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May 15, 2026

Phillip Ellis and Segundo Sanchez  
Division of Engineering  
Florida Public Service Commission  
2540 Shumard Oak Blvd  
Tallahassee, Florida 32399-0688

Subject: Staff's 1st Data Request re: OUC's 2026 Ten-Year Site Plan

Dear Mr. Ellis and Mr. Sanchez

Attached please find the Orlando Utilities Commission (OUC) responses to the subject data request. If you have any questions about the responses, please do not hesitate to contact me.

Respectfully submitted,

/s/ 

Bradley Kushner  
Managing Director  
nFront Consulting LLC  
[BradKushner@nFrontConsulting.com](mailto:BradKushner@nFrontConsulting.com)

### **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.**

OUC Response:

The requested information was provided to the Florida Public Service Commission on 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.**

OUC Response:

The requested information was provided to the Florida Public Service Commission on 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)**

OUC Response:

Please see attached “2026 TYSP Data Request #1.Excel Tables\_OUC” (Excel .xlsx file) and refer to the worksheets titled “Financial Assumptions” and “Financial Escalation”. The requested information is also included in Section 8 of OUC’s 2026 TYSP.

#### **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).**

OUC Response:

This question is not applicable as OUC is not an Investor-Owned Utility.

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.**

OUC Response:

Please see attached "2026 TYSP Data Request #1.Excel Tables\_OUC" (Excel .xlsx file), and refer to the Worksheet titled "Historic Peak Demand". The table presents the monthly coincident peak demands for OUC and the City of St. Cloud combined, the date and hour when these monthly peak demands occurred; and the temperature at the time of these peaks.

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.**

OUC Response:

Average annual residential customer growth for the past 10 years (2016 through 2025) was 2.6 percent, inclusive of both OUC & St. Cloud. This growth was driven by the St. Cloud service territory, which has seen a high level of development over the past years. Commercial growth over the same time period was 2.1 percent, inclusive of both OUC & St. Cloud. Historically, commercial customer growth has coincided with residential growth but at a lower rate. Industrial customers decreased at an average annual growth rate of 1.4 percent, inclusive of both OUC & St. Cloud.

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

OUC Response:

The average kWh usage per customer over the past 10 years (2016 through 2025) has declined slightly for the residential customer segment (-0.6 percent average annual growth rate), increased at an average annual growth rate of 1 percent for the commercial customer segment, and increased at an average annual growth rate of 2.1 percent for the industrial customer segment, inclusive of both OUC & St. Cloud.

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

OUC Response:

Total annual sales growth over the past 10 years (2016 through 2025) has been 1.3%, on average, inclusive of both OUC & St. Cloud. This growth in sales is attributable to the growth in customers.

**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.**

OUC Response:

The forecast provided by OUC includes assumptions for appliance efficiency and saturation related to heating, cooling and other electric load. These assumptions capture historical changes in codes and standards and are used as inputs to the statistically adjusted end-use ("SAE") multi-regression modeling technique developed by Itron, Inc. Additionally, the multi-regression models also capture the impacts of Conservation above the requirements of the codes and standards.

The forecast provided by OUC includes assumptions for Self Service, specifically, customer-sited rooftop solar photovoltaic installations. These assumptions capture historical reductions of load due to Self Service. Projected Self Service was forecasted using adoption curves provided by the National Renewable Energy Lab as part of a recent study performed on OUC's service territory. According to this forecast, Self Service generation is projected to grow at an average annual rate of 8.1% from 2026 to 2035.

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

OUC Response:

OUC does not offer demand response programs, so this question is not applicable.

**c. Total Demand.**

OUC Response:

Please see response to part (d) below.

**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.**

OUC Response:

For 2016 through 2025, actual combined OUC and St. Cloud retail summer peak demand and winter peak demand increased at an average annual growth rate of

approximately 1.9 percent and 1.3 percent, respectively. These trends may be attributed to the growth in sales over the same period.

Historical trends in wholesale peak demand are attributable to the various power sales arrangements that OUC has had in place with different entities.

OUC does not have any customers on interruptible load service agreements.

Historical demand reductions due to conservation are attributable to the types of demand-side management and conservation programs that OUC's customers participated in.

### **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.**

OUC Response:

System-wide temperature data for OUC's service territory utilized for purposes of developing OUC's load forecast is based on information obtained from the National Weather Service's weather station at the Orlando International Airport. OUC also utilizes the Pine Hills weather station for other purposes.

- 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.
- b. Assumptions.
- c. Data sources.
- d. Third-party consultant(s) involved.
- e. Anticipated forecast accuracy.
- f. Any difference/improvement(s) made compared with those forecasts used in the Utility's most recent prior TYSP.

OUC Response:

OUC prepares a set of sales, energy, and demand forecast models each year to support OUC's budgeting and financial planning process as well as long-term planning requirements.

In preparing the forecasts OUC uses:

- internal records
- company knowledge of the service territory and customers
- economic projections from S&P Global
- weather data from the National Oceanic and Atmospheric Administration (NOAA) collected at the Orlando International Airport weather station

- future “normal” weather was based on the continued trend of decreasing heating degree days and increasing cooling degree days since 1980
- OUC draws on outside expertise as needed:
  - economic projection data was provided by S&P Global.
  - software, analysis of end-use equipment and efficiencies, analysis of forecast accuracy, and technical expertise was provided by Itron, Inc.
  - Multiple third-party electric vehicle adoption curves were utilized
  - rooftop solar adoption curves were provided by the National Renewable Energy Laboratory

A detailed explanation of OUC’s forecasting methodology is included in Section 4 of OUC’s 2026 Ten-Year Site Plan.

**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.**

OUC Response:

The resource plan reflected in OUC’s 2026 TYSP is based on the Electric Integrated Resource Plan that was finalized in December 2020, and incorporates changes to OUC’s generating portfolio since that time (specifically, OUC’s purchase in 2021 of the three combustion turbine generating units at the Osceola Generating Station) as well as what OUC currently anticipates with regard to its existing Stanton Energy Center Units 1 and 2. Although the forecasts of peak demand and energy were not specifically utilized for purposes of developing the resource plan reflected in OUC’s 2026 TYSP, the resource plan provides adequate resources to satisfy the forecast energy requirements and exceed the forecast peak demand and reserve margins for all years of the planning period. As noted in OUC’s 2026 TYSP, OUC anticipates refreshing its Electric Integrated Resource Plan within the next 12 months.

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

OUC Response:

Yes. OUC considers the high and low demand and energy forecasts as part of its resource planning process.

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

OUC Response:

In addition to the base-case, two long-term forecast scenarios representing a high and low range around the forecast peak demand and energy were constructed to test for sensitivity of uncertain economic conditions and customer growth. Weather conditions deviating from normal were not included in sensitivity testing due to non-growth-

related impacts and an equal probability of affecting any given year either negatively or positively. The high and low load scenarios represent alternatives to the base-case forecast and are defined by 0.5 percent higher and 0.5 percent lower economic growth rates, respectively.

- 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.**

OUC Response:

Please see the response to 10a above for discussion related to how the resource plan reflected in OUC's 2026 TYSP was developed. The resource plan reflected in OUC's 2026 TYSP provides sufficient capacity and energy resources to maintain reserve margins and satisfy energy requirements for all peak demand and energy forecasts included in OUC's 2026 TYSP.

- 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.**

OUC Response:

This question is not applicable to OUC, as OUC does not use an LOLP methodology for system planning.

**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.**

OUC Response:

OUC's hourly forecasts of demand and energy were not explicitly utilized to develop the resource additions included in OUC's 2026 TYSP. The resource plan reflected in OUC's 2026 TYSP is based on the Electric Integrated Resource Plan that was finalized in December 2020, and incorporates changes to OUC's generating portfolio since that time (specifically, OUC's purchase in 2021 of the three combustion turbine generating units at the Osceola Generating Station) as well as what OUC currently anticipates with regard to its existing Stanton Energy Center Units 1 and 2. Although the forecasts of peak demand and energy were not specifically utilized for purposes of developing the resource plan reflected in OUC's 2026 TYSP, the resource plan provides adequate resources to satisfy the forecast energy requirements and exceed the forecast peak demand and reserve margins for all years of the planning period. As noted in OUC's 2026 TYSP, OUC anticipates refreshing its Electric Integrated Resource Plan within the next 12 months.

**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.**

OUC Response:

OUC does not employ any other forecasting methodologies to address forecast uncertainty.

**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?**

OUC Response:

OUC prepares extreme weather forecasts as part of a reliability review and in particular as part of FRCC scenarios. The resource plan reflected in OUC's 2026 TYSP provides sufficient capacity and energy resources to meet these extreme weather scenarios.

**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.**

OUC Response:

Over the 2026 through 2035 period, the total number of residential customers is forecast to increase at an average annual growth rate of 1.9 percent, the total number of commercial customers is forecast to increase at an average annual growth rate of 0.8 percent, the total number of industrial customers is forecast to increase at an average annual growth rate of 0.7 percent, and the total number of customers across all customer segments is forecast to increase at an average annual growth rate of 1.8 percent,

inclusive of both OUC and St. Cloud. These forecast trends in customer counts can be attributed to household growth within OUC's service territory..

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

OUC Response:

Over the 2026 through 2035 period, the average kWh per residential customers is forecast to increase at an average annual growth rate of 1.3 percent, the average kWh per commercial customers is forecast to increase at an average annual growth rate of 0.5 percent, and the average kWh per industrial customers is forecast to increase at an average annual growth rate of 0.9 percent, inclusive of both OUC and St. Cloud. These forecast trends in average customer consumption for residential customers can be attributed to electrification of transportation. For commercial customers this increase is primarily due to the addition of larger commercial customers than historically.

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

OUC Response:

Over the 2026 through 2035 period, the Total Sales to Ultimate Customers is forecast to increase at an average annual growth rate of 2.3 percent, inclusive of both OUC and St. Cloud,. This forecast trend in total sales can be attributed to the electrification of transportation and customer growth.

**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.**

OUC Response:

There are no closed or opened FPSC dockets or non-docketed FPSC matters based on the same load forecast used in OUC's 2026 TYSP.

**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.**

OUC Response:

As part of OUC's Operating Budget variance reporting, OUC compares actual customer counts and sales for the current fiscal year to the corresponding forecast data utilized in the operating budget. OUC does not have a formal process to evaluate the accuracy of the data forecasted two or more years ago.

- 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.**

OUC Response:

OUC tracks its actual Summer/Winter Peak Energy Demand on an ongoing basis and utilizes these demands in its forecast. Since 2011, OUC has consistently been a summer peaking utility and has had well in excess of a 15 percent reserve margin. As part of the annual forecasting process the new 10-year Summer Peak Energy Demand is compared to the previous year's 10-year forecast and any sizable variances are investigated.

- 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.**

OUC Response:

The forecast provided by OUC includes assumptions for appliance efficiency and saturation related to heating, cooling and other electric load. These assumptions capture historical and projected changes in codes and standards and are used as inputs to the statistically adjusted end-use ("SAE") multi-regression modeling technique developed by Itron, Inc. Additionally, the multi-regression models also capture the impacts of Conservation above the requirements of the codes and standards. While the forecast takes into account the total Conservation impacts it does not explicitly differentiate between what's required by changes in codes and standards and Conservation impacts in excess of the requirements.

The forecast provided by OUC includes assumptions for Self Service, specifically, customer-sited rooftop solar photovoltaic installations. These assumptions capture historical and projected reductions of load due to Self Service. Projected Self Service was forecasted using adoption curves provided by the National Renewable Energy Lab as part of a recent study performed on OUC's service territory. According to this forecast, Self Service generation is projected to 8.1 percent annually from 2026 through 2035.

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

OUC Response:

OUC does not offer demand response programs, so this portion of the question is not applicable.

OUC has seen and is forecasting growth in behind the meter renewable systems. This system growth has reduced sales growth in actuals and throughout the forecast while having minimal impact on actual and forecasted peaks.

**c. Total Demand.**

OUC Response:

Please see response to part (d) below.

**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.**

OUC Response:

For 2026 through 2035, the combined OUC and St. Cloud retail summer peak demand is forecast to increase at an average annual growth rate of 1.4 percent and combined OUC and St. Cloud retail winter peak demand is forecast to increase at an average annual growth rate of 2.2 percent. The winter peak is growing at a faster rate which can be attributed to historic and forecasted weather trends. OUC's forecast winter peak is typically in the shoulder months with a similar load shape as the summer. Weather trends have shown these months are growing CDDs at a faster rate than in the summer months.

Forecast trends in wholesale peak demand are attributable to the various power sales arrangements that OUC currently has in place with different entities.

OUC does not have any customers on interruptible load service agreements.

Forecast demand reductions due to conservation are attributable reductions associated with OUC's Commission-approved FEECA goals, which are addressed later in this document.

**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.**

OUC Response:

The effects of COVID-19 caused a large decrease in 2020 in what would have been much higher peak demand had COVID-19 not occurred. Due to the weather effects that were greatly favorable to higher load, the overall negative effects on load from COVID-19 were largely mitigated in 2020. OUC is not aware of any other anomalies within the historical 10-year period.

**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.**

OUC Response:

Degree days are used for the sales forecast and are the difference between 65 F° and the average daily temperature (high plus low divided by 2). For the peak forecast variations are used where 55 F° and 80 F° are used instead of 65 F° for the winter and summer calculations, respectively.

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

OUC Response:

Historical temperature data is from the National Weather Service’s Orlando International Airport (“MCO”) reporting 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.**

OUC Response:

Converted raw weather data to degree days as described above in the response to number 21a.

- 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.**

OUC Response:

The regression models used data starting in 2011 in order to forecast future energy sales and peak demands.

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

OUC Response:

The models used data starting in 2011 in order to forecast future energy sales and peak demands.

- 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.**

OUC Response:

The linear trends of annual heating and cooling degree days for the 45-year period (1981-2025) were extended through 2035 and used in the sales forecast models to represent normal weather. For the peak demand forecast the average heating and cooling degree days for the 2005 to 2025 20-year period were used to represent normal weather on the peak day.

- 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.**

OUC Response:

This question is not applicable as OUC is not an Investor-Owned Utility

**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.**

OUC Response:

The forecast provided by OUC includes assumptions for customer-sited rooftop solar photovoltaic installations. These assumptions capture historical and projected reductions of load. Projected installations were forecasted using adoption curves provided by the National Renewable Energy Lab as part of a recent study performed on OUC's service territory. According to this forecast, solar rooftop generation is projected to grow at an average annual rate of 8.1% from 2026 to 2035.

- 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.**

OUC Response:

The table below contains the forecast annual impact of customer-owned/leased renewable generation (solar and otherwise) on OUC’s retail demand and energy forecast.

Calendar Year	Sales Impact (GWh)					System Coincident Hourly Peak Demand & NEL Impact		
	OUC		St. Cloud		Total	Summer (MW)	Winter (MW)	NEL (GWh)
	Residential	General Service	Residential	General Service				
2026	(81)	(34)	(78)	(0)	(193)	(28)	-	(208)
2027	(85)	(35)	(82)	(0)	(202)	(30)	-	(217)
2028	(91)	(36)	(88)	(0)	(215)	(32)	(3)	(232)
2029	(101)	(38)	(98)	(0)	(237)	(35)	(4)	(255)
2030	(116)	(41)	(113)	(0)	(270)	(40)	-	(291)
2031	(130)	(44)	(127)	(0)	(301)	(45)	-	(324)
2032	(143)	(45)	(139)	(0)	(328)	(49)	-	(354)
2033	(154)	(47)	(150)	(0)	(352)	(52)	-	(380)
2034	(164)	(49)	(159)	(0)	(372)	(55)	-	(402)
2035	(172)	(51)	(167)	(0)	(390)	(58)	-	(422)

- 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.**

OUC Response:

OUC does not maintain a forecast of the number of customers with renewable generation.

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

OUC Response:

The customer renewable generation forecast is primarily driven by a study NREL performed on OUC’s service territory. This study evaluated the actual rooftop space suitable for solar and assumptions around future pricing and compensation policies..

- 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.**

OUC Response:

The forecast provided by OUC does not explicitly include the impact of customer-sited energy storage installations.

- 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.**

OUC Response:

The forecast provided by OUC does not explicitly include the impact of customer-sited energy storage installations.

- 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.**

OUC Response:

OUC does not maintain a forecast of the number of customers with energy storage.

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

OUC Response:

The forecast provided by OUC does not explicitly include the impact of customer-sited energy storage installations.

- 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.**

OUC Response:

Please see responses to Question Nos. 23(a).

- 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.**

OUC Response:

Please see responses to Question Nos. 23(b).

- 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.**

OUC Response:

Please see attached "2026 TYSP Data Request #1.Excel Tables\_OUC" (Excel .xlsx file), and refer to the Worksheet titled "Customer-Owned Resources" for the requested information.

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.**

OUC Response:

OUC does not currently offer demand response programs to its customers.

- 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.**

OUC Response:

OUC does not currently offer demand response programs to its customers.

- 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?**

OUC Response:

Yes. The projected energy and demand savings for 2026 through 2035 included in OUC's Schedules reflect the goals approved by the Commission in OUC's 2024 FEECA Goalsetting docket.

- 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?**

OUC Response:

The load forecast accounts for demand and energy reductions associated with OUC's goals approved by the Commission. Historical data that is utilized in developing the load forecast accounts for actual demand and energy requirements, which includes actual reductions associated with customer DSM and conservation-related activities.

- 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.**

OUC Response:

This question is not applicable to OUC, as the projected energy and demand savings for 2026 through 2035 included in OUC's Schedules reflect the goals approved by the Commission in OUC's 2024 FEECA Goalsetting docket.

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.**

OUC Response:

Please see attached "2026 TYSP Data Request #1.Excel Tables\_OUC" (Excel .xlsx file), and refer to the Worksheet titled "PEV Charging" for the requested information.

OUC owns and operates more than 160 Level 2 and 34 DCFC public charging stations. OUC is deploying additional charging infrastructure both independently and in coordination with third party operators. OUC is currently constructing a new 6 port DCFC hub in northern Lake Nona and in the late planning stages for additional charging stations near the Orlando professional soccer stadium and a community farm in an economically challenges section of the city. OUC is deploying Congressionally Directed Spending funds for infrastructure supporting a new 6 port DCFC hub on the campus of Valencia Community College owned by Blink, a third-party operator. Significant interest has been expressed by multiple third-party operators for public and private DCFC port deployment around OUC's territory.

**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.**

OUC Response:

OUC has begun to study the impact of PEVs on grid infrastructure. OUC has identified and correlated owner registrations to premise data to begin understanding the impact of PEV ownership on customer load profiles. This work is still in development.

Presently OUC offers no demand response programs, nor are there EV-specific rates. OUC has recently announced its Peak*SHIFT* pricing plan. One aspect of this plan is an opt-out time of day rate structure for residential and general service non-demand customers. It is expected that the lower off-peak pricing will be utilized by EV owners to charge their vehicles at a lower rate. An estimate of this impact has been included in this year's Ten-Year Site Plan.

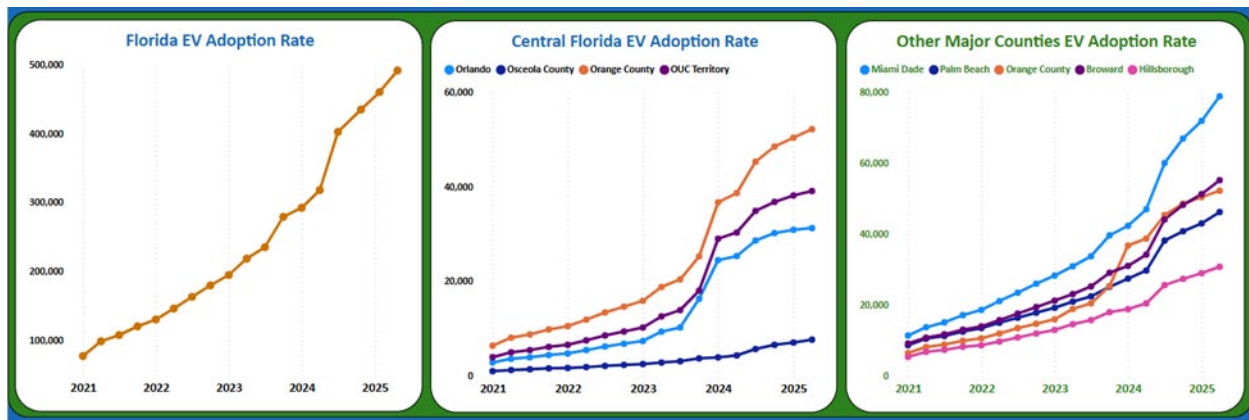
**33. Please explain any historic trends related to the following:**

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

OUC Response:

OUC Battery and Plug-in Electric Vehicle (BEV and PHEV) adoption has slowed in the past year but continues to grow. The dip in the OUC territory adoption shown in the graph below is attributable to a change in data acquisition method from the state DMV which provides registration data with premise-level accuracy previously not available. This resulted in a modification to the total vehicle count in OUC territory. OUC attributes this growth to a number of factors including the variety and number of available vehicles for sale in dealer showrooms, public charging access in Central Florida, customer perceptions of reduced total cost of ownership and the availability of purchase incentives. OUC has been able to attribute an increase in consumption at homes that report the presence of BEV/PHEV. Without submetering it is difficult to separate out consumption due to electric vehicles, however, on average OUC believes the presence of an EV yields an increase of 2,800 kWh/house/vehicle annually. OUC will validate this number through the use of a new disaggregation tool that will be fully deployed in October of 2026.

Orange County is ranked second in the State of Florida for the total number of public charging stations with approximately 35 vehicles per public charging port. This is comparable to large counties like Miami-Dade and Broward, where population is significantly larger.



**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)

OUC Response:

OUC believes that the number of BEV/PHEV will continue to grow in Orange and Osceola County. This assumes that EV vehicles will continue to take share from Internal Combustion Engine (ICE) powertrains, EVs are beginning to populate the used car market as vehicles are returned from initial lease arrangements and as consumer confidence grows around the EV as fit for use. OUC believes that additional DCFC density reduces consumer range anxiety and increases the likelihood that EVs join the consideration set for new and used vehicle purchase.

The EV market has demonstrated a softening, but continues to grow. Forecasts indicate a return to 2023 and 2024 growth levels in late 2028 and 2029. As OUC's new residential demand and TOU rates come into effect, OUC believes that electric vehicle owners will schedule car charging to occur during off-peak hours to obtain the best rate possible. Vehicle manufacturers permit owners to establish a future start time to begin charging, leveraging any off-peak rate savings that can be achieved without additional effort by the owner. This algorithm calculates the required time to achieve desired charge levels and prepares the vehicle to be ready for departure. This type of algorithm will permit random and intermittent charging start times during off-peak and reduce the impact on peak.

**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.**

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

OUC Response:

OUC continues to offer a \$200 rebate for new and used EV/PHEV purchases or leases. OUC offers a \$50.00 rebate for taking a test drive and promote incentives to dealerships for EV sales. OUC provides sales incentives to participating OEM dealerships for the sale of BEV and PHEV, the incentive ranges from \$25.00 - \$75.00 per vehicle sold based on the number of sales per month by a specific representative. OUC does not currently offer any tariffs specific to electric vehicle charging.

OUC will be phasing out the existing \$200 purchase rebate and will be introducing a rebate for income-qualified customers to assist with the purchase of a qualifying EV. This program pays \$1,000 directly to dealers on behalf of the customer to reduce the overall purchase price of the vehicle. OUC is working cooperatively with the City of Orlando and the Jameel Poverty Action Lab to evaluate the most effective methods to incent EV adoption for income qualified customers utilizing OUC's rebate and a combination of energy payment schemes.

OUC has formed an educational subcommittee for electrification of transportation. In addition, OUC:

- conducts Ride and Drive events,
- maintains a web portal for information on purchasing PEVs, and
- has internal and external marketing campaigns

**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.**

OUC Response:

OUC customers, particularly businesses, can express their interest in OUC's OUCs programs via OUC's web presence. This site offers general information on programs available to customers and provides a point of contact for further discussions. Customers

can provide feedback and obtain information through OUC's dedicated EV residential and commercial email addresses.

**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.**

OUC Response:

OUC closely monitors the adoption of EVs through direct and secondary research. OUC gathers EV registration data directly from the Florida Highway Safety and Motor Vehicles (FHSMV) department, providing a statewide adoption assessment to all members of the Drive Electric Florida coalition which includes many of the utilities serving the state of Florida. OUC also monitors adoption and manufacturing trends through trade association memberships. OUC tracks the overall energy sales to separately metered EV charging customers and determines its market share based on those values.

OUC maintains market information and maps on the location and port counts for publicly available charging infrastructure, to understand gaps in access to charging infrastructure where significant adoption exists.

OUC has worked to understand the relationship between DCFC infrastructure installation and EV adoption to determine if adoption drives requests for infrastructure or if infrastructure installation drives adoption. OUC examined registration data by county acquired from FHSMV and the presence of DCFC infrastructure as obtained from the Department of Energy Alternatives Fuel Data Center which includes the date of installation for the DCFC units. Based on our preliminary findings, where DCFC infrastructure is introduced, adoption increases within the next 90 to 180 days.

OUC also maps registered EVs to premises and the location of DCFC and Level 2 charging ports across the Osceola and Orange County to assist in determining charging infrastructure density and any gaps in access. This data assists in decisions to incent or introduce new infrastructure where market opportunities may exist.

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

OUC Response:

OUC's PEV pilot programs currently consist of the following:

- One pilot program is the integration and controls of level three chargers from an operable load concept. The ability to ramp these loads or provides incentives to customers that will allow us to manage demand provides OUC a tool during periods of volatility that will reduce additional assets on the grid and thus reduce costs to our customers. We are testing these controls and communications within our Grid Integration Lab and developing algorithms that will allow us to evaluate these economics before developing a customer program.

- Another pilot program is looking into Vehicle-to-everything (V2X) solutions. We currently have a Vehicle-to-grid (V2G) charger that allows us to test this technology and we are looking at two additional V2X solutions. The batteries in cars are several times the traditional residential storage solutions. This provides a lot of options when it comes to grid controls and economics for our customers.
- Another pilot program is storage integrated PEV chargers. These systems reduce the interconnection size required for PEV high speed chargers. They also provide resiliency during specific events within the grid. The ability to execute multiple charging sessions on a single charge of the battery provides new design abilities for our charging hubs.

Each PEV pilot program is designed to find new ways to partner with our customers or provide them better economics and ensure that OUC deploys PEV in the most sustainable way.

**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.**

OUC Response:

OUC's pilot with the local transit authority point to significant increases to local infrastructure and overall future demand due to low load factors. The transit authority currently has 14 buses and has aggressive adoption plans for EVs and this adoption will require upgrades to infrastructure. The transit authority has a narrow window to fully charge their fleet and will create a significant peak on their feeder in the next year or two. If other fleets in OUC's territory follow the same adoption with limited charging windows, OUC will need to develop mechanisms to flatten the demand of these events or pass through the expense of upgrades required to serve.

OUC continues to monitor the performance of the two DCFC recharging hubs it operates in Orlando. In both instances, the hub transformers were sized to nameplate specification of the attached equipment. Load factors remain very low – in the single and low double-digit ranges. OUC is actively tracking load factors and believes for future hub deployments that sizing the transformers to support 70% of the nameplate load for hub deployments provides sufficient capacity to meet requirements and maintain an adequate safety factor. OUC has been in discussions with third party operators who are sharing data that confirms OUC's findings that actual load profiles on transformers servicing multiple DCFC units consume less than 70% of transformer capacity. OUC is also investigating the use of charge management software to limit the ability of the chargers to call for more power than for which the transformer is rated. OUC is considering the installation of storage infrastructure at its' largest charging hub to assess the impact of storage on transformer capacity and peak demand in the next year.

The Robinson Street Hub consists of 21 DCFC ports – six rated at 240 kW and 15 rated at 150 kW. The hub is open 24 hours a day, 365 days a year and is approximately 17% utilized. Users of the hub spend approximately 40 minutes a session recharging a vehicle. On average customers dispense ~38 kWh of energy per session. Recharge times are largely driven by the vehicle charging algorithms which often cap the rate at which energy is dispensed over time.

Hub volume varies by season. OUC is actively investigating correlations to local events and visitor traffic to better forecast utilization.

The hub located at the Orange County Convention Center consists of six (6) DCFC ports rated at 240 kW. Utilization is approximately 16%, customers spend approximately 37 minutes per session and dispense approximately 34 kWh per session.

For both hubs, approximately 9% of customers visit the hub more than 10 times a month, while between 50% and 55% of the customers at the hubs are first-time users, likely a result of the large number of EVs deployed in the Orlando rental car fleet and the high volume of visitors to the region.

### **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.**

OUC Response:

The load forecast does not include projections of annual energy consumption and demand associated with data centers within our service area. Please see response to Question No. 34 for information related to PEVs.

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

OUC Response:

Since OUC does not currently have any data centers and is not forecasting any data centers they do not impact forecasting accuracy. PEVs are forecasted independently and estimated actual energy is removed from historical sales in order to forecast sales independent of PEV impacts. Inherent uncertainty related to PEV energy consumption and future growth may affect the accuracy of load forecasts.

- 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.**

OUC Response:

OUC's load forecast does not account for other emerging-technology related electrical equipment.

**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.**

OUC Response:

OUC does not have any existing 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.**

OUC Response:

OUC does not have any data centers planned to be in-served in the 2026 planning period.

**c. Planned Data Centers, including data centers that are planned after 2026.**

OUC Response:

OUC does not have any data centers planned to be served over the 2026 through 2035 planning period.

**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.**

OUC Response:

The load forecast does not include projections of annual energy consumption and demand associated with data centers within our service area.

**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.**

OUC Response:

OUC believes its service territory will follow the same patterns that other utilities' are projecting for their service territories

**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.**

OUC Response:

General potential issues and concerns associated with data centers being located in OUC's service territory include uncertainty related to the magnitude and timing of electric loads associated with data centers as well as potential future incremental electric loads and the timing thereof, the relatively high load factor that is associated with the electric loads of data centers, uncertainty of the load actually materializing as planned, the duration of the commitment and

ease of owners relocating data centers, and how to serve such loads under existing rate structures (and the potential need to develop new rate structures).

In the event OUC is approached by entities proposing data centers, OUC anticipates having discussions with those entities to better understand the anticipated timing and magnitude of the initial loads and potential incremental loads moving forward and incorporating such loads into OUC's ongoing resource planning activities. Additionally, OUC may coordinate with other utilities who are experiencing growth in data centers (including utilities that currently serve data centers) to share information and best practices related to the growth in data centers.

**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.**

OUC Response:

OUC has an Emerging Technologies group that evaluates and demonstrates the use of new generation, energy storage, and distributed energy technologies. Successful demonstration of such technologies may lead to their larger scale deployment. Distributed Energy Resources are being evaluated, and both storage and controllable loads are being considered for the grid impact in providing more resiliency and firm capacity. These efforts are also considering the economics and ability to incentivize customers to aid in this effort. In 2025, Emerging Technologies was paired with Data Delivery to deliver better data driven insights throughout the organization and to leverage better understanding of which new technologies are required based on past operations and the adoption of new technologies.

Successful implementation of emerging technologies may lead to enhanced reliability and more sustainable production of energy.

OUC is participating in several research efforts, including:

- 1) Developing a cloud tracking solution in partnership with UCF to allow for better solar generation forecasts. This will allow OUC to better operate support assets to the solar in a more efficient and cost effective way.
- 2) Evaluating the environmental impacts of floating solar on ponds. This research is to ensure that floating solar does not impact the ecology of the ponds they are installed on. Floating solar provides a unique opportunity for us with locations that are distributed throughout the grid, reducing the impacts of clouds on any specific site along with not competing with farm and development for land. The cooling effect also increases output of the panels.
- 3) OUC participated in an EPRI-led project called CO-LOCATED to better understand customer preferences that influence EV, solar, and battery adoption.

The Energy Conservation Cost Recovery clause is not applicable, as OUC is a municipal utility.

**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.**

OUC Response:

OUC is looking at several options for the use of artificial intelligence (AI) as part of its day-to-day operations. Load and Solar forecasting are two items that better insights from AI may be able to improve. Computer vision is being considered for the advancement of our drone program. AI has several uses in the employee and customer spaces, from agentic AI to chat bots, that can be leveraged for education, outreach for customers and other repetitive tasks.

**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.**

OUC Response:

Please see attached “2026 TYSP Data Request #1.Excel Tables\_OUC” (Excel .xlsx file), and refer to the Worksheet titled “Existing Utility”

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

OUC Response:

OUC does not have any utility-owned resources planned to enter service during the current planning period.

**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.**

OUC Response:

Please see attached "2026 TYSP Data Request #1.Excel Tables\_OUC" (Excel .xlsx file), and refer to the Worksheet titled "Unit Performance". Information is only provided for units for which OUC maintains a majority ownership.

- 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.**

OUC Response:

OUC considers the requested information to be confidential and therefore has not provided it in response to this request.

- 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.**

OUC Response:

This question is not applicable as OUC is not an Investor-Owned Utility

- 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.**

OUC Response:

OUC does not have any planned generating units with an in-service date within the current planning period. Therefore, there are no "drop dead" dates or other information to provide in response to this question.

- 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?**

OUC Response:

OUC has not had any planned utility-owned resources within the past year that were cancelled, delayed, or reduced in scope.

- 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.**

OUC Response:

Please see attached “2026 TYSP Data Request #1.Excel Tables\_OUC” (Excel .xlsx file), and refer to the Worksheet titled “Unit Modifications”. OUC does not have any units that are considered as options for repowering to combined cycle. OUC’s existing Stanton Energy Center Units 1 and 2 may be potential candidates to change fuel to operate on 100 percent natural gas; as discussed throughout OUC’s 2026 Ten-Year Site Plan, OUC currently anticipates placing Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026 and anticipates converting Stanton Energy Center Unit 2 to operate on 100 percent natural gas no later than 2027.

**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.**

OUC Response:

OUC is following emerging technologies like small modular reactors (SMR) virtual power plants (VPPs) and Vehicle to Grid (V2x) . SMRs deployment has a long lead time and includes significant permitting and cost considerations. OUC follows development of this technology and works to ensure OUC is positioned correctly to maximize the value of this technology when it comes to market at scale.

VPPs offer promise as a supply side resource but require additional exploration of impact when adoption in the market is significant. OUC is considering economic strategies for deploying this technology to ensure best value and reliability for its customers. OUC believes the deployment of customer-owned storage and addressable appliances may be approaching a tipping point where a pilot of this technology may be warranted.

OUC also tracks the potential for vehicle to grid technology deployment. EVs offer potential to substantially increase the amount of energy storage available for deployment by grid operators. OUC tracks the current state of standards for communication and deployment of this technology. Today, much of the development of this technology remains experimental. One bellwether for advancement will be adoption of a shared communication standard between the automotive (SAE) and utilities (IEEE) industry.

**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).**

OUC Response:

Please see attached “2026 TYSP Data Request #1.Excel Tables\_OUC” (Excel .xlsx file), and refer to the Worksheet titled “Existing Storage”. The information in this worksheet reflects energy storage technologies owned by OUC.

**b. Excel Tables File (Planned Storage).**

OUC Response:

OUC does not have any planned energy storage to be owned by OUC during the current planning period.

**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.**

OUC Response:

Currently OUC dispatches storage as pilot programs to evaluate the function and financial considerations of PV Smoothing, Back-up Power, Volt-Var Support and Peak Shifting/Shaving. These pilot programs will inform the economy and operational ability of these technologies and develop their dispatch algorithms.

**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.**

OUC Response:

In 2020, OUC installed a small-scale (20kW), commercially-available vanadium flow battery system at a demonstration site to help inform OUC’s decisions regarding larger-scale systems in the future. The battery chemistry showed significant promise for future adoption but the execution of the technology had some mechanical issues. In 2022, OUC installed a flywheel storage solution, and has started to evaluate long duration thermal storage systems. OUC had secured funding for a hydrogen demonstration project through the Department of Energy to evaluate hydrogen as a storage medium. However, federal priorities have shifted and this project has been cancelled.

**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).**

OUC Response:

Several aspects of energy storage systems are under consideration (in no particular order): 1) AC- or DC-coupled to renewable energy sources, 2) proximity of AC-coupled systems to renewable energy sources, 3) proximity to heavily-loaded feeders, 4) site/land-use limitations, and 5) potential for value-stacking (e.g. back-up power options). Land availability, setbacks, land use, etc., are considered and limit siting. OUC is actively exploring multiple opportunities

for battery project, such as near a substation and on customer-owned sites. These projects will enable OUC to better understand the cost/benefit of batteries, which is expected to inform the creation of an adoption roadmap. The initial battery project site is co-located at a substation with interconnect into a residential feeder with high solar penetration. This site will provide significant testing opportunities.

**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.**

OUC Response:

OUC has received occasional inquiries from solar PV contractors on behalf of ratepayers regarding OUC's procedures pertaining to behind-the-meter batteries coupled with solar PV systems. Such systems are permitted by OUC and are subject to the same vetting process as solar systems without storage. As of December 31, 2025, OUC has 1,486 customer interconnected battery storage systems.

**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.**

- a. 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.
- b. Please provide a brief assessment of how these benefits, risks, and operational limitations may change over the current planning period.
- c. Please identify and describe any plans to periodically update the Commission on the status of your energy storage pilot programs.

OUC Response:

OUC has completed the installation of a 4 MW/8 MWh battery at a substation in proximity to an existing 74.5 MW solar farm. OUC will evaluate the costs, benefits, risks, and operational limitations of the system. OUC is also considering customer sited solar projects to evaluate distributed energy resource management system (DERMS).

**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.**

- a. 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.

OUC Response:

OUC is currently evaluating opportunities with battery integration with solar PV systems. At this time, OUC does not have operational experience with energy storage systems for the purpose of providing firm capacity from non-firm generation.

**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.**

OUC Response:

OUC does not have any planned generation resource with an in-service date within the current planning period that requires siting under the Power Plant Siting Act.

- 61. Please refer to the Excel Tables File (Planned TLISA). 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.**

OUC Response:

Please see attached "2026 TYSP Data Request #1.Excel Tables\_OUC" (Excel .xlsx file), and refer to the Worksheet titled "Planned TLISA". OUC anticipates the addition of two new transmission lines in the planning period that will require certification under the Transmission Line Siting Act (TLISA). OUC has not yet filed TLISA applications for either project; anticipated approval and in-service dates are shown in the table in response to this question.

**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.**

OUC Response:

Please see attached "2026 TYSP Data Request #1.Excel Tables\_OUC" (Excel .xlsx file), and refer to the Worksheet titled "Existing PPA".

OUC's only PPA with a traditional generator that was in effect by December 31, 2023 is with NextEra Energy (formerly with Southern-Company Florida, LLC) for capacity and energy from Stanton Energy Center Unit A that began in 2001. Gross ratings and DC capacity ratings are not available to report as gross capacity.

- 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.**

OUC Response:

Please see attached "2026 TYSP Data Request #1.Excel Tables\_OUC" (Excel .xlsx file), and refer to the Worksheet titled "Planned PPA".

As these PPAs have not yet been finalized, OUC only has estimates of AC capacity ratings to report as net capacity and corresponding estimates of firm capacity, and OUC does not have DC capacity ratings to report as gross capacity.

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

OUC Response:

As discussed throughout OUC's 2026 Ten-Year Site Plan, OUC anticipates entering into additional solar PPAs (both with and without energy storage); these PPAs are included for information purposes in the Excel table in response to question No. 63(b) and there are not any additional details to discuss related to these PPAs at this time.

- 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?**

OUC Response:

OUC did not have any long-term power purchase agreements within the past year that were cancelled, delayed, or reduced in scope.

- 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.**

OUC Response:

Please see attached “2026 TYSP Data Request #1.Excel Tables\_OUC” (Excel .xlsx file), and refer to the Worksheet titled “Existing PSA”.

As outlined in Section 2.0 of OUC’s 2026 TYSP, OUC’s power sales agreements in effect on December 31, 2025 consist of agreements with the City of Winter Park, Lakeland Electric, the City of Mt. Dora, and the City of Chattahoochee.

- 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.**

OUC Response:

OUC does not have any planned power sale agreements pursuant to which energy will begin to be delivered from OUC to a third-party during the current planning period.

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

OUC Response:

OUC does not have any planned power sales agreements.

- 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?**

OUC Response:

OUC’s long-term power sale agreement with Lake Worth Beach expired 12/31/2025.

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.**

OUC Response:

Please see attached “2026 TYSP Data Request #1.Excel Tables\_OUC” (Excel .xlsx file), and refer to the Worksheet titled “Reliability”.

- 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.**

OUC Response:

Please see attached “2026 TYSP Data Request #1.Excel Tables\_OUC” (Excel .xlsx file), and refer to the Worksheet titled “Hourly Reliability”.

- 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.**

OUC Response:

OUC’s estimated seasonal firm capacity contributions of its solar facilities and purchases are developed based on hourly forecasts of solar and load. For planning purposes, OUC assumes that 50 percent of the solar facility’s nameplate AC rating is available as firm capacity at the time of summer peak demand, and 0 percent of the solar facility’s nameplate AC rating is available as firm capacity at the time of winter peak demand. As the amount of solar available to OUC increases, OUC anticipates that the hour of system peak demand for reliability purposes net of solar generation may shift by one hour in the latter 2 or 3 years of the 10 year forecast.

- 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.**
- a. 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.**

OUC Response:

OUC is currently evaluating opportunities with battery integration with solar PV systems. At this time, OUC does not have operational experience with energy storage systems for the purpose of providing firm capacity from non-firm generation.

**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.**

OUC Response:

OUC considers the requested information to be confidential and as such has not provided it in response to this question.

**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.**

OUC Response:

Please see attached "2026 TYSP Data Request #1.Excel Tables\_OUC" (Excel .xlsx file), and refer to the Worksheet titled "Fuel Usage and Price".

Projected data for 2026 through 2035 reflects dispatch to serve energy required to serve OUC, St. Cloud, Winter Park, City of Mt. Dora, City of Chattahoochee, and Lakeland Electric load obligations as discussed in Section 2 of OUC's 2026 TYSP, and does not reflect any additional economy energy sales or economy energy purchases. Projected data does not reflect any interaction with the Florida Municipal Power Pool. Fuel prices are not included in the table as OUC considers fuel prices to be proprietary and confidential.

**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.**

OUC Response:

The natural gas and fuel oil price forecasts used in OUC's 2026 Ten-Year Site Plan were developed based on a combination of the NYMEX forward curve and projections provided by S&P Global Platts Commodity Insights (Platts). S&P Global Platts purchased the previous firm that OUC used, which was PIRA Energy Group. Among other services, Platts offers insight on a broad range of subjects in the international crude oil, petroleum products, natural gas, electricity, coal, biofuels and emissions markets. Platts clients include international and national integrated oil and gas companies, independent producers, refiners, marketers, oil and gas pipelines, electric and gas utilities, industrials, trading companies, financial institutions and government agencies.

The coal price forecast used in OUC's 2026 Ten-Year Site Plan was developed based on projections by Energy Ventures Analysis, Inc. (EVA) for use by OUC as well as recent offers from coal suppliers of Illinois Basin coal. EVA is a consulting firm that engages in a variety of projects for private and public sector clients related to energy and environmental issues. In the energy area, much of EVA's work is related to analysis of the electric utility industry and fuel markets, particularly oil, natural gas, and coal. EVA's clients in these areas include coal, oil, and natural gas producers; electric utility and industrial energy consumers; and gas pipelines and railroads. EVA also works for a number of public agencies, such as state regulatory commissions, the US Environmental Protection Agency, and the US Department of Energy, as well as interveners in utility rate proceedings, such as consumer counsels and municipalities. Another group of clients include trade and industry associations, such as the Electric Power Research Institute, the Gas Research Institute, and the Center for Energy and Economic Development. EVA has provided testimony to numerous state public utility commissions, including the Florida Public Service Commission. Furthermore, the firm has

filed testimony in a number of cases in both state and federal courts, as well as before the Federal Energy Regulatory Commission.

OUC believes that retaining independent entities such as Platts and EVA to provide their fuel price forecasting expertise, provides authoritative, independent forecasts in and of themselves.

One fuel forecast that OUC typically compares its forecast to is the US Energy Information Administration (EIA) Annual Energy Outlook. The fuel price projections provided by Platts and EVA differ from those presented in the US Energy Information Administration (EIA) Annual Energy Outlook. The forecasting approaches used by Platts and EVA utilize more current information relative to the information relied upon by the EIA in developing its Annual Energy Outlook, as the scopes of the forecasts developed by Platts and EVA specifically for OUC are far less broad than the scope of data provided by EIA. The relatively limited scope allows Platts and EVA to make use of the most current data available and develop forecasts more specific to OUC, rather than a forecast intended to address the US as a whole, as the EIA provides in the Annual Energy Outlook.

OUC continuously reviews other publicly available forecasts and such reviews validate OUC's use of the independent forecasts provided by Platts and EVA. Furthermore, OUC's generation planning activities include analysis of fuel price sensitivities, which provide an even more comprehensive analysis of fuel prices

- 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.**
  - b. Natural Gas.**
  - c. Nuclear.**
  - d. Fuel Oil.**
  - e. Other (please specify each, if any).**

OUC Response:

The following discussion addresses expected industry trends and factors for the 2026 through 2035 period for coal and natural gas, which are the primary fossil fuel types relied upon by the majority of OUC's generating units. The discussion is based on the US Energy Information Administration's Assumptions for Annual Energy Outlook 2026 (2026 AEO) and the Short-Term Energy Outlook (STEO). The overall effect of the trends relative to OUC cannot be determined, as the projections included in 2026 references do not take into account various market factors that may be specific to OUC (i.e. local weather, weather events across the US, the economy, the impact on demand resulting from possible future legislation related to carbon regulations and/or renewable energy standards, etc.).

According to the April STEO, natural gas prices for the Henry Hub will average \$3.10MMBtu for the second and third quarter of 2026. It is estimated U.S natural gas inventories, in 2025-2026, ended withdrawal season about 3% higher than the five-year average. Looking into 2027 it is estimated storage balances will edge below the previous five-year average.

The 2026 AEO is expecting continued growth in natural gas exports through 2040. Based on the 2026 AEO, U.S. liquefied natural gas (LNG) exports are expected to increase to 27.7 Bcf/d by 2030. The anticipated increase in LNG exports is a result of LNG developers being in the midst of significant buildouts. Current assumptions that attribute to the estimated increase are tied to the Counterfactual Baseline case. With a projection of higher Brent crude oil prices, due to increased oil demand, LNG will be more of an economic opportunity. Overall, the EIA expects U.S. LNG exports to continue to increase over the next ten years as increasing LNG capacity is expected to meet increased international demand for natural gas. In regard to dry natural gas, the production in 2026 is forecasted to average 107Bcf/d.

According to the April STEO 2026 Brent crude oil spot prices average \$103 per barrel in March, and is expected to peak in the second quarter of 2026 at \$115/b. It is forecasted that crude oil price will fall below \$90/b in 4Q26 and average \$76 /b in 2027. The price forecast is highly dependent on the assumption, stated in the STEO, on both the duration of the conflict in the middle east and resulting outages in oil production. As of early April 2026, Oil flows through the Strait of Hormuz continues to be limited. For this outlook, the STEO forecasts under the assumptions the conflict does not persist past April and traffic through the Strait of Hormuz gradually resumes. Returning production shut-ins to pre-conflict levels in late 2026.

According to the 2026 AEO, projected future coal use in the United States is heavily dependent on policy assumptions. These policies include regulations on carbon dioxide emissions, and for steam coal plants without Carbon Capture technology to convert to natural gas by 2038 or retire. Current AEO assumptions, based on the policies mentioned previously, coal consumption is expected to decrease from 288 million short tons (MMst) in 2025 to nearly nothing by 2050.

Coal consumption for heat and power in the industrial sector is shown to be decreasing by about 5 MMst by 2050, roughly 30% of industrial use by 2050. Across different areas, there is a drop-off in domestic coal consumption, while U.S. coal produced for exports increase throughout the AEO Projection period. These increases are seen to be about 20 percent across all examined cases, going from 96MMst exported in 2025 to 115 MMst in 2050, assuming no restrictions occur on global coal trade.

According to the STEO, delivered coal prices are forecast to average \$2.42/MMBtu in 2025, and will remain average at \$2.39/MMBtu in 2026 and 2027.

The 2026 AEO shows Nuclear capacity remaining relatively flat across different cases. Nuclear generation, which across all cases considered here, is estimated to go from 17% in 2025 to between 12% and 15% by 2050.

**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.**

OUC Response:

OUC considers fuel prices to be confidential information and, as such, no specific comparison has been developed or provided. In general, actual 2025 delivered fuel prices were lower than forecast for 2025.

**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.**

OUC Response:

There were no notable changes to the process from 2025 to 2026.

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

OUC Response:

The Stanton Energy Center, the Indian River site, and the Osceola Generating Station are reliably served by the Florida Gas Transmission Company (FGT). These sites are currently the only sites in which OUC owns natural gas fired generating units. OUC is confident in FGT's ability to continue to reliably serve these sites into the future. Historically, FGT has demonstrated an ability to provide reliable service and continues to make improvements to its existing natural gas transportation system as well as expand its natural gas transportation system to accommodate the growing need for natural gas across the State of Florida. A recent example is FGT's Phase IX expansion.

In 2022, OUC entered into a four and a half year contract for the storage of natural gas to manage price volatility. The contract provides up to 40,000 MMBtu/day to help ensure power reliability. It is OUC's intent to keep a natural gas storage position in place through the planning period.

Additionally, in 2022, OUC secured an additional 29,850 MMBtu/day of winter capacity on FGT to allow more reliability in cold weather events.

**Environmental**

**79. Please explain if the Company assumes carbon dioxide (CO<sub>2</sub>) 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:**

- a. Please identify the year during the current planning period in which CO<sub>2</sub> compliance costs are first assumed to have a non-zero value.
- b. [Investor-Owned Utilities Only] Please explain if the exclusion of CO<sub>2</sub> compliance costs would result in a different resource plan than that presented in the Company's current planning period TYSP.
- c. [Investor-Owned Utilities Only] Please provide a revised resource plan assuming no CO<sub>2</sub> compliance costs.

OUC Response:

CO<sub>2</sub> compliance costs have not been included in the resource planning process used to generate the resource plan presented in OUC's 2026 TYSP. Parts (b) and (c) of the question are not applicable to OUC as OUC is not an Investor-Owned Utility

- 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.**

OUC Response:

On April 25, 2024, EPA released a pre-publication of final rules regulating greenhouse gas emissions (GHGs) from electric generating units (EGUs) pursuant to Section 111 of the Clean Air Act. As part of this rule, EPA finalized emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs pursuant to Clean Air Act Section 111(d), which include both coal-fired and oil/gas-fired steam generating EGUs. This rule impacts any OUC coal-fired EGUs that are not retired prior to January 1, 2032 by requiring these EGUs to meet GHG emissions limits based on the best system of emission reduction (BSER). The applicable BSER emission limits for existing EGUs are based on unit retirement date.

On June 11, 2025, EPA issued a proposed rule that would result in the repeal of all GHG emission standards, including the April 2024 standards, for fossil fuel-fired power plants. This proposed rule also included an alternative that would result in the repeal of a narrower set of requirements in lieu of a total repeal of all GHG standards. It is unknown what effect, if any, changes to these standards may have on OUC EGUs. On February 18, 2026, the EPA finalized a rule overturning the 2009 Endangerment Finding, removing the legal basis for federal GHG regulation of fossil fuel-fired power plants.

- 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?
- b. What compliance strategy does the Company anticipate employing for the rule?
- c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?
- d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
- 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.
- f. If the answer to any of the above questions is not available, please explain why.

OUC Response:

Please see responses below.

- a. OUC does not currently have any firm plans related to the addition of new generating units that would be affected by this standard.
- b. Not applicable.
- c. Not applicable.
- d. Not applicable.
- e. Not applicable.
- f. See response to (a)

**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.**
- b. **Cross-State Air Pollution Rule (CSAPR).**
- c. **Cooling Water Intake Structures (CWIS) Rule.**
- d. **Coal Combustion Residuals (CCR) Rule.**
- e. **Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units.**
- f. **Affordable Clean Energy Rule or its replacement.**
- g. **Effluent Limitations Guidelines and Standards (ELGS) from the Steam Electric Power Generating Point Source Category.**

OUC Response:

OUC does not anticipate reliability impacts due to EPA rules “b” through “e” and “g” listed above.

The EPA proposed the Mercury and Air Toxics Standards Rule ("MATS Rule") to further regulate mercury and other hazardous air pollutant emissions from electric generating units in April of 2015. In April 2016, the EPA finalized its supplemental finding in order to fulfill the directives of the Supreme Court of the United States. In May 2024, the EPA published a final rule revising this standard to include a new limit for filterable particulate matter and new monitoring requirements, with a three-year deadline to achieve compliance. On June 17, 2025, EPA issued a proposed rule that would repeal the May 2024 MATS rule revisions and would revert to the original 2012 MATS requirements. On February 24, 2026, the final rule repealing the May 2024 MATS revisions was published. OUC does not anticipate reliability impacts due to the repeal of the 2024 MATS Rule revisions.

Related to EPA rule “f” above, in 2015 the Environmental Protection Agency began issuing regulatory requirements associated with GHG emissions that set CO<sub>2</sub> limits for new gas-fired combustion turbines and CO<sub>2</sub> emission guidelines for existing coal, oil, and gas-fired steam generating units. The form and substance of such regulatory requirements have evolved over the past several years. On April 25, 2024, the EPA finalized new standards for carbon dioxide (CO<sub>2</sub>) emissions from new and existing fossil-fueled electric generating units (EGUs). Litigation on this rule began in late 2024 in the DC Circuit Court of Appeals and the case is currently being held in abeyance. On June 11, 2025, EPA issued a proposed rule that would result in the repeal of all GHG emission standards, including the April 2024 standards, for fossil fuel-fired power

plants. This proposed rule also included an alternative that would result in the repeal of a narrower set of requirements in lieu of a total repeal of all GHG standards. On February 18, 2026, the EPA finalized a rule overturning the 2009 Endangerment Finding, removing the legal basis for federal GHG regulation of fossil fuel-fired power plants. OUC does not anticipate reliability impacts due to the repeal of the 2024 standards for CO<sub>2</sub> emissions from new and existing fossil-fueled electric generating units (EGUs).

- 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.**

OUC Response:

Please see attached “2026 TYSP Data Request #1.Excel Tables\_OUC” (Excel .xlsx file), and refer to the Worksheet titled “EPA Operational Effects”.

- 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.**

OUC Response:

Please see attached “2026 TYSP Data Request #1.Excel Tables\_OUC” (Excel .xlsx file), and refer to the Worksheet titled “EPA Cost Effects”. The costs shown in the table correspond to the years in which the expenditures occurred.

- 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.**

OUC Response:

Please see attached “2026 TYSP Data Request #1.Excel Tables\_OUC” (Excel .xlsx file), and refer to the Worksheet titled “EPA Unit Availability”.

- 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.**

OUC Response:

OUC evaluated an SCR retrofit for Stanton Energy Center Unit 1 following the upholding of CSAPR by the Supreme Court in April 2014. Prior to postponing the retrofit when CSAPR was vacated by the US 5th Circuit Court, OUC had invested approximately \$11 million in the project.

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<b>Financial Assumptions</b>			
<b>Base Case</b>			
AFUDC Rate		(%)	7.5
Capitalization Ratios	Debt	(%)	N/A
	Preferred	(%)	N/A
	Equity	(%)	N/A
Rate of Return	Debt	(%)	N/A
	Preferred	(%)	N/A
	Equity	(%)	N/A
Income Tax rate	State	(%)	N/A
	Federal	(%)	N/A
	Effective	(%)	N/A
Other Tax Rate:		(%)	N/A
Discount Rate:		(%)	7.5
Tax - Depreciation Rate:		(%)	N/A

<b>Financial Escalation Assumptions</b>				
<b>Year</b>	<b>General Inflation</b>	<b>Plant Construction Cost</b>	<b>Fixed O&amp;M Cost</b>	<b>Variable O&amp;M Cost</b>
	<b>(%)</b>	<b>(%)</b>	<b>(%)</b>	<b>(%)</b>
<b>2026</b>	2%	2%	2%	2%
<b>2027</b>	2%	2%	2%	2%
<b>2028</b>	2%	2%	2%	2%
<b>2029</b>	2%	2%	2%	2%
<b>2030</b>	2%	2%	2%	2%
<b>2031</b>	2%	2%	2%	2%
<b>2032</b>	2%	2%	2%	2%
<b>2033</b>	2%	2%	2%	2%
<b>2034</b>	2%	2%	2%	2%
<b>2035</b>	2%	2%	2%	2%



2026 TYSP Data Request #1.Excel Tables\_ OUC

TYSP Year  
Question No.

2026 The table presents the monthly coincident peak demands for OUC and the City of St. Cloud  
5 combined.

Year	Month	Actual Peak Demand	Demand Response Activated	Estimated Peak Demand	Day	Hour	System-Average Temperature
		(MW)	(MW)	(MW)			(Degrees F)
2025	1	1,275	0	1,275	22	19	42
	2	1,122	0	1,122	13	17	79
	3	1,156	0	1,156	31	18	80
	4	1,240	0	1,240	1	18	80
	5	1,461	0	1,461	20	18	86
	6	1,415	0	1,415	16	18	86
	7	1,553	0	1,553	28	17	88
	8	1,575	0	1,575	6	16	85
	9	1,379	0	1,379	26	18	84
	10	1,238	0	1,238	8	18	80
	11	1,291	0	1,291	8	16	77
	12	998	0	998	2	19	74
2024	1	962	0	962	22	9	57
	2	964	0	964	12	20	76
	3	1,125	0	1,125	15	18	77
	4	1,252	0	1,252	19	18	80
	5	1,408	0	1,408	9	18	86
	6	1,485	0	1,485	10	17	87
	7	1,472	0	1,472	8	16	88
	8	1,472	0	1,472	14	17	89
	9	1,387	0	1,387	30	18	86
	10	1,342	0	1,342	1	17	92
	11	1,158	0	1,158	11	16	78
	12	953	0	953	18	19	72
2023	1	1,024	0	1,024	16	9	52
	2	1,099	0	1,099	23	17	78
	3	1,223	0	1,223	27	18	82
	4	1,247	0	1,247	4	17	79
	5	1,268	0	1,268	5	16	84
	6	1,400	0	1,400	27	18	86
	7	1,431	0	1,431	18	18	88
	8	1,517	0	1,517	9	17	90
	9	1,376	0	1,376	11	18	84
	10	1,274	0	1,274	13	17	84
	11	1,113	0	1,113	10	16	78
	12	1,006	0	1,006	2	16	78
<b>Notes</b>							
Monthly coincident OUC and St. Cloud peak demands are shown in the table.							

TYSP Year 2026  
 Question No. 27

Resource Type	Customer-Owned Resources										
	Actual	Projected									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
<b>Renewable Resources</b>											
Number of Installations	N/A										
Total Capacity of Installations	132	143	150	160	176	200	223	243	261	276	290
Reduction to Summer Peak Demand (MW)	(27)	(28)	(30)	(32)	(35)	(40)	(45)	(49)	(52)	(55)	(58)
Reduction to Winter Peak Demand (MW)	(3)	-	-	(3)	(4)	-	-	-	-	-	-
Reduction to Net Energy for Load (GWh)	178	193	202	215	237	270	301	328	352	372	390
<b>Energy Storage Resources</b>											
Number of Installations	N/A										
Total Capacity of Installations (MW)											
Total Storage Capacity of Installations (MWh)											
Reduction to Summer Peak Demand (MW)											
Reduction to Winter Peak Demand (MW)											
Reduction to Net Energy for Load (GWh)											
<b>Notes</b>											
(Include Notes Here)											

2026 TYSP Data Request #1.Excel Tables\_OUC

TYSP Year  
Question No.

2026  
28 This question is not applicable as OUC does not currently offer demand response programs to its customers

[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									
<b>Notes</b>									
(Include Notes Here)									

TYSP Year  
Question No.

2026 This question is not applicable as OUC does not currently offer demand response programs to its customers  
29

[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**  
(Include Notes Here)

TYSP Year 2026  
Question No. 31

Year	Number of PEVs	Number of Public PEV Charging Stations	Number of Public DCFC PEV Charging Stations	Cumulative Impact of PEVs		
				Summer Demand	Winter Demand	Annual Energy
				(MW)	(MW)	(GWh)
2026	44,800	47,137	548	37	59	243
2027	57,357	60,310	701	47	76	311
2028	71,148	74,862	871	34	35	386
2029	86,392	90,965	1,058	42	43	469
2030	105,135	109,586	1,275	50	64	565
2031	124,944	130,724	1,521	60	79	674
2032	145,534	152,844	1,779	70	89	788
2033	162,252	174,362	2,029	80	102	899
2034	175,976	193,568	2,252	89	113	998
2035	191,601	213,155	2,481	97	124	1,099
<b>Notes</b>						
<ol style="list-style-type: none"> <li>1. All PEV data is BEV and PHEV vehicles.</li> <li>2. Charging assumption #1 is 75% L2 to 25% DCFC ratio.</li> <li>3. Ratio could change if we determine it's more economical to provide DCFC.</li> <li>4. Charging assumption #2 is all EV's have access to home charging, those that do not will have a heavier need for public charging.</li> <li>5. Charging assumption #3 is 85% of all EV charging is done at home, 15% public charging.</li> <li>6. Charging station forecast represents the total number of chargers needed to support the forecasted annual energy demand.</li> <li>7. Our current installation count is not factored into these projections</li> </ol>						

2026 TYSP Data Request #1.Excel Tables\_OUC

TYSP Year 2026 This question is not applicable as OUC does not currently serve any data centers and does not currently have plans to serve any  
 Question No. 40 data centers.

Data Center Type	Data Centers										
	Actual	Projected									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
<b>Existing Data Centers</b>											
Number of Data Centers											
Total Annual Energy Usage (GWh)											
Impact to Summer Peak Demand (MW)											
Impact to Winter Peak Demand (MW)											
<b>Planned Data Centers (In-service in 2026)</b>											
Number of Data Centers											
Total Annual Energy Usage (GWh)											
Impact to Summer Peak Demand (MW)											
Impact to Winter Peak Demand (MW)											
<b>Planned Data Centers (After 2026)</b>											
Number of Data Centers											
Total Annual Energy Usage (GWh)											
Impact to Summer Peak Demand (MW)											
Impact to Winter Peak Demand (MW)											
<b>Notes</b>											

2026 TYSP Data Request #1.Excel Tables\_OUC

TYSP Year 2026  
Question No. 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
Indian River	A	Brevard	GT	NG	06	89	16 <sup>(1)</sup>	18 <sup>(1)</sup>	16 <sup>(1)</sup>	18 <sup>(1)</sup>	16 <sup>(1)</sup>	18 <sup>(1)</sup>
Indian River	B	Brevard	GT	NG	07	89	16 <sup>(1)</sup>	18 <sup>(1)</sup>	16 <sup>(1)</sup>	18 <sup>(1)</sup>	16 <sup>(1)</sup>	18 <sup>(1)</sup>
Indian River	C	Brevard	GT	NG	08	92	83 <sup>(2)</sup>	88 <sup>(2)</sup>	83 <sup>(2)</sup>	88 <sup>(2)</sup>	83 <sup>(2)</sup>	88 <sup>(2)</sup>
Indian River	D	Brevard	GT	NG	10	92	83 <sup>(2)</sup>	88 <sup>(2)</sup>	83 <sup>(2)</sup>	88 <sup>(2)</sup>	83 <sup>(2)</sup>	88 <sup>(2)</sup>
Stanton Energy Center	1	Orange	ST	BIT	07	87	479 <sup>(3)</sup>	479 <sup>(3)</sup>	453 <sup>(3)</sup>	453 <sup>(3)</sup>	453 <sup>(3)</sup>	453 <sup>(3)</sup>
Stanton Energy Center	2	Orange	ST	BIT	06	96	371 <sup>(4)</sup>	371 <sup>(4)</sup>	352 <sup>(4)</sup>	352 <sup>(4)</sup>	352 <sup>(4)</sup>	352 <sup>(4)</sup>
Stanton Energy Center	A	Orange	CC	NG	10	01	184 <sup>(5)</sup>	189 <sup>(5)</sup>	184 <sup>(5)</sup>	189 <sup>(5)</sup>	184 <sup>(5)</sup>	189 <sup>(5)</sup>
Stanton Energy Center	B	Orange	CC	NG	02	10	298	313	292	307	292	307
St. Lucie <sup>(6)</sup>	2	St. Lucie	NP	UR	06	83	60	62	60	62	60	62
Osceola Generating Station	1	Osceola	GT	NG	12	01	197	197	157	157	157	157
Osceola Generating Station <sup>(7)</sup>	2	Osceola	GT	NG	12	01	197	197	157	157	157	157
Osceola Generating Station	3	Osceola	GT	NG	12	01	197	197	157	157	157	157
Co-Fired Stanton Energy Center Landfill Gas	1/2	Orange	ST	LFG	04	98	See Note (8)	See Note (8)	See Note (8)	See Note (8)	See Note (8)	See Note (8)
OUC Distributed Solar (<250 kW)	8	Orange	Solar	SUN	Various	Various	0.36	0.36	0.36	0.36	0.36	0.36

**Notes**

(1)Reflects an OUC ownership share of 48.8 percent.  
 (2)Reflects an OUC ownership share of 79.0 percent.  
 (3)Reflects an OUC ownership share of 100 percent, as of January 1, 2026.  
 (4)Reflects an OUC ownership share of 71.6 percent and St. Cloud entitlement of 3.4 percent.  
 (5)Reflects an OUC ownership share of 28.0 percent.  
 (6)OUC owns approximately 6.1 percent of St. Lucie Unit No. 2. Reliability exchange divides 50 percent power from Unit No. 1 and 50 percent power from Unit No. 2.  
 (7) Osceola Generating Station Unit 2 is currently not able to provide power to OUC but expected to be able to provide power to OUC by the summer 2026 peak period.  
 (8). LFG is co-fired in Stanton Energy Center Units 1 and 2 and therefore not treated as incremental capacity.

2026 TYSP Data Request #1.Excel Tables\_OUC

TYSP Year  
Question No.

2026 OUC does not have any utility-owned generation resource planned for in-45(b) service during the 2026 through 2035 planning period.

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
<b>Notes</b>												
(Include Notes Here)												

TYSP Year 2026  
 Question No. 46

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Performance (%)						Average Net Operating Heat Rate (ANOHR) (MMBTU/kWh)	
							Planned Outage Factor (POF) (%)		Forced Outage Factor (FOF) (%)		Equivalent Availability Factor (EAF) (%)			
					Mo	Yr	Historic	Projected	Historic	Projected	Historic	Projected	Historic	Projected
Stanton Energy Center	1	Orange	ST	BIT	07	87	5.3%	5.1%	7.9%	3.0%	85.8%	91.9%	11,846	11,136
Stanton Energy Center	2	Orange	ST	BIT	06	96	5.6%	10.1%	0.9%	3.0%	91.8%	86.9%	10,846	10,939
Stanton Energy Center	B	Orange	CC	NG	02	10	8.6%	8.7%	1.9%	3.0%	89.5%	88.3%	7,446	7,177
Indian River	A	Brevard	GT	NG	06	89	3.4%	7.9%	0.1%	2.0%	96.4%	90.1%	14,449	18,906
Indian River	B	Brevard	GT	NG	07	89	2.9%	8.8%	0.1%	2.0%	97.0%	89.2%	14,449	18,810
Indian River	C	Brevard	GT	NG	08	92	2.3%	12.1%	1.1%	2.0%	96.3%	85.9%	14,731	14,807
Indian River	D	Brevard	GT	NG	10	92	43.0%	4.3%	4.5%	2.0%	52.4%	93.7%	14,731	14,797
Osceola Generating Station	1	Osceola	GT	NG	12	01	3.2%	4.8%	0.0%	2.0%	96.7%	93.2%	16,161	11,418
Osceola Generating Station	2	Osceola	GT	NG	12	01	66.0%	7.0%	0.0%	2.0%	34.0%	91.0%	19,343	11,418
Osceola Generating Station	3	St. Lucie	NP	UR	06	02	1.6%	4.8%	0.0%	2.0%	91.3%	93.2%	9,914	11,415

**Notes**

Historical - average of past three years.  
 Projected - average of next ten years.

2026 TYSP Data Request #1.Excel Tables\_OUC

TYSP Year  
Question No.

2026 OUC considers the requested information to be confidential and therefore has not provided it in response to this request.  
47

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Capacity Factor (%)										
							Actual	Projected									
					Mo	Yr	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035

**Notes**

(Include Notes Here)

TYSP Year  
Question No.

2026 This question is not applicable as OUC is not an Investor-Owned Utility  
48

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				
<b>Notes</b>														
(Include Notes Here)														

TYSP Year  
Question No.

2026 OUC does not have any planned generating units with an in-service date within the current planning period. Therefore, there are no “drop dead”  
49 dates or other information to provide in response to this question.

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Final Decision ('Drop Dead') Date	Site Selection		Engineering / Permitting / Procurement		Constuction		Commercial In-Service Date
						Begins	Ends	Begins	Ends	Begins	Ends	
<b>Notes</b>												
(Include Notes Here)												

TYSP Year 2026 OUC does not have any units that are considered as options for repowering to combined cycle. OUC's existing Stanton Energy Center Units 1 and 2 may be potential candidates to change fuel to operate on 100 percent natural gas; as discussed throughout OUC's 2025 Ten-Year Site Plan, OUC currently anticipates placing Stanton Energy Center Unit 1 into extended cold shutdown by the end of May

Question No. 51 2026 and anticipates converting Stanton Energy Center Unit 2 to operate on 100 percent natural gas no later than 2027.

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)	
Stanton Energy Center	1	Orange	ST	BIT	07	87	See Note (1)	See Note (1)	No	No	See Note (1)
Stanton Energy Center	2	Orange	ST	BIT	06	96	See Note (1)	See Note (1)	No	No	See Note (1)
<b>Notes</b>											
1. OUC's existing Stanton Energy Center Units 1 and 2 may be potential candidates to change fuel to operate on 100 percent natural gas; as discussed throughout OUC's 2026 Ten-Year Site Plan, OUC currently anticipates placing Stanton Energy Center Unit 1 into extended cold shutdown by the end of May 2026 and anticipates converting Stanton Energy Center Unit 2 to operate on 100 percent natural gas no later than 2027.											

TYSP Year 2026  
 Question No. 53(a)

Facility or Project Name	Unit No.	County Location	Energy Storage Type	Battery Chemistry (if applicable)	Land Use (Acres)	Facility In-Service or Project Start Date		Unit Capacity (MW)						Storage Capacity (MWh)	Conversion Efficiency (%)
						Mo	Yr	Gross		Net		Firm			
								Sum	Win	Sum	Win	Sum	Win		
Gardenia Lilon Battery	Not Applicable	Orange	Li Ion	Iron Phosphate	<1	1	25	Not Available	Not Available	0.1	0.1	0.1	0.1	0.129	89%
Gardenia Fly Wheels	Not Applicable	Orange	Fly Wheel	NA	<1	5	22	Not Available	Not Available	0.016	0.016	0.016	0.016	0.064	Varies
St. Cloud East Substation #29	Not Applicable	Osceola	Battery	Iron Phosphate	<1	4	24	Not Available	Not Available	4	4	4	4	8	89%
<b>Notes</b>															
(Include Notes Here)															

TYSP Year 2026 OUC does not have any planned OUC-owned energy storage during the 2026 to 2035 planning period.  
 Question No. 53(b)

Facility or Project Name	Unit No.	County Location	Energy Storage Type	Battery Chemistry (if applicable)	Land Use (Acres)	Facility In-Service or Project Start Date		Unit Capacity (MW)						Storage Capacity (MWh)	Conversion Efficiency (MWh)
						Mo	Yr	Gross		Net		Firm			
								Sum	Win	Sum	Win	Sum	Win		
<b>Notes</b>															
(Include Notes Here)															

2026 TYSP Data Request #1.Excel Tables\_OUC

TYSP Year  
Question No.

2026 OUC does not have any planned generation resource with an in-service date within the current planning period that requires 60 siting under the Power Plant Siting Act.

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Certification Dates (if Applicable)	
							Need Approved (Commission)	PPSA Certified
					Mo	Yr		
<b>Notes</b>								
(Include Notes Here)								

TYSP Year 2026  
 Question No. 61

Transmission Line	Line Length	Nominal Voltage	Certification Dates		In-Service Date
	(Miles)		(kV)	Need Approved	
New 230kV Source to St. Cloud West (St. Cloud West to Taft)	> 15 Miles	230	06/2030	TBD	2033
Rocky Pond 230kv Line to Stanton Addition	> 15 Miles	230	06/2031	TBD	2035
<b>Notes</b>					
OUC anticipates the addition of two new transmission lines in the planning period that will require certification under the Transmission Line Siting Act (TLSA). OUC has not yet filed TLSA applications for either project; anticipated approval and in-service dates are shown.					

TYSP Year  
Question No.

2026  
62(a)

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)						
		Firm Capacity (MW)		Delivery Dates							Mo	Yr	Gross		Net		Firm		
		Sum	Win	Start	End								Sum	Win	Sum	Win	Sum	Win	
NextEra Energy	Not Available	342	350	10/03	12/31	Stanton Energy Center	A	Orange	CC	NG	10	01	Not Available	Not Available	657	675	657	675	
NextEra Energy	Not Available	87	87	12/23	12/28	Stanton Energy Center	A	Orange	CC	NG	10	01	Not Available	Not Available	657	675	657	675	
Deriva Energy	Not Available	Not Applicable	Not Applicable	12/11	11/31	RP Orlando - Stanton	N/A	Orange	Solar	SUN	11	11	Not Available	Not Available	5.1	5.1	2.55	0	
Greenwood Sustainable Infrastructure	Not Available	Not Applicable	Not Applicable	09/17	08/37	Ksionek Stanton Solar Site A & C	N/A	Orange	Solar	SUN	9	17	Not Available	Not Available	8.89	8.89	4.45	0	
NextEra Energy	Not Available	Not Applicable	Not Applicable	06/20	06/40	Taylor Creek	N/A	Orange	Solar	SUN	6	20	Not Available	Not Available	74.5	74.5	37.25	0	
NextEra Energy	Not Available	Not Applicable	Not Applicable	06/20	06/40	Harmony	N/A	Osceola	Solar	SUN	6	20	Not Available	Not Available	34.0	34.0	17	0	
NextEra Energy	Not Available	Not Applicable	Not Applicable	12/24	12/44	Storey Bend	N/A	Osceola	Solar	SUN	12	24	Not Available	Not Available	74.5	74.5	37.25	0	
NextEra Energy	Not Available	Not Applicable	Not Applicable	12/24	12/44	Harmony II	N/A	Osceola	Solar	SUN	12	24	Not Available	Not Available	74.5	74.5	37.25	0	
Greenbacker Renewable Energy Corporation	Not Available	Not Applicable	Not Applicable	11/12	11/37	Fleet Solar Project	N/A	Orange	Solar	SUN	11	12	Not Available	Not Available	0.4	0.4	0	0	
ESA Renewables V	Not Available	Not Applicable	Not Applicable	10/13	10/38	Gardenia Solar Project	N/A	Orange	Solar	SUN	10	13	Not Available	Not Available	0.34	0.34	0	0	
Opal Fuels	Not Available	Not Applicable	Not Applicable	11/11	10/31	Port Charlotte/ Collier	N/A	Charlotte/ Collier	Landfill Gas	LFG	11	11	Not Available	Not Available	4	4	4	4	
WM Renewable Energy	Not Available	Not Applicable	Not Applicable	03/16	12/26	Monarch Hills	N/A	Broward	Landfill Gas	LFG	3	16	Not Available	Not Available	6	6	6	6	
LMS Energy	Not Available	Not Applicable	Not Applicable	03/17	02/37	JED LFGTE Project	N/A	Osceola	Landfill Gas	LFG	3	17	Not Available	Not Available	9	9	9	9	
<b>Notes</b>																			
(Include Notes Here)																			

TYSP Year 2026  
Question No. 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)						
		Firm Capacity (MW)		Delivery Dates							Mo	Yr	Gross		Net		Firm		
		Sum	Win	Start	End								Sum	Win	Sum	Win	Sum	Win	
TBD	Not Available	TBD	TBD	6/27	TBD	TBD	TBD	TBD	Solar	SUN	6	27	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/27	TBD	TBD	TBD	TBD	Solar	SUN	6	27	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/29	TBD	TBD	TBD	TBD	Solar	SUN	6	29	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/29	TBD	TBD	TBD	TBD	Solar	SUN	6	29	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/30	TBD	TBD	TBD	TBD	Solar	SUN	6	30	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/30	TBD	TBD	TBD	TBD	Solar	SUN	6	30	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/31	TBD	TBD	TBD	TBD	Solar	SUN	6	31	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/31	TBD	TBD	TBD	TBD	Solar	SUN	6	31	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/32	TBD	TBD	TBD	TBD	Solar	SUN	6	32	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/32	TBD	TBD	TBD	TBD	Solar	SUN	6	32	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/33	TBD	TBD	TBD	TBD	Solar	SUN	6	33	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/33	TBD	TBD	TBD	TBD	Solar	SUN	6	33	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/33	TBD	TBD	TBD	TBD	Solar	SUN	6	33	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/33	TBD	TBD	TBD	TBD	Solar	SUN	6	33	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/33	TBD	TBD	TBD	TBD	Solar	SUN	6	33	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/33	TBD	TBD	TBD	TBD	Solar	SUN	6	33	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/34	TBD	TBD	TBD	TBD	Solar	SUN	6	34	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/34	TBD	TBD	TBD	TBD	Solar	SUN	6	34	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/34	TBD	TBD	TBD	TBD	Solar	SUN	6	34	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/34	TBD	TBD	TBD	TBD	Solar	SUN	6	34	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/34	TBD	TBD	TBD	TBD	Solar	SUN	6	34	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/34	TBD	TBD	TBD	TBD	Solar	SUN	6	34	Not Available	Not Available	74.5	74.5	37.25	0	
TBD	Not Available	TBD	TBD	6/27	TBD	TBD	TBD	TBD	Energy Storage	SUN	6	27	Not Available	Not Available	100	100	100	100	
TBD	Not Available	TBD	TBD	6/31	TBD	TBD	TBD	TBD	Energy Storage	SUN	6	31	Not Available	Not Available	100	100	100	100	
TBD	Not Available	TBD	TBD	6/32	TBD	TBD	TBD	TBD	Energy Storage	SUN	6	32	Not Available	Not Available	150	150	150	150	
TBD	Not Available	TBD	TBD	6/33	TBD	TBD	TBD	TBD	Energy Storage	SUN	6	33	Not Available	Not Available	250	250	250	250	
TBD	Not Available	TBD	TBD	6/34	TBD	TBD	TBD	TBD	Energy Storage	SUN	6	34	Not Available	Not Available	200	200	200	200	

**Notes**  
As these PPAs have not yet been finalized, OUC only has estimates of AC capacity ratings to report as net capacity and corresponding estimates of firm capacity, and OUC does not have DC capacity ratings to report as gross capacity.

TYSP Year 2026  
 Question No. 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		Unit Capacity (MW)						
		Firm Capacity (MW)		Delivery Dates							Gross		Net		Firm				
		Sum	Win	Start	End						Sum	Win	Sum	Win	Sum	Win			
City of Winter Park	Not Available	17 <sup>(1)</sup>	17 <sup>(1)</sup>	1/26	12/26	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)
City of Mt. Dora	Not Available	26 <sup>(1)</sup>	20 <sup>(1)</sup>	01/21	12/30	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)
City of Chattahoochee	Not Available	9 <sup>(1)</sup>	7 <sup>(1)</sup>	01/21	12/27	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)
Lakeland Electric	Not Available	100 <sup>(1)</sup>	50 <sup>(1)</sup>	04/21	12/26	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)	See Note (2)

**Notes**  
 (1) Capacity may vary by year; values shown represent projections for 2026.  
 (2) The sales are all system sales; information requested associated with a specific unit is therefore not applicable.

TYSP Year  
Question No.

2026 OUC does not have any planned power sale agreements pursuant to which energy will begin to be delivered from OUC to a third-party during the current planning period.  
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		Unit Capacity (MW)										
		Firm Capacity (MW)		Delivery Dates							Mo	Yr	Gross		Net			Firm					
		Sum	Win	Start	End								Sum	Win	Sum	Win		Sum	Win				
<b>Notes</b> (Include Notes Here)																							

<b>Loss of Load Probability, Reserve Margin, and Expected Unserved Energy</b>						
<b>Base Case Load Forecast</b>						
<b>Year</b>	<b>Loss of Load Probability (Days/Yr)</b>	<b>Annual Isolated Reserve Margin (%) (Including Firm Purchases)</b>	<b>Expected Unserved Energy (MWh)</b>	<b>Loss of Load Probability (Days/Yr)</b>	<b>Annual Assisted Reserve Margin (%) (Including Firm Purchases)</b>	<b>Expected Unserved Energy (MWh)</b>
2026	N/A	N/A	0	N/A	57%	0
2027	N/A	N/A	0	N/A	60%	0
2028	N/A	N/A	0	N/A	58%	0
2029	N/A	N/A	0	N/A	53%	0
2030	N/A	N/A	0	N/A	51%	0
2031	N/A	N/A	0	N/A	49%	0
2032	N/A	N/A	0	N/A	27%	0
2033	N/A	N/A	0	N/A	38%	0
2034	N/A	N/A	0	N/A	46%	0
2035	N/A	N/A	0	N/A	43%	0

TYSP Year 2026  
Question No. 69

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	889	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	0
2	808	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	0
3	752	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	0
4	720	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	0
5	716	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	0
6	767	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	0
7	859	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	0
8	906	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	2.6
9	972	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	28
10	1,068	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	138.8
11	1,178	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	210.9
12	1,284	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	223
13	1,434	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	214.7
14	1,550	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	197.5
15	1,592	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	191.5
16	1,610	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	163.4
17	1,626	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	148.4
18	1,610	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	120.6
19	1,559	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	82.4
20	1,483	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	50.2
21	1,450	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	7.2
22	1,343	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	0.8
23	1,181	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	0
24	1,014	0	See Notes	429	See Notes	See Notes	60	1,145	352	0	19	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	882	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0
2	858	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0
3	847	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0
4	853	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0
5	883	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0
6	964	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0
7	1,088	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0
8	1,160	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0.7
9	1,149	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	20.5
10	1,110	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	106.7
11	1,070	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	171.5
12	1,036	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	174
13	1,008	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	190.6
14	982	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	182
15	965	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	187.5
16	973	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	169.3
17	999	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	155.9
18	1,076	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	119.1
19	1,181	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	34.7
20	1,194	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0.9
21	1,174	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0
22	1,132	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0
23	1,071	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0
24	1,003	0	See Notes	437	See Notes	See Notes	62	1,179	352	0	19	0

Notes:

"Total Load" reflects forecast peak summer 2026 and winter 2026 peak day for coincident demands for OUC and STC and includes projected sales to Winter Park, Mt. Dora, Chattahoochee, and Lakeland; "Sales" is therefore not populated separately and peak demand may not match peak demands shown in OUC's 2026 TYSP due to coincidence/non-coincidence of peaks.

"Purchases" includes OUC's purchases associated with Stanton Energy Center Unit A.

OUC does not have any existing utility scale energy storage that is relied upon to meet customer load requirements so no data is provided for "Energy Storage."

"Coal" includes Stanton Energy Center Unit 2; Stanton Energy Center Unit 1 is not included as OUC currently anticipates placing the unit in extended cold shutdown by the end of May 2026.

"Other" includes Landfill Gas purchases.

"Solar" includes solar purchases.

TYSP Year  
Question No.

2026 OUC considers the requested information to be confidential and as such has not provided it in response to this question.  
72

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							
	2020							
	2021							
	2022							
	2023							
	2024							
Projected	2025							
	2026							
	2027							
	2028							
	2029							
	2030							
	2031							
	2032							
	2033							
2034								
2035								
<b>Notes</b>								
(Include Notes Here)								

TYSP Year 2026  
 Question No. 73

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	464	See Note (1)	3,464	See Note (1)	3,903	See Note (1)	0	See Note (1)	0	See Note (1)	0	See Note (1)	0	See Note (1)
	2017	467		3,955		3,326		0		0		0			
	2018	470		4,204		3,422		0		0		0			
	2019	449		3,614		3,554		0		0		0			
	2020	500		2,778		4,090		0		0		0			
	2021	464		3,152		3,583		0		0		0			
	2022	487		1,978		4,953		0		0		0			
	2023	494		1,938		5,144		0		0		0			
	2024	433		1,608		5,753		0		4		0			
	2025	469		2,105		5,059		0		1		0			
Projected	2026	503	See Note (1)	1,398	See Note (1)	5,443	See Note (1)	0	See Note (1)	0	See Note (1)	0	See Note (1)	729	See Note (1)
	2027	496		1,281		5,341		0		0		1,084			
	2028	504		0		6,789		0		0		1,086			
	2029	502		0		6,601		0		0		1,447			
	2030	503		0		6,398		0		0		1,811			
	2031	503		0		6,093		0		0		2,174			
	2032	505		0		5,911		0		0		2,543			
	2033	503		0		5,203		0		0		3,447			
	2034	503		0		4,487		0		0		4,356			
	2035	503		0		4,696		0		0		4,356			

**Notes**

1. Fuel prices are not included in the table as OUC considers fuel prices to be proprietary and confidential.  
 "Other" includes LFG and solar.

2026 TYSP Data Request #1.Excel Tables\_OUC

TYSP Year 2026 This question is not applicable, as OUC does not currently have any firm plans related to the addition of new generating units that would be affected by this Question No. 81e standard.

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				
<b>Notes</b>				
(Include Notes Here)				

TYSP Year 2026  
Question No. 83

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)		ELGS	Estimated EPA Rule Impacts: Operational Effects					
					Mo	Yr	Net			ACE or replacement	MATS	CSAPR/CAIR	CWIS	CCR	
							Sum	Win						Non-Hazardous Waste	Special Waste
Stanton Energy Center	1	Orange	ST	BIT	07	87	453 <sup>(1)</sup>	453 <sup>(1)</sup>	N/A	On April 25, 2024, EPA released a pre-publication of final rules regulating greenhouse gas emissions (GHGs) from electric generating units (EGUs) pursuant to Section 111 of the Clean Air Act. As part of this rule, EPA finalized emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs pursuant to Clean Air Act Section 111(d), which include both coal-fired and oil/gas-fired steam generating EGUs. This rule impacts any OUC coal-fired EGUs that are not retired prior to January 1, 2032 by requiring these EGUs to meet GHG emissions limits based on the best system of emission reduction (BSER). The applicable BSER emission limits for existing EGUs are based on unit retirement date. The installation of infrastructure required to meet BSER emission limits may require the unit to be offline for a period of time. On June 11, 2025, EPA issued a proposed rule that would result in the repeal of all GHG emission standards, including the April 2024 standards, for fossil fuel-fired power plants. This proposed rule also included an alternative that would result in the repeal of a narrower set of requirements in lieu of a repeal of all GHG standards. It is unknown what effect, if any, changes to these standards may have related to operations. On February 18, 2026, the EPA finalized a rule overturning the 2009 Endangerment Finding, removing the legal basis for federal GHG regulation of fossil fuel-fired power plants.	N/A	N/A	N/A	Landfill Cell 2 (30 Acres) construction started on July 15, 2019 with substantial completion on December 31, 2020. CCR Rule requires the base of the liner to be located on average 5 feet above the upper limit of the uppermost aquifer and increased the thickness of clay composite liner from 6 to 12 inches. CCR required the closure of Landfill Cell 1 to have a minimum of 40 mil HDPE liner on the top & slope of the landfill.	N/A
Stanton Energy Center	2	Orange	ST	BIT	06	96	352 <sup>(2)</sup>	352 <sup>(2)</sup>	N/A	On April 25, 2024, EPA released a pre-publication of final rules regulating greenhouse gas emissions (GHGs) from electric generating units (EGUs) pursuant to Section 111 of the Clean Air Act. As part of this rule, EPA finalized emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs pursuant to Clean Air Act Section 111(d), which include both coal-fired and oil/gas-fired steam generating EGUs. This rule impacts any OUC coal-fired EGUs that are not retired prior to January 1, 2032 by requiring these EGUs to meet GHG emissions limits based on the best system of emission reduction (BSER). The applicable BSER emission limits for existing EGUs are based on unit retirement date. The installation of infrastructure required to meet BSER emission limits may require the unit to be offline for a period of time. On June 11, 2025, EPA issued a proposed rule that would result in the repeal of all GHG emission standards, including the April 2024 standards, for fossil fuel-fired power plants. This proposed rule also included an alternative that would result in the repeal of a narrower set of requirements in lieu of a repeal of all GHG standards. It is unknown what effect, if any, changes to these standards may have related to operations. On February 18, 2026, the EPA finalized a rule overturning the 2009 Endangerment Finding, removing the legal basis for federal GHG regulation of fossil fuel-fired power plants.	N/A	N/A	N/A	Landfill Cell 2 (30 Acres) construction started on July 15, 2019 with substantial completion on December 31, 2020. CCR Rule requires the base of the liner to be located on average 5 feet above the upper limit of the uppermost aquifer and increased the thickness of clay composite liner from 6 to 12 inches. CCR required the closure of Landfill Cell 1 to have a minimum of 40 mil HDPE liner on the top & slope of the landfill.	N/A

Notes  
 (1). Represents OUC's 100% ownership share as of January 1, 2026.  
 (2). Represents OUC's 71.7% ownership share as well as City of St. Cloud's 3.4% entitlement.

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)		ELGS	Estimated EPA Rule Impacts: Cost Effects					
					Mo	Yr	Net			ACE or replacement	MATS	CSAPR/ CAIR	CWIS	CCR	
							Sum	Win						Non-Hazardous Waste	Special Waste
Stanton Energy Center	1	Orange	ST	BIT	07	87	453 <sup>(1)</sup>	453 <sup>(1)</sup>	N/A	On April 25, 2024, EPA released a pre-publication of final rules regulating greenhouse gas emissions (GHGs) from electric generating units (EGUs) pursuant to Section 111 of the Clean Air Act. As part of this rule, EPA finalized emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs pursuant to Clean Air Act Section 111(d), which include both coal-fired and oil/gas-fired steam generating EGUs. This rule impacts any OUC coal-fired EGUs that are not retired prior to January 1, 2032 by requiring these EGUs to meet GHG emissions limits based on the best system of emission reduction (BSER). The applicable BSER emission limits for existing EGUs are based on unit retirement date. The installation of infrastructure required to meet BSER emission limits may require the unit to be offline for a period of time. On June 11, 2025, EPA issued a proposed rule that would result in the repeal of all GHG emission standards, including the April 2024 standards, for fossil fuel-fired power plants. This proposed rule also included an alternative that would result in the repeal of a narrower set of requirements in lieu of a repeal of all GHG standards. It is unknown what effect, if any, changes to these standards may have related to costs. On February 18, 2026, the EPA finalized a rule overturning the 2009 Endangerment Finding, removing the legal basis for federal GHG regulation of fossil fuel-fired power plants.	On April 25, 2024 the EPA released a pre-publication of the final rule amending the existing "National Emission Standards for Hazardous Air Pollutants for: the Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs), commonly referred to as the Mercury and Air Toxics Standards (MATS). As a result of these rule changes, the current filterable particulate matter (PM) limit of 0.03 lb/MMBtu applicable to the Stanton Energy Center's coal units will be reduced from 0.03 lb/MMBtu to 0.01 lb/MMBtu. The rule changes would also require the installation of PM CEMS on any operational coal unit within three years of the publication of the final rule.	N/A – Note that OUC has \$11 million in stranded costs associated with SCR, which has been postponed following vacature of CSAPR.	N/A	\$6.5M +\$2.1M. Landfill Cell 2 incurred \$10M additional cost of fill dirt due to CCR Rule requiring the base of the liner to be located on average 5 feet above the upper limit of the uppermost aquifer and \$3.5M for the additional 6 inches of clay. Landfill Cell 1 Closure incurred an additional cost of \$6M due to design, material & construction cost. In 2023, the total closure and 30-year long-term care costs associated with landfill Cell 1 and 2 were estimated at ~\$64M. On April 25, 2024 EPA released a pre-publication of the final rule amending the existing Coal Combustion Residuals rule. As a result of changes made to the rule, the closed SEC landfill is considered a CCR management unit (CCRMU) and subject to the applicable groundwater monitoring, corrective action, closure, and post-closure care requirements. Costs to comply with the 2024 CCR rule may be significant. On April 13, 2026, the EPA published a proposed rule amending the 2024 CCR regulations that includes the removal of all CCRMU requirements entirely which, if finalized, would no longer require OUC to incur compliance costs associated with the 2024 CCR regulations.	N/A
Stanton Energy Center	2	Orange	ST	BIT	06	96	352 <sup>(2)</sup>	352 <sup>(2)</sup>	N/A	On April 25, 2024, EPA released a pre-publication of final rules regulating greenhouse gas emissions (GHGs) from electric generating units (EGUs) pursuant to Section 111 of the Clean Air Act. As part of this rule, EPA finalized emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs pursuant to Clean Air Act Section 111(d), which include both coal-fired and oil/gas-fired steam generating EGUs. This rule impacts any OUC coal-fired EGUs that are not retired prior to January 1, 2032 by requiring these EGUs to meet GHG emissions limits based on the best system of emission reduction (BSER). The applicable BSER emission limits for existing EGUs are based on unit retirement date. The installation of infrastructure required to meet BSER emission limits may require the unit to be offline for a period of time. On June 11, 2025, EPA issued a proposed rule that would result in the repeal of all GHG emission standards, including the April 2024 standards, for fossil fuel-fired power plants. This proposed rule also included an alternative that would result in the repeal of a narrower set of requirements in lieu of a repeal of all GHG standards. It is unknown what effect, if any, changes to these standards may have related to costs. On February 18, 2026, the EPA finalized a rule overturning the 2009 Endangerment Finding, removing the legal basis for federal GHG regulation of fossil fuel-fired power plants.	On April 25, 2024 the EPA released a pre-publication of the final rule amending the existing "National Emission Standards for Hazardous Air Pollutants for: the Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs), commonly referred to as the Mercury and Air Toxics Standards (MATS). As a result of these rule changes, the current filterable particulate matter (PM) limit of 0.03 lb/MMBtu applicable to the Stanton Energy Center's coal units will be reduced from 0.03 lb/MMBtu to 0.01 lb/MMBtu. The rule changes would also require the installation of PM CEMS on any operational coal unit within three years of the publication of the final rule.	N/A	N/A	\$6.5M +\$2.1M. Landfill Cell 2 incurred \$10M additional cost of fill dirt due to CCR Rule requiring the base of the liner to be located on average 5 feet above the upper limit of the uppermost aquifer and \$3.5M for the additional 6 inches of clay. Landfill Cell 1 Closure incurred an additional cost of \$6M due to design, material & construction cost. In 2023, the total closure and 30-year long-term care costs associated with landfill Cell 1 and 2 were estimated at ~\$64M. On April 25, 2024 EPA released a pre-publication of the final rule amending the existing Coal Combustion Residuals rule. As a result of changes made to the rule, the closed SEC landfill is considered a CCR management unit (CCRMU) and subject to the applicable groundwater monitoring, corrective action, closure, and post-closure care requirements. Costs to comply with the 2024 CCR rule may be significant. On April 13, 2026, the EPA published a proposed rule amending the 2024 CCR regulations that includes the removal of all CCRMU requirements entirely which, if finalized, would no longer require OUC to incur compliance costs associated with the 2024 CCR regulations.	N/A
<b>Notes</b> (1). Represents OUC's 100% ownership share as of January 1, 2026. (2). Represents OUC's 71.7% ownership share as well as City of St. Cloud's 3.4% entitlement.															

TYSP Year 2026  
Question No. 85

Facility Name	Unit No.	County Location	Unit Type	Primary Fuel	Commercial In-Service		Unit Capacity (MW)		ELGS	Estimated EPA Rule Impacts: Unit Availability					
					Mo	Yr	Net			ACE or replacement	MATS	CSAPR/CAIR	CWIS	CCR	
							Sum	Win						Non-Hazardous Waste	Special Waste
Stanton Energy Center	1	Orange	ST	BIT	07	87	453 <sup>(1)</sup>	453 <sup>(1)</sup>	No Outage Req'd	On April 25, 2024, EPA released a pre-publication of final rules regulating greenhouse gas emissions (GHGs) from electric generating units (EGUs) pursuant to Section 111 of the Clean Air Act. As part of this rule, EPA finalized emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs pursuant to Clean Air Act Section 111(d), which include both coal-fired and oil/gas-fired steam generating EGUs. This rule impacts any OUC coal-fired EGUs that are not retired prior to January 1, 2032 by requiring these EGUs to meet GHG emissions limits based on the best system of emission reduction (BSER). The applicable BSER emission limits for existing EGUs are based on unit retirement date. The installation of infrastructure required to meet BSER emission limits may require the unit to be offline for a period of time. On June 11, 2025, EPA issued a proposed rule that would result in the repeal of all GHG emission standards, including the April 2024 standards, for fossil fuel-fired power plants. This proposed rule also included an alternative that would result in the repeal of a narrower set of requirements in lieu of a repeal of all GHG standards. It is unknown what effect, if any, changes to these standards may have related to OUC EGU availability. On February 18, 2026, the EPA finalized a rule overturning the 2009 Endangerment Finding, removing the legal basis for federal GHG regulation of fossil fuel-fired power plants.	No Outage Req'd	No Outage Req'd	No Outage Req'd	No Outage Req'd	No Outage Req'd
Stanton Energy Center	2	Orange	ST	BIT	06	96	352 <sup>(2)</sup>	352 <sup>(2)</sup>	No Outage Req'd	On April 25, 2024, EPA released a pre-publication of final rules regulating greenhouse gas emissions (GHGs) from electric generating units (EGUs) pursuant to Section 111 of the Clean Air Act. As part of this rule, EPA finalized emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs pursuant to Clean Air Act Section 111(d), which include both coal-fired and oil/gas-fired steam generating EGUs. This rule impacts any OUC coal-fired EGUs that are not retired prior to January 1, 2032 by requiring these EGUs to meet GHG emissions limits based on the best system of emission reduction (BSER). The applicable BSER emission limits for existing EGUs are based on unit retirement date. The installation of infrastructure required to meet BSER emission limits may require the unit to be offline for a period of time. On June 11, 2025, EPA issued a proposed rule that would result in the repeal of all GHG emission standards, including the April 2024 standards, for fossil fuel-fired power plants. This proposed rule also included an alternative that would result in the repeal of a narrower set of requirements in lieu of a repeal of all GHG standards. It is unknown what effect, if any, changes to these standards may have related to OUC EGU availability. On February 18, 2026, the EPA finalized a rule overturning the 2009 Endangerment Finding, removing the legal basis for federal GHG regulation of fossil fuel-fired power plants.	No Outage Req'd	No Outage Req'd	No Outage Req'd	No Outage Req'd	No Outage Req'd
<b>Notes</b>															
(1). Represents OUC's 100% ownership share as of January 1, 2026.															
(2). Represents OUC's 71.7% ownership share as well as City of St. Cloud's 3.4% entitlement.															