

225 North Pearl Street
Jacksonville, FL 32202-4513

May 13, 2026



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

Commission Clerk:

On behalf of JEA, please accept the Staff's Data Request #1.

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

Sincerely,

A handwritten signature in blue ink, appearing to read "René Wilson", with a long horizontal flourish extending to the right.

René Wilson, E.I.
Electric Systems Engineer
JEA

Ten-Year Site Plan Data Request #1

Instructions: Accompanying this data request is a Microsoft Excel (Excel) document titled “Data Request #1.Excel Tables,” (Excel Tables File). For each question below that references the Excel Tables File, please complete the table and provide, in Excel Format, all data requested for those sheet(s)/tab(s) identified in parenthesis.

Ten-Year Site Plan Filing

1. Please provide an electronic copy of the Company’s Ten-Year Site Plan (TYSP) for the current planning period (2026-2035) in PDF format.

Completed April 1, 2026.

2. Please provide an electronic copy of all schedules and tables in the Company’s current planning period TYSP in Excel format.

Completed April 1, 2026.

Financial

3. Please refer to the Excel Tables File tabs listed below. Complete the tables by providing information on the financial assumptions and financial escalation assumptions used in developing the Company’s TYSP. If any of the requested data is already included in the Company’s current planning period TYSP, state so on the appropriate form.
 - a. **Excel Tables File (Financial Assumptions)**
 - b. **Excel Tables File (Financial Escalation)**

Please see attached Excel file.

Load & Demand Forecasting

Historic Load & Demand

4. **[Investor-Owned Utilities Only]** Please refer to the **Excel Tables File (Hourly System Load)**. Complete the table by providing, on a system-wide basis, the hourly system load in megawatts (MW) for the period January 1 through December 31 of the year prior to the current planning period. For leap years, please include load values for February 29. Otherwise, leave that row blank.
 - a. Please also describe how loads are calculated for those hours just prior to and following Daylight Savings Time (March 9, 2025, to November 2, 2025).

N/A

5. Please refer to the **Excel Tables File (Historic Peak Demand)**. Complete the table by providing information on the monthly peak demand experienced during the three-year period

prior to the current planning period, including the actual peak demand experienced, the amount of demand response activated during the peak, and the estimated total peak if demand response had not been activated. Please also provide the day, hour, and system-average temperature at the time of each monthly peak.

[Please see attached Excel file.](#)

6. Regarding the Utility's customer and energy consumption data in the Utility's 2026 TYSP, please explain any historic trends, identify the major factors that contribute to the growth/decline of the trends, and provide other information as requested below in each of the following:

- a. Growth of customers, by customer type (residential, commercial, industrial) as well as Total Customers.

From 2016-2025, historical residential customer count grew by approximately 2.1%/year on average and historical commercial customer count grew by approximately 1.2%/year on average. Both trends were driven by population growth (1.3%/year), commercial employment growth (2.0%/year), and commercial real estate inventory growth (1.3%/year) in Jacksonville. The industrial customer count decreased by approximately 0.2%/year on average.

- b. Average KWh consumption per customer, by customer type (residential, commercial, industrial).

From 2016-2025, historical residential per customer consumption decreased by approximately 0.6%/year on average. JEA's funding of demand-side management programs, increased electric rates, a trend towards more efficient multi-family housing construction, and the 2023 SEER rating standards that mandated more efficient new air conditioners contributed to this trend. Historical commercial per customer consumption decreased by approximately 0.8%/year on average. JEA's funding of demand-side management and energy efficiency programs contributed to this trend. Industrial per customer consumption grew by approximately 0.1%/year on average. Similar to JEA's offerings to residential customers, JEA also offered energy audit programs to commercial and industrial customers and provided education and recommendations on low- and no-cost energy-saving practices. JEA offered financial incentives to commercial customers for energy efficient lighting and other energy efficient products.

- c. Total Sales (GWh) to Ultimate Customers.

From 2016-2025, historical total sales to ultimate customers grew by approximately 0.7%/year on average. Continued customer account growth due to economic growth in the region more than offset the improved energy efficiency per customer, contributing to this trend.

7. Please explain any historic trends, identify the major factors that contribute to the observed historic trends, and provide other information as requested below in each of the following components of Summer/Winter Peak Demand in the Utility's 2026 TYSP:

- a. Demand Reduction due to the Company's energy efficiency and/or conservation program(s) and Self Service, by customer type (residential, commercial, industrial) as well as by Total Customers.

The estimated impact of JEA's conservation programs are detailed in Section 2.3 of the 2026 TYSP (Table 2: DSM Portfolio – Energy Efficiency Programs and Table 3: DSM Programs). Estimated demand reductions for residential and commercial/industrial customers are shown in Schedule 3.1 and Schedule 3.2 of JEA's 2026 TYSP.

- b. Demand Reduction due to Demand Response programs, Demand Side Renewable Systems and/or Self Service, by customer type (residential, commercial, industrial).

JEA does not currently and did not in the past have any demand response programs for residential, commercial and industrial customers. Currently, the only demand reduction is JEA's interruptible customers, which consist of large commercial and industrial customers.

Regarding Demand Side Renewable Systems and Self-Service, JEA facilitates customer-owned rooftop solar and generation through its historical Net Metering policies and its current Distributed Generation (DG) Policy. Because customer-owned rooftop solar operates behind-the-meter, its exact historic demand reduction at the time of system peak is not discretely sub-metered. Instead, the historical peak reduction impacts of these Demand Side Renewable Systems are already inherently embedded within JEA's historical Total Demand.

- c. Total Demand.

Historically, Total Peak Demand has exhibited an overarching upward trend. While energy efficiency measures, alongside changing customer behaviors, electric rate changes, and an increase in multifamily housing, have placed downward pressure on average per customer energy usage, system peak demand still continued to climb. While the peaks in any given year fluctuates based on weather severity, as reflected in Schedule 3.1 and Schedule 3.2 in 2026 TYSP, the overall upward trend in the historical peaks is a strong indicator of sustained economic and population growth within JEA's service territory over the past decade.

- d. Net Firm Demand, by the sources of peak demand appearing in Schedule 3.1 and Schedule 3.2 of the current planning period TYSP

Historically, Net Firm Demand follows the exact same trend as Total Demand, with Net Firm Demand reflecting reductions associated with conservation and energy efficiency measures.

Forecasted Load

8. Please identify the weather station(s) used for calculation of the system-wide temperature used for preparing the Utility's load forecasts. If more than one weather station is utilized, please describe how a system-wide average is calculated.

JEA only utilizes NOAA Weather Station: Jacksonville International Airport (USW00013889).

9. Please explain, to the extent not addressed in the Utility's 2026 TYSP, how the reported forecasts of the number of customers, demand, and total retail energy sales were developed. In the Utility's response, please include the following information:

- a. Methodology.

Please see the TYSP.

- b. Assumptions.

We assume historical trends and correlations in econometric data, customer data, and weather data will continue to hold true in the future.

- c. Data sources.

Please see the TYSP.

- d. Third-party consultant(s) involved.

Customer-sited renewables analysis on rooftop solar PV and battery storage installation was conducted by Resource Innovations.

- e. Anticipated forecast accuracy.

JEA continues to monitor forecast error. If the error is above 2%, JEA will review the forecast methodology and make adjustments.

- f. Any difference/improvement(s) made compared with those forecasts used in the Utility's most recent prior TYSP.

Confirmed new development projects were incorporated into the first seven years of the industrial customer sales and demand forecasts.

10. The following requests pertain to the Utility's load forecasts in the Utility's 2026 TYSP.

- a. Please explain how the forecasts of annual demand and energy are used by the Utility in the resource planning process undertaken to identify optimal resource additions for the period included in the TYSP.

We use PLEXOS software to run a capacity expansion model of JEA's resource needs based on the load forecast, allowing us to identify the most reliable and cost-effective resource additions. As shown in the 2026 TYSP, an Advanced-Class 1x1 Combined Cycle is the first cost-effective resource selected by the model.

- b. Does the Utility prepare low case and high case demand and energy forecasts? Why or why not?

Yes. The high and low cases are often used in JEA's IRP sensitivity studies. They are also used in JEA's internal ad-hoc studies.

- c. If so, what conditional changes generate low case and high case forecasts for the Utility, and how are probabilities assigned to such forecasts?

We look at high and low sensitivities based on plus and minus 3% of the hourly system load and net firm peak demand in the base forecast.

- d. If low and high case forecasts are prepared, explain whether and how such forecasts may impact resource planning and additions appearing in the TYSP. Give specific examples.

The high and low cases are used to confirm the resource decisions from the base case. An Advanced-Class 1x1 Combined Cycle is the most cost-effective option in the base case load forecast as well as the low and high case load forecasts.

11. For those utilities which use an all-hours loss of load probability (LOLP) methodology for system planning, please answer the following questions comparing the Utility's 50 percent probability (P50) load forecast and any forecasts developed for its LOLP analysis.

- a. What conditions are reflected in each of the Utility's load forecast models and forecast inputs that allow it to produce its P50 load forecasts?
- b. Are comparisons of the Utility's P50 load forecasts to actual results or other methods used for purposes of forecast bias testing? If so, how is such testing used?
- c. Explain how the Utility's use of an all-hours LOLP analysis has resulted in changes to the Utility's load forecast methodologies, data, assumptions, etc.
- d. Explain how the Utility's use of an all-hours LOLP analysis has modified the ways the Utility's load forecast is used by the Utility for resource planning.
- e. Explain, if applicable, how the Utility's use of an all-hours LOLP analysis incorporates different weather scenarios that impact the Utility's demand throughout the year.

- f. Explain, if applicable, how the Utility's use of an all-hours LOLP analysis incorporates variations of its base demand forecast (i.e., P50) for purposes of resource planning.
- g. Explain how the Utility's hourly load forecasts of demand and energy used in its all-hours LOLP analysis, as opposed to the annual forecasts based on its P50 load forecast, are used to select the resource additions included in its TYSP.

JEA does not use an all-hours loss of load probability (LOLP) methodology for system planning. Therefore, the questions in this section are not applicable to JEA.

12. Please explain how the Utility's hourly load forecasts of demand and energy are used to select the resource additions included in its TYSP. Give specific examples.

We use the PLEXOS software to run a capacity expansion model of JEA's resource needs based on the hourly load forecast to select the most reliable and cost-effective resource additions. As shown in the 2026 TYSP, an Advanced-Class 1x1 Combined Cycle is the first cost-effective resource selected by the model.

13. Beyond traditional econometric and end-use models, does the Utility employ any alternative load forecasting methodologies to address forecast uncertainty? If so, please describe those methods.

We look at high and low sensitivities based on plus and minus 3% of the hourly system load and net firm peak demand in the base forecast.

14. Does the Utility incorporate weather variability or extreme weather scenarios into its load forecasting process? If so, how are these scenarios reflected in resource planning decisions?

The high and low load forecasts also represent mild-weather and harsh-weather years, respectively. JEA currently does not incorporate extreme weather scenarios. The high and low load forecasts are used in IRP studies and JEA's internal ad-hoc studies.

15. Regarding the Utility's base case forecasts in the Utility's 2026 TYSP, please explain the forecasted trends, identify the major factors (currently and in the forecasted period) that contribute to the growth/decline of the trends, and provide other information as requested below in each of the following:

- a. Growth of customers, by customer type (residential, commercial, industrial) as well as Total Customers.

JEA expects the historic trends mentioned in response to Question 6 to continue and contribute to future customer growth: population growth (0.5%/year on average), commercial employment growth (0.9%/year on average), and commercial real estate inventory growth to continue (0.5%/year on average).

Overall, Moody's Analytics' forecasted percentage growth for all parameters used in the 2026 TYSP was similar to those used in 2025 TYSP. The industrial customer count is forecasted to grow by approximately 1.4%/year on average.

- b. Average KWh consumption per customer, by customer type (residential, commercial, industrial).

JEA expects the historic trends mentioned in response to Question 6 to continue. Residential per customer consumption will grow by approximately 0.2%/year on average. Upward pressure on per customer consumption due to shrinking household size will offset downward pressure from continued JEA funding of demand-side management programs, increased electric rates, a trend towards more efficient multi-family housing construction, and the 2023 SEER rating standards that mandated more efficient new air conditioners contributed to this trend. Commercial per customer consumption will shrink by approximately 1.1%/year on average. Continued JEA funding of demand-side management and energy efficiency programs will contribute to this trend. Industrial per customer consumption will shrink by approximately 0.1%/year on average. Similar to JEA's offerings to residential customers, JEA also offers energy audit programs to commercial and industrial customers and provides education and recommendations on low- and no-cost energy-saving practices. JEA offers financial incentives to commercial customers for energy efficient lighting and other energy efficient products.

- c. Total Sales (GWh) to Ultimate Customers.

JEA forecasted Total Sales to Ultimate Customers to grow by approximately 1.2%/year on average due to a continuation of the historic trends and continued economic growth mentioned in response to Question 6.

- 16. Please identify all closed and open Florida Public Service Commission (FPSC) dockets and all non-docketed FPSC matters which were/are based on the same load forecast used in the Utility's current planning period TYSP.

None.

- 17. Please reference the Utility's customer and base case energy sales forecasts in the Utility's 2026 TYSP. Please explain whether the Utility evaluates the accuracy of its forecasts of customer growth and annual retail energy sales presented in its past TYSPs. If so, please provide the actual/forecast comparisons (in Excel format) with a narrative explaining the Company's methodology. If not, please explain why the Utility elects not to perform such an analysis.

JEA compares actual values against forecasted values for years 2005-2025 in a matrix. Then, the percentage variance between the actual and forecasted values is calculated for each year to determine whether the forecast overestimated or underestimated the actual value. The 2025 forecast underestimated the Actual Net Energy by 3.5%. JEA will continue to observe

its forecast errors and should the forecast error remain above the acceptable error range, JEA will reevaluate and revamp its forecast process and methodology.

Please see the attached Excel file “Forecast Error Energy” sheet for more information.

18. Please reference the Utility’s base case demand forecasts in the Utility’s 2026 TYSP. Please explain whether the Utility evaluates the accuracy of its forecasts of Summer/Winter Peak Demand presented in its past TYSPs. If so, please provide the actual/forecast comparisons (in Excel format) with a narrative explaining the Company’s methodology. If not, please explain why the Utility elects not to perform such an analysis.

JEA utilizes the same method as described in response to Question 17.

JEA compares actual values against forecasted values for years 2005-2025 in a matrix. Then, the percentage variance between the actual and forecasted values is calculated for each year to determine whether the forecast overestimated or underestimated the actual value. The 2025 forecast overestimated the total net winter peak by 2.1% and underestimated the total net summer peak by 1.2%. The 2025 forecast was more accurate than the 2024 forecast. JEA will continue to observe its forecast errors and should the forecast error remain above the acceptable error range, JEA will reevaluate and revamp its forecast process and methodology.

Please see the attached Excel file “Forecast Error Peaks” sheet for more information.

19. Please explain any current and forecasted trends, identify the major factors that contribute to the observed current and forecasted trends, and provide other information as requested below in each of the following components of the Utility’s base case Summer/Winter Peak Demand the Utility’s 2026 TYSP:
 - a. Demand Reduction due to the Company’s energy efficiency and/or conservation program(s) and Self Service, by customer type (residential, commercial, industrial) as well as by Total Customers.

Currently and over the forecast period, the trend for demand reduction due to conservation programs represents a steady accumulation of estimated peak reductions. These forecasted reductions are driven by JEA’s approved Florida Energy Efficiency and Conservation Act (FEECA) goals as well as other conservation programs offered by JEA. As detailed in Section 2.3 of the 2026 TYSP (Table 2: DSM Portfolio – Energy Efficiency Programs and Table 3: DSM Programs), JEA calculates the estimated future impacts of these programs. The figures provided in the “Cumulative Conservation” columns of Schedule 3.1 and Schedule 3.2 represent these estimated ongoing and future initiatives.

- b. Demand Reduction due to Demand Response programs, Demand Side Renewable Systems and/or Self Service, by customer type (residential, commercial, industrial).

JEA does not currently offer nor does it forecast any active demand response for residential, commercial and industrial customers. The forecasted demand reductions

continue to be driven exclusively by JEA's interruptible rate for large commercial and industrial customers. A major factor in this forecasted trend is JEA's incorporation of the confirmed future expansion of a large interruptible customer, which drives an expected increase in the projected interruptible load.

Regarding Demand Side Renewable Systems, JEA expects continued adoption of customer-sited rooftop solar under its Distributed Generation (DG) Policy. To account for this, JEA utilizes a specific forecast provided by our consultant, Resource Innovations. This model forecasts future customer adoption and explicitly quantifies the expected demand reductions from these systems during the time of system peaks. These projected peak reductions are subsequently incorporated into JEA's overall forecasted load.

c. Total Demand.

The forecasted trend for Total Demand is a continued upward trend. While the explicitly forecasted peak reductions from Demand Side Renewable Systems and baseline efficiency trends place downward pressure on overall load, these reductions are outpaced by broader growth factors. The major drivers contributing to the forecasted growth remain consistent with the historical drivers discussed in response to Question 7, primarily with sustained population expansion and economic growth within JEA's service territory. Furthermore, a specific major driver of the forecasted near-term increase is the incorporation of confirmed new large industrial development projects that JEA has modeled into the total demand forecast.

d. Net Firm Demand, by the sources of peak demand appearing in Schedule 3.1 and Schedule 3.2 of the current planning period TYSP.

Forecasted Net Firm Demand exhibits a continued upward trend, driven by the same economic, population, and new industrial development factors fueling Total Demand. However, unlike historical metered data, the forecasted Net Firm Demand is explicitly calculated by subtracting the projected cumulative conservation and forecasted interruptible load from the forecasted Total Demand. Therefore, the forecast Net Firm Demand trend presents JEA's anticipated firm peak load obligations after fully accounting for the expansion of its commercial and industrial interruptible agreements, forecasted solar adoption, and ongoing energy efficiency initiatives.

20. Please explain any anomalies caused by non-weather events with regard to annual historical data points for the period 10 years prior to the current planning period that have contributed to the following:

- a. Summer Peak Demand.
- b. Winter Peak Demand.
- c. Annual Retail Energy Sales.

Starting in 2023 the new SEER rating standards required new air conditioners in Southern states to be a minimum 15 SEER, which contributed to a decrease in

electricity usage. The COVID-19 pandemic contributed to a decline in energy consumption and peak demand in 2020 and 2021 historical data.

21. Please provide responses to the following questions regarding the weather factors considered in the Utility's retail energy sales and peak demand forecasts:

- a. Please identify, with corresponding explanations, all the weather-related input variables that were used in the respective Retail Energy Sales, Winter Peak Demand, and Summer Peak Demand models.

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.

- b. Please specify the source(s) of the weather data used in the aforementioned forecasting models.

JEA uses NOAA Local Climatological Data and Preliminary Monthly Climate Data (CF6) from the Jacksonville International Airport weather station.

- c. Please explain in detail the process/procedure/method, if any, the Utility utilized to convert the raw weather data into the values of the model input variables.

JEA does not convert the raw weather data. Instead, JEA pairs the hourly load data with the hourly temperature and the daily heating and cooling degrees with the respective daily energy.

- d. Please specify with corresponding explanations:

- (1) How many years' historical weather data was used in developing each retail energy sales and peak demand model.

10 years.

- (2) How many years' historical weather data was used in the process of these models' calibration and/or validation.

10 years.

- e. Please explain how the projected values of the input weather variables (that were used to forecast the future retail energy sales or demand outputs for each planning years 2026–2035) were derived/obtained for the respective retail energy sales and peak demand models.

Energy Sales Forecast:

NOAA historical actual heating and cooling degree days are used to develop the normalized energy sales. Days are divided into three categories: weekdays,

Saturday/holidays, and Sunday. The LINEST excel function is used on the actual degree days and net energy for each customer class (residential, commercial & industrial) to produce a normal curve. This normal curve is created under the three categories mentioned above. Under each category, we look at October (shoulder month), winter, and summer segments. Finally, the normal degree days are applied to the normal curve to produce the normal MWh consumption for each customer class.

Peak Forecast:

JEA uses SAS to develop the normalized peak forecast. Hourly system load data and maximum and minimum temperatures are input into SAS. Normalized peaks are calculated by performing non-linear regression analysis on our 10-year historical peaks and temperatures to identify the least squared peaks for each year. Some of the assumptions used for this model include:

- JEA load = gross hourly load – AUX – CMC Steel & maximum and minimum temperatures.
- The winter peak is the lowest daily temperature during the months of December, January and February.
- The summer peak is the highest daily temperature during the months of July, August and September.
- Two of the parameters used in the non-linear regression analysis are the highest and lowest record temperatures in Jacksonville of 103°F for summer and 16°F for winter

22. **[Investor-Owned Utilities Only]** If not included in the Utility’s 2026 TYSP, please provide load forecast sensitivities (high band, low band) to account for the uncertainty inherent in the base case forecasts in the following TYSP schedules, as well as the methodology used to prepare each forecast:

- a. Schedule 2.1 – History and Forecast of Energy Consumption and Number of Customers by Customer Class.
- b. Schedule 2.2 - History and Forecast of Energy Consumption and Number of Customers by Customer Class.
- c. Schedule 2.3 - History and Forecast of Energy Consumption and Number of Customers by Customer Class.
- d. Schedule 3.1 - History and Forecast of Summer Peak Demand.
- e. Schedule 3.2 - History and Forecast of Winter Peak Demand.
- f. Schedule 3.3 - History and Forecast of Annual Net Energy for Load.
- g. Schedule 4 - Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month.

N/A

Demand-Side Resources

23. Please address the following questions regarding the impact of all customer-owned/leased renewable generation (solar and otherwise) on the Utility forecasts.

- a. Please explain in detail how the Utility’s load forecast for the 2026-2035 period accounts for the impact of all forms of customer’s renewable generation.

A customer-sited renewables analysis on rooftop solar PV and battery storage installation was conducted by Resource Innovations group for JEA. The analysis results in a combined forecast with customer-owned generation and customer-owned storage and no way to separate the two. 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 + 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 customer-sited renewable forecast was included 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.

- b. Please provide the annual impact, if any, of all forms of customer’s renewable generation on the Utility’s retail demand and energy forecasts, by class, by year, and in total, for the 2026 through 2035 period.

	Winter Peak			Summer Peak			Energy		
	DER MW	Net Peak MW	DER %	DER MW	Net Peak MW	DER %	DER MWh	NEL GWh	DER %
2026	-0.16	3,011	-0.005%	-1.95	2,896	-0.067%	-9,595	13,386	-0.072%
2027	-0.34	3,102	-0.011%	-4.24	2,978	-0.142%	-20,801	13,785	-0.151%
2028	-0.57	3,200	-0.018%	-6.98	3,065	-0.228%	-34,550	14,147	-0.244%
2029	-0.80	3,238	-0.025%	-9.72	3,100	-0.313%	-47,918	14,324	-0.335%
2030	-1.06	3,279	-0.032%	-12.75	3,140	-0.406%	-62,692	14,503	-0.432%
2031	-1.34	3,310	-0.040%	-15.91	3,170	-0.502%	-77,819	14,659	-0.531%
2032	-1.64	3,346	-0.049%	-15.16	3,202	-0.473%	-94,284	14,817	-0.636%
2033	-1.91	3,369	-0.057%	-17.48	3,227	-0.542%	-108,666	14,941	-0.727%
2034	-2.18	3,394	-0.064%	-25.14	3,251	-0.773%	-123,043	15,070	-0.816%
2035	-2.27	3,420	-0.066%	-15.31	3,282	-0.466%	-127,866	15,219	-0.840%

- c. If the Utility maintains a forecast for the planning horizon (2026-2035) of the number of customers with renewable generation, by customer class, please provide.

	Number of Customers	
	Residential	Non-Residential
2026	10158	164
2027	11232	185
2028	12438	210
2029	13778	237
2030	15243	266
2031	16800	297
2032	18447	331
2033	20009	347
2034	21481	365
2035	21904	385

- d. Please provide the source of all data for responses to parts (b) and (c) above.

Historical customer data came from JEA internal sources. Forecasted data was produced by our consultant Resource Innovations using JEA’s historical customer data.

- 24. Please address the following questions regarding the impact of all customer-owned/leased energy storage devices on the Utility forecasts.

- a. Please explain in detail how the Utility’s load forecast for the 2026-2035 period accounts for the impact of all forms of customer’s energy storage.

Please see the response to Question 23.

- b. Please provide the annual impact, if any, of all forms of customer’s energy storage on the Utility’s retail demand and energy forecasts, by class, by year, and in total, for the 2026 through 2035 period.

Please see the response to Question 23.

- c. If the Utility maintains a forecast for the planning horizon (2026-2035) of the number of customers with energy storage, by customer class, please provide.

Please see the response to Question 23.

- d. Please provide the source of all data for responses to parts (b) and (c) above.

Please see the response to Question 23.

25. Please explain how the anticipated growth of customer-owned renewable generation resources is reflected in the Utility's load forecast for the 2026-2035 period. In the Utility's response, address whether, and what type of, modeling adjustments are used for this purpose.

The net energy for load already reflects the impact of the forecasted demand and energy from customer-owned renewable generation and storage resources.

26. Does the Utility's load forecast for the 2026-2035 period recognize all forms of renewable generation resources in terms of a measurable demand reduction (in megawatts), a measurable energy reduction (in megawatt hours), or both? Please explain the Utility's response.

JEA recognizes both. The consultant Resource Innovations provides the forecast in hourly form, which allows JEA to incorporate it into both the demand and energy forecast.

27. Please refer to the **Excel Tables File (Customer-Owned Resources)**. Complete the table by providing the forecasted data on customer-owned resources for the current planning period, including the number, capacity, and impact on forecasts of customer-owned renewable and energy storage resources.

Please see attached Excel file.

FEECA

28. **[FEECA Utilities Only]** Please refer to the **Excel Tables File (DR Participation)**. Complete the table by providing for each source of demand response annual customer participation information for three years prior to the current planning period. Please also provide a summary of all sources of demand response using the table.

JEA does not have a demand response customer program at this time.

29. **[FEECA Utilities Only]** Please refer to the **Excel Tables File (DR Annual Activations)**. Complete the table by providing for each source of demand response annual usage information for three years prior to the current planning period. Please also provide a summary of all demand response using the table.

JEA does not have a demand response program at this time.

30. **[FEECA Utilities Only]** Please refer to the Utility's 2026 TYSP.
- a. Do the Company's energy and demand savings amounts reflected on the DSM and Conservation-related portions of all energy and demand savings schedules (Schedules 2.1, 2.2, and 2.3 for energy savings and Schedules 3.1, 3.2, and 3.3 for demand savings) reflect the Company's goals that were approved by the Commission in the 2024 FEECA Goalsetting dockets?

Yes, the energy and demand savings amounts reflect our goals that were approved by the Commission in the 2024 FEECA Goalsetting dockets, in addition to other programs we offer to our customers that are economically beneficial.

- b. If applicable, discuss what adjustments to the Load Forecast are made to the schedules when demand and energy savings achievements fall short of the Company's goals that were approved by the Commission?

N/A

- c. If the Company's demand and energy savings from the 2024 FEECA Goalsetting dockets are not reflected in the above-noted schedules, please explain what savings assumptions from the 2024 FEECA Goalsetting dockets are incorporated within the ten-year site plan schedules, and why.

They are reflected in the above noted schedules.

Plug-in Electric Vehicles (PEVs)

31. Please refer to the **Excel Tables File (PEV Charging)**. Complete the table by providing estimates of the requested information within the Utility's service territory for the current planning period. Direct current fast charger (DCFC) PEV charging stations are those that require a service drop greater than 240 volts and/or use three-phase power.

Please see attached Excel file.

32. Please identify and describe all methods and programs the Utility has used, if any, to address the impact of PEVs charging on seasonal peak demand, including any special rates or tariffs, demand-side management programs (including PEV-centric demand response), and customer education. As part of the Utility's response, provide the estimated impact of each method or program on seasonal peak demand.

JEA monitors the number of electric vehicles that are registered to operate in the utility service area. In 2025, JEA concluded a study of EV driving and charging habits in northeast Florida. The study was conducted by the Electric Power Research Institute (EPRI) and JEA, and included telematic data from vehicles operating in the JEA service area. The study will help JEA predict distribution grid impacts as the number of electric vehicles increases over time. JEA provides education and awareness through the utility website and at periodic events.

33. Please explain any historic trends related to the following:
 - a. PEV counts
 - b. PEV charging installation counts
 - c. Annual energy consumption
 - d. Seasonal Peak Demand (Summer and Winter)

There is no major driver on the forecasted PEV counts that JEA can identify at this time. TESLA ownership represents 75% of Duval County total PEV registrations in 2024, followed by Ford as the next highest ownership in Duval County and representing 4% of the total PEV registrations.

JEA does not have any technology in place to be notified when a customer has installed a PEV charging station in their home. However, we have seen an increase in the number of public charging stations installed throughout our service territory as new developments are built.

34. Please explain any current or forecasted trends related to the following:

- a. PEV counts
- b. PEV charging installation counts
- c. Annual energy consumption
- d. Seasonal Peak Demand (Summer and Winter)

JEA does not have any technology in place to be notified when a customer has installed a PEV charging station in their home. However, we have seen an increase in the number of public charging stations installed throughout our service territory as new developments are built.

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

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

The peak capacity is determined based on the average on-board charging rate of each vehicle brand and the forecast peak capacity per PEV grows by 0.01 kW per year.

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

35. Please describe any utility programs or tariffs currently offered to customers relating to PEVs, and describe whether any new or additional programs or tariffs relating to PEVs will be offered to customers within the current planning period.

There are no PEV specific rates or tariffs. Commercial and Industrial customers may participate in the Fleet Electrification Program, an advisory program that helps fleet owners determine if electric vehicles are a good choice for their businesses. C&I customers may benefit from Time-of-Use rates by charging during off-peak hours. There are also the JEA Drive Electric Program and Fleet Electrification Program which provide information to customers on switching to electric vehicles.

- a. Of these programs or tariffs, are any designed for or do they include educating customers on electricity as a transportation fuel?

The Drive Electric Program (residential customers) and Fleet Electrification Program both provide objective information on switching to electricity as a transportation fuel. Both programs have sophisticated Total Cost of Ownership Calculators online at the utility website. These free calculators estimate and illustrate financial and environmental costs and benefits based on inputs from customers.

- b. Does the Utility have any programs where customers can express their interest or expectations for electric vehicle infrastructure as provided for by the Utility? If so, please describe in detail.

JEA's Fleet Electrification Program provides a direct communication conduit between non-residential customers and JEA. One goal of the program is to establish expectations early in the pre-design process so that companies understand infrastructure constraints and timelines.

36. Has the Utility conducted or contracted any research to determine demographic and regional factors that influence the adoption of PEVs applicable to its service territory? If so, please describe in detail the methodology and findings.

JEA has access to anonymized electric vehicle registration data down to the zip code level. During the EPRI study concluded in 2025, some effort was given to locating the number of EVs registered in each zip code and projecting load growth over time. No specific demographic factors were used in the analysis. The study focused on infrastructure age, size, and available capacity.

37. If applicable, please list and briefly describe all PEV pilot programs the Utility is currently implementing and the status of each program.

None.

38. If applicable, please describe any key findings and metrics of the Utility's PEV pilot program(s) which reveal the PEV impact to the demand and energy requirements of the Utility.

Not applicable as there are no PEV pilot programs.

Emerging Technologies

39. With respect to the energy consumption resulting from the emerging technologies-related electrical equipment (specifically PEVs and Data Centers):

- a. Please explain how PEVs and Data Centers are recognized in the Utility's sales forecasting models.

JEA developed a PEV load and energy forecast based on forecasted automobile sales and vehicle electrification trends. This PEV forecast is then incorporated into the base load forecast.

Data centers are not separately recognized in JEA's sales forecasting model as they are currently a small portion of our industrial customer base and there are currently no confirmed plans for new data centers. Therefore, data centers are forecast as part of the wider industrial customer base. However, JEA did take into account confirmed plans to expand three existing small data centers and their effects on the forecasted load and energy.

- b. Please explain whether PEVs and Data Centers have notable impacts on the forecasting accuracy of the Utility's annual retail energy sales models.

The PEV forecast does not have a notable impact on forecasting accuracy in the short-term, as it is currently a relatively small portion of JEA's load and energy. However, as vehicle electrification increases, we expect PEV to have a larger impact on accuracy in the out-years.

Data centers do not have a notable impact on forecasting accuracy as they are currently a relatively small portion of JEA's load and energy. There are also no confirmed plans for new data centers.

- c. Please identify any other emerging technologies-related electrical equipment the Utility has specifically recognized in its sales forecasting models, and explain whether any such equipment has notable impacts on the forecasting accuracy of the Utility's annual retail energy sales model.

JEA has not recognized any other emerging technologies in its sales forecasting model.

40. Please refer to the **Excel Tables File (Data Centers)**. Complete the table by providing information on the data centers in the Utility's service area for the time period specified.

- a. Existing Data Centers, including data centers being served as of December 31, 2025.
- b. Planned Data Centers, including data centers that are planned to be in-service in 2026.
- c. Planned Data Centers, including data centers that are planned after 2026.

Please see attached Excel file.

41. Does the load forecast in the Utility's 2026 TYSP include projections of annual energy consumption and demand associated with data centers within the Utility's service area during the forecasting time horizon (2026-2035)?

- a. If such projections have been made, please provide details of the projections, including the type of data centers expected to contribute to energy/demand, and the factors that are driving this energy consumption and demand.

JEA did not perform a separate forecast for existing data centers due to their small demand. Data center demand is embedded in the forecast trend analysis. JEA did incorporate planned expansions of existing data centers in the industrial forecast. No other data center projections are included in the forecast.

- b. If no specific projections have been made, please explain the Utility's assumption(s) or belief(s) regarding the likely pattern of load growth associated with this industry within its service territory.

JEA is currently assessing the potential impact of load growth driven by the increasing number of data centers. At this time, JEA has no planned load growth attributed to new data centers.

42. Please identify all issues and/or concerns, if any, the Utility expects to arise from the growth in data centers in the Utility's service territory, and explain how the Utility anticipates responding to such issues or concerns.

JEA has received numerous large (>50 MW) data center inquiries. In order to serve these data centers, JEA would need to construct more generating resources. As mentioned in response to Question 41, JEA is actively assessing the potential impact of load growth driven by data centers. In addition, the utility is conducting internal evaluations to understand how this growth could affect operations and to determine whether existing resources can meet the anticipated demand.

43. **[FEECA Utilities Only]** Please identify and discuss the Utility's role in the research and development of utility power technologies, including, but not limited to, research programs that are funded through the Energy Conservation Cost Recovery Clause. As part of this response, please describe any plans to implement the results of research and development into the Utility's system portfolio, and the timing of such implementation. In addition, discuss how any anticipated benefits will affect the Utility's customers.

In 2025, JEA piloted and now offers the JEA Virtual Commissioning (VCx) Program as a complimentary service for targeted peak usage commercial customers through Power TakeOff on behalf of JEA. A trained Energy Advisor remotely analyzes building energy data without needing an on-site visit. Participation is quick and easy with no eligibility criteria for equipment, fees, or enrollment paperwork. Usually schools, government buildings and churches are highly targeted segments due to the more defined and predictable occupancy schedules.

How it Works:

- **Utility Meter Data Analysis:** A remote analysis offers insights into energy usage at the facility, helping the customer identify unexpected and wasted usage.
- **Customized Recommendations:** Through ongoing communication and discussions with a trained energy advisor, the customer receives recommendations for their facility that are easy to implement and have little or no cost. This includes real-time evaluation of energy efficiency improvements combined with whole-building strategies.
- **Virtually Delivered:** No on-site visits or in-person audits are required. Communication with an energy advisor is conducted by email or phone.
- **Measured Results:** Customers will see the impact of the adjustments made. The dedicated energy advisor will evaluate and confirm the energy saving impact. Common energy-saving opportunities offered are optimizing equipment schedules, managing equipment start-up and shut-down schedules and identifying equipment setbacks to address unnecessary usage. Ongoing monitoring and interaction after scheduling changes occur is core to the program offering to ensure consistent long-term savings.

44. Please explain whether and how the Utility has employed, or considered using, any type of artificial intelligence or other new technologies and tools in its sales and demand forecasting, operation, customer service, and cybersecurity management.

JEA’s Leadership Team has approved a three-year AI Roadmap developed by Technology Services. This roadmap addresses Governance, Data Protection, Cyber Security, Use Case Development, Prioritization and Change Management. The roadmap recognizes the organic, bottom-up nature that will power the development of use cases while at the same time providing support and controls to ensure the responsible deployment of AI. Prior to the deployment of this roadmap, much work was already underway and completed within the Customer Experience area to harness the power of AI. Some of the solutions in development and deployed include:

- Identification of broken water meters
- Identification of water leaks
- Customer Segmentation
- AI Agent to assist Call Center
- Forecasting incoming calls to Call Center

JEA recently completed a project with a third party to deploy AI technology in the Call Center to monitor calls for call handling accuracy and agent quality. This tool will also assess customer sentiment and categorize the call type.

Generation & Transmission

Utility-Owned Resources

45. Please refer to the **Excel Tables File** tabs listed below. Complete the tables by providing information on the utility-owned generation resources for the time period listed. When completing the tables, please consider the following factors: (i) for multiple small (<1 MW) distributed resources of the same type and fuel source, provide a single entry; (ii) for solar facilities, if available, provide the nameplate DC capacity as the gross capacity, the nameplate AC capacity as the net capacity, and the firm contribution during time of system peak as the firm capacity. If a solar facility is combined with an energy storage system, identify the capacity of the energy storage system in a separate line.

- a. **Excel Tables File (Existing Utility Generation)**, including each utility-owned generation resource in service as of December 31 of the year prior to the current planning period.

[Please see attached Excel file.](#)

- b. **Excel Tables File (Planned Utility Generation)**, including each utility-owned generation resource that is planned to enter service during the current planning period.

[Please see attached Excel file.](#)

46. Please refer to the **Excel Tables File (Unit Performance)**. Complete the table by providing information on each utility-owned generation resource in service during the current planning period. For historic performance, use the past three years for a historical average. For projected performance, use an average of the next 10-year period for projected factors.

[Please see attached Excel file.](#)

47. Please refer to the **Excel Tables File (Unit Dispatch)**. Complete the table by providing the actual and projected capacity factors for each utility-owned generation resource in service during the current planning period for the 11-year period beginning one year prior to the current planning period.

[Please see attached Excel file.](#)

48. **[Investor-Owned Utilities Only]** Please refer to the **Excel Tables File (Solar and Storage Sites)**. Complete the table by providing information on each of the Company’s existing and planned solar and/or energy storage facilities, including the Order and date of Commission approval (or Pending if not yet approved). Identify the associated cost recovery mechanism (such as in a base rate case, the environmental cost recovery clause, solar base rate adjustment, or special tariffs such as SolarTogether, SolarTogether Extension, and Clean Energy Connection) for each facility as well.

[N/A.](#)

49. Please refer to the **Excel Tables File (Planned Construction)**. Complete the table by providing information on all planned generating units with an in-service date within the current planning period. For each planned unit, provide the final decision (“drop dead”) date

for a decision on whether or not to construct each unit, and the estimated dates for site selection, engineering, permitting, procurement, and construction.

- a. For each planned utility-owned generation resource or group of resources, provide a narrative response discussing the current status of the project.

JEA has identified a JEA-owned site to build a 1x1 Advanced-Class Combined Cycle commissioning in the 2031 timeframe. JEA is moving forward in 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.

50. Please list and discuss any planned utility-owned resources that have, within the past year, been cancelled, delayed, or reduced in scope. What was the primary reason for the changes? What, if any, were the secondary reasons?

The 1x1 Advanced-Class Combined Cycle originally had an anticipated commissioning date in the 2030 timeframe, however due to finalization of power island vendor guaranteed delivery dates, the estimated date has been pushed out to 2031.

51. Please refer to the **Excel Tables File (Unit Modifications)**. Complete the table by providing information on all of the Company's units that are either will or are potential candidates to change fuel types or be repower, such as conversion to a Combined Cycle unit component.

Please see attached Excel file.

52. Please identify and discuss emerging power generation and transmission technologies your Company is considering. As part of this response, please describe any formal steps the Company has or will take for possible implementation of the technology.

At this time, JEA has no new emerging power generation or transmission technologies planned for implementation within the 2026 TYSP horizon.

Energy Storage

53. Please refer to the **Excel Tables File** tabs listed below. Complete the table by providing information on all energy storage technologies that are currently either part of the Company's system portfolio or are part of a pilot program sponsored by the Company during the current planning period.

- a. **Excel Tables File (Existing Storage).**
- b. **Excel Tables File (Planned Storage).**

Please see attached Excel file.

54. If applicable, please describe the strategy of how the Company charges and discharges its energy storage facilities. As part of the response discuss if any recent local, state, or federal legislation or regulation has changed how the Company plans to dispatch its energy storage facilities.

Currently, JEA does not own or operate any battery energy storage facilities. There is one existing utility scale lithium-ion storage system in the service territory, that is DC-coupled and co-located with the Imeson (SunPort) Solar facility; it is discharged to smooth the solar generation. One additional utility scale storage system will be added to the Miller Solar Energy Center, set to commission in December 2026. This system will have grid and solar-charge capability.

55. Briefly discuss any progress in the development and commercialization of non-lithium-ion based battery storage technology the Company has observed in recent years.

Sodium-ion batteries have seen progress towards commercialization with the recently announced 60 GWh deal signed between CATL (manufacturer) and HyperStrong (integrator). However, Lithium-ion is still more cost effective and has better energy density, so sodium-ion applications have more to overcome before they can be a viable contender as an alternative to lithium-ion.

56. Briefly discuss any considerations reviewed in determining the optimal positioning of energy storage technology in the Company's system (e.g., Closer to/further from sources of load, generation, or transmission/distribution capabilities).

JEA is still in the process of identifying optimal placement of energy storage technology on the system. JEA typically considers proximity to load and transmission and distribution system capabilities when evaluating the optimal location of energy storage. JEA anticipates performing a future study to help inform the optimal placement.

57. Please explain whether customers have expressed interest in energy storage technologies. If so, describe the type of customer (residential, commercial industrial) and how their interests have been addressed.

Customers have expressed interest in energy storage technologies. The vast majority have been residential customers with only a very small handful of commercial customers exploring the installation of energy storage.

JEA has streamlined its interconnection process for both PV and energy storage.

58. Please identify and describe the objectives and methodologies of all energy storage pilot programs currently running or in development with an anticipated launch date within the current planning period. If the Company is not currently participating in or developing energy storage pilot programs, has it considered doing so? If not, please explain.
- Please discuss any pilot program results, addressing all anticipated benefits, risks, and operational limitations when such energy storage technology is applied on a utility scale (> 2 MW) to provide for either firm or non-firm capacity and energy.
 - Please provide a brief assessment of how these benefits, risks, and operational limitations may change over the current planning period.
 - Please identify and describe any plans to periodically update the Commission on the status of your energy storage pilot programs.

JEA currently has no energy storage pilot programs running. In the past, a pilot microgrid was considered, leveraging the existing relationship with a local university, however those plans have not been finalized and there is no current identified in-service date.

59. If the Company utilizes non-firm generation sources in its system portfolio, please detail whether it currently utilizes or has considered utilizing energy storage technologies to provide firm capacity from such generation sources. If not, please explain.
- Based on the Company's operational experience, please discuss to what extent energy storage technologies can be used to provide firm capacity from non-firm generation sources. As part of your response, please discuss any operational challenges faced and potential solutions to these challenges.

While JEA does not currently have energy storage technology providing firm capacity from non-firm generation sources, JEA's methodology is that capacity for solar PV assets is limited to 20% (solely for the summer); however, if that solar PV asset is co-located with a battery energy storage system (BESS), firm capacity would be provided from the full rating of the battery asset only. The planned Miller Solar Energy Center will comprise of a 74.9 MW solar PV asset paired with a 50 MW/4-hour BESS. Therefore, the 50 MW BESS will provide 50 MW of firm capacity for the 74.9 MW solar PV asset. The justification for this stems from the limitations cited in the Power Plant Siting Act. The site is constrained to a maximum output of 74.9 MW at any given time from the sum of both assets, meaning neither can discharge to their full capacities simultaneously. As such, the solar would only yield 14.9 MW of firm summer capacity (20% of the nameplate), compared to the 50 MW provided by the battery.

Siting

60. Please refer to the **Excel Tables File (Planned PPSA)**. Complete the table by providing information on each planned generation resource that requires siting under the Power Plant Siting Act. For each planned unit, provide the date of the Commission's Determination of Need and Power Plant Siting Act certification, if applicable.

Please see attached Excel file.

61. Please refer to the **Excel Tables File (Planned TLSA)**. Complete the table by providing a list of all proposed transmission lines for the current planning period that require certification under the Transmission Line Siting Act. Please also include in the table transmission lines that have already been approved, but are not yet in-service.

Please see attached Excel file.

Power Purchase and/or Sale Agreements

62. Please refer to the **Excel Tables File** tabs listed below. Complete the tables by providing information on each power purchase agreement (PPA) for the time period listed. If the PPA is associated with a particular generating unit(s), provide additional information about those units if available. When completing the tables, please consider the following factors: (i) for multiple small (<1 MW) distributed resources of the same type and fuel source, provide a single entry; (ii) for solar facilities, if available, provide the nameplate DC capacity as the gross capacity, the nameplate AC capacity as the net capacity, and the firm contribution during time of system peak as the firm capacity. If a solar facility is combined with an energy storage system, identify the capacity of the energy storage system in a separate line.
- a. **Excel Tables File (Existing PPA)**, including each PPA still in effect by December 31 of the year prior to the current planning period pursuant to which energy was delivered to the Company during said year.
 - b. **Excel Tables File (Planned PPA)**, including each PPA pursuant to which energy will begin to be delivered to the Company during the current planning period.

[Please see attached Excel file.](#)

63. For each planned power purchase, provide a narrative response discussing the current status of the associated agreement.

[The Florida Renewable Partners \(FRP\) projects, comprising of the 50 MW Forest Trail Solar Energy Center and the 74.9 MW solar paired with 50 MW/4-hour battery energy storage system Miller Solar Energy Center are currently under construction, with site grading almost complete. All projects are still on track to commission December 31, 2026.](#)

[An 80 MW increase to capacity and transmission service for the 200 MW FPL PPA was approved by the JEA Board to help meet JEA’s growing demand. The contract is in final negotiations.](#)

[From 2027 – 2032, JEA will be purchasing 150 MW of firm capacity, energy, and transmission, with an option for an additional 50 MW to serve native load as a result of the Dalton and Santee Cooper Power Sales Agreements \(see response to Question 66\). This agreement, noted as the “TEA Backfill Purchase”, is in final negotiations.](#)

[In November 2025, JEA executed the FMPA Winter PPA for seasonal purchases for Winter 2025/26 at 50 MW and Winter 2026/27 at 125 MW to help meet capacity needs.](#)

[JEA anticipates coordinating with The Energy Authority to acquire short-term winter and summer seasonal market purchases to maintain JEA’s 15 percent reserve margin for years 2027 through 2031.](#)

64. Please list and discuss any long-term power purchase agreements that have, within the past year, been cancelled, delayed, or reduced in scope. What was the primary reason for the change? What, if any, were the secondary reasons?

The Caldwell Solar Energy Center (originally part of the FRP project scope), comprising of 74.9 MW solar PV paired with 50 MW/4-hour lithium-ion battery, was terminated in November 2025, due to the macroeconomic impacts from the evolving renewable energy market. JEA will now be purchasing a total of 125 MW of solar PV from the two remaining projects (Miller Solar Energy Center, Forest Trail Solar Energy Center).

The Florida Municipal Power Agency project (approximately 150 MWAC to be purchased from two facilities located in Florida) 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 FMPPA Board of Directors approved the termination of the solar agreement and JEA was released from its contractual obligations

A series of additional 74.9 MW PPAs, originally included in efforts to meet JEA's aspirational goal of 35% clean energy by 2030, were removed from the planning horizon. Given regulatory changes and other factors affecting practicality and affordability, as well as unprecedented load growth, JEA will continue to evaluate the current cost and practical ability to meet the aspirational clean energy goal.

65. Please refer to the **Excel Tables File** tabs listed below. Complete the tables by providing information on each power sale agreement (PSA) for the time period listed. If the PSA is associated with a particular generating unit(s), provide additional information about those units if available. When completing the tables, please consider the following factors: (i) for multiple small (<1 MW) distributed resources of the same type and fuel source, provide a single entry; (ii) for solar facilities, if available, provide the nameplate DC capacity as the gross capacity, the nameplate AC capacity as the net capacity, and the firm contribution during time of system peak as the firm capacity. If a solar facility is combined with an energy storage system, identify the capacity of the energy storage system in a separate line.
- a. **Excel Tables File (Existing PSA)**, including each PSA still in effect by December 31 of the year prior to the current planning period pursuant to which energy was delivered by the Company during said year.
 - b. **Excel Tables File (Planned PSA)**, including each PSA pursuant to which energy will begin to be delivered by the Company during the current planning period.

Please see attached Excel file.

66. For each planned power sale, provide a narrative response discussing the current status of the associated agreement.

In February 2026, the JEA Board approved the 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. The contract is in final negotiations.

67. Please list and discuss any long-term power sale agreements within the past year that were cancelled, expired, or modified. What was the primary reason for the change? What, if any, were the secondary reasons?

JEA does not have any Power Sale Agreements that have been cancelled, expired, or modified within the past year.

Reliability

68. Please refer to the **Excel Tables File (Annual Reliability)**. Complete the table by providing the loss of load probability, reserve margin, and expected unserved energy for each year of the planning period.

Please see attached Excel file.

69. Please refer to **Excel Tables File (Hourly Reliability)**. Provide an example hourly contribution of the Company's generating units compared to the system demand for a typical seasonal peak day for each season (Summer and Winter). As part of this response, provide the typical hourly demand and contribution of non-firm renewable resources (such as solar or wind), energy storage (charging and discharging separately), nuclear, natural gas, coal, oil, firm renewables, all other generation, purchased power, power sales, and demand response, if applicable.

Please see attached Excel file. Please note, the reported peaks are based on 2026 forecasted seasonal peaks. Data is from JEA's production modeling. The reported load reflects reductions from energy efficiency.

70. Describe in detail the methodology the Utility used to determine the seasonal firm capacity contribution of its solar facilities or purchases and provide the percentage contribution for each facility, if applicable. As part of this discussion, please explain whether the Company's existing and/or future solar facilities shift the hour of system peak demand for reliability planning purposes net of solar generation.

JEA includes 20% of its total solar portfolio in its summer firm capacity only; no contribution is allotted for winter. Additionally, JEA includes the output from the FPL solar PPA at hour 17 in its summer firm capacity.

There is no shift on the hour of system peak at this time

71. If the Company utilizes non-firm generation sources in its system portfolio, please detail whether it currently utilizes or has considered utilizing energy storage technologies to provide firm capacity from such generation sources. If not, please explain.
- Based on the Company's operational experience, please discuss to what extent energy storage technologies can be used to provide firm capacity from non-firm generation sources. As part of your response, please discuss any operational challenges faced and potential solutions to these challenges.

Please see response to Question 59.

Fuel Supply & Transportation

72. Please refer to the **Excel Tables File (Energy Rates)**. Complete the table by providing information on the Utility's firm capacity and energy purchases, non-firm energy purchases, and the Utility's as-available energy rate. If the Utility uses multiple areas for as-available energy rates, please provide a system-average rate as well.

Please see attached Excel file.

73. Please refer to the **Excel Tables File (Fuel Usage & Price)**. Complete the table by providing, on a system-wide basis, the actual annual fuel usage (in GWh) and average fuel price (in nominal \$/MMBTU) for each fuel type utilized by the Utility in the 10-year period prior to the current planning period. Also, provide the forecasted annual fuel usage (in GWh) and forecasted annual average fuel price (in nominal \$/MMBTU) for each fuel type forecasted to be used by the Utility in the current planning period.

Please see attached Excel file.

74. Does the Utility compare its fuel price forecasts to recognized, authoritative independent forecasts? If so, please identify all such forecasts and discuss how the Utility conducts its comparison. If not, please explain.

Forecasted fuel prices reflected in this planning horizon were developed using established industry-accepted methodologies, and current market conditions. JEA enlisted Black & Veatch, who 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.

75. Please identify and discuss expected industry trends and factors for each fuel type listed below that may affect the Utility during the current planning period.
- a. Coal.

Coal prices in nominal dollars are expected to increase during the forecast period. Delivered Colombian coal is forecasted to be priced lower than delivered domestic coal during the study period. Over the long term, coal consumption in the electric power sector is forecasted to continue to decline as a result of increased competition with natural gas and renewable generation.

- b. Natural Gas.

Natural gas prices at Henry Hub, are expected to increase significantly from current levels in the next 5 to 10 years because of new LNG export terminals coming on-line and rising gas use from the power sector to support data centers.

c. Nuclear.

N/A

d. Fuel Oil.

JEA maintains diesel inventory at Brandy Branch, Kennedy, Greenland, and Northside. Additional diesel supply is purchased from time to time in the open market as needed. The price of diesel fuel oil is projected in nominal dollars to increase throughout the forecast period and remain higher than the price of natural gas.

e. Other (please specify each, if any).

JEA uses circulating fluidized bed technology in Northside Generating Station Units 1 and 2. This technology allows JEA to use a blend of petroleum coke, bituminous coal, biomass, and natural gas in these units. During the planning period, JEA expects the petroleum coke market to typically trade at a discount to coal.

76. Please provide a comparison of the Utility's 2025 fuel price forecast used to prepare its 2025 TYSP and its actual 2025 delivered fuel prices.

The largest change between JEA's 2025 fuel price forecast compared to 2025 actual prices was an approximately 27% decrease in the actual cost of solid fuel. The second largest change was an approximately 21% increase in the cost of natural gas.

77. Please explain any notable changes in the Utility's forecast of fuel prices used to prepare the Utility's current TYSP compared to the forecast process used to prepare the Utility's prior TYSP.

Fuel forecasts in this TYSP are produced following the same process as the prior year.

78. Please identify and discuss steps that the Utility has taken to ensure natural gas supply availability and transportation over the current planning period.

JEA utilizes firm transportation on Florida Gas Transmission, Southern Natural Gas, and SNG Elba Express/Cypress pipeline. In addition, JEA has a firm long-term agreement for gas supply delivered to Jacksonville using Florida Gas Transmission and Southern Natural Gas pipelines. To deliver natural gas to JEA's Greenland Energy Center, JEA has a long-term contract with SeaCoast Gas Transmission, LLC. The various transportation contracts allow JEA the ability to access natural gas from diverse supply regions.

Environmental

79. Please explain if the Company assumes carbon dioxide (CO₂) compliance costs in the resource planning process used to generate the resource plan presented in the Company's current planning period TYSP. If the response is affirmative, answer the following questions:
- Please identify the year during the current planning period in which CO₂ compliance costs are first assumed to have a non-zero value.

JEA has not modeled any costs for CO₂ compliance at this time due to uncertainties of potential future regulations and what compliance options JEA would take.

- [Investor-Owned Utilities Only]** Please explain if the exclusion of CO₂ compliance costs would result in a different resource plan than that presented in the Company's current planning period TYSP.

N/A

- [Investor-Owned Utilities Only]** Please provide a revised resource plan assuming no CO₂ compliance costs.

N/A

80. Provide a narrative explaining the impact of any existing environmental regulations relating to air emissions and water quality or waste issues on the Company's system during the previous year. As part of your narrative, please discuss the potential for existing environmental regulations to impact unit dispatch, curtailments, or retirements during the current planning period.

The current and planned electricity generation mix for JEA will be a key factor in complying with any new CO₂ requirements. In addition to the atmospheric sinks of CO₂ emissions, other avenues of offsetting the carbon footprint are carbon capture from industrial processes or direct capture from ambient air, storage and transport of the captured carbon, the use hydrogen and certain biologic processes. These avenues will require substantial technological advances for meaningful and cost-effective results, with their viability in Florida still uncertain. Under the current Trump administration, the possibility of new CO₂ regulations is highly improbable. The following paragraphs describe the historical efforts to regulate CO₂ emissions in the U.S.

The Clean Power Plan (CPP), introduced by the Obama EPA in 2015, aimed to set emission guidelines for existing utility units, with individual statewide emission rate goals. However, on October 16, 2017, the Trump EPA proposed to repeal the CPP, rejecting its beyond the fence line, generation-shifting approach. In its place, the Affordable Clean Energy (ACE) rule was proposed by the Trump EPA in 2018 and published in 2019. The ACE rule replaced the CPP, focusing on regulating CO₂ emissions from electric generating units, particularly coal-fired units, with an emphasis on heat rate improvement (HRI) as the Best System of Emission Reduction (BSER). Florida's electric utilities had already been reducing CO₂ emissions substantially, and the ACE rule aimed to reinforce these reductions while allowing states flexibility in designing their State Plans.

However, the DC Circuit Court vacated the ACE rule on January 9, 2021, and remanded it back to the EPA. Despite this, the court did not reinstate the CPP. The court's decision was challenged, with a group of states and the North American Coal Corporation seeking U.S. Supreme Court review. On October 29, 2021, the Supreme Court agreed to review the appeal of the vacatur of the ACE rule. A decision was reached on June 30, 2022, reversing the previous decision made on January 9, 2021. Following this, the Biden EPA proposed a replacement for the ACE rule on May 23, 2023.

New Source Performance Standards (NSPS), codified in 40 CFR Part 60, Subpart TTTTa, requires that new stationary combustion turbines that serve generators capable of selling more than 25 MW to a utility distribution system and supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis must meet a CO₂ emission limit of 800 to 1,250 lb/MWh (gross) on a 12-month rolling average. These limits represent the Best System of Emission Reduction under Section 111(b) of the Clean Air Act. Monitoring requirements for CO₂ emissions are based on 40 CFR Part 75. The proposed NGS SJRPP Unit 3 Combined Cycle facility will incorporate operational practices and control technologies to meet or exceed these standards.

The most recent Greenhouse Gas (GHG) rule for power plants aimed to address CO₂ and other GHG emissions from fossil fuel-fired electric generating units (EGU's) under Section 111 of the Clean Air Act (CAA). The rule was finalized on May 9, 2024, potentially avoiding Congressional Review Act (CRA) being before the deadline of August 1, 2024. However, the motion to hold the case in abeyance still exists at this time. As such, the state plans are due by May 9, 2026. This, however, provided an exemption for existing gas-fired combustion turbines. Starting on March 26, 2024, the EPA initiated the process of gathering input regarding the regulation of the entire fleet of existing gas combustion turbines under the Clean Air Act 111(d). On June 17, 2025, the EPA proposed a rule to repeal these rules.

On September 16, 2025, the EPA also proposed a rule to repeal the mandatory GHG reporting requirements. On February 27, 2026, it was decided to extend the reporting deadline to the Fall of 2026. On February 18, 2026, the 2009 Endangerment Finding was repealed for vehicles, and may possibly be extended to the power plants later.

New and Revised NSPS's: EPA proposed a new rule for stationary combustion turbines (CT) on November 22, 2024 (Subpart KKKKa) and finalized on January 15, 2026. The rule also revises the current Subparts GG and KKKK.

NSPS Subpart KKKKa applies to sources constructed, modified, and reconstructed after 12/13/24. It establishes nitrogen oxides (NO_x) emissions standards for various combustion turbine size, utilization, and design efficiency. It requires that selective catalytic reduction (SCR) be the best system of emissions reduction (BSER) for new, large combustion turbines (> 850 MMBtu/hr) with a high utilization rate (> 45 percent on 12-calendar-month period). The use of good combustion controls remains the BSER for limiting NO_x emissions from all other combustion turbine subcategories. Sulfur dioxide (SO₂) standards from Subpart KKKK

do not change. It also does not establish standards for any new criteria pollutants, including particulate matter (PM/PM₁₀ /PM_{2.5}) or carbon monoxide (CO).

A new subcategory for temporary CT applies to small and medium CTs (i.e., up to 850 MMBtu/hr) may be used in a single location for up to 24 consecutive months. Operations during a system emergency, identified as Energy Emergency Alert 1, 2, or 3 is not included when calculating a turbine’s 12-calendar month utilization. CTs covered under KKKKa are not covered under KKKK or GG, and vice-versa. KKKKa maintains exemption for emergency-standby CTs.

National Emission Standard for Hazardous Air Pollutants (NESHAP): 40 CFR 63 Subpart YYYY (for Combustion Turbines) has also been revised. As a result of the Residual Risk and Technical Review (RTR) in 2020, EPA will not be imposing additional controls. The agency is however proposing revisions to Start-up, Shut-down and Malfunction (SSM) provisions, adding requirements for E-reporting, and lifting of the stay for new gas-fired CTs. These revisions are not expected to impact JEA’s existing EGUs, unless they are significantly “modified or reconstructed” or if JEA constructs a new combustion turbine.

Although the rule was stayed in 2004 after EPA received a petition to delist the gas turbines from source categories that would be subject to NESHAP. After the 2020 RTR, EPA decided to keep the stay because an updated petition was received to delist the source category. Then, after Sierra Club petition and EPA’s own risk analysis, the stay was lifted on February 28, 2022. However, JEA’s “existing” CTs at Northside Generating Station and Brandy Branch Generating Stations are not currently subject to the rule due to their commencement dates. Furthermore, JEA’s “new” CTs at Kennedy Generation Station and Greenland Energy Center are not currently subject to the rule because neither facility is a major source of HAPs.(i.e., they do not have a potential to emit more than 10 tpy of any individual HAP or more than 25 tpy of total HAPs.)

40 CFR 63 Subpart UUUUU (a.k.a. Mercury Air Toxics Standard or MATS): On December 27, 2018, EPA signed a proposal regarding the MATS Supplemental Cost Finding and Residual Risk and Technology Review (RTR). It concluded as follows:

- Regulation of HAPs is not “appropriate or necessary,” after reconsidering the cost analysis, because the costs “grossly outweigh the quantified HAP benefits.”
- Coal- and oil-fired EGUs would not be delisted from 112 regulation, and the 2012 MATS rule would remain in place.
- Regarding the RTR, no revisions to MATS are warranted.
- On April 23, 2023, EPA proposed to strengthen and update MATS to reflect recent developments in control technologies and the performance of these plants. This proposed rule reflects the most significant improvements and updates to MATS since EPA first issued these standards in February 2012. JEA’s CFBs at NGS may be required to implement continuous PM emission monitors to demonstrate compliance with the PM emission standards, in lieu of stack testing, within 3 years from the date of the final rule (May 7, 2024), i.e., by May 7, 2027.

- EPA proposed to revise the filterable PM emission standard from 0.030 pounds per million British thermal units of heat input (lb/MMBtu) to 0.010 lb/MMBtu or possibly even lower. Based on historical stack test results, JEA's CFBs should be able to meet the new limits.
- EPA is considering creating a subcategory for acid gas HAP emissions from EGUs burning eastern bituminous coal refuse, which would affect 10 units in PA and WV.

The EPA reconsidered the MATS regulations based on the industry claim the EPA underestimated the compliance costs and that the rule imposes undue burden on certain coal plants. On February 24, 2026, the EPA issued a final rule to repeal the MATS amendments described above.

Startup, Shutdown and Malfunction (SSM) SIP Call

On May 2015, EPA issued a SSM SIP call, which is a notice of rulemaking that would require 36 states (including Florida) to revise provisions in their State Implementation Plans ("SIPs") related to air emissions from sources during times of startup, shutdown, and equipment malfunction ("SSM"). Numerous parties have challenged the SSM Action in these consolidated cases. On October 31, 2016, the parties completed merits briefing. Oral argument is scheduled for May 8, 2017 has been cancelled. On April 18, 2017, the DOJ filed a motion for the DC Circuit Court continue the oral argument currently as scheduled to allow the new Administration adequate time to review the SSM Action to determine whether it will be reconsidered. With this continuance, EPA officials in the new Administration are expected to scrutinize the SSM Action to determine whether it should be maintained, modified, or otherwise reconsidered. EPA reversed its decision in 2020 stating that the cost of compliance outweighs the emissions benefits from the regulation. In January 2021, it was again reviewed by the Biden Administration and concluded that it was indeed appropriate and necessary.

On March 1, 2024, the U.S. Court of Appeals for the DC Circuit largely vacated EPA's "SIP Call" that required states to remove from their respective air quality plans regulatory waivers for excess air emissions during periods of SSM. The court held that EPA did not make the necessary or appropriate determination required by the CAA to order states to eliminate automatic SSM exemptions, director's discretion provisions, and affirmative defenses that function as SSM exemptions. The decision resolves, for now, a decades old debate over how the CAA can recognize elevated emissions associated with SSM events. On September 5, 2025, D.C. Circuit, in SSM Litigation Group v. EPA, decided to allow affirmative defense for malfunctions.

National Ambient Air Quality Standards (NAAQS):

- On June 2, 2010, EPA revised the primary NAAQS for sulfur dioxide (SO₂) by implementing a new 1-hour standard of 75 parts per billion (ppb) (calculated as the three-year average of the 99th percentile of the annual distribution of daily maximum 1-hour average concentrations). JEA's NGS Unit 3 is permitted to burn No. 6 fuel oil with sulfur content of greater than 1% by weight and could potentially cause or contribute to

exceedance of this 1-hour SO₂ standard. Based on comprehensive dispersion modeling analyses, it was determined that probability of compliance with the 1-hour SO₂ standard is greater than 99.5 percent as long as the unit does not burn No. 6 fuel oil for more than 14 days in a calendar year. Greater number of days of oil operation is also possible with less confidence levels. This determination is conservative since it also assumed all other NGS steam generating units are operating at full load.

- On December 27, 2024, a secondary NAAQS for SO₂ of 10ppb, annual average over three consecutive years, was also published. The rule is in abeyance at this time.
- EPA finalized the NAAQS Fine Particulate Matter ("PM_{2.5}") standards in September 2006. Since then, the EPA established a more stringent 24-hour average PM_{2.5} standard and kept the annual average PM_{2.5} standard and the 24-hour coarse particulate matter standard unchanged. The EPA issued a final PM_{2.5} rule on December 14, 2012, that reduced the annual PM_{2.5} standard from 15 µg/m³ to 12 µg/m³. The rule left the 24-hour PM_{2.5} standard of 35 µg/m³ unchanged. The change in the PM_{2.5} has not resulted in non-attainment designation for Duval County and has not had a material adverse effect on the operations of JEA's generating facilities. On January 23, 2023, EPA proposed to retain the daily standard of 35 µg/m³ and lower the annual standard from 12 to between 9 and 10 µg/m³. On March 6, 2024, EPA lowered the NAAQS for annual PM_{2.5} to 9.0 µg/m³, but retained the daily and secondary standards. EPA also approved corrections to PM_{2.5} data from T640/T640X monitors on May 16, 2025, and the entire State of Florida is projected to be in attainment. This new NAAQS will only impact JEA if dispersion modeling is required to obtain an air permit. On November 25, 2025, The EPA moved to vacate annual PM_{2.5} NAAQS.
- On October 1, 2015, the EPA revised its NAAQS for ground-level ozone to 70 parts per billion ("ppb"), which is more stringent than the 75-ppb standard set in 2008. The Clean Air Act mandates that EPA publish initial area designations within two years of the promulgation of a new standard (i.e., by October 2017), but allows for a one-year extension if the Administrator determines he "has insufficient information to promulgate the designations." On November 16, 2017, EPA published a final rule establishing initial area designations for the 2015 NAAQS for ozone EPA, designating 2,646 counties (including all counties in Florida) as "attainment/unclassifiable." EPA is designating areas as "attainment/unclassifiable" where one or more monitors in the county are attaining the 2015 ozone NAAQS, or where EPA does not have reason to believe the county is violating the 2015 ozone NAAQS or contributing to a violation of the 2015 ozone NAAQS in another county. States with nonattainment areas will have up to three years following designation to submit a revised state implementation plan ("SIP") outlining strategy and emission control measures to achieve compliance. In November 2017, Duval County was deemed unclassifiable pending acceptable monitoring results expected at the end of 2018. Duval County is projected to be in attainment of the revised standard. On August 14, 2019, EPA published the proposal to redesignate Duval County from unclassifiable to attainment/unclassifiable for the 2015 Ozone NAAQS. In the event that Duval County was to become a non-attainment area, JEA's power plants (e.g., Northside and Brandy Branch) could be required to comply with additional emission control requirements (e.g., increased usage of ammonia in their Selective catalytic reduction/Selective non-catalytic reduction ("SCR/SNCR")) for nitrogen oxides and

volatile organic compounds which are precursors to ozone formation. The nature and consequences of a non-attainment designation cannot be predicted at this time. On January 20, 2021, the Biden-Harris administration reviewed the Ozone NAAQS as contained in 85 Fed. Reg. 87256 dated December 31, 2020. In April 2022, EPA staff recommended retention of 70 ppb.

- On March 14, 2021, EPA withdrew a denial of petition to create a NAAQS for CO₂.

Regional Haze

EPA and other agencies have been monitoring visibility in national parks and wilderness areas since 1988. In 1999, the EPA announced a major effort to improve air quality in national parks and wilderness areas. The Regional Haze Rule calls for state and federal agencies to work together to improve visibility in 156 national parks and wilderness areas such as the Grand Canyon, Yosemite, the Great Smokies and Shenandoah.

As a result of the second planning period of the rule, JEA reduced the use of Fuel Oil No. 6 and its sulfur content. EPA is now considering revisions to the Regional Haze Rule that would affect the third planning period. The main regional haze Class I Areas affecting Florida are the Okefenokee Swamp, the St. Marks National Wildlife Refuge/Bradwell Bay, the Chassahowitzka NWR, and Everglades NP.

In order to satisfy the Regional Haze Phase II requirements, JEA applied for additional permit conditions to restrict the sulfur content of No. 6 fuel oil at Unit 3 and no additional controls are expected to be necessary. JEA informed FDEP if it will burn only natural gas or fuel oil with no more than 1% sulfur by weight in Unit 3 and with a much lower capacity factor, in light of the new Combined Cycle being planned.

On January 6, 2026, the EPA final rule changed SIP due date to July 31, 2031 from July 31, 2028.

On February 18, 2026, a guidance was issued directing EPA to consider grid reliability in second planning period.

Risk Management Program (RMP)

On February 24, 2026, the EPA published a proposed rule in the Federal Register that would revise elements of the 2024 Safer Communities by Chemical Accident Prevention (SCCAP) amendments to the RMP program. The proposal reflects a shift toward a more targeted, performance-based framework intended to reduce regulatory burden. JEA's Brandy Branch Generating Station is subject to the RMP program due to the use of ammonia for NOx control.

81. For the U.S. EPA's Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units Rule:

- a. Will your Company be materially affected by the rule?

In the unlikely event that this rule is retained as it, it will impact JEA's planned new 1x1 Advanced-Class Combined Cycle facility as well as its existing EGUs.

- b. What compliance strategy does the Company anticipate employing for the rule?

To be determined.

- c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?

To be determined.

- d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?

To be determined.

- e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Refer to the **Excel Tables File (Emissions Cost)**. Complete the table by providing information on the costs for the current planning period.

N/A at this time.

- f. If the answer to any of the above questions is not available, please explain why.

N/A at this time.

82. Explain any expected reliability impacts resulting from each of the EPA rules listed below. As part of your explanation, please discuss the impacts of transmission constraints and changes to units not modified by the rule that may be required to maintain reliability.

- a. Mercury and Air Toxics Standards (MATS) Rule.

N/A

- b. Cross-State Air Pollution Rule (CSAPR).

N/A

- c. Cooling Water Intake Structures (CWIS) Rule.

To be determined.

- d. Coal Combustion Residuals (CCR) Rule.

JEA does not expect any reliability impacts resulting from the CCR Rule.

- e. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units.

To be determined.

- f. Affordable Clean Energy Rule or its replacement.

N/A

- g. Effluent Limitations Guidelines and Standards (ELGS) from the Steam Electric Power Generating Point Source Category.

N/A

83. Please refer to the **Excel Tables File (EPA Operational Effects)**. Complete the table by identifying, for each unit affected by one or more of EPA's rules, what the impact is for each rule, including; unit retirement, curtailment, installation of additional emissions controls, fuel switching, or other impacts identified by the Company.

Please see attached Excel file.

84. Please refer to the **Excel Tables File (EPA Cost Effects)**. Complete the table by identifying, for each unit impacted by one or more of the EPA's rules, what the estimated cost is for implementing each rule over the course of the planning period.

Please see attached Excel table. Note that the CCR rule only applies to the decommissioned St. John's River Power Park (SJRPP), as there are costs associated with maintaining the landfills at the site. See below for more information.

Solid Waste Rules: The CCR rule applies to Area B of the decommissioned St. John's River Power Park (SJRPP) and does not apply to management of byproducts at Northside Generating Station as long as it continues to burn a fuel mix with less than 50 percent coal. The operating cell within Area B of SJRPP was closed and closure construction was completed in January 2022 in accordance with specified performance standards. The facility will continue to comply with the monitoring requirements of the rule in accordance with the post-closure and corrective action plans for groundwater. JEA's current estimate for corrective measures and long-term closure near \$6.7 million. On November 4, 2024, EPA's Coal Combustion Residuals Surface Impoundments and CCR Management Units Rule became final. EPA finalized this Rule to regulate coal ash of inactive CCR Surface Impoundments and inactive CCR Management Units and establishes groundwater monitoring, corrective action, closure, and post-closure care requirements. The rule applies to the closed Area A landfills (1&2) at SJRPP. Initial costs impacts are anticipated to be approx. \$500k (Facility Evaluation: \$55k, Groundwater Network Evaluation: \$15k, Closure Evaluation: \$10k, Groundwater Monitoring: \$60k, Closure/Post-Closure Care: \$300k, Legal: \$60k). Level of effort beyond the initial two years will be determined by the facility evaluations, ground water network evaluation results and closure evaluations

85. Please refer to the **Excel Tables File (EPA Unit Availability)**. Complete the table by identifying, for each unit impacted by one or more of EPA's rules, when and for what

duration units would be required to be offline due to retirements, curtailments, installation of additional controls, or additional maintenance related to emission controls. Include important dates relating to each rule.

[Please see attached Excel file.](#)

86. If applicable, identify any currently approved costs for environmental compliance investments made by your Company, including but not limited to renewable energy or energy efficiency measures, which would mitigate the need for future investments to comply with recently finalized or proposed EPA regulations. Briefly describe the nature of these investments and identify which rule(s) they are intended to address.

[N/A](#)

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2026 TYSP Data Request #1.Excel Tables - JEA.xlsx

Financial Assumptions		
Base Case		
AFUDC Rate	(%)	4.75
Capitalization Ratios	Debt	(%) 100
	Preferred	(%) 0
	Equity	(%) 0
Rate of Return	Debt	(%) 4.75
	Preferred	(%) 0
	Equity	(%) 0
Income Tax rate	State	(%) 0
	Federal	(%) 0
	Effective	(%) 0
Other Tax Rate:	(%)	0
Discount Rate:	(%)	4.75
Tax - Depreciation Rate:	(%)	N/A

2026 TYSP Data Request #1.Excel Tables - JEA.xlsx

Financial Escalation Assumptions				
Year	General Inflation	Plant Construction Cost	Fixed O&M Cost	Variable O&M Cost
	(%)	(%)	(%)	(%)
2026	3.5	3.5	3.5	3.5
2027	3.5	3.5	3.5	3.5
2028	3.5	3.5	3.5	3.5
2029	3.5	3.5	3.5	3.5
2030	3.5	3.5	3.5	3.5
2031	3.5	3.5	3.5	3.5
2032	3.5	3.5	3.5	3.5
2033	3.5	3.5	3.5	3.5
2034	3.5	3.5	3.5	3.5
2035	3.5	3.5	3.5	3.5

Year	Month	Actual Peak Demand	Demand Response Activated	Estimated Peak Demand	Day	Hour	System-Average Temperature
		(MW)	(MW)	(MW)			(Degrees F)
2025	1	2913	0	2913	25	8	29
	2	2336	0	2336	21	8	34
	3	1826	0	1826	31	17	82
	4	2171	0	2171	27	18	83
	5	2601	0	2601	20	18	92
	6	2597	0	2597	25	18	90
	7	2849	0	2849	29	15	95
	8	2767	0	2767	1	17	97
	9	2406	0	2406	23	17	87
	10	1998	0	1998	8	17	81
	11	2155	0	2155	12	8	37
	12	2220	0	2220	31	9	37
2024	1	2416	0	2416	17	9	31
	2	2043	0	2043	20	8	39
	3	1767	0	1767	15	18	83
	4	2121	0	2121	19	18	84
	5	2470	0	2470	9	17	77
	6	2664	0	2664	10	17	97
	7	2592	0	2592	12	17	93
	8	2675	0	2675	9	16	93
	9	2486	0	2486	2	18	88
	10	2280	0	2280	1	16	86
	11	2002	0	2002	7	16	83
	12	2262	0	2262	4	8	33
2023	1	2326	0	2326	16	8	30
	2	1813	0	1813	24	16	86
	3	2049	0	2049	27	18	84
	4	2081	0	2081	5	17	84
	5	2230	0	2230	16	17	86
	6	2598	0	2598	27	18	94
	7	2699	0	2699	21	17	97
	8	2756	0	2756	11	17	97
	9	2463	0	2463	7	17	91
	10	2057	0	2057	5	17	82
	11	2043	0	2043	29	8	35
	12	2016	0	2016	20	8	39

Notes

System Net Peak Demand, Hour Ending. System Average Temperature during peak hour.

2023-2024 temperatures revised to temperature during peak hour instead of average daily temperature on day of peak hour

Nov. and Dec. 2024 Actual Peak Demand revised to fix typo.

Calendar Year	Actual Net Energy (GWh)																				
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2015	12,868	17,207	17,119	17,119	14,715	14,105	15,090	13,805	13,414	12,769	12,718										
2016	12,937		17,511	17,512	15,000	14,285	15,303	13,928	13,445	12,849	12,848	12,883									
2017	12,672			17,820	15,297	14,876	15,443	14,108	13,516	12,928	12,914	12,993	12,933								
2018	12,813				15,625	15,192	15,619	14,292	13,612	12,992	12,963	12,813	12,807	12,586							
2019	12,797					15,692	15,795	14,481	13,690	13,063	13,009	12,901	12,985	12,694	12,696						
2020	12,740						16,009	14,672	13,742	13,126	13,062	12,987	13,089	12,763	12,765	12,948					
2021	12,540							14,881	13,809	13,168	13,121	13,065	13,179	12,830	12,832	13,002	12,808				
2022	12,930								13,872	13,227	13,186	13,122	13,293	12,905	12,907	13,053	12,949	12,837			
2023	12,733										13,286	13,274	13,175	13,415	12,980	12,982	13,133	13,064	12,974	12,973	
2024	13,255											13,371	13,233	13,533	13,047	13,048	13,222	13,187	13,090	13,047	12,899
2025	13,479												13,294	13,645	13,120	13,120	13,313	13,315	13,197	13,140	13,036
2026														13,755	13,198	13,199	13,415	13,438	13,297	13,242	13,161
2027																13,281	13,282	13,518	13,559	13,386	13,341
2028																		13,282	13,518	13,559	13,386
2029																	13,366	13,615	13,678	13,473	13,437
2030																			13,615	13,678	13,473
2031																				13,791	13,527
2032																					13,527
2033																					13,704
2034																					13,903
																					13,647
																					13,610
																					13,618
																					13,722
																					13,738
																					13,807
																					13,841
																					13,885
																					13,941
																					14,042

Calendar Year	Actual Net Energy (GWh)																				
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2015	12,868	(25.2%)	(24.8%)	(24.8%)	(12.6%)	(8.8%)	(14.7%)	(6.8%)	(4.1%)	0.8%											
2016	12,937		(26.1%)	(26.1%)	(13.8%)	(9.4%)	(15.5%)	(7.1%)	(3.8%)	0.7%	0.7%	0.4%									
2017	12,672			(28.9%)	(17.2%)	(14.8%)	(17.9%)	(10.2%)	(6.2%)	(2.0%)	(1.9%)	(2.5%)	(2.0%)								
2018	12,813				(18.0%)	(15.7%)	(18.0%)	(10.3%)	(5.9%)	(1.4%)	(1.2%)	0.0%	0.0%	1.8%							
2019	12,797					(18.4%)	(19.0%)	(11.6%)	(6.5%)	(2.0%)	(1.6%)	(0.8%)	(1.4%)	0.8%	0.8%						
2020	12,740						(20.4%)	(13.2%)	(7.3%)	(2.9%)	(2.5%)	(1.9%)	(2.7%)	(0.2%)	(0.2%)	(1.6%)					
2021	12,540							(15.7%)	(9.2%)	(4.8%)	(4.4%)	(4.0%)	(4.9%)	(2.3%)	(2.3%)	(3.6%)	(2.1%)				
2022	12,930								(6.8%)	(2.2%)	(1.9%)	(1.5%)	(2.7%)	0.2%	0.2%	(0.9%)	(0.1%)	0.7%			
2023	12,733									(4.2%)	(4.1%)	(3.3%)	(5.1%)	(1.9%)	(1.9%)	(3.0%)	(2.5%)	(1.9%)	(1.8%)		
2024	13,255										(0.9%)	0.2%	(2.1%)	1.6%	1.6%	0.2%	0.5%	1.3%	1.6%	2.8%	
2025	13,479											1.4%	(1.2%)	2.7%	2.7%	1.2%	1.2%	2.1%	2.6%	3.4%	3.5%

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Resource Type	Customer-Owned Resources										
	Actual	Projected									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Renewable Resources											
Number of Installations	337	955	1095	1231	1367	1494	1588	1681	1578	1490	443
Total Capacity of Installations ⁽³⁾⁽⁴⁾	3.5										
Reduction to Summer Peak Demand (MW) ⁽¹⁾⁽²⁾		(2)	(2)	(3)	(3)	(3)	(3)	1	(2)	(8)	10
Reduction to Winter Peak Demand (MW) ⁽¹⁾⁽²⁾		0	0	(1)	0	0	0	(1)	0	0	0
Reduction to Net Energy for Load (GWh) ⁽¹⁾⁽²⁾		(10)	(11)	(14)	(13)	(15)	(15)	(16)	(14)	(14)	(5)
Energy Storage Resources ⁽²⁾											
Number of Installations	291										
Total Capacity of Installations (MW)	3.3										
Total Storage Capacity of Installations (MWh)											
Reduction to Summer Peak Demand (MW) ⁽¹⁾											
Reduction to Winter Peak Demand (MW) ⁽¹⁾											
Reduction to Net Energy for Load (GWh) ⁽¹⁾											
Notes											
<p>(1) JEA does not currently track the actual demand or energy reduction from customer-owned resources.</p> <p>(2) The forecasted renewable resources demand and energy reduction combines both renewable resources and energy storage resources.</p> <p>(3) JEA does not have a forecast for the total capacity of the renewable or energy storage installations.</p> <p>(4) Renewable resources total capacity is in MW.</p> <p>(5) Reported installations, capacity, and peak and load reductions are incremental.</p>											

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[Demand Response Source or All Demand Response Sources]									
Year	Participating Customers			Available Capacity (MW)					
				Summer			Winter		
	Start of Year	Lost	Added	Start of Year	Lost	Added	Start of Year	Lost	Added
2023									
2024									
2025									
Notes									
N/A. JEA does not have a demand response program.									

[Demand Response Source or All Demand Response Sources]														
Year	Summer							Winter						
	Total Events	Customers Activated			Capacity Activated (MW)			Total Events	Customers Activated			Capacity Activated (MW)		
		Average Event	Max Event	Peak Day	Average Event	Max Event	Peak Day		Average Event	Max Event	Peak Day	Average Event	Max Event	Peak Day
2023														
2024														
2025														
Notes														
N/A. JEA does not have a demand response program.														

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Year	Number of PEVs	Number of Public PEV Charging Stations	Number of Public DCFC PEV Charging Stations ¹	Cumulative Impact of PEVs		
				Summer Demand	Winter Demand	Annual Energy
				(MW)	(MW)	(GWh)
2026	29,643	324		2	1	26
2027	35,787	365		5	1	54
2028	42,565	409		7	2	86
2029	50,017	456		10	3	121
2030	58,111	506		14	4	159
2031	66,844	558		17	4	200
2032	76,205	613		21	5	244
2033	86,227	671		25	7	291
2034	96,911	732		29	8	341
2035	108,251	796		49	9	395
Notes						
(1) JEA does not forecast DCFC PEV charging stations separately.						

Data Center Type	Data Centers										
	Actual	Projected									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Existing Data Centers											
Number of Data Centers	5	5	5	5	5	5	5	5	5	5	5
Total Annual Energy Usage (GWh)	38.768793	43.773793	48.778793	151.025793	154.026793	157.032793	157.032793	157.032793	157.032793	157.032793	157.032793
Impact to Summer Peak Demand (MW)	5.32039	6.19939	7.07839	26.45839	26.98539	27.51339	27.51339	27.51339	27.51339	27.51339	27.51339
Impact to Winter Peak Demand (MW)	5.06522	5.94422	6.82322	26.20322	26.73022	27.25822	27.25822	27.25822	27.25822	27.25822	27.25822
Planned Data Centers (In-service in 2026)											
Number of Data Centers	0	0	0	0	0	0	0	0	0	0	0
Total Annual Energy Usage (GWh)	0	0	0	0	0	0	0	0	0	0	0
Impact to Summer Peak Demand (MW)	0	0	0	0	0	0	0	0	0	0	0
Impact to Winter Peak Demand (MW)	0	0	0	0	0	0	0	0	0	0	0
Planned Data Centers (After 2026)											
Number of Data Centers	0	0	0	0	0	0	0	0	0	0	0
Total Annual Energy Usage (GWh)	0	0	0	0	0	0	0	0	0	0	0
Impact to Summer Peak Demand (MW)	0	0	0	0	0	0	0	0	0	0	0
Impact to Winter Peak Demand (MW)	0	0	0	0	0	0	0	0	0	0	0
Notes											
The Existing Data Center GWh and MW forecast is based on 2025 actuals as a baseline, with three small data center expansions incorporated.											

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Question No.

2026
45(a)

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)					
							Gross		Net		Firm	
					Mo	Yr	Sum	Win	Sum	Win	Sum	Win
Brandy Branch	GT1	Duval	GT	NG	5	2001	180	193	179	191	179	191
Brandy Branch	CT2	Duval	CT	NG	5	2001	190.5	212.2	189.7	211.7	189.7	211.7
Brandy Branch	CT3	Duval	CT	NG	10	2001	190.5	212.2	189.7	211.7	189.7	211.7
Brandy Branch	STM4	Duval	CA	WH	1	2001	210	225	200	216.1	200	216.1
Greenland Energy Center	GT1	Duval	GT	NG	6	2011	180	193	179	191	179	191
Greenland Energy Center	GT2	Duval	GT	NG	6	2011	180	193	179	191	179	191
J. D. Kennedy	GT7	Duval	GT	NG	6	2000	180	193	179	191	179	191
J. D. Kennedy	GT8	Duval	GT	NG	6	2009	180	193	179	191	179	191
Northside	1	Duval	ST	PC	5	2003	310	310	293	293	293	293
Northside	2	Duval	ST	PC	4	2003	310	310	293	293	293	293
Northside	3	Duval	ST	NG	6	1977	540	540	524	524	524	524
Northside	GT3	Duval	GT	DFO	1	1975	50.4	62	50	61.6	50	61.6
Northside	GT4	Duval	GT	DFO	1	1975	50.4	62	50	61.6	50	61.6
Northside	GT5	Duval	GT	DFO	12	1974	50.4	62	50	61.6	50	61.6
Northside	GT6	Duval	GT	DFO	12	1974	50.4	62	50	61.6	50	61.6
Notes												
(Include Notes Here)												

TYSP Year
Question No.

2026
45(b)

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)					
							Gross		Net		Firm	
					Mo	Yr	Sum	Win	Sum	Win	Sum	Win
Advanced-Class 1x1 CC	TBD	Duval	CCCT	NG	01	2031			582	678	582	678
Advanced-Class 1x0 CT I ¹	TBD	Duval	GT	NG	01	2035			374	453	374	453
Advanced-Class 1x0 CT II ¹	TBD	Duval	GT	NG	01	2035			374	453	374	453
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.												

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Performance (%)						Average Net Operating Heat Rate (ANOHR) (MMBTU/kWh) ¹	
							Planned Outage Factor (POF) (%)		Forced Outage Factor (FOF) (%)		Equivalent Availability Factor (EAF) (%)		Historic ²	Projected
					Mo	Yr	Historic	Projected	Historic	Projected	Historic	Projected		
Brandy Branch	GT1	Duval	GT	NG	5	2001	4.70%	3.07	0.15%	3.00	95.00%	93.93	11,102	10,432
Brandy Branch	CT2, CT3, STM4	Duval	CC	NG	1	2005	6.46%	5.07	1.43%	2.00	91.23%	92.93	6,971	6,476
Greenland Energy Center	GT1	Duval	GT	NG	6	2011	4.43%	2.68	2.77%	3.00	92.10%	94.32	11,404	11,636
Greenland Energy Center	GT2	Duval	GT	NG	6	2011	3.81%	2.57	2.35%	3.00	93.98%	94.43	10,979	11,638
J. D. Kennedy	GT7	Duval	GT	NG	6	2000	2.48%	2.87	1.07%	3.00	97.31%	94.13	11,427	10,908
J. D. Kennedy	GT8	Duval	GT	NG	6	2009	1.02%	3.34	0.53%	3.00	97.31%	93.66	11,643	11,409
Northside	1	Duval	ST	PC	5	2003	9.91%	13.35	9.96%	5.00	77.40%	81.65	11,588	9,708
Northside	2	Duval	ST	PC	4	2003	13.94%	8.32	2.83%	5.00	77.77%	86.68	11,576	9,571
Northside	3	Duval	ST	NG	6	1977	20.40%	8.67	1.98%	5.00	73.26%	86.33	11,250	11,168
Northside	GT3	Duval	GT	DFO	1	1975	0.49%	2.49	20.27%	5.00	75.12%	92.51	18,192	19,226
Northside	GT4	Duval	GT	DFO	1	1975	4.50%	1.42	6.26%	5.00	74.95%	93.58	21,237	14,900
Northside	GT5	Duval	GT	DFO	12	1974	0.65%	3.26	3.61%	5.00	89.96%	91.74	22,036	19,712
Northside	GT6	Duval	GT	DFO	12	1974	9.97%	2.30	6.70%	5.00	81.35%	92.70	23,443	19,775
Advanced-Class 1x1 CC	TBD	TBD	CCCT	NG	1	2031	N/A	3.84	N/A	3.00	N/A	93.16	N/A	6,382
Advanced-Class 1x0 CT I ³	TBD	Duval	GT	NG	1	2035	N/A	3.84	N/A	3.80	N/A	92.36	N/A	9,817
Advanced-Class 1x0 CT II ³	TBD	Duval	GT	NG	1	2035	N/A	3.84	N/A	3.80	N/A	92.36	N/A	9,817

Notes

1. ANOHR listed in units of BTU/kWh.
2. Historical - average of past three years (2023-2025).
3. 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.

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Capacity Factor (%)										
							Actual	Projected									
								2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Brandy Branch	GT1	Duval	GT	NG	5	2001	20.3	8	12	6	4	4	3	3	5	6	1
Brandy Branch	CT2, CT3, STM4	Duval	CC	NG	1	2005	83	84	78	83	81	78	80	79	78	79	80
Greenland Energy Center	GT1	Duval	GT	NG	6	2011	22.9	32	31	23	17	16	10	11	15	15	7
Greenland Energy Center	GT2	Duval	GT	NG	6	2011	17.9	33	34	23	17	14	10	10	15	15	7
J. D. Kennedy	GT7	Duval	GT	NG	6	2000	12.8	7	14	8	5	5	4	4	8	7	2
J. D. Kennedy	GT8	Duval	GT	NG	6	2009	6.6	12	16	10	7	6	5	6	8	9	2
Northside	1	Duval	ST	PC	5	2003	25	18	15	53	62	75	33	37	39	31	29
Northside	2	Duval	ST	PC	4	2003	40.7	21	40	43	54	74	42	41	42	45	35
Northside	3	Duval	ST	NG	6	1977	29.8	44	52	42	32	27	0	0	0	0	0
Northside	GT3	Duval	GT	DFO	1	1975	0.3	0.1	0.1	0.3	0.1	0.2	0.0	0.0	0.1	0.1	0.0
Northside	GT4	Duval	GT	DFO	1	1975	0.2	0.0	0.1	0.2	0.0	0.2	0.0	0.0	0.0	0.1	0.0
Northside	GT5	Duval	GT	DFO	12	1974	0.4	0.0	0.1	0.3	0.1	0.2	0.0	0.0	0.0	0.2	0.0
Northside	GT6	Duval	GT	DFO	12	1974	0.4	0.0	0.1	0.3	0.1	0.2	0.0	0.1	0.1	0.2	0.0
Advanced-Class 1x1 CC	TBD	Duval	CCCT	NG	1	2031	N/A	0	0	0	0	0	76	77	74	76	77
Advanced-Class 1x0 CT I ¹	TBD	Duval	GT	NG	1	2035	N/A	0	0	0	0	0	0	0	0	0	13
Advanced-Class 1x0 CT II ¹	TBD	Duval	GT	NG	1	2035	N/A	0	0	0	0	0	0	0	0	0	13

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.

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Facility Name	Unit No.	County Location	Solar Type	Energy Storage Type	Facility In-Service Date		Unit Capacity (MW)				Land Use (Acres)	Commission Approval		Cost Recovery Mechanism
			(Fixed/Tracking)		Mo	Yr	Net		Firm			Order No.	Approval Date	
							Sum	Win	Sum	Win				
Notes														
N/A														

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Final Decision ('Drop Dead') Date ¹	Site Selection		Engineering / Permitting / Procurement		Construction		Commercial In-Service Date
						Begins ²	Ends ¹	Begins ³	Ends	Begins	Ends	
Advanced-Class 1x1 CC	TBD	Duval	CCCT	NG	Aug-25	Jun-23	Aug-25	Sep-24	Mar-27	Jan-28	Jan-31	Jan-31
Advanced-Class 1x0 CT I ⁴	TBD	Duval	GT	NG	TBD	TBD	TBD	TBD	TBD	TBD	TBD	Jan-35
Advanced-Class 1x0 CT II ⁴	TBD	Duval	GT	NG	TBD	TBD	TBD	TBD	TBD	TBD	TBD	Jan-35
Notes												
<p>1. JEA Board delivered decision to proceed on this date.</p> <p>2. Siting process began after the JEA 2023 Integrated Resource Plan (IRP).</p> <p>3. Power island equipment solicitation released September 2024.</p> <p>4. 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.</p>												

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Planned Modification (if any)	Eligible Modifications			Potential Issues
					Mo	Yr		Fuel Switching	Combined Cycle Conversion	Other (Explain)	
Brandy Branch	GT1	Duval	GT	NG	5	2001			X	Unit uprate	
Greenland Energy Center	GT1	Duval	GT	NG	6	2011			X	Unit uprate	
Greenland Energy Center	GT2	Duval	GT	NG	6	2011			X	Unit uprate	
J. D. Kennedy	GT7	Duval	GT	NG	6	2000			X		
J. D. Kennedy	GT8	Duval	GT	NG	6	2009			X		
Northside	3	Duval	ST	NG	6	1977	2031; RFO Only				
Northside	1	Duval	ST	PC	5	2003		X			
Northside	2	Duval	ST	PC	4	2003		X			
Northside	GT3	Duval	GT	DFO	1	1975		X			
Northside	GT4	Duval	GT	DFO	1	1975		X			
Northside	GT5	Duval	GT	DFO	12	1974		X			
Northside	GT6	Duval	GT	DFO	12	1974		X			
Notes											
(Include Notes Here)											

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 Question No. 53(a)

Facility or Project Name	Unit No.	County Location	Energy Storage Type	Battery Chemistry (if applicable)	Land Use	Facility In-Service or Project Start Date		Unit Capacity (MW)						Storage Capacity (MWh)	Conversion Efficiency (%)
								Gross		Net		Firm			
								Sum	Win	Sum	Win	Sum	Win		
Imeson (SunPort) Solar	N/A	Duval	Battery	Lithium-ion	(Acres) 0.08	Mo Dec	Yr 2019	2	2	2	2	2	2	4	90
Notes															

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 Question No. 53(b)

Facility or Project Name	Unit No.	County Location	Energy Storage Type	Battery Chemistry (if applicable)	Land Use	Facility In-Service or Project Start Date		Unit Capacity (MW)						Storage Capacity (MWh)	Conversion Efficiency ¹ (MWh)
								Gross		Net		Firm			
								Sum	Win	Sum	Win	Sum	Win		
FRP Miller Solar, LLC	N/A	Duval	Battery	Lithium-ion	5	Dec	2026	50	50	50	50	50	50	200	168
Notes															
(1) Energy for efficiency of first year of operation shown.															

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Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Certification Dates (if Applicable)	
					Mo	Yr	Need Approved	PPSA Certified
							(Commission)	
Advanced-Class 1x1 CC	TBD	Duval	CCCT	NG	1	2031	To be confirmed	TBD

Notes

1. JEA Board delivered decision to proceed with CCCT build on August 25, 2025.
2. Siting process began after the JEA 2023 Integrated Resource Plan (IRP).
3. Power island equipment solicitation released in September 2024.

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2026
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Transmission Line	Line Length	Nominal Voltage	Certification Dates		In-Service Date
	(Miles)	(kV)	Need Approved	TLSA Certified	
Notes					
None.					

Contract Information						Provide If Associated with Specific Unit(s)												
Seller Name	Date Contract Approved	Contract Terms				Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW) ¹					
		Firm Capacity (MW)		Delivery Dates							Mo	Yr	Gross		Net		Firm ²	
		Sum	Win	Start	End								Sum	Win	Sum	Win	Sum	Win
Trail Ridge Energv, LLC	05/06	0	0	12/08	12/26	Trail Ridge I	N/A	Duval	IC	Methane	Dec	2008	9.1	9.1	9.1	9.1	9.1	9.1
LES	08/13	0	0	02/14	12/26	Trail Ridge II	N/A	Sarasota	IC	Methane	Feb	2015	6	6	6	6	6	6
Rev Renewables	05/09	0	0	09/10	09/40	Jacksonville Solar	N/A	Duval	Solar PV	SUN	Sep	2010	15	12	12	12	2.4	0
Northwest Jacksonville Solar Partners, LLC	08/15	0	0	05/17	05/42	NW JAX Solar	N/A	Duval	Solar PV	SUN	May	2017	9.4	9.4	7	7	1.4	0
Old Plank Road Solar Farm LLC	12/15	0	0	10/17	10/37	Old Plank Road Solar	N/A	Duval	Solar PV	SUN	Oct	2017	4	4	3	3	0.6	0
C2 Starratt Solar LLC	11/15	0	0	12/17	12/37	Starratt Solar	N/A	Duval	Solar PV	SUN	Dec	2017	7	7	5	5	1	0
Inman Solar Incorporated	11/15	0	0	01/18	01/38	Simmons Road Solar	N/A	Duval	Solar PV	SUN	Jan	2018	2.6	2.6	2	2	0.4	0
Hecate Energy Blair Road, LLC	08/15	0	0	01/18	01/38	Blair Site Solar	N/A	Duval	Solar PV	SUN	Jan	2018	4.9	4.9	4	4	0.8	0
JAX Solar Developers, LLC	12/16	0	0	10/18	10/38	Old Kings Road Solar	N/A	Duval	Solar PV	SUN	Oct	2018	1.3	1.3	1	1	0.2	0
Imeson Solar, LLC (Solar)	03/16	0	0	12/19	12/39	SunPort Solar	N/A	Duval	Solar PV	SUN	Dec	2019	9	9	5	5	1	0
Imeson Solar, LLC (Battery) ³	03/16	2	2	12/19	12/39	SunPort Solar	N/A	Duval	Solar PV	SUN	Dec	2019	2	2	2	2	2	2
FPL ⁴	03/23	150	150	04/23	04/28	FPL Solar PPA	N/A	Multiple	Solar PV	SUN	Multiple	Multiple	-	-	-	-	150	150
FPL ⁵	08/20	200	200	01/22	01/42	-	-	-	-	NG	-	-	200	200	200	200	200	200
MEAG	06/08	103	103	07/23	07/43	Plant Vogtle	3	Burke	Nuclear	NUC	Jul	2023	103	103	103	103	103	103
MEAG	06/08	103	103	04/24	04/44	Plant Vogtle	4	Burke	Nuclear	NUC	Apr	2024	103	103	103	103	103	103
FMPA	11/25	0	50	12/25	02/26	-	-	-	-	NG	-	-	0	50	0	50	0	50

Notes

(1) Solar capacity based on AC rating.
(2) For solar within the service territory, 20% effective load carrying capability (ELCC) applied to Summer only; no capacity credit allotted for Winter.
(3) Battery rated at 2 MW/4MWh and is DC-coupled with solar system.
(4) Energy sourced from multiple facilities in FPL service territory. Will not extend at end of term.
(5) Traditional purchase; system product.

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Question No.

2026
62(b)

Contract Information						Provide If Associated with Specific Unit(s)													
Seller Name	Date Contract Approved	Contract Terms				Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW) ¹						
		Firm Capacity (MW)		Delivery Dates							Mo	Yr	Gross		Net		Firm ²		
		Sum	Win	Start	End								Sum	Win	Sum	Win	Sum	Win	
FRP Miller Solar, LLC (Solar)	05/24	0	0	12/26	12/61	Miller Solar PPA	N/A	Duval	Solar PV	SUN	Dec	2026	74.9	74.9	74.9	74.9	0	0	
FRP Miller Solar, LLC (Battery)	05/24	50	50	12/26	12/61	Miller Solar PPA	N/A	Duval	Solar PV	SUN	Dec	2026	50	50	50	50	50	50	
FRP Forest Trail Solar, LLC	05/24	0	0	12/26	12/61	Forest Trail Solar PPA	N/A	Duval	Solar PV	SUN	Dec	2026	50	50	50	50	10	0	
FPL ³	TBD	80	80	06/26	01/42	-	-	-	-	NG	-	-	80	80	80	80	80	80	
FMPA	11/25	0	125	12/26	02/27	-	-	-	-	NG	-	-	0	125	0	125	0	125	
TEA Backfill Purchase	TBD	150	150	06/27	12/32	-	-	-	-	NG	-	-	150	150	150	150	150	150	
TEA Backfill Purchase	TBD	50	50	12/28	12/32	-	-	-	-	NG	-	-	50	50	50	50	50	50	
TEA Seasonal Purchase I ⁴	TBD	0	29	12/26	03/27	-	-	-	-	NG	-	-	0	29	0	29	0	29	
TEA Seasonal Purchase II ⁴	TBD	0	107	12/27	03/28	-	-	-	-	NG	-	-	0	107	0	107	0	107	
TEA Seasonal Purchase II ⁴	TBD	91	0	06/28	09/28	-	-	-	-	NG	-	-	91	0	91	0	91	0	
TEA Seasonal Purchase III ⁴	TBD	0	22	12/28	03/29	-	-	-	-	NG	-	-	0	22	0	22	0	22	
TEA Seasonal Purchase IV ⁴	TBD	0	34	12/29	03/20	-	-	-	-	NG	-	-	0	34	0	34	0	34	
TEA Seasonal Purchase IV ⁴	TBD	15	0	06/30	09/30	-	-	-	-	NG	-	-	15	0	15	0	15	0	
TEA Seasonal Purchase V ⁴	TBD	0	72	12/30	03/31	-	-	-	-	NG	-	-	0	72	0	72	0	72	

Notes

(1) Solar capacity based on AC rating.
(2) For solar within the service territory, 20% effective load carrying capability (ELCC) applied to Summer only; no capacity credit allotted for Winter.
(3) Traditional purchase; system product. Expansion of existing 200 MW PPA; agreement is in final negotiations.
(4) Short term seasonal purchases expected to maintain reserve margin 2027 - 2031.

TYSP Year
Question No.

2026
65(a)

Contract Information						Provide If Associated with Specific Unit(s)														
Buyer Name	Date Contract Approved	Contract Terms				Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service ¹		Unit Capacity (MW)							
		Firm Capacity (MW)		Delivery Dates							Mo	Yr	Gross		Net		Firm			
		Sum	Win	Start	End								Sum	Win	Sum	Win	Sum	Win		
Notes																				
N/A																				

TYSP Year 2026
 Question No. 65(b)

Contract Information						Provide If Associated with Specific Unit(s)														Land Use (Acres)
Buyer Name	Date Contract Approved	Contract Terms				Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service ¹		Unit Capacity (MW)							
		Firm Capacity (MW)		Delivery Dates							Gross		Net		Firm					
		Sum	Win	Start	End						Mo	Yr	Sum	Win	Sum	Win	Sum	Win		
Santee Cooper	02/26	206	206	2027	2028	Vogtle	3 & 4	Burke	Nuclear	NUC	7/4	23/24	206	206	206	206	206	206	206	
Santee Cooper	02/26	103	103	2028	2029	Vogtle	3 & 4	Burke	Nuclear	NUC	7/4	23/24	103	103	103	103	103	103	103	
Dalton	02/26	103	103	2028	2029	Vogtle	3 & 4	Burke	Nuclear	NUC	7/4	23/24	103	103	103	103	103	103	103	
Dalton	02/26	129	129	2029	2030	Vogtle	3 & 4	Burke	Nuclear	NUC	7/4	23/24	129	129	129	129	129	129	129	
Dalton	02/26	103	103	2030	2032	Vogtle	3 & 4	Burke	Nuclear	NUC	7/4	23/24	103	103	103	103	103	103	103	

Notes

1. Vogtle Units 3 and 4 were commissioned on July 31st, 2023 and April 29th, 2024, respectively.

2026 TYSP Data Request #1.Excel Tables - JEA.xlsx

Loss of Load Probability, Reserve Margin, and Expected Unserved Energy						
Base Case Load Forecast						
Year	Loss of Load Probability (Days/Yr)	Annual Isolated Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)	Loss of Load Probability (Days/Yr)	Annual Assisted Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)
2026	0.02	22%	0	N/A	N/A	N/A
2027	0.03	18%	0	N/A	N/A	N/A
2028	0.03	15%	0	N/A	N/A	N/A
2029	0.1	15%	0	N/A	N/A	N/A
2030	0.1	15%	0	N/A	N/A	N/A
2031	0	33%	0	N/A	N/A	N/A
2032	0.01	32%	0	N/A	N/A	N/A
2033	0.02	28%	0	N/A	N/A	N/A
2034	0.02	27%	0	N/A	N/A	N/A
2035	0.05	33%	0	N/A	N/A	N/A

Peak Summer Day Hourly Dispatch (MW)												
Hour	Customer Oriented		Power Transactions		Energy Storage		Generation Resources					
	Load	Demand Response	Sales	Purchases	Charging	Discharging	Nuclear	Natural Gas	Coal	Oil	Other	Solar
1	1512.66	0	0	280	0	0	206	737.57	274.1	0	15	0
2	1416.15	0	0	280	0	0	206	651.45	263.7	0	15	0
3	1348.58	0	0	280	0	0	206	613.18	234.4	0	15	0
4	1308.91	0	0	280	0	0	206	573.51	234.4	0	15	0
5	1305.67	0	0	280	0	0	206	570.27	234.4	0	15	0
6	1354.07	0	0	280	0	0	206	618.63	234.4	0	15	0.04
7	1412.46	0	0	280	0	0	206	643.79	263.7	0	15	3.96
8	1486.85	0	0	280	0	0	206	686.9	269.21	0	15	29.74
9	1587.61	0	0	280	0	0	206	742	264.08	0	15	80.53
10	1740.41	0	0	280	0	0	206	852.99	263.7	0	15	122.72
11	1934	0	0	280	0	0	206	999.43	285.5	0	15	148.07
12	2138.46	0	0	280	0	0	206	1188.27	285.5	0	15	163.69
13	2322.1	0	0	280	0	0	206	1367.24	285.5	0	15	168.35
14	2581.32	0	0	371.25	0	0	206	1540.49	285.5	0	15	163.06
15	2766.44	0	0	567.53	0	0	206	1540.49	285.5	0	15	151.9
16	2863.12	0	0	580	0	0	206	1620.42	285.5	24	15	132.21
17	2892.36	0	0	580	0	0	206	1654.66	293	36	15	107.71
18	2861.21	0	0	580	0	0	206	1654.7	293	36	15	76.51
19	2727.5	0	0	580	0	0	206	1588.93	285.5	12	15	40.07
20	2446.18	0	0	391.43	0	0	206	1540.49	285.5	0	15	7.74
21	2299.48	0	0	280	0	0	206	1512.96	285.5	0	15	0.01
22	2175.71	0	0	280	0	0	206	1389.2	285.5	0	15	0
23	1960.27	0	0	280	0	0	206	1173.77	285.5	0	15	0
24	1719.99	0	0	280	0	0	206	940.13	278.85	0	15	0

Peak Winter Day Hourly Dispatch (MW)												
Hour	Customer Oriented		Power Transactions		Energy Storage		Generation Resources					
	Total Load	Demand Response	Sales	Purchases	Charging	Discharging	Nuclear	Natural Gas	Coal	Oil	Other	Solar
1	2079.26	0	0	200	0	0	206	1335.26	323	0	15	0
2	2162.15	0	0	236.85	0	0	206	1351.3	353	0	15	0
3	2250.12	0	0	294.82	0	0	206	1351.3	383	0	15	0
4	2349.47	0	0	364.17	0	0	206	1351.3	413	0	15	0
5	2465.58	0	0	450.28	0	0	206	1351.3	443	0	15	0
6	2643.75	0	0	405.05	0	0	206	1544.7	473	0	15	0
7	2874.39	0	0	419.67	0	0	206	1730.6	503	0	15	0.12
8	3007.64	0	0	499.07	0	0	206	1744.6	533	0	15	9.97
9	2897.24	0	0	325.03	0	0	206	1730.6	563	0	15	57.6
10	2520.94	0	0	263.66	0	0	206	1351.3	586	0	15	98.99
11	2193.74	0	0	297.55	0	0	206	970.23	578.5	0	15	126.46
12	1914.59	0	0	312.66	0	0	206	670.4	571	0	15	139.53
13	1775.46	0	0	200	0	0	206	670.4	539.48	0	15	144.57
14	1673.9	0	0	254.8	0	0	206	481.33	574.17	0	15	142.59
15	1598.78	0	0	200	0	0	206	481.33	562.35	0	15	134.09
16	1559.83	0	0	200	0	0	206	484.5	539.52	0	15	114.81
17	1605.51	0	0	257.09	0	0	206	484.5	571	0	15	71.91
18	1641.68	0	0	200	0	0	206	635.22	564.69	0	15	20.76
19	1795.64	0	0	330.38	0	0	206	670.4	571	0	15	2.86
20	1827.09	0	0	364.07	0	0	206	670.4	571	0	15	0.62
21	1819.06	0	0	356.66	0	0	206	670.4	571	0	15	0
22	1752.04	0	0	289.64	0	0	206	670.4	571	0	15	0
23	1639.92	0	0	200	0	0	206	670.4	548.52	0	15	0
24	1557.92	0	0	200	0	0	206	648.4	488.52	0	15	0

Note: Peaks are based on 2026 forecasted seasonal peaks. Data is from JEA's production modeling. The reported load reflects reductions from energy efficiency.

Year		Firm Purchase Rates		Non-Firm Purchase Rates		As-Available Energy Rates		
		Annual Average	Escalation Rate	Annual Average	Escalation Rate	Annual Average	On-Peak Average	Off-Peak Average
		(\$/MWh)	(%)	(\$/MWh)	(%)	(\$/MWh)	(\$/MWh)	(\$/MWh)
Actual	2016							
	2017							
	2018							
	2019	\$30.72						
	2020	\$88.00	186%					
	2021	\$89.97	2%					
	2022	\$67.65	-25%					
	2023	\$41.61	-38%					
	2024	\$24.45	-41%					
Projected	2025	\$23.32	-5%	\$55.71	78%			
	2026	\$90.82	289%	\$62.49	12%			
	2027	\$36.96	-59%	\$65.60	5%			
	2028	\$40.75	10%	\$74.50	14%			
	2029	\$60.73	49%	\$86.50	16%			
	2030	\$70.02	15%	\$100.09	16%			
	2031	\$80.31	15%	\$102.66	3%			
	2032	\$83.27	4%	\$105.35	3%			
	2033	\$109.27	31%	\$108.68	3%			
	2034	\$111.90	2%	\$111.55	3%			
	2035	\$120.80	8%	\$114.70	3%			
Notes								
(Include Notes Here)								

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil		Hydrogen		Other (Specify)	
		GWh	\$/MMBTU	GWh	\$/MMBTU	GWh	\$/MMBTU	GWh	\$/MMBTU	GWh	\$/MMBTU	GWh	\$/MMBTU	GWh	\$/MMBTU
Actual	2016	N/A	N/A	6,733	2.42	4,724	2.98	16	5.39	3	11.00	N/A	N/A	N/A	N/A
	2017	N/A	N/A	5,360	3.05	5,751	3.28	0	7.69	3	13.39	N/A	N/A	N/A	N/A
	2018	N/A	N/A	3,557	3.01	6,574	3.66	24	10.01	18	15.98	N/A	N/A	N/A	N/A
	2019	N/A	N/A	3,287	2.37	6,306	2.78	1	9.66	4	14.85	N/A	N/A	N/A	N/A
	2020	N/A	N/A	3,019	2.18	8,215	2.19	1	6.53	5	11.46	N/A	N/A	N/A	N/A
	2021	N/A	N/A	2,743	4.12	7,656	4.14	11	10.57	7	15.35	N/A	N/A	N/A	N/A
	2022	N/A	N/A	1,237	6.64	7,559	7.63	40	13.81	5	21.03	N/A	N/A	45	2.58
	2023	N/A	N/A	1,349	4.93	7,263	3.09	11	11.70	3	18.36	N/A	N/A	56	2.63
	2024	N/A	N/A	780	3.45	8,253	2.76	4	15.59	5	17.21	N/A	N/A	31	2.76
	2025	N/A	N/A	1,332	3.37	7,429	4.17	4	14.10	16	16.02	N/A	N/A	28	2.63
Projected	2026	N/A	N/A	868	4.85	8,308	4.25	1.33	15.04	1	15.97	N/A	N/A	141	2.64
	2027	N/A	N/A	1,219	4.96	8,524	4.03	0.00	15.30	2	15.92	N/A	N/A	198	2.64
	2028	N/A	N/A	2,135	5.05	7,808	4.39	0.40	15.47	6	15.35	N/A	N/A	348	2.64
	2029	N/A	N/A	2,559	5.30	6,874	4.91	0.00	15.54	1	15.86	N/A	N/A	417	2.64
	2030	N/A	N/A	3,278	5.43	6,390	5.41	0.00	15.81	4	16.37	N/A	N/A	534	2.64
	2031	N/A	N/A	1,666	5.56	9,553	5.46	2.30	16.00	1	16.79	N/A	N/A	271	2.64
	2032	N/A	N/A	1,724	5.69	9,593	5.45	0.56	16.32	1	17.31	N/A	N/A	281	2.64
	2033	N/A	N/A	1,789	5.90	9,643	5.48	2.72	16.44	1	17.75	N/A	N/A	291	2.64
	2034	N/A	N/A	1,678	6.04	9,838	5.48	8.68	16.60	3	18.32	N/A	N/A	273	2.64
	2035	N/A	N/A	1,413	6.18	10,433	5.51	0.00	16.73	0	18.87	N/A	N/A	230	2.64

Notes
1. 'Coal' consists of coal and petcoke consumption
2. 'Other' consists of biomass consumption

TYSP Year

2026

Question No.

81e

Year	Estimated Cost of Standards of Performance for Greenhouse Gas Emissions Rule for New Sources Impacts (Present-Year \$ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
Notes				
To be determined, but no costs for compliance with CO2 standards expected at this time.				

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)		Estimated EPA Rule Impacts: Operational Effects						
					Mo	Yr	Net		ELGS	ACE or replacement ¹	MATS	CSAPR/CAIR	CWIS	CCR	
							Sum	Win						Non-Hazardous Waste	Special Waste
NGS	1	Duval	ST	PC	5	2003	293	293	TBD	TBD	N/A	N/A	TBD	N/A	N/A
NGS	2	Duval	ST	PC	4	2003	293	293	TBD	TBD	N/A	N/A	TBD	N/A	N/A
NGS	3	Duval	ST	NG	6	1977	524	524	TBD	TBD	N/A	N/A	TBD	N/A	N/A
BBGS	2-3-STM	Duval	CCCT	NG	1	2001	579.4	639.5	N/A	TBD	N/A	N/A	N/A	N/A	N/A
NGS/SJRPP	3	Duval	CCCT	NG	1	2031	582	678	N/A	TBD	TBD	N/A	N/A	N/A	N/A
Notes															
1. To be determined.															

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)		Estimated EPA Rule Impacts: Cost Effects ¹						
					Mo	Yr	Net		ELGS	ACE or replacement	MATS	CSAPR/CAIR	CWIS	CCR ²	
							Sum	Win						Non-Hazardous Waste	Special Waste
NGS	1	Duval	ST	PC	5	2003	293	293	TBD	TBD	N/A	N/A	TBD	N/A	N/A
NGS	2	Duval	ST	PC	4	2003	293	293	TBD	TBD	N/A	N/A	TBD	N/A	N/A
NGS	3	Duval	ST	NG	6	1977	524	524	TBD	TBD	N/A	N/A	TBD	N/A	N/A
BBGS	2-3-STM	Duval	CCCT	NG	1	2001	579.4	639.5	N/A	TBD	N/A	N/A	N/A	N/A	N/A
SJRPP NGS	3	Duval	CCCT	NG	1	2031	582	678	N/A	TBD	TBD	N/A	N/A	N/A	N/A
Notes															
1. Certain cost effects of rule impacts are still to be determined, while others do not apply.															
2. CCR rule does not apply to any of JEA's current generating units, but some cost impacts expected from the landfills at the decommissioned SJRPP.															

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)		Estimated EPA Rule Impacts: Unit Availability						
					Mo	Yr	Net		ELGS	ACE or replacement	MATS	CSAPR/CAIR	CWIS	CCR	
							Sum	Win						Non-Hazardous Waste	Special Waste
NGS	1	Duval	ST	PC	5	2003	293	293	None expected	TBD	None expected	N/A	None expected	N/A	N/A
NGS	2	Duval	ST	PC	4	2003	293	293	None expected	TBD	None expected	N/A	None expected	N/A	N/A
NGS	3	Duval	ST	NG	6	1977	524	524	None expected	TBD	None expected	N/A	None expected	N/A	N/A
BBGS	2-3-STM	Duval	CCCT	NG	1	2001	579.4	639.5	N/A	TBD	None expected	N/A	N/A	N/A	N/A
SJRPP NGS	3	Duval	CCCT	NG	1	2031	582	678	N/A	TBD	TBD	N/A	N/A	N/A	N/A
Notes															
(Include Notes Here)															