	2,631	-2.2%	2,433	-6.4%	55.0%	0.1%
2018	12,813	1.1%	2,495	-5.2%	3,011	23.8%	48.6%	-11.6%
2019	12,797	-0.1%	2,591	3.8%	2,410	-20.0%	56.4%	16.1%
2020	12,740	-0.4%	2,582	-0.3%	2,445	1.5%	56.3%	-0.1%
2021	12,540	-1.6%	2,511	-2.7%	2,532	3.6%	56.5%	0.4%
2022	12,930	3.1%	2,728	8.6%	2,599	2.6%	54.1%	-4.3%
2023	12,733	-1.5%	2,753	0.9%	2,326	-10.5%	52.8%	-2.4%
2024	13,255	4.1%	2,675	-2.8%	2,416	3.9%	56.6%	7.1%
2025	13,479	1.7%	2,849	6.5%	2,913	20.6%	52.8%	-6.6%
Forecast								
2026	13,386	-0.7%	2,772	-2.7%	2,901	-0.4%	52.7%	-0.3%
2027	13,785	3.0%	2,850	2.8%	2,988	3.0%	52.7%	0.0%
2028	14,147	2.6%	2,930	2.8%	3,077	3.0%	52.5%	-0.3%
2029	14,324	1.3%	2,961	1.1%	3,114	1.2%	52.5%	0.0%
2030	14,503	1.2%	2,997	1.2%	3,147	1.1%	52.6%	0.2%
2031	14,659	1.1%	3,023	0.9%	3,180	1.0%	52.6%	0.0%
2032	14,817	1.1%	3,052	1.0%	3,210	0.9%	52.7%	0.1%
2033	14,941	0.8%	3,070	0.6%	3,226	0.5%	52.9%	0.3%
2034	15,070	0.9%	3,092	0.7%	3,252	0.8%	52.9%	0.1%
2035	15,219	1.0%	3,119	0.9%	3,275	0.7%	53.0%	0.3%
Average Annual Growth Rate (2016 - 2025)		0.5%		0.6%		1.3%		-0.4%
Average Annual Growth Rate (2026 - 2035)		1.4%		1.3%		1.4%		0.1%

Table 5-6 Forecast Firm Peak Demand and Net Energy for Load

Calendar Year	Summer Firm Peak Demand (MW)	Winter Firm Peak Demand (MW)	Net Energy for Load (GWh)	Load Factor
2026	2,772	2,901	13,386	52.7%
2027	2,850	2,988	13,785	52.7%
2028	2,930	3,077	14,147	52.5%
2029	2,961	3,114	14,324	52.5%
2030	2,997	3,147	14,503	52.6%
2031	3,023	3,180	14,659	52.6%
2032	3,052	3,210	14,817	52.7%
2033	3,070	3,226	14,941	52.9%
2034	3,092	3,252	15,070	52.9%
2035	3,119	3,275	15,219	53.0%
2036	3,146	3,289	15,372	53.4%
2037	3,177	3,321	15,530	53.4%
2038	3,203	3,338	15,679	53.6%
2039	3,226	3,358	15,833	53.8%
2040	3,253	3,388	15,979	53.8%
2041	3,291	3,399	16,134	54.2%
2042	3,325	3,437	16,285	54.1%
2043	3,361	3,454	16,444	54.3%
2044	3,394	3,469	16,601	54.6%
2045	3,434	3,505	16,757	54.6%
2046	3,469	3,518	16,882	54.8%
2047	3,503	3,515	17,010	55.2%
2048	3,530	3,553	17,146	55.1%
2049	3,568	3,550	17,278	55.3%
2050	3,598	3,561	17,414	55.3%
2051	3,634	3,593	17,555	55.1%
2052	3,679	3,610	17,707	54.9%
2053	3,717	3,634	17,862	54.9%
2054	3,759	3,640	18,028	54.7%
2055	3,790	3,650	18,149	54.7%
2056	3,797	3,660	18,174	54.6%
2057	3,814	3,695	18,196	54.5%
2058	3,830	3,683	18,221	54.3%
2059	3,840	3,735	18,247	54.2%
2060	3,852	3,733	18,273	54.2%

5.3 JEA Reliability Criteria

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 in accordance with Rule 25-6.035, Florida Administrative Code.

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, 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.

5.4 JEA's Existing and Planned Capacity Resources

As discussed in Section 3 herein, JEA's existing owned generating units consist of generating facilities located on four plant sites within the City of Jacksonville: Kennedy, (NGS, Brandy Branch, and GEC. JEA has a number of PPAs, as discussed in Section 3 herein. These PPAs provide JEA with diverse sources of power, including solar, landfill gas, nuclear, and natural gas.

5.5 JEA's Capacity Needs

Table 5-7 and Table 5-8, respectively, illustrate JEA's projected need for additional winter and summer capacity to maintain JEA's 15 percent reserve margin. The projected capacity requirements shown in Table 5-7 and Table 5-8 take into account JEA's forecast annual winter and summer firm peak demand, existing owned generating units, existing and planned PPAs, and JEA's 15 percent reserve margin, all as discussed previously in Section 3. As illustrated in Table 5-7 and Table 5-8, JEA is projected to require additional capacity to maintain reserve margin requirements beginning in the winter of 2028, with capacity requirements increasing thereafter, particularly in 2035 due to the planned retirement of NGS 3. Given the near-term need for capacity, for purposes of this Need Study it has been assumed that JEA will purchase capacity through TEA as needed through 2030, with 2031 as the initial year in which installation of new generating resources is feasible.

At the time of filing its 2026 TYSP, JEA anticipated short-term sales of Vogtle capacity to Dalton Utilities and to Santee Cooper in amounts different than those shown as "Exports (MW)" in Table 5-7 and Table 5-8, which reflect current expectations. More specifically, the 2026 TYSP anticipated exports of 206 MW in 2027 and 2028, 129 MW in 2029, and 103 MW in 2030, consistent with the analyses discussed in Section 6.4 and throughout this Need Study. JEA now anticipates short-term sales only to Dalton Utilities. The difference between the "Exports (MW)" reflected in Table 5-7 and Table 5-8, which affect only the short-term period prior to the anticipated in-service date of SJRPP Unit 3, as compared to the sales reflected in the 2026 TYSP and analyses discussed in this Need Study do not impact the timing of the need for capacity in 2031or the relative economics between expansions plans specifically detailed in Section 6.4 and discussed throughout this Need Study.

Table 5-7 Projected Annual Capacity Requirements - Winter

Calendar Year	Firm Winter Peak Demand (MW)	Firm Winter Peak Demand + 15% Reserves	Existing Owned Capacity (MW)	Existing and Planned Purchases (MW)	Exports (MW)	Total Available Capacity (MW)	Excess Capacity (Deficit) to Maintain 15% Reserve Margin
2026	2,901	3,336	2,952	468	0	3,420	84
2027	2,988	3,436	2,952	661	0	3,613	177
2028	3,077	3,538	2,952	686	(103)	3,535	(3)
2029	3,114	3,581	2,952	736	(123)	3,565	(16)
2030	3,147	3,619	2,952	736	(111)	3,577	(42)
2031	3,180	3,657	2,952	736	(103)	3,585	(72)
2032	3,210	3,692	2,952	736	(103)	3,585	(107)
2033	3,226	3,710	2,952	536	0	3,488	(222)
2034	3,252	3,740	2,952	536	0	3,488	(252)
2035	3,275	3,766	2,428	536	0	2,964	(802)
2036	3,289	3,782	2,428	536	0	2,964	(818)
2037	3,321	3,819	2,428	536	0	2,964	(855)
2038	3,338	3,838	2,428	536	0	2,964	(874)
2039	3,358	3,862	2,428	536	0	2,964	(898)
2040	3,388	3,896	2,428	536	0	2,964	(932)
2041	3,399	3,908	2,428	536	0	2,964	(944)
2042	3,437	3,953	2,428	256	0	2,684	(1,269)
2043	3,454	3,972	2,428	256	0	2,684	(1,288)
2044	3,469	3,989	2,428	153	0	2,581	(1,408)
2045	3,505	4,030	2,428	50	0	2,478	(1,552)
2046	3,518	4,046	2,428	50	0	2,478	(1,568)
2047	3,515	4,043	2,428	50	0	2,478	(1,565)
2048	3,553	4,086	2,428	50	0	2,478	(1,608)
2049	3,550	4,082	2,428	50	0	2,478	(1,604)
2050	3,561	4,095	2,428	50	0	2,478	(1,617)
2051	3,593	4,132	2,428	50	0	2,478	(1,654)
2052	3,610	4,152	2,428	50	0	2,478	(1,674)
2053	3,634	4,179	2,428	50	0	2,478	(1,701)
2054	3,640	4,186	2,428	50	0	2,478	(1,708)
2055	3,650	4,198	2,428	50	0	2,478	(1,720)
2056	3,660	4,209	2,428	50	0	2,478	(1,731)
2057	3,695	4,249	2,428	50	0	2,478	(1,771)
2058	3,683	4,236	2,428	50	0	2,478	(1,758)
2059	3,735	4,295	2,428	50	0	2,478	(1,817)
2060	3,733	4,293	2,428	50	0	2,478	(1,815)

Table 5-8 Projected Annual Capacity Requirements – Summer

Calendar Year	Firm Summer Peak Demand (MW)	Firm Summer Peak Demand + 15% Reserves	Existing Owned Capacity (MW)	Existing and Planned Purchases (MW)	Exports (MW)	Total Available Capacity (MW)	Excess Capacity (Deficit) to Maintain 15% Reserve Margin
2026	2,772	3,188	2,782	601	0	3,383	195
2027	2,850	3,277	2,782	796		3,578	301
2028	2,930	3,369	2,782	703	(103)	3,382	13
2029	2,961	3,406	2,782	753	(123)	3,412	6
2030	2,997	3,447	2,782	753	(111)	3,424	(23)
2031	3,023	3,477	2,782	753	(103)	3,432	(45)
2032	3,052	3,510	2,782	753	(103)	3,432	(78)
2033	3,070	3,531	2,782	553	0	3,335	(196)
2034	3,092	3,556	2,782	553	0	3,335	(221)
2035	3,119	3,587	2,258	553	0	2,811	(776)
2036	3,146	3,618	2,258	553	0	2,811	(807)
2037	3,177	3,653	2,258	553	0	2,811	(842)
2038	3,203	3,684	2,258	550	0	2,809	(875)
2039	3,226	3,710	2,258	550	0	2,808	(902)
2040	3,253	3,741	2,258	549	0	2,807	(934)
2041	3,291	3,785	2,258	547	0	2,806	(979)
2042	3,325	3,823	2,258	266	0	2,524	(1,299)
2043	3,361	3,866	2,258	163	0	2,421	(1,444)
2044	3,394	3,903	2,258	60	0	2,318	(1,584)
2045	3,434	3,949	2,258	60	0	2,318	(1,631)
2046	3,469	3,989	2,258	60	0	2,318	(1,671)
2047	3,503	4,028	2,258	60	0	2,318	(1,710)
2048	3,530	4,059	2,258	60	0	2,318	(1,741)
2049	3,568	4,103	2,258	60	0	2,318	(1,785)
2050	3,598	4,138	2,258	60	0	2,318	(1,820)
2051	3,634	4,179	2,258	60	0	2,318	(1,860)
2052	3,679	4,231	2,258	60	0	2,318	(1,913)
2053	3,717	4,274	2,258	60	0	2,318	(1,956)
2054	3,759	4,322	2,258	60	0	2,318	(2,004)
2055	3,790	4,359	2,258	60	0	2,318	(2,040)
2056	3,797	4,366	2,258	60	0	2,318	(2,048)
2057	3,814	4,386	2,258	60	0	2,318	(2,068)
2058	3,830	4,404	2,258	60	0	2,318	(2,086)
2059	3,840	4,416	2,258	60	0	2,318	(2,098)
2060	3,852	4,430	2,258	60	0	2,318	(2,112)

6.0 Evaluation of Generating Alternatives

6.1 Overview of Evaluation Process

JEA conducted a comprehensive analysis to evaluate the need for the proposed SJRPP Unit 3 and the relative economics of this option and other candidate resource options. JEA's Board selected moving forward with construction and operation of SJRPP Unit 3 based on the results of an IRP process that began over three years ago and has been continually refined with updated information and assumptions through the date of this Need Study. That process included extensive economic analyses of self-build options, including renewable generation and energy storage. Multiple power purchase alternatives were evaluated through a robust market test RFP process that was overseen by an independent evaluator. The evaluations also considered non-economic attributes and risk factors. JEA then performed additional comprehensive economic modeling utilizing updated and refined information, including its 2026 load forecast and updated cost information, to verify that the addition of SJRPP Unit 3 in the 2031 timeframe remained the most cost-effective alternative to meet its need for power.

6.2 Selection of SJRPP Unit 3

6.2.1 Technology Assessment

The IRP process considered various generating resource options, including multiple configurations of solar photovoltaic (PV) and energy storage options, numerous different natural gas options (including a range of sizes, types, simple and combined cycle configurations, and conversion of existing simple cycle units to combined cycle configuration), biomass technologies, and nuclear. Other renewable resources such as hydropower, geothermal, and wind, were not considered as they are not feasible within JEA's service territory. Given regulatory limitations, JEA did not evaluate the addition of any new coal-fired generating units. While the use of hydrogen may be an option as a fuel source in the future, including for SJRPP Unit 3, units operating solely on hydrogen were not evaluated given the lack of necessary infrastructure and demonstrated use for large-scale power production.

JEA performed a detailed assessment of various technologies at multiple locations on the JEA system, including economic modeling and consideration of system benefits and risks. Through this assessment, JEA selected an advanced class 1x1 combined cycle generating unit, which provides reliable dispatchable power, allows for more efficient use of natural gas, reduces system emissions, and provides support to reliably integrate more renewable energy into the JEA system.

6.2.2 Site Assessment

After selection of combined cycle technology, JEA considered two existing JEA-owned sites for the location of the Project - GEC and SJRPP. The GEC site is located south and east of the St. John's River. The site has generated electricity since 2011 and has two natural gas-fired combustion turbines with a total capacity of 382 MW in the winter and 357 MW in the summer. The SJRPP site is located on the north side of Jacksonville and is the previous location of SJRPP Units 1 & 2.

JEA carefully evaluated both sites based on a variety of economic, environmental, and strategic factors, including but not limited to existing and neighboring land uses, existing infrastructure, fuel supply, water availability, wastewater disposal options, environmental impacts, site access, and project schedule. After careful evaluation of the GEC and SJRPP locations, the SJRPP site was selected based on advantages related to surrounding land uses, potential environmental impacts, existing infrastructure, and overall site compatibility.

6.2.3 Vendor Selection

JEA initiated a competitive solicitation process to solicit proposals from major equipment manufacturers that provide the major equipment associated with construction of an advanced class 1x1 combined cycle unit. The major equipment, referred to as the "power island," includes the CTG, HRSG, STG, and associated ancillary equipment. JEA's power island solicitation was issued in September 2024 through a posting on the Zycus platform. The solicitation was managed by the JEA Procurement team. Proposals were received in December 2024 from GE Vernova and Mitsubishi Power Americas in response to the power island solicitation. Following review and evaluation of the responses to the power island solicitation, JEA selected GE Vernova for the power island for SJRPP Unit 3 as the most economic option.

6.3 Market Alternatives Considered

Following the identification of SJRPP Unit 3 as the best self-build option, JEA sought to determine whether there was a lower cost alternative available in the power market from another utility or from an independent power producer through the issuance of a *Solicitation for Long-Term Firm Dispatchable Capacity and Energy Resources* on October 2, 2024 (Market Test RFP) with responses due on April 21, 2025. The Market Test RFP process was overseen by an independent evaluator (Merrimack Energy).

The Market Test RFP was issued to solicit proposals for firm, dispatchable capacity and associated energy. JEA indicated in the Market Test RFP Instructions document that it intended to provide a 1x1 combined cycle self-build resource (Self-Build Resource) in response to the Market Test RFP and evaluate resource alternatives submitted that complied with the requirements of the Market Test RFP relative to the Self-Build Resource. JEA also stated that it anticipated that the generation technology having the highest likelihood of success as an alternative to the Self-Build Resource would be an advanced-class combined cycle technology resource, with operating parameters that included the ability to operate in baseload and load-following roles across the full unit load range. The general characteristics of the Self-Build Resource were included in the Market Test RFP instructions.

JEA received four proposals from one respondent in response to the Market Test RFP, three of which were deemed compliant with the minimum requirements. A team of JEA staff with specialized expertise in a variety of areas (JEA Evaluators) reviewed and evaluated the three compliant third-party responses and the Self-Build Resource relative to the evaluation criteria and methodology provided in the Market Test RFP documents available to all respondents.

JEA first conducted an economic/quantitative evaluation of the RFP-compliant proposals and Self-Build Resource. The economic evaluation utilized PLEXOS® modeling to assess the CPWC to the JEA system over a 35-year time horizon of the proposed resources and the Self-Build Resource as part of competing expansion plans. PLEXOS® is a widely used planning tool that is routinely used by JEA and within the industry. The proposals and Self-Build Resource were compared using CPWC, which includes the sum of present value of annual system costs for each year. In the CPWC calculation, annual costs are discounted to the start of the evaluation period using the JEA cost of capital and then the present worth of the annual costs are summed. Individual cost components accounted for in the CPWC calculation include the capital costs associated with new resource additions, variable and fixed operating and maintenance (VOM and FOM) costs, system fuel costs, and power purchase costs.

Figure 6-1 illustrates, conceptually, how the CPWC is derived. The CPWC figure is compared against competing expansion plans developed under base case (most likely case) assumptions, and under sensitivity cases in which one or more base case input assumptions are considered in the PLEXOS® model. Generally, the plan having the lowest CPWC under the base case plan and that is also the least-cost plan or at least competitive across the selected sensitivities is considered the preferred plan from an economic perspective.

		2026	2027	2028	2029	2030	...	2060
System-wide Variable Costs								
Fuel Costs		$	$	$	$	$		$
Variable O&M Costs		$	$	$	$	$		$
Variable PPA Costs		$	$	$	$	$		$
Fixed Costs								
New Unit Capital Costs		$	$	$	$	$		$
System Fixed O&M		$	$	$	$	$		$
Fixed PPA Costs (Capital plus Fixed O&M)		$	$	$	$	$		$
Total Incremental Annual Cost		$	$	$	$	$		$
Cumulative Present Worth Costs	**CPWC $**							

Figure 6-1 Conceptual Calculation of the Cumulative Present Worth Cost (CPWC) of an Expansion Plan

The quantitative/economic evaluation of the proposals and Self-Build Resource included base cases with varying assumptions relative to the GHG Rule[3] as well as various sensitivities, including high load forecast, low load forecast, and high gas price. The qualitative/risk assessment evaluation considered commercial experience and credit worthiness, transmission status, costs and impacts, fuel supply, operational flexibility, project status and design, and environmental considerations.

The Self-Build Resource was scored by the JEA Evaluators as the highest-ranking resource option from both a quantitative and qualitative perspective. Merrimack Energy reviewed the quantitative scores, conducted a review of the qualitative scoring, and likewise agreed that the Self-Build Resource ranked highest in quantitative and qualitative categories.

6.4 Updated Economic Evaluation of Generation Alternatives

6.4.1 Methodology

To confirm SJRPP Unit 3 as the least-cost alternative utilizing the most up-to-date and refined information available, JEA again engaged Black & Veatch to perform an updated evaluation of generating unit alternatives reflecting updated load forecasts and fuel price projections, updates to existing and planned future resources, updated cost and performance estimates, and updated assumptions relative to the GHG Rule and clean energy goals. This evaluation and underlying assumptions are detailed below.

The updated economic evaluations were performed using PLEXOS® and involved the development of multiple competing expansion plans involving different resource option additions. For each expansion plan, the total cost resulting from the addition of new resources and the dispatch of resources to meet energy requirements over the planning horizon was calculated. The economics of competing expansion plans were compared using the CPWC over the 35-year planning period (i.e., 2026 through 2060).

[3] At the time of the RFP, EPA had not proposed repeal of the GHG Rule or the 2009 Endangerment Finding. As such, JEA's analysis included multiple base cases with assumptions relative to implementation of the GHG Rule.

6.4.2 Economic Parameters

The updated economic analysis consisted of a base case simulation and several sensitivity cases modeled in PLEXOS®. These cases differed according to the input assumptions made. In this section, the primary input assumptions are described, beginning with the base case.

6.4.2.1 JEA's Cost of Capital, Discount Rate, Levelized Fixed Charge Rates, and General Inflation Rate

In the base case simulations, it was assumed that JEA's cost of financing was 4.75 percent. The interest during construction rate and the discount rate used for present worth calculations were also 4.75 percent.

The analysis utilized a levelized fixed charge rate, defined as the single, levelized rate that is applied to the total in-service capital cost of a new resource to determine the levelized dollar return needed to recover the capital cost over the designated recover period. An annual bond issuance fee of 1 percent and an annual property insurance cost of 0.63 percent were also part of the levelized fixed charge rate. Table 6-1 shows the resulting levelized fixed charge rates that were applied to various technologies. The rates differ due to the different capital recovery periods assumed for the candidate technologies.

Table 6-1 Levelized Fixed Charge Rates

Capital Recovery Period (Years)	Levelized Fixed Charge Rate	Technology
20	8.56%	Reciprocating Engine / Combustion Turbine / Energy Storage
30	7.01%	Combined Cycle
40	6.32%	Nuclear

The analysis assumed a general inflation rate of 3.5 percent. This rate was applied to all inputs subject to escalation other than fuel costs, which were forecasted in real terms, then escalated to current year dollars using an annual inflation rate of 2.60 percent.

6.4.3 Clean Energy and Greenhouse Gas Assumptions

Consistent with the discussion regarding JEA's aspirational clean energy goals in Section 3 herein, the updated evaluations outlined in this Need Study do not include the requirement that a specified percentage of JEA's energy requirements be met using clean energy. The PLEXOS® modeling, however, allowed the addition of solar and energy storage resources beyond JEA's existing and planned solar and energy storage resources if economical. Similarly, the PLEXOS® modeling allowed the addition of nuclear resources beyond JEA's existing nuclear resources if economical. It was assumed that no federal tax incentives would apply to solar projects.

Based upon EPA's proposed repeal of the GHG Rule and repeal of the 2009 Endangerment Finding as discussed in Section 3 herein, the updated evaluations did not reflect any costs or other limitations associated with regulations related to the emissions of CO_2/GHG; i.e., the modeling assumed GHG regulations were not in place.

6.4.4 Capital and Operating Cost and Performance Estimates

The estimated capital and operating costs and performance for the generating unit alternatives, as applicable to each alternative in the updated modeling are summarized on Table 6-2. Inputs consist of capital costs, seasonal output (MW), net plant heat rate (NPHR), fixed and variable operating and maintenance (O&M) costs, and start costs (if not otherwise reflected in the variable O&M cost). The capital and operating cost assumptions/estimates in the updated analysis are based on various models and data bases that were adjusted for this study based on recent market conditions and contracts.

6.4.5 Fuel Cost Assumptions

JEA's existing units operate on various fuel types, including natural gas, diesel petroleum coke, and biomass. In order to evaluate JEA's existing units and the generating unit alternatives JEA engaged Black & Veatch to develop projections of fuel prices. The fuel price projections include projections of delivered fuel forecasts for natural gas, the mix of solid fuel used in NGS Units 1 and 2, diesel, and nuclear. For the base case, Black & Veatch utilized natural gas price projections developed as part of its proprietary Energy Market Perspective (EMP) forecast, updated in 2025. The EMP is Black & Veatch's in-house integrated North America energy markets outlook, that incorporates projections of load growth, energy efficiency, distributed energy resources (DER), thermal and renewable capacity additions, generation unit retirements, plus energy and fuel market trends.

To reflect near-term market conditions, Black & Veatch combined the long-term fundamental forecasts developed in the EMP process with the six-month average NYMEX Henry Hub futures from July to December 2024. The specific blending strategy was as follows:

- 2025: 100% Henry Hub Futures
- 2026: 75% Henry Hub Futures + 25% fundamental-based projection
- 2027: 50% Henry Hub Futures + 50% fundamental-based projection
- 2028: 25% Henry Hub Futures + 75% fundamental-based projection
- 2029: 15% Henry Hub Futures + 85% fundamental-based projection
- From 2030 onwards: 100% fundamental-based projection

Driven by the advance in shale production technology, the US is the leading natural gas producer and exporter of natural gas. Consumers in the US lower 48 have been enjoying a relatively stable cost of gas even in the face of rising demand. For example, in the ten-year period between 2016 and 2025, total LNG exports and gas delivered to the power sector grew from 28 Bcf/d[4] to 51 Bcf/d while the natural gas Citygate price has only increased from $3.71/MMBtu to $4.85[5]/MMBtu. In the base case, the Henry Hub price is expected to increase from the current level, driven primarily by rising demand from Gulf Coast LNG terminals and demand for natural gas from the power sector due, in part, to data center demand. Over 30 Bcf/d of growth is expected from these two sources between now and 2050.

[4] https://www.eia.gov/dnav/ng/hist/n3045us2a.htm; https://www.eia.gov/dnav/ng/hist/n9133us2A.htm
[5] https://www.eia.gov/dnav/ng/hist/n3050us3a.htm

Table 6-2 Cost (in 2031$) and Performance Assumptions for Generating Alternatives

Candidate Option	In-Service Capital Cost ($M)	In-Service Capital Cost ($/kW of Winter MW)	Summer Rating (MW)	Winter Rating (MW)	Full Load Net Plant Heat Rate (Btu/kWh; higher heating value)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)	Start Cost ($/Start)
GE LM6000 PF SPRINT 2x0	$401.11	$4,031.26	76.1	99.5	8,831	$21.52	$10.66	N/A
GE 7FA.05 1x0	$617.95	$2,621.76	208.7	235.7	10,080	$12.13	N/A	$13,214
GE 7HA.03 1x0	$925.75	$2,044.05	374.2	452.9	9,031	$7.06	N/A	$34,419
Wartsila 18V50DF 5x0	$322.31	$3,605.26	83.8	89.4	8,380	$33.02	$9.65	N/A
GE 7FA.05 1x1	$1,501.66	$3957.11	342.2	379.5	6,940	$14.89	$3.52	N/A
GE 7HA.03 1x1	$1,570.00	$2,317.00	581.6	677.6	6,317	$13.08	$1.11	$69,884
Conversion of existing GEC CTGs	$817.58	$2,486.56	297.3	328.8	6,832	$13.78	$3.38	N/A
Conversion of existing GEC CTGs	$1,447	$2,191.43	597.2	660.3	6,803	$8.75	$3.28	N/A
75 MW Photovoltaic Solar Array (1)(2)	First year PPA cost $89.5/MWh	N/A	75	75	N/A	N/A	N/A	N/A
50 MW Lithium Ion 4-hour Battery Storage (1)	$51.54	$1,030.76	50	50	N/A	$58.73	N/A	N/A
100 MW Vanadium Redox 10-hour Battery Storage (1)	$286.50	$2864.97	100	100	N/A	$129.22	N/A	N/A
75 MW Solar and 50 MW 4-hour Battery Storage Hybrid (1)	First year PPA cost $89.5/MWh + $115.32/kW-yr	N/A	75-50	75-50	N/A	N/A	N/A	N/A
Small Modular Reactors(2)	$1,480.02	$19,221.04	77	77	10,400	$157.55	$4.12	N/A
GE 7HA.03 1x1 with Carbon Capture and Sequestration	$3,716.90	$6,206.21	509.9	598.9	7,162	$75.24	$15.33	N/A
GE 7HA.03 1x1 Hydrogen	$2,364.96	$3,489.17	583.5	677.8	6,522	$10.39	$6.55	N/A
GE LM6000 PF SPRINT 2x0 Hydrogen	$466.75	$4,690.95	76.1	99.5	9,477	$21.52	$10.66	N/A

1. “Summer Rating” and “Winter Rating” represents nameplate rating; summer and winter ratings are less than nameplate ratings shown.
2. For battery energy storage options and nuclear options, the capital costs shown in this table reflect a 30% investment tax credit (ITC). It has been assumed that beginning in 2034 the ITC is reduced to 22.5% and further reduced to 15% in 2035, with no subsequent ITC.

The total delivered cost of natural gas was estimated by adding the estimated cost of natural gas transportation to the natural gas commodity price forecasts. These transportation costs include high-pressure interstate transportation from Henry Hub to Florida and low-pressure transportation and distribution across the local gas distribution utility PGS. The forecasted costs of transportation and distribution were developed in close coordination with the JEA fuels group and PGS, particularly with respect to JEA's existing natural gas transportation arrangements and incremental requirements for firm and interruptible gas delivery.

Diesel and coal price forecasts for the near-term are the six-month average settlement futures prices between July and December 2024 on NYMEX. Prices beyond the NYMEX futures horizon were derived based on the Energy Information Administrations (EIA's) Annual Energy Outlook (AEO) projected price growth rates for these fuels.

Table 6-3 shows the delivered fuel price assumptions for base case simulations in 2025 dollars per MMBtu. The delivered fuel price assumptions were escalated at the fuel inflation rate of 2.60 percent to arrive at the nominal fuel costs.

Table 6-3 Base Case Fuel Price Assumptions $2025/MMBtu

Year	Natural Gas ($/MMBtu)	Northside Units 1 and 2 ($/MMBtu)	Residual/Diesel Fuel Oil ($/MMBtu)
2026	$3.87	$4.73	$16.38
2027	$4.08	$4.75	$15.69
2028	$4.49	$4.76	$14.74
2029	$4.97	$4.84	$14.85
2030	$5.50	$4.84	$14.94
2031	$5.55	$4.83	$14.93
2032	$5.54	$4.83	$15.00
2033	$5.57	$4.86	$14.99
2034	$5.56	$4.85	$15.08
2035	$5.59	$4.84	$15.14
2036	$5.53	$4.86	$15.18
2037	$5.47	$4.90	$15.21
2038	$5.48	$4.79	$15.24
2039	$5.42	$4.79	$15.28
2040	$5.35	$4.79	$15.34
2041	$5.41	$4.79	$15.44
2042	$5.41	$4.79	$15.44
2043	$5.41	$4.80	$15.51
2044	$5.44	$4.79	$15.47

Year	Natural Gas ($/MMBtu)	Northside Units 1 and 2 ($/MMBtu)	Residual/Diesel Fuel Oil ($/MMBtu)
2045	$5.49	$4.80	$15.54
2046	$5.55	$4.81	$15.69
2047	$5.71	$4.82	$15.71
2048	$5.90	$4.83	$15.74
2049	$6.12	$4.85	$15.82
2050	$6.17	$4.86	$15.82
2051	$6.30	$4.87	$15.84
2052	$6.43	$4.87	$15.85
2053	$6.57	$4.87	$15.84
2054	$6.71	$4.86	$15.83
2055	$6.85	$4.85	$15.80
2056	$6.99	$4.84	$15.77
2057	$7.14	$4.83	$15.73
2058	$7.29	$4.81	$15.68
2059	$7.45	$4.79	$15.62
2060	$7.60	$4.76	$15.56

Black & Veatch also developed a high and a low fuel forecast for the required fuels. The high case Henry Hub price forecast assumed, depending on the year, approximately 10 to 15 percent higher demand from the power sector than in the base case and blended with the same NYMEX forward curves.

Black & Veatch derived the low case Henry Hub price forecasts leveraging the EIA AEO 2025 cases—specifically the “High Oil and Gas Supply, High Oil Prices, Low Economic Growth”, and “Low Zero-Carbon Technology” cases. For each case and each year, a price “scaler” was derived relative to the AEO reference case Henry Hub price projection. These scalers were then averaged across both EIA cases listed in the previous sentence and applied to Black & Veatch’s base case Henry Hub price forecasts to develop the low case prices.

Black & Veatch’s high and low case Henry Hub price forecasts are shown in Table 6-4, expressed in 2025 dollars.

Table 6-4 High and Low Fuel Price Assumptions, $2025/MMBtu

Year	High Fuel Price Forecast, $/MMBtu			Low Fuel Price Forecast, $/MMBtu		
	Natural Gas	NS CFB	Residual/ Diesel Fuel Oil	Natural Gas	NS CFB	Residual/ Diesel Fuel Oil
2026	$3.96	$4.73	$16.38	$3.75	$4.73	$16.38
2027	$4.44	$4.75	$15.69	$3.82	$4.75	$15.69
2028	$5.32	$4.76	$14.74	$4.08	$4.76	$14.74
2029	$5.91	$4.84	$14.85	$4.42	$4.84	$14.85
2030	$6.37	$4.84	$14.94	$4.79	$4.84	$14.94
2031	$6.46	$4.83	$14.93	$4.80	$4.83	$14.93
2032	$6.19	$4.83	$15.00	$4.69	$4.83	$15.00
2033	$6.26	$4.86	$14.99	$4.56	$4.86	$14.99
2034	$6.30	$4.85	$15.08	$4.48	$4.85	$15.08
2035	$6.42	$4.84	$15.14	$4.47	$4.84	$15.14
2036	$6.34	$4.86	$15.18	$4.42	$4.86	$15.18
2037	$6.24	$4.90	$15.21	$4.37	$4.90	$15.21
2038	$6.15	$4.79	$15.24	$4.40	$4.79	$15.24
2039	$6.05	$4.79	$15.28	$4.41	$4.79	$15.28
2040	$5.96	$4.79	$15.34	$4.37	$4.79	$15.34
2041	$6.01	$4.79	$15.44	$4.44	$4.79	$15.44
2042	$6.00	$4.79	$15.44	$4.42	$4.79	$15.44
2043	$6.00	$4.80	$15.51	$4.34	$4.80	$15.51
2044	$6.04	$4.79	$15.47	$4.36	$4.79	$15.47
2045	$6.08	$4.80	$15.54	$4.40	$4.80	$15.54
2046	$6.14	$4.81	$15.69	$4.45	$4.81	$15.69
2047	$6.32	$4.82	$15.71	$4.53	$4.82	$15.71
2048	$6.43	$4.83	$15.74	$4.68	$4.83	$15.74
2049	$6.62	$4.85	$15.82	$4.87	$4.85	$15.82
2050	$6.65	$4.86	$15.82	$4.91	$4.86	$15.82
2051	$6.76	$4.87	$15.84	$5.01	$4.87	$15.84
2052	$6.87	$4.87	$15.85	$5.11	$4.87	$15.85
2053	$6.98	$4.87	$15.84	$5.21	$4.87	$15.84
2054	$7.10	$4.86	$15.83	$5.32	$4.86	$15.83

Year	High Fuel Price Forecast, $/MMBtu			Low Fuel Price Forecast, $/MMBtu		
	Natural Gas	NS CFB	Residual/ Diesel Fuel Oil	Natural Gas	NS CFB	Residual/ Diesel Fuel Oil
2055	$7.21	$4.85	$15.80	$5.42	$4.85	$15.80
2056	$7.33	$4.84	$15.77	$5.53	$4.84	$15.77
2057	$7.45	$4.83	$15.73	$5.64	$4.83	$15.73
2058	$7.57	$4.81	$15.68	$5.75	$4.81	$15.68
2059	$7.69	$4.79	$15.62	$5.87	$4.79	$15.62
2060	$7.82	$4.76	$15.56	$5.99	$4.76	$15.56

6.4.6 Existing JEA NGS Generation and Bridge Purchase Assumptions

For the 35-year planning period, it was necessary to make assumptions about the operation and possible retirement dates for the three largest JEA NGS units. Based on JEA's current plans, the updated analysis assumed that NGS Unit 3 would continue normal operation until new generation is commercially operable at which time, NGS Unit 3 would be placed in limited use status limited to operating on fuel oil, serving as a back-up resource during peak demand periods, system emergencies, or unexpected equipment outages and limited to fuel oil. JEA's analysis assumes NGS Unit 3 will be taken out of service in 2035. NGS Units 1 and 2 are assumed to continue operating without limitations during the planning period.

As described elsewhere in this Study, JEA has a need for additional capacity beginning in the winter of 2028. For purposes of the updated PLEXOS® evaluations, JEA assumed that short-term bridge purchases would be utilized to meet capacity needs through 2030, given the time required to bring a new generating resource into service.

6.4.7 Results

6.4.7.1 Base Case and Next Lowest Cost Alternative

For the Base Case, the PLEXOS® modeling indicates the addition of a 7HA.03 678 MW (net winter output) 1x1 advanced class combined cycle (the proposed SJRPP Unit 3) with an in-service date of 2031 is included in the resource plan having the lowest CPWC. The CPWC of the resource plan including the proposed SJRPP Unit 3 plan is approximately $27,359 million, which is approximately $92 million lower in cost than the next lowest cost resource plan (Next Lowest Cost Alternative).

The Next Lowest Cost Alternative is the resource plan which utilizes the Base Case assumptions but does not allow the model to select the addition of a combined cycle unit in 2031 for the purpose of comparing the cost of the Base Case to the next lowest cost alternative. This Next Lowest Cost Alternative resource plan includes the addition of a 7HA.03 simple cycle combustion turbine in 2031 followed by a 7HA.03 1x1 advanced class combined cycle plus a 7HA.03 simple cycle in 2035. Importantly, the Next Lowest Cost Alternative resource plan would still include the addition of combined cycle technology in the relatively near-term, essentially reflecting a 4-year delay of the addition of the proposed SJRPP Unit 3 as compared to the Base Case least-cost resource plan, further confirming JEA's need for SJRPP Unit 3.

6.4.7.2 Sensitivity Analyses

In recognition that forecasting key modeling inputs and assumptions over a 35-year timeframe involves some uncertainty, JEA performed a number of sensitivity analyses:

- Delay of the Unit 1 Year – Reflects delaying the addition of SJRPP Unit 3 from 2031 to 2032.
- High Load Growth – Reflects a 0.74 percent average annual growth rate with the winter peak starting at 2,991 MW in 2026 and ending at 3,847 MW in 2060. The summer peak is projected to increase from 2,858 MW in 2026 to 3,959 MW in 2060, a 0.93 percent average annual growth rate. The overall average annual growth rate in system peak that accounts for the shift in system peak from winter to summer is 0.83 percent. The NEL was projected to increase at an average annual rate of 0.92 percent in the high load growth case, from 13,787 GWh in 2026 to 18,795 GWh in 2060.
- Low Load Growth – Reflects a 0.74 average annual growth rate with the winter peak starting at 2,810 MW in 2026 and ending at 3,612 MW in 2060. The summer peak is projected to increase from 2,685 MW in 2026 to 3,736 MW in 2060, a 0.98 percent average annual growth rate. The overall average annual growth rate in system peak that accounts for the shift in system peak from winter to summer is 0.84 percent. The NEL was projected to increase at an average annual rate of 0.92 percent in the low load growth case, from 12,984 GWh in 2026 to 17,751 GWh in 2060.
- High Natural Gas Prices – Reflects the high natural gas price as shown in Table 6-4.
- Low Natural Gas Prices – Reflects the low natural gas price as shown in Table 6-4.
- High Capital Cost – Reflects a 10 percent higher capital cost than shown in Table 6-2 for natural gas, nuclear, hydrogen, and solar PV resources.

6.5 Results of the Expansion Planning Model Runs

The results of the PLEXOS® simulations for the Base Case and the sensitivity cases listed above are shown in Table 6-5. As shown in Table 6-5, in all cases and sensitivities (with the exception of the Next Lowest Cost Alternative and one-year delay sensitivities, in which the model was not allowed to choose the combined cycle in 2031), the combined cycle was selected as the preferred incremental resource and part of the least-cost plan.

As shown in Table 6-5:

- Denying the addition of SJRPP Unit 3 in 2031 would increase the CPWC by $92 million, and the lowest cost resource plan (Next Lowest Cost Alternative) that does not include the addition of SJRPP Unit 3 includes an equivalent 7HA.03 1x1 combined cycle in 2035.
- Delaying the proposed SJRPP Unit 3 from 2031 until 2032 would increase the CPWC of the resource plan by $20 million as compared to the Base Case resource plan that includes the addition of SJRPP Unit 3 in 2031.

Table 6-5 CPWC Results for Base Case and Sensitivities

Case Description	CPWC ($ Millions)	Resource Addition Selected for 2031
Base Case (Least-cost)	$27,359	7HA.03 1x1 CC (SJRPP Unit 3)
Next Lowest Cost Alternative (Base Case, but not allowed to build 1x1 CC in 2031)	$27,451	1x0 GE 7HA.03 Simple Cycle (7HA.03 1x1 CC added in 2035)
Delay of the Unit 1 Year	$27,379	7HA.03 1x1 CC (in 2032) (SJRPP Unit 3)
High Load Growth	$28,191	7HA.03 1x1 CC (SJRPP Unit 3)
Low Load Growth	$25,723	7HA.03 1x1 CC (SJRPP Unit 3)
High Natural Gas Prices	$28,661	7HA.03 1x1 CC (SJRPP Unit 3)
Low Natural Gas Prices	$24,780	7HA.03 1x1 CC (SJRPP Unit 3)
High Capital Cost	$27,747	7HA.03 1x1 CC (SJRPP Unit 3)

7.0 Evaluation of Non-Generating Alternatives

JEA is subject to the Florida Energy Efficiency and Conservation Act (FEECA), section 366.82, Florida Statutes, which requires the Commission to adopt and periodically review JEA's conservation goals. JEA's current numeric conservation goals were established by the Commission in 2024.[6] Subsequently, the Commission approved JEA's 2025 Demand-Side Management Plan (2025 DSM Plan). JEA continues to implement DSM programs that are beneficial and meet JEA's FEECA goals as well as additional programs that are beneficial. Projected demand and energy reductions associated with JEA's existing DSM programs are reflected in the load forecast and associated projected need for capacity discussed throughout Section 5 herein, which demonstrates JEA's need for capacity beyond the demand reductions projected to result from JEA's DSM programs.

7.1 Current Conservation & Demand-Side Management

7.1.1 DSM Programs Included in JEA's 2025 DSM Plan

JEA offers the following DSM programs that are included in JEA's 2025 DSM Plan:

- Energy Survey Programs: Free efficiency assessments to residential, commercial, and industrial customers. The JEA representative breaks down the customer's utility consumption into components to discuss with the customer and conducts a walk-through inspection to identify where improvements can be made.
- Residential Home Efficiency Upgrades Rebates Program: The Residential Home Efficiency Upgrades Rebates Program consists of incentives (rebates) for customers to improve the efficiency of their homes through the installation of qualifying heat pump water heaters, improvements to the heating, ventilation, and air conditioning (HVAC) systems, or ceiling insulation.
- Residential Energy Efficient Products Rebates Program: The Residential Energy Efficient Products Rebates Program consists of incentives (rebates) for customers to improve the efficiency of their homes through the installation of ENERGY STAR clothes washers, room air conditioners, and smart thermostats.
- Residential Neighborhood Energy Efficiency Program: Offers education concerning the efficient use of energy and water as well as the direct installation of an array of energy and water efficient measures at no cost to income-qualified customers.
- Commercial/Industrial Prescriptive Lighting Rebates Program: Pays a financial incentive to customers to install high efficiency lighting technology.

7.1.2 Additional DSM Programs

In addition to the DSM programs included in JEA's 2025 DSM Plan (as described above), JEA offers the following programs to its customers as of the date of this report.

- Energy Efficient Products, which pays a financial incentive to encourage the use of high efficiency appliances.

[6] In re: Commission review of numeric conservation goals (JEA), Docket No. 20240016-EG, Order No. PSC-2024-0432-FOF-EG (Sept. 20, 2024).

- MyWay Prepaid Program, which is available to all residential customers and especially appropriate for those who prefer to prepay for services. It is consumer-focused experience for environmentally conscious consumers who like to keep consumption in mind. Customers who participate in prepaid programs, like MyWay, typically reduce consumption because they're frequently informed of how they're using their utilities.
- Commercial Prescriptive Program, which pays a financial incentive to encourage the use of high efficiency HVACR, cooking and water heating products and services.
- Small Business Program, which promotes the use of high efficiency HVAC, water heating, and appliances in the small business sector.
- Custom Commercial Program, which promotes the use of custom efficiency measures based on the specific application for each customer.

JEA's overall DSM achievements in 2025 through FEECA programs were a winter peak reduction of 1,545 kW, a summer peak reduction of 1,758 kW, and an energy reduction of 9,738 MWh. Through non-FEECA DSM programs, JEA achieved a winter peak reduction of 103 KW, a summer peak reduction of 201 kW, and an energy reduction of 1,043 MWh.

7.2 Potential for Conservation and DSM Savings to Mitigate Need

JEA's forecast of resource needs presented in Section 5 herein takes into account projected reductions associated with the DSM programs included in JEA's 2025 DSM Plan and approved by the Commission, as well as JEA's additional conservation efforts. The DSM goals and programs proposed by JEA and approved by the Commission were based on the evaluations of technical, economic, and achievable potential conducted by Resource Innovations and presented in a DSM Market Potential Study (MPS) in 2024. To ensure that the analysis regarding the ability of reasonably available conservation measures to mitigate the need for SJRPP Unit 3 was as current as possible, Resource Innovations performed an update of the analysis, as described below.

Resource Innovations utilized the framework of the 2024 FEECA MPS, including customer segmentation, forecast disaggregation, and DSM measure impacts, and applied updates that aligned with JEA's current load and economic forecasts. The updated MPS found no material change in energy efficiency (EE) achievable potential as compared to the 2024 FEECA MPS -- 0.01 MW in 2031, 0.02 MW in 2033, and 0.02 MW in 2035 for winter peak savings, and 0.06 MW in 2031, 0.07 MW in 2033, and 0.09 MW for summer peak savings. For demand response (DR), the updated MPS resulted in achievable potential of 50.2 MW in 2031, 60.2 MW in 2033, and 68.0 MW for winter peak savings, and 49.3 MW in 2031, 59.7 MW in 2033, and 67.9 MW in 2035 for the summer peak savings. The DR potential reflects maximum achievable potential and is not reflective of what may be practicably achievable by JEA as it included several measures competing for the same load and did not consider practical limitations to implementation. Even if JEA could practicably and cost-effectively realize the full achievable DR potential described above, it falls well short of mitigating the need for SJRPP Unit 3. To mitigate the need for SJRPP Unit 3, JEA would need more than 30 times the amount of DSM reflected in JEA's current goals for 2031 and 46 times the amount of DSM JEA achieved. The updated MPS confirms that there are no additional cost-effective, reasonably available conservation or DSM measures to mitigate the need for SJRPP Unit 3.

8.0 Adverse Consequences of Denial

As discussed throughout this Need Study, JEA will require additional capacity to maintain winter and summer reserve margin requirements beginning as early as the winter of 2028, with the need for capacity increasing significantly over the 2031 through 2035 period and consistently increasing thereafter. JEA's projected need for capacity is influenced by a number of factors, including projected load growth (winter and summer peak demand as well as annual energy requirements) and the assumption that NGS Unit 3 is removed from service beginning in 2035. Figure 8-1 illustrates JEA's projected need for additional capacity to maintain reserve margin requirements.

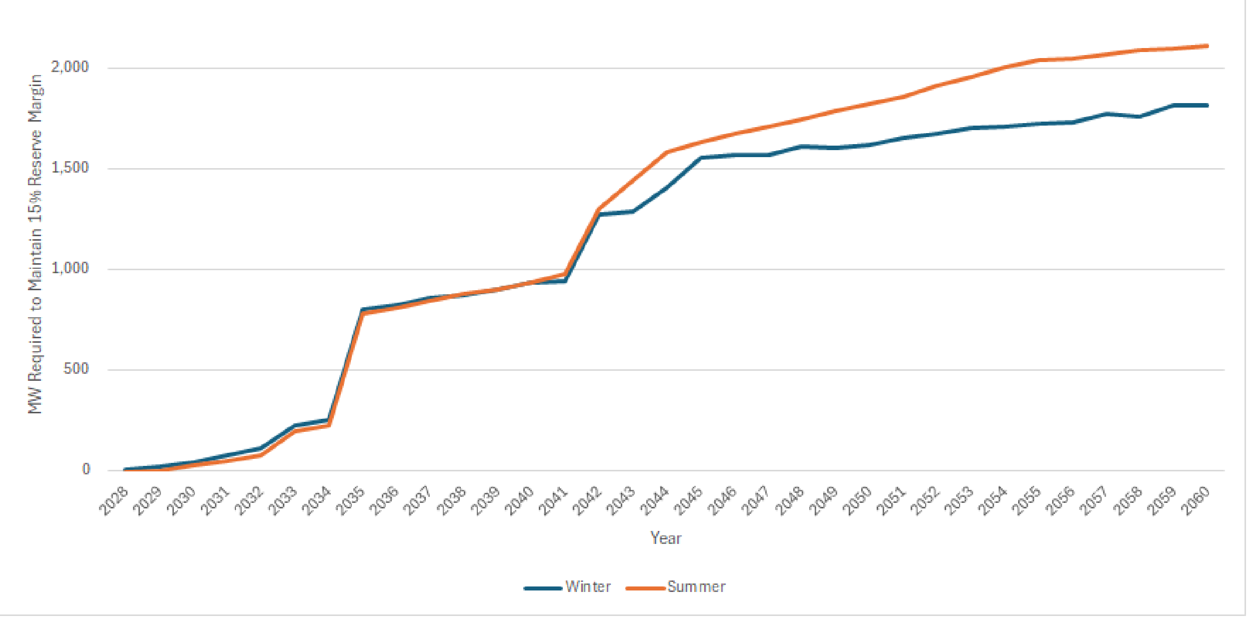

Figure 8-1 JEA's Projected Need for Capacity

The analysis presented throughout this Need Study demonstrates that the addition of SJRPP Unit 3 in 2031 is part of JEA's least-cost (most economic) resource plan to reliably meet JEA's forecast demand (peak demand and annual energy requirements) for JEA's base case (expected capital costs, loads, and fuel prices) as well as sensitivities that encompass a wide range of variations to capital costs, load forecasts, and fuel price projections. SJRPP Unit 3 is the most cost-effective alternative under the base case and all sensitivities. For the base case evaluations, the least-cost resource plan including SJRPP Unit 3 in 2031 is approximately $92 million lower in CPWC than the least-cost resource plan that does not include SJRPP Unit 3 in 2031. It is important to note that the least-cost resource plan within the base case evaluations that does not include SJRPP Unit 3 in 2031 includes a similar advanced class, 1x1 combined cycle in 2035, which is essentially just a delay in the addition of a unit similar to SJRPP Unit 3 for a 4 year period, further demonstrating the benefit to JEA's system (and customers) of the addition of an advanced class, combined cycle resource such as SJRPP Unit 3.

Reflected in the economic analysis is the benefit of JEA being able to place NGS Unit 3 in limited use on liquid fuel which also serves to make more efficient use of natural gas by utilizing natural gas in SJRPP Unit 3 rather than NGS Unit 3, reflecting an efficiency improvement of approximately 37 percent. Not only does the addition of SJRPP Unit 3 result in more efficient utilization of natural gas, increasing fuel diversity by reducing reliance on natural gas per unit of electricity generated, SJRPP Unit 3 will allow JEA to reduce CO_2 emissions, as SJRPP Unit 3 will have a CO_2 emissions rate of 0.37 tons CO_2 per MWh, as compared to NGS Unit 3's CO_2 emissions rate of 0.59 tons CO_2 per MWh. For illustrative purposes, the least-cost resource plan including the addition of SJRPP Unit 3 in 2031 as compared to the least-cost resource plan that does not include SJRPP Unit 3 in 2031 is projected to decrease CO_2 emissions by 5.7 million tons; as noted above, this reduction in CO_2 essentially occurs over only a 4 year period as the least-cost resource plan without SJRPP Unit 3 in 2031 includes a similar advanced class combined cycle in 2035.

Non-approval of the requested need determination would mean that JEA's customers would be denied the most cost-effective option to meet JEA's need while providing flexibility relative to dispatch and operations to enhance grid reliability and mitigate risk. Further, if SJRPP Unit 3 is not approved, JEA would be unable to place NGS Unit 3 into limited use and would instead have to continue to rely on a less efficient resource that is approaching the end of its ability to continue to operate reliably. The cost to upgrade NGS Unit 3 to allow continued operation absent SJRPP Unit 3 would exceed $834 million.

JEA's required reserve margin is projected to fall below the minimum reserve level beginning in the winter of 2028 with increasing capacity requirements thereafter. While additional off-system purchases could perhaps be made to contribute towards maintaining the target reserve margin, this would require importing increasingly large volumes of power (72 MW by 2031, increasing to 222 MW by 2033 and 802 MW by 2035). The current configuration of JEA's transmission system could not support importing this amount of power and would require substantial and costly upgrades; further, the timing of such transmission system upgrades may not be feasible to meet JEA's needs.

9.0 Conclusions

As demonstrated throughout this Need Study, SJRPP Unit 3 affirmatively addresses the criteria set forth in Section 403.519(3), Florida Statutes, and as such the Florida Public Service Commission should approve the addition of SJRPP Unit 3.

JEA performed a robust analysis of supply-side (including technically and commercially viable renewable energy and energy storage resources), including a transparent and competitive process to solicit power supply proposals as potential alternatives to SJRPP Unit 3 that was overseen by an independent evaluator. As discussed throughout this Need Study, JEA's resource planning process and analysis demonstrates that the proposed SJRPP Unit 3 is the most cost-effective and system-beneficial way for JEA to continue to reliably serve its customers, and there are no alternatives (including renewable and energy storage) that are more cost-effective than the proposed SJRPP Unit 3.

SJRPP Unit 3 will provide reliable dispatchable power, allow for more efficient use of natural gas, reduce system CO_2 emissions, provide support to reliably integrate power import into the JEA system, enhance flexibility and reliability, and help avoid costly updates that would otherwise be necessary to extend the life of JEA's existing NGS unit 3. JEA offers numerous DSM programs to its customers to support reductions in peak demand and energy requirements There are no reasonably available, cost-effective conservation measures to mitigate the need for the proposed SJRPP Unit 3.

Denial of the proposed SJRPP Unit 3 would mean that JEA and its customers would be denied the most cost-effective, system-beneficial, power supply solution to meet JEA's need while providing flexibility relative to dispatch and operations to enhance grid reliability and mitigate risk. JEA estimates that the CPWC impact of the denial of a need determination for SJRPP Unit 3 would be approximately $92 million. A delay of just one year would have CPWC economic impacts of approximately $20 million.

Attachment A. JEA 2026 Ten-Year Site Plan

Building Community®

TEN-YEAR SITE PLAN

April 2026

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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.

This Ten-Year Site Plan (TYSP) provides information and data that will facilitate the FPSC's review. The 2026 TYSP provides information related to JEA's power supply strategy to adequately meet the forecasted needs of its customers for the planning period from January 1st, 2026 through December 31st, 2035. 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 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	Jacksonville, FL	GT	NG	DFO	PL	WA	06/2000	(a)	203,800	173,200	179	191	Utility	OP
	8	Jacksonville, FL	GT	NG	DFO	PL	WA	06/2009	(a)	224,000	173,200	179	191	Utility	OP
Northside										1,601,856	1,407,100	1,310	1,356		
	1	Jacksonville, FL	ST	PC	BIT	WA		05/2003	(a)	350,000	297,500	293	293	Utility	OP
	2	Jacksonville, FL	ST	PC	BIT	WA		04/2003	(a)	350,000	297,500	293	293	Utility	OP
	3	Jacksonville, FL	ST	NG	RFO	PL	WA	07/1977	01/2035	626,300	563,700	524	524	Utility	OP
	33-36	Jacksonville, FL	GT	DFO		TK		01/1975	(a)	275,556	248,400	200	246	Utility	OP
Brandy Branch										946,200	745,100	758	831		
	1	Jacksonville, FL	GT	NG	DFO	PL	TK	05/2001	(a)	203,800	173,200	179	191	Utility	OP
	2	Jacksonville, FL	CT	NG		PL		05/2001	(a)	237,000	173,200	190	212	Utility	OP
	3	Jacksonville, FL	CT	NG		PL		10/2001	(a)	237,000	173,200	190	212	Utility	OP
	4	Jacksonville, FL	CA	WH				01/2005	(a)	268,400	225,500	200	216	Utility	OP
Greenland Energy Center										448,000	346,400	357	382		
	1	Jacksonville, FL	GT	NG	DFO	PL	TK	06/2011	(a)	224,000	173,200	179	191	Utility	OP
	2	Jacksonville, FL	GT	NG	DFO	PL	TK	06/2011	(a)	224,000	173,200	179	191	Utility	OP
JEA System Total												**2,782**	**2,952**		

Notes:

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

(b) Numbers may not add to JEA System Total 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. An increase of up to 100 MW in capacity and transmission service for the Cooperation Agreement was approved by the JEA Board to help meet JEA's growing demand. The agreement is in final negotiations for an 80 MW increase in capacity, starting June 1, 2026.

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 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 OnSite Partners, LLC (formerly American Electric Power OnSite Partners). 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 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 of four facilities, totaling 280 MW_{AC} of solar and energy storage systems, to Florida Renewable Partners (FRP). Contracts for four facilities were originally in negotiations, and due to costly wetland impacts at the proposed Peterson Solar Energy Center, the scope was narrowed to the following: Forest Trail Solar Energy Center, 50 MW_{AC}; Caldwell Solar Energy Center, 74.9 MW_{AC}, and Miller Solar Energy Center, 74.9 MW_{AC}, with the Caldwell and Miller Solar Energy Centers each paired with a 50 MW, 4-hour battery energy storage system. As the projects phased through development, the evolving macroeconomic climate for renewables resulted in the termination of the Caldwell Solar Energy Center and battery energy storage system as of November 13, 2025. The project scope has now been optimized to a total of two renewable energy facilities: Miller Solar Energy Center, 74.9 MW_{AC}, paired with 50 MW, 4-hour battery energy storage system, and Forest Trail Solar Center, 50 MW_{AC}. JEA and FRP have executed power purchase agreements, lease option contracts, and energy storage agreements for the projects. Both facilities are expected to be commissioned by December 31st, 2026.

JEA entered into a 20-year solar agreement with the Florida Municipal Power Agency (FMPA) to purchase approximately 150 MW_{AC} from two facilities located in Florida. The projects were scheduled to commission in December 2026, but were delayed to October 2028, due to longer network upgrade timelines and other nationwide challenges with solar project development. Resultantly, in June 2025, the FMPA Board of Directors approved the termination of the solar agreement and JEA was released of its obligations.

Many factors have negatively impacted the economics of new solar development, including the elimination of subsidies on utility-scale solar projects. In addition, several planned solar projects in which JEA intended to participate were cancelled; transmission/interconnection equipment supply chain issues persist and continue to impact project costs and schedule; and finding appropriately sized, environmentally suitable land to support utility-scale solar in Duval County is prohibitively expensive such that extensive transmission upgrades would be necessary to import solar power to JEA's system. JEA will continue to evaluate cost-effective solar as part of its resource planning process.

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.

Vogtle Units 3 and 4 were commissioned on July 31st, 2023 and April 29th, 2024, respectively. Each unit is supplying approximately 103 MW of net firm capacity to JEA.

In February 2026, the JEA Board approved sale of up to 206 MW of Vogtle capacity and energy to Dalton Utilities and Santee Cooper from 2027 – 2032. To support the sale commitments, JEA will be purchasing 150 MW of firm capacity, energy, and transmission, with an option for an additional 50 MW to serve native load. This agreement, noted as the “TEA Backfill Purchase” in Table 5 (see Section 3.2 herein), is in final negotiations.

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**	07/31/2023	07/31/2043	103	Annual
	Unit 4	04/29/2024	04/29/2044	103	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
Forest Trail Solar PPA		12/31/26	12/31/61	50	Annual
Miller Solar PPA		12/31/26	12/31/61	74.9	Annual

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.

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 94 percent of JEA's distribution load, including 57 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 smaller loads that are within the boundaries of the 4.16 kV or 13.2 kV systems. JEA has approximately 7,607 miles of distribution circuits of which approximately 59.2 percent is underground.

1.3 Clean Energy

1.3.1 JEA Clean Energy Goals

On April 25th, 2023, JEA's Board of Directors approved clean energy goals. JEA has incorporated a significant amount of clean energy into its power supply portfolio, including numerous solar power purchase agreements, and continues to explore opportunities to incorporate additional clean energy while ensuring alignment with system reliability, affordability, and adaptability. Given regulatory changes and other factors affecting practicality and affordability, as well as unprecedented load growth, JEA continues to evaluate the current cost and practical ability to meet the aspirational clean energy goals and will utilize information from its next Integrated Resource Plan to inform leadership decisions moving forward. As such, JEA is not incorporating assumptions relative to its aspirational clean energy goals in this Ten-Year Site Plan.

1.3.2 Renewable Energy

1.3.2.1 JEA Distributed Energy

JEA has Solar PV systems installed at various customer sites in the community such as the Chamber of Commerce, Jacksonville University, a fire station and multiple Duval County public school locations that are approximately 100kW in total. However, all of these systems are at end of life and next step options are being evaluated.

In 2009 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 allowed existing customers the option to be grandfathered under the 2014 Net Metering Policy for a period of 20 years. When JEA enacted the DG Policy on April 1st, 2018, JEA rolled out a residential Battery Incentive Program pilot. The pilot, subject to lawfully appropriated funds, provided financial incentive towards the cost of an energy storage system. Used in concert with the 2018 DG Policy, the pilot was intended to assist customers in being efficient energy users. Customers who elected 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 were subject to review and change to optimize adoption. Between the inception of the pilot and July 2022 when the pilot ended, over 700 residential storage systems have been installed.

1.3.2.2 Renewable Energy Credits (REC)

JEA has acquired 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, a portion of those attributes have been inventoried. In 2025, JEA certified over 150,000 Solar RECs under the Green-e® Energy certification structure and tracked over 300,000 landfill gas RECs through the North America Renewables (NAR) registry.

1.3.2.3 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 percentage (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 was 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 allowed large business customers to choose to have up to 100 percent of their energy needs met by solar power, with the SolarMax rate replacing their fuel charge. JEA then retires the RECs commensurate with their consumption in NAR. Companies selected either a five or ten-year contract term. The program is currently closed to new customers as JEA fulfills the contractual obligations of the current customers, while continuing to explore other innovative programs to offer.

1.3.2.4 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.

1.3.2.4 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 biomass (approximately up to 240 tons per day) in Northside Unit 2 due to the high price of petroleum coke. 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 1,000 tons per day of biomass in Northside units 1 and 2. JEA continues to co-fire biomass when available and economically beneficial.

1.3.3 Clean Energy Research Efforts

1.3.3.1 Collaboration with University of North Florida

JEA's clean energy research efforts have focused on the development of clean energy 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.
- JEA, Miller Electric, and UNF have joined forces under the DOE-backed "Emerge" initiative to train the next generation of energy professionals. Through hands-on training, industry certifications, and expert mentorship, EMERGE equips participants with cutting-edge skills in renewable energy and microgrid technologies. This program is shaping the “Technician of the Future,” preparing a workforce capable of building and maintaining resilient, sustainable energy systems to meet the demands of an evolving grid.
- 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 contributing $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.

1.3.3.2 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 projects will also host 50 MW of BESS alongside the 75 MW_{AC} Miller solar facility. JEA will continue to evaluate the integration of additional storage resources as future studies are conducted.

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, demand-side management (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 accounts and CBRE Jacksonville for total commercial inventory square footages. JEA develops its annual forecast using SAS and Microsoft Office Excel.

JEA's Calendar Year 2026 baseline forecast used 10 years of historical data. Using the shorter period allows JEA to capture the most 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 sales, total population, number of households, median household income and 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 sales, total commercial employment and gross domestic product from Moody's Analytics, JEA's total commercial accounts, and commercial inventory square footage from the CBRE Jacksonville Office Figures Q3 2025 Report.

The industrial energy forecast was developed using multiple regression analysis of weather normalized historical industrial energy sales, gross domestic product, total industrial employment, and total proprietors' profits from Moody's Analytics, and JEA's total industrial accounts. The first 7 years of the forecast also incorporate confirmed new development projects and their expected demand, as well as increase consumption from existing industrial customers due to expansion.

The lighting energy forecast was developed using the historical actual energy and number of luminaries. 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.

JEA's forecasted Compounding Annual Growth Rate (CAGR) for net energy for load during the TYSP period is 1.43 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 CAGR for net firm peak demand during the TYSP period is 1.32 percent for summer and 1.36 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 120 MW of interruptible peak load for the summer and 107 MW for the winter which remain constant throughout the study period. For 2026, the interruptible load represents 3.7 percent of the forecasted total peak demand in the summer and 3.4 percent of the forecasted total peak demand in the winter.

2.3.2 Demand-Side Management Programs

JEA continues to offer DSM programs as included in JEA's 2025 Demand-Side Management Plan (approved by the Florida Public Service Commission in April 2025) that contribute to meeting JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals, as well as additional programs that are economically beneficial. 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 associated with its current DSM programs is shown in Table 2. JEA's current and planned DSM programs are summarized by commercial/industrial and residential programs in Table 3.

Table 2: DSM Portfolio – Energy Efficiency Programs

ANNUAL INCREMENTAL		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy (GWh)	Residential	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04
	Commercial/ Industrial	11.36	11.36	11.36	11.36	11.36	11.36	11.36	11.36	11.36	11.36
	Total	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**	**23.40**
Summer Peak (MW)	Residential	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26
	Commercial/ Industrial	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08
	Total	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**	**4.34**
Winter Peak (MW)	Residential	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28
	Commercial/ Industrial	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01
	Total	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**	**4.29**

Table 3: DSM Programs

Commercial/Industrial Programs	Residential Programs
Commercial/Industrial Energy Assessment Program	Residential Energy Assessment Program
Commercial/Industrial Prescriptive & Prescriptive Lighting Program	Residential Home Efficiency Upgrades Program
Commercial/Industrial Custom Program	Residential Energy Efficient Products Program
Small Business Program	Residential Neighborhood Energy Efficiency (NEE) Program

2.4 Customer-Sited Renewables

A customer-sited renewables analysis on rooftop solar PV and battery storage installation was conducted by Resource Innovations group for JEA.

The customer-sited solar PV analysis accounted for available roof space (including pitched versus 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. 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 and other costs using the extensive sensitivity analysis capabilities of the modeling software.

The battery storage analysis focused primarily on potential for paired solar and 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 solar-paired storage systems, accounting for electric rate structure, system characteristics, customer load profile, and solar PV generation profile.

The potential peak demand and energy reductions associated with the customer-sited renewable analysis are reflected in JEA’s 2026 TYSP forecast. JEA removes from the total load forecast all seasonal, coincidental non-firm sources and adds the different sources of additional demand, to derive a firm load forecast.

2.5 Plug-in Electric Vehicles Peak Demand and Energy

The forecasts of demand and energy associated with PEVs 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 forecasted 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 Average Annual Growth Rate (AAGR) for PEVs summer and winter coincidental peak demand of 41.18 percent and 35.39 percent, respectively, and total energy of 34.86 percent during the TYSP period.

2.6 Electrification

JEA's electrification load forecast has been updated to reflect the most current approved program goals and actual performance for the Electrification Rebate Program (ERP) and Fleet Electrification Program (FEP). The forecast aligns with updated annual targets through fiscal year 2027 for FEP and fiscal year 2028 for ERP, with the final year levels extended through the remainder of the planning horizon.

ERP goals were developed using a balanced approach informed by both the ICF (2019) and EPRI (2025) market potential studies, reflecting updated assessments of convertible load and evolving market conditions. Recent program performance has met or exceeded established goals, and the revised forecast incorporates these realized results.

The ERP contract was renewed in 2026, supporting continued program implementation through fiscal year 2028. Beyond the current contract term, the forecast assumes continued program activity at levels generally consistent with recent performance. However, consistent with market potential analyses, electrification opportunities are expected to diminish around 2030 as market saturation increases, potentially resulting in a gradual moderation of incremental load growth in the outer years of the planning 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)	(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
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	13,348,772
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	6,022	470,564	12,797	4,104	56,724	72,359	2,691	203	13,254,576
2025	6,081	479,288	12,641	4,194	57,376	73,096	2,648	198	13,389,674
2026	6,075	485,840	12,504	4,022	58,168	69,136	2,754	211	13,054,071
2027	6,174	492,159	12,546	4,027	58,935	68,335	3,033	215	14,107,857
2028	6,262	498,274	12,568	4,035	59,713	67,577	3,285	219	15,001,436
2029	6,351	504,171	12,597	4,046	60,504	66,865	3,357	222	15,120,763
2030	6,441	509,869	12,633	4,057	61,311	66,176	3,427	224	15,297,656
2031	6,531	515,323	12,674	4,070	62,134	65,498	3,475	227	15,307,034
2032	6,620	520,487	12,719	4,082	62,969	64,829	3,526	230	15,329,031
2033	6,707	525,330	12,766	4,097	63,813	64,196	3,544	233	15,209,228
2034	6,794	529,885	12,822	4,109	64,666	63,548	3,567	236	15,114,511
2035	6,892	534,234	12,901	4,122	65,527	62,901	3,600	240	14,999,094

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

Calendar Year	(11) Street & Highway Lighting GWH	(12) Other Sales to Ultimate Customers GWH	(13) Total Sales to Ultimate Customers GWH	(14) Sales for Resale GWH	(15) Utility Use & Losses GWH	(16) Net Energy for Load GWH	(17) Other Customers (Avg. Number)	(18) Total Number of Customers
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	56	0	12,873	60	321	13,255	0	527,491
2025	57	0	12,980	69	431	13,479	0	536,862
2026	57	0	12,908	0	479	13,386	0	544,219
2027	58	0	13,293	0	493	13,785	0	551,309
2028	58	0	13,641	0	506	14,147	0	558,206
2029	59	0	13,812	0	512	14,324	0	564,897
2030	59	0	13,984	0	518	14,503	0	571,404
2031	59	0	14,135	0	524	14,659	0	577,684
2032	60	0	14,288	0	530	14,817	0	583,686
2033	60	0	14,407	0	534	14,941	0	589,376
2034	61	0	14,531	0	539	15,070	0	594,787
2035	61	0	14,675	0	544	15,219	0	600,001

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.	
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	2,753	0	0	0	0	0	0	2,753
2024	2,675	0	0	0	0	0	0	2,675
2025	2,849	0	0	0	0	0	0	2,849
2026	2,896	120	0	0	0	2	2	2,772
2027	2,978	120	0	0	0	4	4	2,850
2028	3,066	124	0	0	0	6	6	2,930
2029	3,100	124	0	0	0	8	7	2,961
2030	3,140	124	0	0	0	10	9	2,997
2031	3,170	124	0	0	0	12	11	3,023
2032	3,201	124	0	0	0	13	12	3,052
2033	3,227	124	0	0	0	17	16	3,070
2034	3,251	124	0	0	0	18	17	3,092
2035	3,282	124	0	0	0	20	19	3,119

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.	
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	2,599	0	0	0	0	0	0	2,599
2022/23	2,326	0	0	0	0	0	0	2,326
2023/24	2,416	0	0	0	0	0	0	2,416
2024/25	2,913	0	0	0	0	0	0	2,913
2025/26	3,012	107	0	0	0	3	1	2,901
2026/27	3,103	107	0	0	0	6	2	2,988
2027/28	3,200	111	0	0	0	9	3	3,077
2028/29	3,238	111	0	0	0	10	3	3,114
2029/30	3,279	111	0	0	0	16	5	3,147
2030/31	3,309	111	0	0	0	14	4	3,180
2031/32	3,346	111	0	0	0	19	6	3,210
2032/33	3,370	111	0	0	0	25	8	3,226
2033/34	3,393	111	0	0	0	23	7	3,252
2034/35	3,420	111	0	0	0	26	8	3,275

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.	
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	13,255	0	0	0	0	0	0	13,255
2025	13,479	0	0	0	0	0	0	13,479
2026	13,409	0	0	0	0	12	11	13,386
2027	13,831	0	0	0	0	24	22	13,785
2028	14,216	0	0	0	0	36	33	14,147
2029	14,416	0	0	0	0	48	44	14,324
2030	14,618	0	0	0	0	60	55	14,503
2031	14,797	0	0	0	0	72	66	14,659
2032	14,978	0	0	0	0	84	77	14,817
2033	15,125	0	0	0	0	96	88	14,941
2034	15,277	0	0	0	0	108	99	15,070
2035	15,449	0	0	0	0	120	110	15,219

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 2025**		**Forecast 2026**		**Forecast 2027**		**Forecast 2028**	
	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	2,913	1,254	2,901	1,077	2,988	1,110	3,077	1,144
February	2,336	881	2,439	935	2,515	964	2,595	994
March	1,826	923	2,291	979	2,362	1,009	2,438	1,041
April	2,171	1,029	2,217	966	2,281	996	2,350	1,027
May	2,601	1,226	2,551	1,123	2,624	1,157	2,703	1,192
June	2,597	1,284	2,723	1,257	2,799	1,292	2,877	1,331
July	2,849	1,407	2,767	1,359	2,844	1,397	2,924	1,438
August	2,767	1,351	2,772	1,342	2,850	1,379	2,930	1,420
September	2,406	1,174	2,646	1,205	2,722	1,240	2,804	1,277
October	1,998	1,022	2,507	1,098	2,584	1,133	2,667	1,147
November	2,155	927	2,219	993	2,288	1,024	2,361	1,037
December	2,220	1,002	2,467	1,051	2,543	1,085	2,625	1,098
Annual Peak/ Total Energy	2,913	13,479	2,901	13,386	2,988	13,785	3,077	14,147

Schedule 5: Fuel Requirements

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Fuel	**Type**	**Units**	**Actual 2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
(1)	**NUCLEAR**													
		TOTAL	**TRILLION BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**COAL**[(a)]													
		TOTAL	**1000 TON**	**574**	**312**	**433**	**755**	**902**	**1,146**	**591**	**612**	**637**	**595**	**504**
	RESIDUAL													
(3)		STEAM	1000 BBL	7	15	0	5	0	0	31	7	34	100	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**	**7**	**15**	**0**	**5**	**0**	**0**	**31**	**7**	**34**	**100**	**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	36	4	7	17	4	18	2	2	6	14	0
(10)		**TOTAL**	**1000 BBL**	**36**	**4**	**7**	**17**	**4**	**18**	**2**	**2**	**6**	**14**	**0**
	NATURAL GAS													
(11)		STEAM	1000 MCF	15,741	19,502	22,746	18,647	14,530	12,390	77	81	85	93	72
(12)		CC	1000 MCF	31,237	29,572	27,273	29,249	28,365	27,395	55,677	55,686	54,388	55,399	56,112
(13)		CT/GT	1000 MCF	14,270	17,083	18,376	12,397	8,914	7,985	5,747	6,193	9,131	9,382	13,030
(14)		**TOTAL**	**1000 MCF**	**61,249**	**66,156**	**68,395**	**60,294**	**51,809**	**47,769**	**61,500**	**61,960**	**63,604**	**64,874**	**69,214**
(15)	**OTHER (BIOMASS)**													
		TOTAL	**1000 TON**	**28**	**123**	**171**	**298**	**356**	**452**	**233**	**241**	**251**	**235**	**199**

Note:

(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 2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
(1)	**Firm Inter-Region Interchange**		GWH	**2,521**	**1,769**	**3,069**	**3,383**	**3,484**	**3,106**	**1,967**	**1,961**	**1,214**	**1,279**	**1,014**
(2)	**Firm Inter-Region Interchange - Nuclear**		GWH	**1,613**	**1,693**	**0**	**0**	**614**	**818**	**828**	**885**	**1,634**	**1,634**	**1,765**
(3)	**NUCLEAR**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(4)	**COAL**[(a)]		GWH	**1,334**	**868**	**1,219**	**2,135**	**2,559**	**3,278**	**1,666**	**1,724**	**1,789**	**1,678**	**1,413**
(5)	**RESIDUAL**	STEAM	GWH	4	1	0	0	0	0	2	1	3	9	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**		**4**	**1**	**0**	**0**	**0**	**0**	**2**	**1**	**3**	**9**	**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	1	0
(11)		CT		16	1	2	6	1	6	1	1	1	3	0
(12)		**TOTAL**		**16**	**1**	**2**	**6**	**1**	**6**	**1**	**1**	**1**	**4**	**0**
(13)	**NATURAL GAS**	STEAM	GWH	1,482	2,023	2,379	1,934	1,491	1,246	0	0	0	0	0
(14)		CC		4,646	4,775	4,412	4,723	4,568	4,405	9,041	9,041	8,815	8,983	9,106
(15)		CT		1,300	1,509	1,733	1,150	816	737	510	551	826	846	1,327
(16)		**TOTAL**		**7,427**	**8,307**	**8,524**	**7,807**	**6,874**	**6,388**	**9,550**	**9,592**	**9,641**	**9,828**	**10,433**
(17)	**NUG**		GWH	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(18)	**RENEWABLES**	LANDFILL GAS	GWH	50	129	0	0	0	0	0	0	0	0	0
(19)		SOLAR		462	453	749	444	352	350	350	349	344	342	340
(20)		SOLARSMART/SOLARMAX[(b)]		24	24	24	24	24	24	24	24	24	24	24
(21)		**TOTAL**		**536**	**606**	**773**	**468**	**376**	**373**	**373**	**373**	**368**	**366**	**364**
(22)	**OTHER (BIOMASS)**		GWH	**28**	**141**	**198**	**348**	**417**	**534**	**271**	**281**	**291**	**273**	**230**
(23)	**NET ENERGY FOR LOAD**[(c)]		GWH	**13,479**	**13,386**	**13,785**	**14,147**	**14,324**	**14,503**	**14,659**	**14,817**	**14,941**	**15,070**	**15,219**

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 2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
(1)	**Firm Inter-Region Interchange**		%	**18.7**	**13.2**	**22.3**	**23.9**	**24.3**	**21.4**	**13.4**	**13.2**	**8.1**	**8.5**	**6.7**
(2)	**Firm Inter-Region Interchange - Nuclear**		%	**12.0**	**12.6**	**0.0**	**0.0**	**4.3**	**5.6**	**5.6**	**6.0**	**10.9**	**10.8**	**11.6**
(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)]		%	**9.9**	**6.5**	**8.8**	**15.1**	**17.9**	**22.6**	**11.4**	**11.6**	**12.0**	**11.1**	**9.3**
(5)	**RESIDUAL**	STEAM	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	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**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**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		0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		**TOTAL**		**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
(13)	**NATURAL GAS**	STEAM	%	11.0	15.1	17.3	13.7	10.4	8.6	0.0	0.0	0.0	0.0	0.0
(14)		CC		34.5	35.7	32.0	33.4	31.9	30.4	61.7	61.0	59.0	59.6	59.8
(15)		CT		9.6	11.3	12.6	8.1	5.7	5.1	3.5	3.7	5.5	5.6	8.7
(16)		**TOTAL**		**55.1**	**62.1**	**61.8**	**55.2**	**48.0**	**44.0**	**65.1**	**64.7**	**64.5**	**65.2**	**68.5**
(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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(19)		SOLAR		3.4	3.4	5.4	3.1	2.5	2.4	2.4	2.4	2.3	2.3	2.2
(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
(21)		**TOTAL**		**4.0**	**4.5**	**5.6**	**3.3**	**2.6**	**2.6**	**2.5**	**2.5**	**2.5**	**2.4**	**2.4**
(22)	**OTHER (BIOMASS)**		%	**0.2**	**1.1**	**1.4**	**2.5**	**2.9**	**3.7**	**1.8**	**1.9**	**1.9**	**1.8**	**1.5**
(23)	**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 Resource Planning

JEA utilizes its Integrated Resource Planning (IRP) process to evaluate and inform long-term resource decisions, including scenarios and sensitivities to consider environmental legislative and regulatory action, load growth forecasts, fuel costs, costs of new generation, continued operation of existing generating units, and other factors. JEA has used the IRP process for decades, with the most recent IRP conducted in 2023 and another planned in the 2026/2027 timeframe. The assumptions and information utilized in JEA's IRPs, however, are continually updated to fully inform JEA leadership decisions relative to resource additions. For example, given EPA's repeal of the 2009 Endangerment Finding and the proposed repeal of the GHG regulations for electrical generating units, for purposes of this TYSP, JEA is assuming that the GHG Rule is not in effect moving forward. In addition, as explained in Section 1.3.1, JEA is not incorporating its aspirational clean energy goals at this time.

The resource expansion plan included in this TYSP is representative of what is presently indicated considering the most common/frequent near-term resource additions identified across multiple scenarios and sensitivities. 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, including continued operation of existing resources and new resource additions, as part of its ongoing resource planning activities.

The addition of a 1x1 advanced-class combined cycle combustion turbine (CCCT) configuration in the 2031 timeframe is part of the least-cost resource plan across all of JEA's current modeled scenarios and sensitivities. JEA anticipates moving forward with seeking a Determination of Need from the Florida Public Service Commission and certification under Florida's Electrical Power Plant Siting Act (PPSA), section 403.501, et. seq., in the second quarter of 2026. Upon commercial operation of the new CCCT unit, Northside Unit 3 will be placed in limited use status and operated at or below 8% annual capacity factor, serving as a back-up resource during peak demand periods, system emergencies, or unexpected equipment outages. Maintaining Northside Unit 3 in limited use is necessary based on increased demand and to ensure reliable service during periods of extreme weather and/or when other generating units or purchased power are unavailable.

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.

Based on consideration of generating resources and the load forecast reflected in this TYSP, JEA anticipates coordinating with TEA to acquire short-term winter and summer seasonal market purchases to maintain JEA's 15 percent reserve margin for years 2027 through 2031. These purchases will account for up to 3 percent of respective forecasted firm winter and summer peak demand. Please refer to Table 5 for more information related to the projected timing and magnitude of these short-term seasonal purchases, which are referred to as "TEA Backfill Purchases."

3.2 Resource Plan

To develop the resource plan outlined in this TYSP submittal, JEA conducted a comprehensive evaluation of existing electric supply resources, customer energy requirements and peak demand forecasts, fuel price and availability projections, committed unit additions, existing capacity changes, and annual and seasonal capacity purchase additions. Tables 4a and 4b identify the specific years in which resource needs arise across the 2026 through 2035 planning period. Table 5 and TYSP Schedules 8 and 9 present additional information related to the ten-year resource addition plan designed to address those identified needs. TYSP Schedules 7.1 and 7.2 reflect the combined effect of incorporating those resource additions, demonstrating that JEA meets or exceeds the minimum 15% reserve margin requirement throughout the planning period.

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
2026	2,782	601	0	0	3,383	2,772	611	22%	611	22%
2027	2,782	796	-206	0	3,372	2,850	522	18%	522	18%
2028	2,782	703	-206	0	3,279	2,930	349	12%	349	12%
2029	2,782	753	-129	0	3,406	2,961	445	15%	445	15%
2030	2,782	753	-103	0	3,432	2,997	435	15%	435	15%
2031	2,782	753	-103	0	3,432	3,023	409	14%	409	14%
2032	2,782	753	-103	0	3,432	3,052	380	12%	380	12%
2033	2,782	553	0	0	3,335	3,070	265	9%	265	9%
2034	2,782	553	0	0	3,335	3,092	243	8%	243	8%
2035	2,258	553	0	0	2,811	3,119	-308	-10%	-308	-10%

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
2025/26	2,952	471	0	0	3,423	2,901	522	18%	522	18%
2026/27	2,952	661	-206	0	3,407	2,988	419	14%	419	14%
2027/28	2,952	686	-206	0	3,432	3,077	355	12%	355	12%
2028/29	2,952	736	-129	0	3,559	3,114	445	14%	445	14%
2029/30	2,952	736	-103	0	3,585	3,147	438	14%	438	14%
2030/31	2,952	736	-103	0	3,585	3,180	405	13%	405	13%
2031/32	2,952	736	-103	0	3,585	3,210	375	12%	375	12%
2032/33	2,952	536	0	0	3,488	3,226	262	8%	262	8%
2033/34	2,952	536	0	0	3,488	3,252	236	7%	236	7%
2034/35	2,428	536	0	0	2,964	3,275	-311	-9%	-311	-9%

Table 5: Resource Plan

Year (1)	**Resource Plan**
2026	Trail Ridge Contract Expires (-15 MW)(2)
	Forest Trail Solar Energy Center PPA (50 MW_{AC})(3)
	Miller Solar Energy Center PPA (~75 MW_{AC})(3)
	Miller Battery Energy Storage (50 MW_{AC})(3)
	FMPA Winter PPA (50 MW Winter)
2027	Vogtle 3 & 4 Sale (-206 MW)
	FPL PPA (+80 MW)
	TEA Backfill Purchase (150 MW)
	TEA Purchase (29 MW Winter)
	FMPA Winter PPA (125 MW Winter)
2028	FPL Solar PPA (-150 MW)
	Vogtle 3 & 4 Sale (-206 MW)
	TEA Purchase (91 MW Summer, 107 MW Winter)
2029	Vogtle 3 & 4 Sale (-129 MW)
	TEA Backfill Purchase (200 MW)
	TEA Purchase (22 MW Winter)
2030	Vogtle 3 & 4 Sale (-103 MW)
	TEA Purchase (15 MW Summer, 34 MW Winter)
2031	Vogtle 3 & 4 Sale (-103 MW)
	Advanced-Class 1x1 CCCT (677.6 MW Winter)(4)
	TEA Purchase (72 MW Winter)
2032	Vogtle 3 & 4 Sale (-103 MW)
2033	TEA Backfill Purchase Expires (-200 MW)
2034	
2035	Northside 3 Retires (-524 MW)(4)
	Advanced-Class 1x0 CT I (453 MW Winter)
	Advanced-Class 1x0 CT II (453 MW Winter)

Notes:
(1) All dates are subject to change.
(2) Trail Ridge contract ends December 31, 2026.
(3) Please refer to Section 1.1.3.5 for details about the Planned Solar PPAs.
(4) 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
2026	2,782	601	0	0	3,383	2,772	611	22%	0	611	22%
2027	2,782	796	-206	0	3,372	2,850	522	18%	0	522	18%
2028	2,782	794	-206	0	3,370	2,930	440	15%	0	440	15%
2029	2,782	753	-129	0	3,406	2,961	445	15%	0	445	15%
2030	2,782	768	-103	0	3,447	2,997	450	15%	0	450	15%
2031	3,364	753	-103	0	4,014	3,023	990	33%	0	990	33%
2032	3,364	753	-103	0	4,014	3,052	962	32%	0	962	32%
2033	3,364	553	0	0	3,917	3,070	846	28%	0	846	28%
2034	3,364	553	0	0	3,917	3,092	824	27%	0	824	27%
2035	3,588	553	0	0	4,141	3,119	1,022	33%	0	1,022	33%

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
2025/26	2,952	471	0	0	3,423	2,901	522	18%	0	522	18%
2026/27	2,952	690	-206	0	3,436	2,988	448	15%	0	448	15%
2027/28	2,952	793	-206	0	3,539	3,077	462	15%	0	462	15%
2028/29	2,952	758	-129	0	3,581	3,114	467	15%	0	467	15%
2029/30	2,952	770	-103	0	3,619	3,147	472	15%	0	472	15%
2030/31	3,630	736	-103	0	4,263	3,180	1,082	34%	0	1,082	34%
2031/32	3,630	736	-103	0	4,263	3,210	1,052	33%	0	1,052	33%
2032/33	3,630	536	0	0	4,166	3,226	940	29%	0	940	29%
2033/34	3,630	536	0	0	4,166	3,252	913	28%	0	913	28%
2034/35	4,011	536	0	0	4,547	3,275	1,272	39%	0	1,272	39%

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	
Northside	Unit 3	Jacksonville, FL	ST	NG	RFO	PL	WA	N/A	Jul-1977	Jan-2035	626,300	-524	-524	RT
Advanced-Class 1x1 CC	TBD	Jacksonville, FL	CCCT	NG	DFO	PL	TK/WA	Jan-2028	Jan-2031	Unknown	706,000	582	678	P
Advanced-Class 1x0 CT I	TBD	Jacksonville, FL	GT	NG	DFO	PL	TK	TBD	Jan-2035	Unknown	TBD	374	453	P
Advanced-Class 1x0 CT II	TBD	Jacksonville, FL	GT	NG	DFO	PL	TK	TBD	Jan-2035	Unknown	TBD	374	453	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:	582
4	Winter MW:	678
5	**Technology Type:**	CCCT
6	**Anticipated Construction Timing:**	
7	Field Construction Start-date:	Jan-2028
8	Commercial In-Service date:	Jan-2031
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:**	Power 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):	4%
20	Forced Outage Factor (FOF):	3%
21	Equivalent Availability Factor (EAF):	93%
22	Resulting Capacity Factor (%):	75%
23	Average Net Operating Heat Rate (ANOHR)(1):	Confidential
24	**Projected Unit Financial Data:**	
25	Book Life:	30 years
26	Total Installed Cost (In-Service year $/kW):	$2,315.63
27	Direct Construction Cost ($/kW):	Included in Line 26
28	AFUDC Amount ($/kW):	Included in Line 26
29	Escalation ($/kW):	Included in Line 26
30	Fixed O&M (2024 $/kW-yr)(1):	Confidential
31	Variable O&M ($/MWh)(1):	Confidential

Notes:
(1) Data is confidential.

1	**Plant Name and Unit Number:**	Advanced-Class 1x0 CT I & II(1)
2	**Capacity:**	
3	Summer MW:	374 each
4	Winter MW:	453 each
5	**Technology Type:**	CT
6	**Anticipated Construction Timing:**	
7	Field Construction Start-date:	TBD
8	Commercial In-Service date:	Jan-2035
9	**Fuel:**	
10	Primary:	NG
11	Alternate:	DFO
12	**Air Pollution Control Strategy:**	As required by new source Performance Standards
13	**Cooling Method:**	TBD
14	**Total Site Area:**	TBD
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):	TBD
20	Forced Outage Factor (FOF):	TBD
21	Equivalent Availability Factor (EAF):	TBD
22	Resulting Capacity Factor (%):	TBD
23	Average Net Operating Heat Rate (ANOHR)(1):	TBD
24	**Projected Unit Financial Data:**	
25	Book Life:	TBD
26	Total Installed Cost (In-Service year $/kW):	TBD
27	Direct Construction Cost ($/kW):	TBD
28	AFUDC Amount ($/kW):	TBD
29	Escalation ($/kW):	TBD
30	Fixed O&M (2024 $/kW-yr):	TBD
31	Variable O&M ($/MWh):	TBD

Notes:
(1) JEA has not made any commitments for the addition of these units and will continue to evaluate potential additions of such units as part of JEA's long-term resource planning process.

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

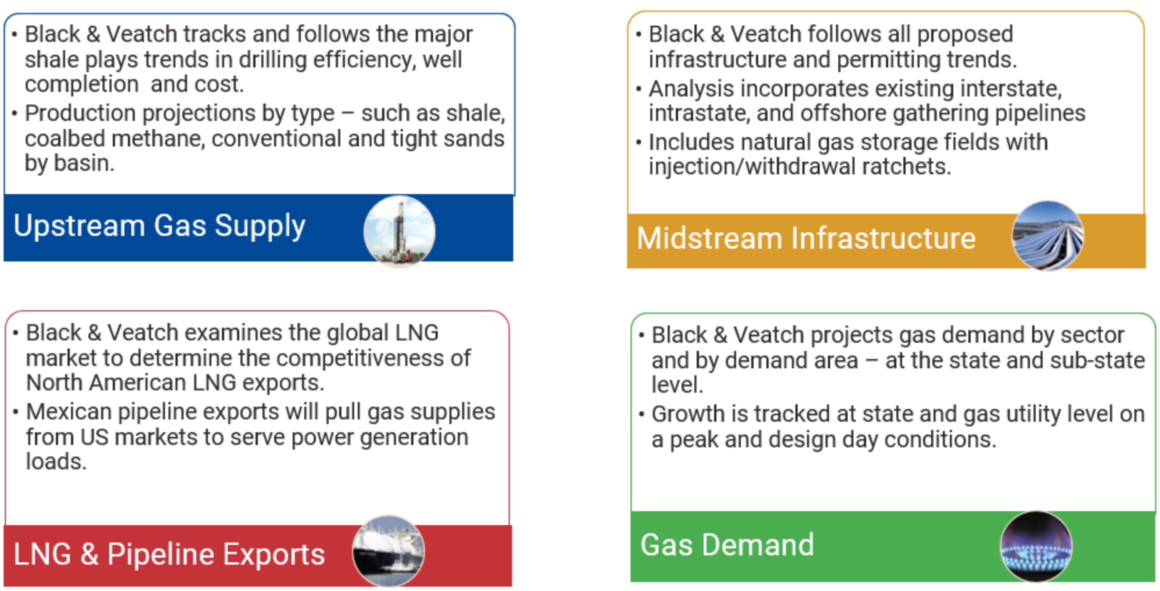
<table>
<tr><td>1</td><td>Point of Origin and Termination</td><td rowspan="9">None to Report</td></tr>
<tr><td>2</td><td>Number of Lines</td></tr>
<tr><td>3</td><td>Right of Way</td></tr>
<tr><td>4</td><td>Line Length</td></tr>
<tr><td>5</td><td>Voltage</td></tr>
<tr><td>6</td><td>Anticipated Construction Time</td></tr>
<tr><td>7</td><td>Anticipated Capital Investment</td></tr>
<tr><td>8</td><td>Substations</td></tr>
<tr><td>9</td><td>Participation with Other Utilities</td></tr>
</table>

4. Other Planning Assumptions and Information

4.1 Fuel Price Forecast

Forecasted fuel prices reflected in this TYSP were developed by Black & Veatch Management Consulting, LLC (Black & Veatch) using established industry-accepted methodologies, and current market conditions. Black & Veatch employs the Gas Pipeline Competition Model (GPCM) that incorporates recent developments in the natural gas market to project future supply, demand, and price trends. GPCM is a comprehensive market simulation system which models the entire North American natural gas value chain, including production basins, gas pipelines and storage infrastructure and sector-level demand. This model is widely utilized by the natural gas market participants such as upstream exploration and production companies, midstream pipelines and storage owners and operators, downstream utilities, independent power producers, industrial gas consumers, government agencies, and investment, trading, and banking organizations.

An overview of GPCM's key model assumptions is provided in the figure below.



4.2 Economic Parameters

This section presents the economic parameters used by JEA in the evaluations performed to determine JEA's least-cost expansion plan to satisfy forecast capacity requirements as presented in 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 3.50 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, debt service reserve contributions, and insurance cost. For JEA's plan development, the long term tax-exempt municipal bond rate is assumed to be 4.75 percent. This rate is based on JEA's judgment and expectation that the long-term financial markets will return to historical stable behavior under more stable economic conditions.

4.2.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax-exempt municipal bond interest rate of 4.75 percent.

4.2.4 Interest during Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 4.75 percent.

4.2.5 Levelized Fixed Charge Rate

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR (LFCR) that has the same present value as the year-by-year 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 4.75 percent tax-exempt municipal bond interest rate, a 1.00 percent bond issuance fee, and a 0.63 percent annual property insurance cost. The resulting 20-year FCR is 8.56 percent and the 25-year FCR is 7.62 percent.

5. Environmental and Land Use Information

JEA intends to propose the addition of a 678 MW net winter-rated capability, dual-fired 1x1 advanced-class CCCT with a 2031 in-service date through a Petition for Determination of Need from the Commission pursuant to section 403.519, Florida Statutes, and a Site Certification Application (SCA) filed with the Florida Department of Environmental Protection pursuant to Florida's Electrical Power Plant Siting Act, section 403.501, et. seq., Florida Statutes, in 2026. The unit will be located at JEA's existing St. Johns River Power Park (SJRPP) site, occupying approximately 200 acres of the larger approximately 1,600-acre parcel. SJRPP is the former location of two 612 MW coal-fired units (SJRPP Units 1 & 2) decommissioned and demolished in 2018 and 2019. Location of the unit at SJRPP will allow utilization of existing infrastructure and minimize environmental impacts. The City of Jacksonville Planning Commission approved a Zoning Exception to allow use of the SJRPP site for the new unit on December 4, 2025. Detailed environmental and land use information will be presented in the SCA.