City of Tallahassee
Your Own Utilities℠

Electric & Gas Utility | 2602 Jackson Bluff Road | Tallahassee | FL | 32304 | 850-891-4968

May 13, 2019

Clerk's Office
State of Florida Public Service Commission

Dear Sir/Madam:

The following pages are the City of Tallahassee Utilities' responses to the "Ten-Year Site Plans for Florida's Electric Utilities Supplemental Data Request #1" pursuant to the request received from Florida Public Service Commission Staff member Mr. Doug Wright. Please note that copies of all tables have been separately provided in Microsoft Excel spreadsheet format to Mr. Wright via e-mail per his request. If you should have any questions regarding this report, please feel free to contact me at (850) 891-3130 or paul.clark@talgov.com. Thank you.

Sincerely,

Paul Clark

Paul D. Clark, II
Principal Engineer

Attachments

General Items

1. Please provide an electronic copy of the Company's 2019–2028 Ten-Year Site Plan (2019 TYSP) in PDF format and the accompanying Schedules 1−10 in Microsoft Excel format.

   Hardcopy and electronic copies of the City of Tallahassee ("TAL"), Electric & Gas Utility's report entitled "Ten-Year Site Plan: 2019-2028" ("2019 TYSP") and Schedules 1 through 10 were filed electronically with the Office of the Commission Clerk and hardcopies were submitted to FPSC staff (Thomas Ballinger) on Friday, March 29, 2019.

2. Please provide all data requested in the attached forms labeled "Appendix A." If any of the requested data is already included in the Company's 2019 TYSP, state so on the appropriate form.

   The data requested in the Excel file entitled "Data Request #1 - Appendix A.xls" are provided electronically herewith. If requested data is already included in TAL's 2019 TYSP, it is so stated on the appropriate form.

Load & Demand Forecasting

3. **[Investor-Owned Utilities Only]** Please provide, on a system-wide basis, the hourly system load for the period January 1, 2018, through December 31, 2018, in Microsoft Excel format.

   Not applicable (NA). TAL is a municipal utility.

4. Please provide the monthly peak demand experienced in the period 2016–2018, 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.

Historic Peak Demand Timing & Temperature

Year	Month	Actual Peak Demand (MW)	Demand Response Activated (MW)	Estimated Peak Demand (MW)	Day	Hour	System-Average Temperature (Degrees F)
2018	1	621	0	621	1/18/2018	800	36
	2	433	0	433	2/1/2018	900	61
	3	416	0	416	3/15/2018	900	49
	4	390	0	390	4/23/2018	1800	72
	5	494	0	494	5/31/2018	1700	82
	6	596	0	596	6/20/2018	1600	88
	7	560	0	560	7/13/2018	1600	84
	8	558	0	558	8/28/2018	1600	84
	9	581	0	581	9/14/2018	1600	85
	10	507	0	507	10/3/2018	1800	82
	11	457	0	457	11/28/2018	800	42
	12	505	0	505	12/12/2018	800	43
2017	1	533	0	533	1/9/2017	800	40
	2	378	0	378	2/17/2017	800	53
	3	444	0	444	3/16/2017	800	44
	4	477	0	477	4/28/2017	1800	78
	5	510	0	510	5/16/2017	1700	80
	6	550	0	550	6/23/2017	1500	83
	7	584	0	584	7/28/2017	1600	85
	8	598	0	598	8/18/2017	1600	88
	9	522	0	522	9/29/2017	1700	81
	10	528	0	528	10/10/2017	1500	83
	11	404	0	404	11/6/2017	1600	69
	12	501	0	501	12/11/2017	800	45
2016	1	511	0	511	1/20/2016	800	44
	2	505	0	505	2/11/2016	800	51
	3	402	0	402	3/16/2016	1800	80
	4	471	0	471	4/29/2016	1700	80
	5	496	0	496	5/31/2016	1500	82
	6	560	0	560	6/13/2016	1700	87
	7	563	0	563	7/29/2016	1700	87
	8	597	0	597	8/23/2016	1800	89
	9	526	0	526	9/20/2016	1700	85
	10	469	0	469	10/8/2016	1800	84
	11	423	0	423	11/4/2016	1700	75
	12	390	0	390	12/10/2016	900	45
Notes							
(Include Notes Here)							

5. Please identify the weather station(s) used for calculation of the system-wide temperature for the Company's service territory. If more than one weather station is utilized, please describe how a system-wide average is calculated.

   System-wide temperature for TAL's service territory is obtained from the National Weather Service's Tallahassee Regional Airport (KTLH) weather station.

6. Please explain how the Company's load and demand forecasting used in its 2019 TYSP was developed. In your response please include the following information: methodology, assumptions, data sources, third-party consultant(s) involved, and any difference/improvement made compared with the load and demand forecasting used in the Company's 2018 Ten-Year Site Plan.

   The 2019 Load Forecast relies upon an econometric forecast of monthly customer counts and sales by major customer classification, with the forecast for certain large loads reflecting a weather-normalized base adjusted in future years for only expected changes due to new facilities or other factors. The total of these forecasts is adjusted for estimated losses to derive a forecast of system NEL. Similarly, monthly peak demand is derived from forecasted NEL and estimated load factors, based on an econometric analysis of historical load factors and long-term averages of peak day weather conditions. Annual NEL and seasonal peak demands are calculated from the resulting monthly values.

   Historical and projected economic and demographic data is obtained from Woods and Poole Economics (W&P); historical and projected population data is obtained from the University of Florida's Bureau of Economic Research (BEBR); historical taxable sales data is obtained from the Florida Department of Revenue; and housing market indicators are obtained from the Bureau of the Census and other sources. A consensus forecast of economic and demographic data is developed based on weighted average growth rates from the W&P and BEBR datasets, weighted heavily toward the BEBR growth rates, which were somewhat lower. Taxable sales data are forecasted based on its estimated relationship with retail sales data reported and forecasted by W&P. Weather data is obtained from the National Climatic Data Center; future weather conditions are assumed to be equal to recent average weather conditions. Finally, the price of electricity is derived from the City's billing records and forecasted based on projections published by the Energy Information Administration (EIA) in the 2018 Annual Energy Outlook (AEO).

7. Please identify all closed and opened FPSC dockets and all non-docketed FPSC matters which were/are based on the same load forecast used in the Company's 2019 TYSP.

   There are no open or closed FPSC dockets or non-docketed FPSC matters which were/are based on the same load forecast used in TAL's 2019 TYSP.

8. **[Investor-Owned Utilities Only]** Does your Company review the accuracy of its customer, load, and demand forecasts presented in its TYSP by comparing the actual data for a given year to the data forecasted one, two, three, four, five, or six years prior?
   a. If the response is affirmative, please explain the method used in such review.
   b. If the response is affirmative, please provide the results of such review for each forecast presented in the TYSPs filed, or to be filed, to the Commission from 2001 to 2019 with supporting workpapers in Microsoft Excel format.
   c. If the response is negative, please explain why not.

   NA. TAL is a municipal utility.

9. Please explain any recent and forecasted trends in customer growth, by customer type (residential, commercial, industrial) and as a whole.

TAL's customer count growth has picked up somewhat relative to the period immediately following the Great Recession. Residential and commercial customer compound average growth rates (CAGR) were 0.5% and -0.1%, respectively, over 2008-2013; growth rates over 2013-2018 have increased to 1.0% and 0.7%, respectively. These growth rates can be compared to pre-Great Recession CAGRs for residential and commercial customer counts of 2.4% and 2.3%, respectively, over 1998-2007. TAL does not serve any industrial customers.

These variations in customer count growth correlate well to variations in rates of change in Leon County population, household formation, and economic activity. For example, total employment and average income per household both suffered declines over 2008-2013 (0.4% and 1.1% per year, respectively) but have rebounded strongly since 2013, having increased by 2.0% and 1.6% per year, respectively. Leon County population growth has been fairly steady since 2008 at approximately 0.8% per year, though household counts grew more slowly during 2008-2013 (1.1% per year) than the most recent period (1.4% per year).

The 2019 forecast incorporates economic and demographic projections for Leon County based on a blend of W&P and BEBR, reflecting projected CAGRs for population, household counts, employment, and average income of 0.9%, 0.8%, 1.3%, and 1.2%, respectively, over 2019-2029. This population projection represents a slightly lower growth rate than used in the 2018 Ten Year Site Plan, which was based on a similar blend of W&P and BEBR's 2017 population forecast and reflected a CAGR of 1.1% for the same ten-year period.

As a result of the expected continuation of favorable economic conditions, growth rates for residential and commercial counts are expected to continue growing at rates that are similar to the most recent historical period, with both projected to grow at 1.0% per year.

10. Please explain any recent and forecasted trends in electricity use per customer, by customer type (residential, commercial, industrial) and as a whole.

Electricity use per customer for both residential and commercial customers has declined since the outset of the Great Recession. However, over the last few years, this rate of decline has slowed for commercial classes, and average residential usage has stabilized, on a weather-normalized basis. The primary drivers of this decline include the following:

- *Increases in end use efficiency standards, particularly for HVAC systems, that have been filtering into the stock of equipment through replacements and new builds*
- *Modifications to the State of Florida Energy Efficiency Code for Building Construction*
- *TAL's energy efficiency and demand-side management (DSM) programs (discussed in Section 2.1.3)*
- *Significant increases in the price of electricity on TAL's system (similar to increases across most Florida utilities) over 2006-2009, which resulted primarily from the run-up in the cost of natural gas*
- *Economic conditions since the outset of the Great Recession*

Changes to end use efficiency standards and building code changes over the last two decades continue to gradually diffuse into the stock of end uses and buildings. The impact of the HVAC efficiency standard change effective in 2006 is estimated to have been particularly impactful in reducing consumption over 2006 to the present and to be essentially fully diffused by approximately 2021.

The last two factors above have improved considerably over the last few years. Natural gas prices have returned to the generally low prices that were typical of the 1990s, resulting in much lower cost of electricity to TAL's customers. Economic conditions in the U.S. and across the Florida peninsula have improved, which should also be supportive of electric consumption going forward, though the efficiency improvements discussed above and TAL's DSM program are projected to be dominant factors.

TAL's load forecast reflects continued decreases in use per customer for both residential and commercial classes which offsets, to some degree, robust growth in residential and commercial customer counts.

11. Please explain any recent and forecasted trends in peak demand by the sources of peak demand appearing in Schedule 3.1 of the 2019 TYSP.

Peak demands on TAL's system have been relatively flat since the Great Recession, being impacted by many of the same factors discussed in TAL's responses to questions #9 and #10. Summer peak demand, in particular, declined significantly through 2013 but has since recovered to pre-recession levels. TAL intends to utilize DSM resources to offset a significant portion of the anticipated growth in peak demand over the forecast horizon, keeping summer peak demand relatively flat through 2024.

12. **[Investor-Owned Utilities Only]** If not included in the Company's 2019 TYSP to be filed by April 1, 2019, 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.

NA. TAL is a municipal utility.

13. Please discuss whether the Company included plug-in electric vehicle (PEV) loads in its demand and energy forecasts for the 2019 TYSP. If so, how were these impacts accounted for in the modeling and forecasting process?

The demand and energy forecasts in TAL's 2019 TYSP do not include any load data specific to plug-in electric vehicles (PHEV). However, projections of the number of electric vehicles, the number of public electric vehicle (EV) charging stations, and the estimated demand and energy impacts of the EVs by year and the methodology used to develop those projections are provided in response to Questions 14 and 15. From those responses it can be seen that TAL does not expect a substantive impact on demand and energy requirements related to EVs or charging stations in the 2019-2028 reporting period.

14. Please discuss the methodology and the assumptions (or, if applicable, the source(s) of the data) used to estimate the number of PEVs operating in the Company's service territory and the methodology used to estimate the cumulative impact on system demand and energy consumption.

    TAL has only estimated the current number of PEVs in its Electric Utility service area. This estimate is based on vehicle registrations within Leon County as provided by the State of Florida Department of Highway Safety and Motor Vehicles.

    Due to the low penetration of PEVs within the service area, TAL has not performed any formal studies to estimate the cumulative impact on system demand and energy consumption from the impacts of PEV charging on peak demand. Also, due to the low penetration of PEVs with in the service area, TAL has not performed any formal analysis of the impact of PEV charging stations on Electric Utility load requirements. To the extent that PEV loads are part of the historical load, TAL's forecast methodology would include a future load impact from PEVs. TAL does not, however, specifically model PEV loads in its forecast process.

15. Please include the following information within the Utility's service territory: an estimate of the number of PEVs, an estimate of the number of public PEV charging stations, an estimate of the number of public "quick-charge" PEV charging stations (i.e., charging stations requiring a service drop greater than 240 volts and/or using three-phase power), and the estimated demand and energy impacts of the PEVs by year. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

Electric Vehicle Charging Impacts

Year	Number of PEVs	Number of Public PEV Charging Stations	Number of Public "Quick-charge" PEV Charging Stations	Cumulative Impact of PEVs		
				Summer Demand (MW)	Winter Demand (MW)	Annual Energy (GWh)
2018	1,379	1,412	2		N/A	
2019	1,392	1,412	2			
2020	1,406	1,413	2			
2021	1,420	1,421	4			
2022	1,435	1,435	4			
2023	1,449	1,449	4			
2024	1,463	1,463	6			
2025	1,478	1,478	6			
2026	1,493	1,495	6			
2027	1,508	1,510	8			
2028	1,524	1,526	8			
Notes						
Due to the low expected penetration of EVs within the service area, TAL has not performed any formal analysis of the impact on system load and energy requirements.						

16. Please describe any Company 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 2019–2028 period.

    For the planning period 2019 -2028, TAL has not performed any formal studies of how load management or rate design tools may mitigate the demand impacts of PEV charging on peak demand. Due to the low estimated number of existing PEVs TAL believes that any impact on peak demand will be minimal, at least in the near term. However, TAL does currently offer a "Nights and Weekends" time-of-use rate that would incentivize customers with PEVs receiving service under the associated tariff to defer charging to off-peak periods.

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

    No, f*or the planning period 2019 -2028, TAL does not foresee the development of such programs.*

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

    No, f*or the planning period 2019 -2028, TAL does not offer such programs.*

17. Please describe how the Company monitors the installation of PEV public charging stations in its service area?

    Due to the low penetration of PEV's, TAL monitors public EV charging stations within the service territory via the electrical permitting process by the local jurisdiction Building Department.

18. Please describe any instances since January 1, 2018, in which upgrades to the distribution system were made where PEVs were a contributing factor.

    On 10/30/2018 a 750KVA, 480Y/277V transformer was installed at 1400 Village Square Blvd for an Electrify America electric vehicle charging station. There have been no other instances since January 1, 2018, in which upgrades to the distribution system were made where PEVs were a contributing factor.

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

    No, for the planning period 2019-2028, TAL has not conducted or contracted for any research as described above, nor does TAL foresee the development of such programs.

20. What processes or technologies, if any, are in place that allow the Utility to be notified when a customer has established an electrical vehicle charging station in the home?

    TAL would only be notified of in-home PEV charging if an electrical permit is issued for the installation.

21. **[FEECA Utilities Only]** For each source of demand response, use the table below to provide the customer participation information listed on an annual basis. Please also provide a summary of all sources of demand response using the chart below. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

[Demand Response Source or All Demand Response Sources]										
Year	**Beginning Year: Number of Customers**	**Available Capacity (MW)**		**New Customers Added**	**Added Capacity (MW)**		**Customers Lost**	**Lost Capacity (MW)**		
		Sum	Win		Sum	Win		Sum	Win	
2009	NA. TAL is not a FEECA utility.									
2010										
2011										
2012										
2013										
2014										
2015										
2016										
2017										
2018										
Notes										
(Include Notes Here)										

22. **[FEECA Utilities Only]** For each source of demand response, use the table below to provide the usage information listed on an annual basis. Please also provide a summary of all demand response using the chart below. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

[Demand Response Source or All Demand Response Sources]										
Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	NA. TAL is not a FEECA utility.									
2010										
2011										
2012										
2013										
2014										
2015										
2016										
2017										
2018										
Notes										
(Include Notes Here)										

23. **[FEECA Utilities Only]** For each source of demand response, use the table below to provide the seasonal peak activation information listed on an annual basis. Please also provide a summary of all demand response using the chart below. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

[Demand Response Source or All Demand Response Sources]							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak?	Number of Customers Activated	Capacity Activated	Activated During Peak?	Number of Customers Activated	Capacity Activated
		(Y/N)		(MW)	(Y/N)		(MW)
2009	NA. TAL is not a FEECA utility.						
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
Notes							
(Include Notes Here)							

Generation & Transmission

24. Please identify and describe each existing utility-owned renewable resource as of December 31, 2018, that delivered energy during the year. Please include the facility's name, unit type, fuel type, its installed capacity (AC-rating for photovoltaic (PV) systems), its net firm capacity or contribution during peak demand (if any), capacity factor for 2018 based off of the installed capacity, and its in-service date. For multiple small distributed renewable resources (<250 kW per installation), such as rooftop solar panels, please include a single combined entry for the resources that share the same unit & fuel type. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

Existing Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Net Firm Capacity (MW)		Capacity Factor	In-Service Date
			Sum	Win	Sum	Win	(%)	(MM/YYYY)
TAL	PV	SUN	0.232	0.232	0.000	0.000	15.0	01/1993
Notes								
(Include Notes Here)								

25. Please identify and describe each planned utility-owned renewable resource for the period 2019–2028. Please include each proposed facility's name, unit type, fuel type, its installed capacity (AC-rating for PV systems), its net firm capacity or anticipated contribution during peak demand (if any), anticipated typical capacity factor, and projected in-service date. For multiple small distributed renewable resources (<250 kW per installation), such as rooftop solar panels, please include a single combined entry for the resources that share the same unit & fuel type. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

Planned Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Net Firm Capacity (MW)		Capacity Factor	In-Service Date
			Sum	Win	Sum	Win	(%)	(MM/YYYY)
Unsited	PV	SUN	0.1	0.1	0.0	0.0	15	12/2020
Notes								
(Include Notes Here)								

26. Please refer to the list of planned utility-owned renewable resources for the period 2019–2028 above. Discuss the current status of each project.

The planned utility-owned renewable resources for the period 2019 through 2028 are multiple small distributed renewable resources (< 250 kW per installation), such as rooftop solar panels. The planned systems will be installed as financial constraints allow.

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

TAL did not have any planned utility-owned renewable resources within the past year that were cancelled, delayed, or reduced in scope.

28. Please identify and describe each purchased power agreement with a renewable generator that delivered energy during 2018. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

Existing Renewable Purchased Power Agreements

Seller Name	Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Contracted Firm Capacity (MW)		In-Service Date	Contract Term (MM/YY)	
				Sum	Win	Sum	Win	(MM/YY)	Start	End
FL Solar 1, LLC	SF1	PV	SUN	20	20	0	0	12/17	12/17	12/37
Notes										
(Include Notes Here)										

29. Please identify and describe each purchased power agreement with a renewable generator that is anticipated to begin delivering renewable energy to the Company during the period 2019–2028. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

Renewable Purchased Power Agreements

Seller Name	**Facility Name**	**Unit Type**	**Fuel Type**	**Installed Capacity (MW)**		**Contracted Firm Capacity (MW)**		**In-Service Date**	**Contract Term (MM/YY)**	
				Sum	Win	Sum	Win	(MM/YY)	Start	End
FL Solar 4, LLC	SF2	PV	SUN	40	40	0	0	12/19	12/19	12/39
Notes										
(Include Notes Here)										

30. Please refer to the list of renewable purchased power agreements that are anticipated to begin delivering capacity and/or energy to the Company during the period 2019–2028. Discuss the current status of each project.

In June 2018, the TAL executed a Purchase Power Agreement (PPA) with Origis Energy USA, for 40 MW_{ac} utility scale solar project. The permitting is expected to be completed by the end of the second quarter of 2019 and commercial operations by the end of the fourth quarter of 2019.

31. Please list and discuss any renewable purchased power agreements within the past year that were cancelled, expired, delayed, or modified. What was the primary reason for the changes? What, if any, were the secondary reasons?

In 2018, there were no renewable purchased power agreements within the past year that were cancelled, expired, delayed, or modified.

32. Please provide the actual and projected annual output for all renewable resources on the Company's system, including utility-owned resources (firm, non-firm, and co-firing), purchases (firm, non-firm, and co-firing), and customer-owned generation, for the period 2019–2028.

Renewable Generation by Source

Renewable Source	Annual Renewable Generation (GWh)										
	Actual	Projected									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Utility - Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utility - Non-Firm[1]	22.5	7.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Utility - Co-Firing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Purchase - Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Purchase - Non-Firm	37.5	40.7	122.8	121.8	121.2	120.6	120.3	119.4	118.8	118.2	118.0
Purchase - Co-Firing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer - Owned	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	60.3	48.7	124.1	123.1	122.5	121.9	121.6	120.7	120.1	119.5	119.3
Notes											
[1]City-owned solar PV and former Corn Hydro generation. Corn Hydro Plant decommissioned February 2019.											

33. Please complete the table below, providing a list of all of the Company's plant sites that are potential candidates for utility-scale (>2 MW) solar installations. As part of this response, please provide the plant site's name, approximate land area available for solar installations, potential installed capacity rating of a PV installation, and a description of any major obstacles that could affect utility-scale solar installations at any of these sites, such as land devoted to other uses or other requirements.

Candidate Sites - Solar

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues
A. B. Hopkins	75	10	The land may be needed for other uses or other requirements.

34. Please complete the table below, providing a list of all of the Company's plant sites that are potential candidates for utility-scale wind installations. As part of this response, please provide the plant site's name, approximate land area available, potential installed capacity rating of a wind farm installation, and a description of any major obstacles that could affect utility-scale wind installations at any of these sites, such as land devoted to other uses or other requirements.

Candidate Sites - Wind

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues
NA			

35. Please describe any actions the Company engages in to encourage production of renewable energy within its service territory.

TAL continues to promote solar PV through its Net Metering Program, which offers the customer kWh credits at the full retail rate for energy returned to the grid.

36. **[Investor-Owned Utilities Only]** Please discuss whether the Company has been approached by renewable energy generators during 2018 regarding constructing new renewable energy resources. If so, please provide the number and a description of the type of renewable generation represented.

NA. TAL is a municipal utility.

37. Does the Company consider solar PV to contribute to one or both seasonal peaks for reliability purposes? If so, please provide the percentage contribution and explain how the Company developed the value.

Due to the intermittent nature of Solar PV, TAL does not count the capacity for reliability purpose. A review of data from the 20 MWac project delivering energy to the Electric & Gas Utility shows that solar PV production does not match the seasonal morning peaks and provides little to no support of afternoon/evening peaks.

Due to the inability of solar PV to match the Electric & Gas Utility's peaks, no value has been assigned to the solar PV capacity.

38. Please identify whether a declining trend in costs of energy storage technologies has been observed by the Company.

TAL has observed a declining trend in costs of energy storage (ES) technologies, specifically in the Lithium Ion technologies. The primary driver of the downward cost pressure is the EV manufacturers demand for longer range batteries. TAL continues to monitor the cost trends through several different means, including but not limited to the Energy Storage Association.

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

Lead Acid has demand among the uninterruptible power supply (UPS) and the utility task vehicle (UTV) manufacturers to progress that technology. Flow Batteries do not appear to have other manufacturers or users besides the electric industry to progress the technology. Though TAL can participate in related studies, TAL is not in the position to fund research and development for the ES market.

40. 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.)

TAL continues to study the deployment of ES at transmission voltage levels, as this would normally be coupled with renewable energy (RE) resources such as solar PV. TAL also continues to study the deployment of ES at the distribution levels, as this would normally be decoupled from a RE resource such as solar PV. This strategy would place ES resources closer to the load centers.

41. Please provide whether ratepayers have expressed interest in energy storage technologies. If so, how have their interests been addressed?

To date, a small number of ratepayers have expressed a general interest in ES technologies for residential use. TAL has met with some groups to determine their level of interest and found that ratepayers are not willing to invest in ES without subsidies.

42. Please complete the table below, identifying 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. As part of this response, please identify the project to which the energy storage technology is associated with, whether this project is a pilot program or not, the in-service date or pilot start date associated with the energy storage technology, and the maximum capacity output and maximum energy stored of/by the energy storage technology under normal operating conditions.

Project Name	Pilot Program (Y/N)	In-Service/ Pilot Start Date	Max Capacity Output (MW)	Max Energy Stored (MWh)
TAL does not have energy storage technologies that are currently either part of the system portfolio or are part of a pilot program .				
Notes				
(Include Notes Here)				

43. 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 next 10 years. If the Company is not currently participating in or developing energy storage pilot programs, has it considered doing so? If not, please explain.

    TAL does not have any ES pilot programs currently running or in development with an anticipated launch date within the next 10 years.

    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.

       NA

    b. Please provide a brief assessment of how these benefits, risks, and operational limitations may change over the next 10 years.

       NA

    c. Please identify and describe any plans to periodically update the Commission on the status of your energy storage pilot programs.

       TAL does not currently have plans to initiate ES pilot programs but will update the Commission if/when its plans change.

44. 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. If not, please explain.

    TAL utilizes 20 MW_{ac} of non-firm generation from Solar PV and will be adding another 40 MW_{ac} of non-firm Solar PV generation during the fourth quarter 2019 or first quarter of 2020. TAL has considered, but has not initiated any formal plans, to study the effects on the bulk electric system if ES is coupled or decoupled from the Solar PV.

45. Please identify and describe any programs you offer that allow your customers to contribute towards the funding of specific renewable projects, such as community solar programs.

    a. Please describe any such programs in development with an anticipated launch date within the next 10 years.

TAL offers a community solar program in the form of a solar subscription program from the 20 MW_{ac} Solar PV project. The program is named "Solar Choice". The program offers the customer the choice to replace up to 100% of their Energy Cost Recovery Charge with a flat 5-cents/kwh charge for 20 years. This program is designed to pay for the PPA cost of the 20 MW_{ac} Solar Project without subsidization by non-participating customers. The program is fully subscribed and there is a waiting list for subscriptions to the 40 MW project. The Solar Choice program is open to residential and commercial customers. The program highlights include:

- *Allows customers to subscribe to the solar farm output:*
  - *Residential: 25%, 50% or 100% options*
  - *Commercial – Non-Demand and Demand: 25%, 50%, 100%*
  - *Commercial – Large Demand: Limited to 10% of annual sales*
- *Fixed cost of $0.05 per kwh for 20 years*
- *Replaces the current ECRC*
- *Portability within the City's Electric system*
- *SF1 (20 MW) is fully subscribed*
- *SF2 (40 MW) there is a waiting list for subscriptions*

The number of subscriptions for the Solar Choice program as of 1/1/19 were as follows:

- *Total Customers - 2,235*
- *Residential – 2,188*
- *Commercial – 47*
- *Residential Customers by %*
  - *25% - 221*
  - *50% - 655*
  - *100% - 1359*

46. Please identify and discuss the Company's role in the research and development of utility power technologies. As part of this response, please describe any plans to implement the results of research and development into the Company's system portfolio and discuss how any anticipated benefits will affect your customers.

TAL does not fund research but does participate in matching grant opportunities by partnering with other municipal utilities and colleges and universities. One such grant opportunity is an initiative to increase the deployment of solar and storage within the state by municipals. The project, Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) was formed to carry out a 3-year project to study and assist in developing pathways for successful expansion of grid-integrated solar, energy storage, and other distributed energy resources in Florida in a way that maximizes value and reduces risk. The team includes Tallahassee Technology and R&D firm, Nhu Energy, Inc, working closely with the Florida Municipal Electric Association and the Florida Office of Energy, to oversee and guide the project, supported in research and analysis by the National Renewable Energy Laboratory, Lawrence Berkeley National Laboratory, and the Southern Alliance for Clean Energy, and Florida's municipal utilities. The project scope includes performing Florida-specific studies and analysis and providing support to utilities, with the aim of enabling and increasing the overall value derived from growth in the deployment of solar, energy storage, and other distributed energy resources (DER) integrated into the Florida electric power system.

47. **[Investor-Owned Utilities Only]** Provide, on a system-wide basis, the historical annual average as-available energy rate in the Company's service territory for the period 2009–2018. If the Company uses multiple areas for as-available energy rates, please provide a system-average rate as well. Also, provide the projected annual average as-available energy rate in the Company's service territory for the period 2019–2028.

As-Available Energy Rates

Year		As-Available Energy ($/MWh)	On-Peak Average ($/MWh)	Off-Peak Average ($/MWh)
Actual	2009	NA. TAL is a municipal utility.		
	2010			
	2011			
	2012			
	2013			
	2014			
	2015			
	2016			
	2017			
	2018			
Projected	2019			
	2020			
	2021			
	2022			
	2023			
	2024			
	2025			
	2026			
	2027			
	2028			
Notes				
(Include Notes Here)				

48. Please complete the following table detailing planned unit additions, including information on capacity and in-service dates. Please include only planned conventional units with an in-service date past January 1, 2018. For each planned unit, provide the date of the Commission's Determination of Need and Power Plant Siting Act certification (if applicable), and the anticipated in-service date.

Planned Unit Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions				
NA				
Combustion Turbine Unit Additions				
NA				
Combined Cycle Unit Additions				
NA				
Steam Turbine Unit Additions				
NA				
Reciprocating Internal Combustion Engine (RICE) Unit Additions				
Hopkins IC 5	18	NA	NA	6/1/2020
Notes				
(Include Notes Here)				

49. For each of the planned generating units contained in the Company's 2019 TYSP, please discuss the "drop dead" date for a decision on whether or not to construct each unit. Provide a time line for the construction of each unit, including regulatory approval, and final decision point.

    The "drop dead" date for a decision on whether to construct Hopkins IC 5, the only planned generating unit contained in TAL's 2019 TYSP, has passed. Construction is expected to commence June 3, 2019.

50. Please provide an estimate of the revenue requirements of the Company based upon the 2019 TYSP's planned generating units.

    TAL provided an estimate of $1.881 billion cumulative present worth of revenue requirements (CPWRR) for 2018 through 2045 for the generation expansion plan reflected in its 2017 TYSP in its response to this same question in the FPSC's 2017 TYSP Supplemental Data Request ("SDR"). The generation expansion plan reflected in TAL's 2017 and 2018 TYSPs included an 18.6 MW reciprocating internal combustion engine (RICE) generator with in-service dates of summer 2024 and 2025, respectively. In anticipation of this need and to take advantage of more favorable equipment pricing, in September 2018 the City Commission authorized advancing the in-service date of this RICE generator to summer 2020. However, TAL has not re-evaluated the associated CPWRR.

51. For each of the planned generating units contained in the Company's 2019 TYSP, please identify the next best alternative that was rejected for each unit. Provide information similar to Schedule 9 regarding each of the next best alternative unit(s). As part of this response, please also provide the additional revenue requirement that would have been associated with the next best alternative compared to the planned unit.

As explained in its response to this same question in the FPSC's 2017 and 2018 TYSP SDRs TAL did not evaluate each of planned generating unit additions individually. Instead TAL evaluated different combinations of these units as alternative expansion plans. That evaluation was not intended to consider a wide array of potential generation technologies and combustion fuels but instead to evaluate replacing retiring older, gas-fired generating units with new gas-fired RICE generating units to provide a more diverse capacity mix, improved efficiency, greater commitment/dispatch flexibility and lower emissions profiles.

As explained in its response to Question #50 above and the same question in the FPSC's 2018 TYSP SDR, TAL did not re-evaluate its base or any alternative generation expansion plans or the CPWRR associated therewith for its 2018 and 2019 TYSP. The CPWRR for the next best alternative generation expansion plan in the 2017 evaluation was estimated as $1.886 billion.

52. For each existing and planned unit on the Company's system, provide the following data based upon historic data from 2018 and projected capacity factor values for the period 2019–2028. Please complete the tables below and provide an electronic copy in Microsoft Excel format.

Projected Unit Information – Capacity Factor (%)

Plant	Unit	Unit	Fuel	Actual	Projected									
	#	Type	Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hopkins	2	CC	NG	46.3%	50.9%	51.9%	43.7%	50.6%	50.5%	49.2%	51.0%	51.2%	44.8%	52.9%
Hopkins	CT3	GT	NG	30.2%	2.1%	2.9%	2.5%	1.3%	1.5%	2.6%	1.4%	1.4%	3.2%	2.3%
Hopkins	CT4	GT	NG	21.8%	2.3%	3.3%	2.4%	1.0%	1.7%	2.6%	1.7%	1.6%	3.3%	2.7%
Hopkins	IC1	IC	NG	0.1%	13.0%	17.6%	20.7%	11.3%	11.9%	20.6%	12.9%	12.7%	23.0%	18.0%
Hopkins	IC2	IC	NG	0.1%	13.1%	17.9%	18.4%	11.2%	11.0%	19.4%	12.3%	12.7%	21.9%	16.7%
Hopkins	IC3	IC	NG	0.2%	13.1%	16.0%	19.4%	10.4%	11.7%	19.0%	12.1%	12.7%	21.4%	16.9%
Hopkins	IC4	IC	NG	0.1%	13.1%	18.0%	18.9%	10.7%	11.5%	18.7%	12.3%	12.6%	21.3%	16.3%
Hopkins	IC5	IC	NG	NA	NA	7.5%	19.3%	11.2%	12.4%	18.8%	12.1%	12.1%	21.0%	16.2%
Purdom	8	CC	NG	61.5%	70.9%	63.6%	73.9%	70.5%	70.5%	68.6%	71.1%	71.4%	75.3%	68.0%
Sub 12	IC1	IC	NG	3.0%	7.1%	8.4%	8.8%	5.9%	5.7%	8.8%	6.2%	6.9%	9.6%	9.0%
Sub 12	IC2	IC	NG	3.7%	6.7%	8.8%	9.2%	6.5%	7.0%	9.4%	6.6%	6.5%	10.3%	8.7%
Notes														
Hopkins IC 1-4 were not commercially available until Spring 2019. All 2018 generation associated with these units was during testing. Hopkins IC 5 is expected to be in service by June 2020.														

53. For each existing unit on the Company's system, please provide the planned retirement date. If the Company does not have a planned retirement date for a unit, please provide an estimated lifespan for units of that type and a non-binding estimate of the retirement date for the unit.

Existing Units with Planned Retirement date

Plant	Unit No.	Expected Retirement (Month/Year)
S. O. Purdom	8	12/40

Existing Units without Planned Retirement date

Plant	Unit No.	Estimated Lifespan (Years)	Non-Binding Estimated Retirement (Month/Year)	
A. B. Hopkins	2	40	6/48	[1]
	GT-3	40	9/45	[2]
	GT-4	40	11/45	[3]
	IC1-4	30	2/49	[4]
Substation 12	IC1-2	30	10/48	[5]

Notes

[1] Estimated as 40 years beyond June 2008 in-service date of combustion turbine used to repower unit to combined cycle operation.

[2] Estimated as 40 years beyond September 2005 in-service date.

[3] Estimated as 40 years beyond November 2005 in-service date.

[4] Estimated as 30 years beyond February 2019 in-service date.

[5] Estimated as 30 years beyond October 2018 in-service date.

54. Please complete the table below, providing a list of all of the Company's steam units that are potential candidates for repowering to operation as Combined Cycle units. As part of this response, please provide the unit's current fuel type, summer capacity rating, in-service date, and what potential conversion, fuel-switching, or repowering would be most applicable. Also include a description of any potential issues that could affect repowering efforts at any of these sites, related to such things as unit age, land availability, or other requirements.

Repowering Candidate Units - Steam

Plant Name	Fuel Type	Summer Capacity (MW)	In-Service Date	Potential Conversion	Potential Issues
Hopkins 2	NG	300	6/2008	2 x 1 Combined Cycle	See notes

Notes

Potential issues include balancing the repowered unit's output with load requirements (minimum unit loading would exceed TAL's minimum load requirements), adding a catalyst layer to existing selective catalytic reduction (SCR) system to accommodate the higher NOx emissions associated with the addition of a second combustion turbine (CT) , and expansion of the Hopkins switchyard to interconnect the second CT.

55. Please identify each of the Company's existing (as of December 31, 2018) and planned (between 2019–2028) power purchase contracts, including firm capacity imports reflected in Schedule 7 of the Company's 2019 TYSP. Provide the seller, the term of the contract, amount of seasonal capacity purchased, the primary fuel (if applicable, such as with a unit purchase), whether it is included in the Utility's firm peak capacity, and a description of the source of the purchase (such as the name of the unit in a unit purchase).

Existing Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Capacity	Description
	Begins	Ends	Summer	Winter	%			
NA								
Notes								
(Include Notes Here)								

Planned Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Capacity	Description
	Begins	Ends	Summer	Winter	%			
NA								
Notes								
(Include Notes Here)								

56. Please identify each of the Company's existing (as of December 31, 2018) and planned (between 2019–2028) power sales, including firm capacity exports reflected in Schedule 7 of the Company's 2019 TYSP. Provide the purchaser, the term of the contract, amount of seasonal capacity sold, the primary fuel (if applicable, such as with a unit purchase), whether it is included in the Utility's firm peak demand, and a description of the sale (such as the name of the unit in a unit purchase).

Existing Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter	%			
NA								
Notes								
(Include Notes Here)								

Planned Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter	%			
NA								
Notes								
(Include Notes Here)								

57. Please list and discuss any long-term power sale or purchase agreements within the past year that were cancelled, expired, or modified.

TAL had no long-term power sale or purchase agreements that were cancelled, expired, or modified within the past year.

58. Please provide a list of all proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act. Please also include those that have been approved, but are not yet in-service, when completing the table below.

Transmission Projects Requiring TLSA Approval

Transmission Line	**Line Length**	**Nominal Voltage**	**Date Need Approved**	**Date TLSA Certified**	**In-Service Date**
	(Miles)	(kV)			
NA					
Notes					
(Include Notes Here)					

Environmental

59. 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 2018 period. As part of your narrative, please discuss the potential for existing environmental regulations to impact unit dispatch, curtailments, or retirements during the 2019–2028 period.

<u>Air Emission Impacts</u>

TAL is subject to the requirements of the Acid Rain Program and had more than sufficient allowances of sulfur dioxide (SO2) and nitrogen oxides (NOx) to meet the needs of the 2018 calendar year. TAL should have sufficient allowances for the foreseeable future. Much of the impact from environmental regulations that TAL was previously subject to have been minimized due to legal challenges of regulations, which resulted in stays or remands.

<u>Water Impacts</u>

<u>Cooling Water Intake Structure (CWIS)Rule</u>

The Cooling Water Intake Structure (CWIS) Rule has no impact since the Sam O. Purdom (Purdom) Generation Station Gas Turbine 2 (aka CT2) retired on 10/26/2018 and Purdom does not meet the established regulatory threshold under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities.

<u>Numeric Nutrient Criteria Rule (NNC)</u>

Purdom continues to implement strategies to comply with the Numeric Nutrient Criteria Rule (NNC). Purdom was issued an Administrative Order (AO) A0-030-TL to ensure that the discharge will not contribute to the non-attainment of the Total Nitrogen in the receiving water (St Marks River). On March 14, 2019, the Florida Department of Environmental Protection (Department) terminated the AO as the City complied with all requirements.

<u>Lake Talquin Total Maximum Daily Load (TMDL) Rule</u>

The proposed Lake Talquin Total Maximum Daily Load (TMDL) Rule, which would have provided a Waste Load Allocation (WLA) of total Phosphorus (TP) of 2,187 kg/year and WLA of total Nitrogen (TN) of 1,020 kg/year for the Arvah B. Hopkins Electric Generating Station (Hopkins) was challenged and subsequently invalidated on March 2, 2018. This decision invalidating the FDEP rule does not affect TAL operations as TAL's NPDES permit remains administratively continued at Hopkins. There are no current Waste Load

Allocations for TP and TN at Hopkins. Hopkins will need to comply with the Water Quality Standard of TP at Beaver Creek. This step will include TAL's performing two temporally independent Stream Condition Index studies (SCI) and achieving an average of 40 (but no sample less than 35).

Water Quality Triennial Review

The Florida Department of Environmental Protection (DEP) announces initiation of the Triennial Review of state surface water quality standards as required by the Federal Clean Water Act. All surface water quality standards in Chapter 62-4, Chapter 62-302 Chapter 62-303, and Chapter 62-304, Florida Administrative Code, are under review and may be revised as part of the Triennial Review. The workshops/hearings are scheduled to begin May 2019. Impacts are unknown at this time.

Water Management District Issues - Proposed Rule 40A-8.031- Minimum Flows for the St. Marks River Rise

The minimum flow for St. Marks River Rise is established as an allowable reduction of 33 cubic feet per second from the baseline period average daily spring flow. The Rule does not appear to have an impact on the Purdom facility.

Waste Impacts

Field erected storage tank systems have to be maintained and inspected according to the frequency established and implemented in accordance with API std 653 and repairs performed based on the recommendations in the inspection report in compliance with the Rule 62-762.702, Florida Administrative Code. Five year in-service external API-653 inspections for both generating stations are required.

60. Please complete the table below, providing actual and projected amounts of regulated air pollutants and carbon dioxide emitted, on an annual and per megawatt-hour basis, by the Company's generation fleet. Please also provide an electronic copy of the completed table in Microsoft Excel format.

Emissions of Registered Air Pollutants & CO2

Year		SOX		NOX		Mercury		Particulates		CO2	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2009	0.00600	8	0.30900	434	NA	NA	0.05100	72	851	1,193,491
	2010	0.03500	52	0.35000	512	NA	NA	0.05000	74	830	1,217,028
	2011	0.04000	6	0.20400	282	NA	NA	0.05000	69	847	1,174,318
	2012	0.05000	7	0.33600	423	NA	NA	0.05000	68	991	1,246,444
	2013	0.04000	8	0.30600	411	NA	NA	0.05000	73	959	1,288,759
	2014	0.00492	7	0.29500	415	NA	NA	0.05000	56	984	1,381,137
	2015	0.00490	7	0.31100	424	NA	NA	0.05700	77	958	1,302,973
	2016	0.00500	7	0.29970	400	NA	NA	0.05495	73	918	1,223,680
	2017	0.00464	6	0.31200	431	NA	NA	0.05380	74	892	1,229,914
	2018	0.00470	7	0.28189	397	NA	NA	0.05168	73	863	1,217,442
Projected	2019	0.00470	7	0.28189	403	NA	NA	0.05168	74	863	1,232,984
	2020	0.00470	7	0.28189	406	NA	NA	0.05168	74	863	1,242,481
	2021	0.00470	7	0.28189	407	NA	NA	0.05168	75	863	1,247,230
	2022	0.00470	7	0.28189	409	NA	NA	0.05168	75	863	1,254,138
	2023	0.00470	7	0.28189	411	NA	NA	0.05168	75	863	1,258,455
	2024	0.00470	7	0.28189	414	NA	NA	0.05168	76	863	1,267,089
	2025	0.00470	7	0.28189	415	NA	NA	0.05168	76	863	1,270,975
	2026	0.00470	7	0.28189	417	NA	NA	0.05168	76	863	1,277,019
	2027	0.00470	7	0.28189	419	NA	NA	0.05168	77	863	1,283,063
	2028	0.00470	7	0.28189	422	NA	NA	0.05168	77	863	1,292,561
Notes											
(Include Notes Here)											

61. For the U.S. Environmental Protection Agency's (EPA's) Mercury and Air Toxics Standards (MATS) Rule:

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

No. This rule is not applicable to TAL.

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

NA

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

NA

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

NA

e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding MATS-related costs:

Year	Estimated Cost of Mercury and Air Toxics Standards (MATS) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	*NA*			
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

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

62. For the U.S. EPA's Cross-State Air Pollution Rule (CSAPR):

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

No. The State of Florida was recently found to not be subject to CSAPR. As such, until CSAPR or some other similar rule is promulgated, TAL is not affected.

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

NA

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

NA

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

NA

e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding CSAPR-related costs:

Year	**Estimated Cross-State Air Pollution Rule (CSAPR) Rule Impacts (2019 $ millions)**			
	Capital Costs	**O&M Costs**	**Fuel Costs**	**Total Costs**
2019	*NA*			
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

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

63. For the U.S. EPA's Cooling Water Intake Structures (CWIS) Rule:

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

No. There will be no impact from this Rule.

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

NA

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

NA

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

NA

e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding CWIS-related costs:

Year	**Estimated Cost of Cooling Water Intake Structures Rule (CWIS) Rule Impacts (2019 $ millions)**			
	Capital Costs	**O&M Costs**	**Fuel Costs**	**Total Costs**
2019	NA			
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

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

64. For the U.S. EPA's Coal Combustion Residuals Rule (CCR), both for classification of coal ash as a "Non-Hazardous Waste" and as a "Special Waste."

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

      No. There will be no impact from this Rule.

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

      NA

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

      NA

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

      NA

   e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding CCR-related costs:

Year	Estimated Coal Combustion Residuals Rule (CCR) Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	*NA*			
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

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

65. 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?

At this time, TAL does not anticipate the construction of any new combined cycle or simple cycle units that would trigger this rule.

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

If TAL were to construct units subject to the rule, TAL will implement best operational practices to minimize emissions.

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

NA

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

NA

e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding costs:

Year	Estimated Cost of Standards of Performance for Greenhouse Gas Emissions Rule for New Sources Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	*NA*			
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

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

66. Please identify, 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. As part of this response, please also indicate the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy in Microsoft Excel format.

Estimated Impacts of EPA's Rules on Generating Units

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Type of New and Proposed EPA Rule Impacts					Anticipated Impacts
				MATS	CSAPR/ CAIR	CWIS	CCR		
							Non-Hazardous Waste	Special Waste	
Hopkins 2A	CT	NG	300		X				Note 1
Purdom 8	CT	NG	222		X				Note 1
Purdom GT2	GT	NG	10			X			Note 2
Hopkins 1	ST	NG	76		X				Notes 1, 3
Hopkins GT 3	GT	NG	46		X				Note 1
Hopkins GT 4	GT	NG	46		X				Note 1
Hopkins IC 1	IC	NG	18						Note 1
Hopkins IC 2	IC	NG	18						Note 1
Hopkins IC 3	IC	NG	18						Note 1
Hopkins IC 4	IC	NG	18						Note 1
Substation 12 IC 1	IC	NG	9						Note 1
Substation 12 IC 2	IC	NG	9						Note 1

Notes

[1]As of 2017, Florida will not be subject to CSAPR/CAIR. However, if Ozone standard changes, the impact will be a shortfall of allowances. Must purchase additional allowances.

[2]No impact from this Rule. Purdom GT 2 was retired on 10/26/2018 and the Sam O. Purdom Generation Station does not meet the established requirements under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities.

[3]Hopkins 1 retired November 2018.

67. Please identify, 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. As part of this response, please indicate the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy in Microsoft Excel format.

Estimated Unit Cost of EPA's Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Cost of EPA Rules Impacts (2019 $ millions)						
				MATS	CSAPR/ CAIR	CWIS	CCR		Anticipated Impacts	Total Cost
							Non-Hazardous Waste	Special Waste		
Hopkins 2A	CT	NG	300		Note 1					
Purdom 8	CT	NG	222		Note 1					
Purdom GT2	GT	NG	10		Note 1	Note 2				
Hopkins 1	ST	NG	76		Notes 1, 3					
Hopkins GT 3	GT	NG	46		Note 1					
Hopkins GT 4	GT	NG	46		Note 1					
Hopkins IC 1	IC	NG	18		Note 1					
Hopkins IC 2	IC	NG	18		Note 1					
Hopkins IC 3	IC	NG	18		Note 1					
Hopkins IC 4	IC	NG	18		Note 1					
Substation 12 IC 1	IC	NG	9		Note 1					
Substation 12 IC 2	IC	NG	9		Note 1					

Notes

[1]As of 2017, Florida will not be subject to CSAPR/CAIR. However, if Ozone standard changes, the impact will be a shortfall of allowances. Must purchase additional allowances.

[2]No impact from this Rule. Purdom GT 2 was retired on 10/26/2018 and the Sam O. Purdom Generation Station does not meet the established requirements under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities.

[3]Hopkins 1 retired November 2018.

68. Please identify, for each unit impacted by one or more of EPA's rules, when and for what duration units would be required to be offline due to retirements, curtailments, installation of additional controls, or additional maintenance related to emission controls. Include important dates relating to each rule. Please complete the table below and provide an electronic copy in Microsoft Excel format.

Estimated Timing of Unit Impacts of EPA's Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Timing of EPA Rule Impacts (Month/Year - Duration)				
				MATS	CSAPR/ CAIR	CWIS	CCR	
							Non-Hazardous Waste	Special Waste
Purdom GT2	GT	NG	10		Note 1	Note 2		
Hopkins 1	ST	NG	76		Notes 1, 3			

Notes

1 As of 2017, Florida will not be subject to CSAPR/CAIR. However, if Ozone standard changes, the impact will be a shortfall of allowances. Must purchase additional allowances.

2 No impact from this Rule. Purdom GT 2 was retired on 10/26/2018 and the Sam O. Purdom Generation Station does not meet the established requirements under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities.

3 Hopkins 1 retired November 2018.

69. 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 units not modified by the rule, that may be required to maintain reliability if unit retirements, curtailments, additional emissions control upgrades, or longer outage times due to each of these EPA rules.

a. Mercury and Air Toxics Standards (MATS) Rule. *NA*

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

c. Cooling Water Intake Structures (CWIS) Rule.

No impact from this Rule. Purdom GT 2 was retired on 10/26/2018 and the Sam O. Purdom Generation Station does not meet the established requirements under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities.

d. Coal Combustion Residuals (CCR) Rule. *NA*

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

No impacts are expected until such time any applicable units are built.

70. 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.

TAL has invested in the development of two utility-scale solar photovoltaic (PV) facilities and seven reciprocating internal combustion engines (RICE). These investments combined with TAL's demand management programs would mitigate future demand to build more fossil-fueled units. The seven RICE provide necessary reliability and to provide support to the two solar projects.

Field erected storage tank systems must be maintained and inspected according to the frequency established and implemented in accordance with API std 653 and repairs performed based on the recommendations in the inspection report in compliance with the Rule 62-762.702, Florida Administrative Code.

Purdom continues to implement strategies to comply with the Numeric Nutrient Criteria Rule (NNC). Purdom was issued an Administrative Order (AO) A0-030-TL to ensure that the discharge will not contribute to the non-attainment of the Total Nitrogen in the receiving Water (St Marks River). On March 14, 2019, the Florida Department of Environmental Protection (Department) provided concurrence to the City of Tallahassee's request to terminate the AO. Purdom continues to implement operation training for all shifts on the zero-discharge system, which focuses on running the process to meet the new nutrient criteria.

In 2017, the Purdom facility completed a material balance study and identified that the crystallizer concentrate stream as the only waste stream that consistently maintains a total nitrate composition that would contribute to a discharge exceeding the Florida Impaired Water Rule. An emphasis was placed on operating the crystallizer in a manner that would separate additional amounts of crystallizer concentrate into distillate and salt residue. By doing this, Purdom now operates at a point where it is successfully able to maintain total nitrates available for discharge at levels that consistently meet the Florida's Impaired Waters Rule.

71. What steps has your Company taken, is currently taking, or is planning to take to address curbing carbon dioxide emissions for existing sources? How has your Company addressed the ruling by the U.S. Supreme Court that carbon dioxide is a pollutant under the Clean Air Act? How does your Company plan on addressing carbon dioxide emissions from existing sources during the 10-year site planning period?

Over the past few years TAL has implemented multiple steps to address carbon dioxide emissions from existing sources. TAL has utilized demand side management, energy efficiency programs, informational programs to encourage prudent energy usage amongst our customers, as well as the usage of natural gas as TAL's primary fuel. TAL has tracked its carbon intensity (lb/MWh) for over 20 years and has reduced its carbon intensity 38% from 1990 levels.

TAL has implemented multiple major electric generating improvements over the last decade that have significantly improved the efficiency and environmental profile of the fleet. These include the construction of Combined Cycle Combustion Turbine Unit No. 8 at the Purdom, two Sprint Combustion Turbines at the Hopkins, and the repowering of Unit No. 2 at the Hopkins from a conventional steam boiler to a combined cycle unit. Additionally, TAL has entered into an agreement with Origis Energy to develop two utility-scale solar photovoltaic (PV) facilities. This investment could mitigate the need for future investments to comply with the standards of performance for greenhouse gas emissions from electric utility generating units.

TAL retired its oldest unit, Boiler #1 at Hopkins, as well as four smaller units that all had reached the end of useful service. These older units were replaced by four large reciprocating internal combustion engines (18 MW a piece) that will support the two solar facilities. As a result of the various efficiency improvements made to the electric generating fleet, further improvements and CO_2 reductions are not readily available except through conservation initiatives or the use of renewable resources. In addition, TAL utilized more than 99% clean burning pipeline natural gas (by heat input) for calendar years 2012 through 2018. It is generally expected to continue this trend in upcoming years if the price of natural gas remains low comparatively to diesel fuel.

Fuel Supply & Transportation

72. Please provide, 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 Company in the period 2009–2018. 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 Company in the period 2019–2028. As part of this response, please complete the table below and provide the completed table in Microsoft Excel format.

Average Fuel Price Comparison

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	2009	NA	NA	NA	NA	2,612	8.57	0	9.32	4	18.66
	2010	NA	NA	NA	NA	2,614	7.69	6	9.08	3	22.15
	2011	NA	NA	NA	NA	2,703	6.96	2	9.08	0	20.86
	2012	NA	NA	NA	NA	2,509	5.54	NA	NA	0	18.86
	2013	NA	NA	NA	NA	2,662	4.51	NA	NA	2	23.58
	2014	NA	NA	NA	NA	2,788	4.82	NA	NA	10	23.57
	2015	NA	NA	NA	NA	2,704	4.44	NA	NA	0	NA
	2016	NA	NA	NA	NA	2,562	3.92	NA	NA	76	22.54
	2017	NA	NA	NA	NA	2,635	3.79	NA	NA	0	NA
	2018	NA	NA	NA	NA	2,808	3.79	NA	NA	1	23.09
Projected	2019	NA	NA	NA	NA	2,829	3.48	NA	NA	0	12.19
	2020	NA	NA	NA	NA	2,769	3.49	NA	NA	0	12.53
	2021	NA	NA	NA	NA	2,772	3.42	NA	NA	0	12.54
	2022	NA	NA	NA	NA	2,805	3.43	NA	NA	0	12.62
	2023	NA	NA	NA	NA	2,814	3.49	NA	NA	0	12.92
	2024	NA	NA	NA	NA	2,823	3.60	NA	NA	0	13.24
	2025	NA	NA	NA	NA	2,843	3.69	NA	NA	0	13.57
	2026	NA	NA	NA	NA	2,857	3.83	NA	NA	0	13.91
	2027	NA	NA	NA	NA	2,855	3.93	NA	NA	0	14.26
	2028	NA	NA	NA	NA	2,889	4.03	NA	NA	0	14.62
Notes											

73. Please discuss how the Company compares its fuel price forecasts to recognized, authoritative independent forecasts.

TAL based its fuel price forecasts for natural gas and distillate fuel oil on the CME Group/New York Mercantile Exchange (CME/NYMEX) forward prices. Because TAL does not have a recent fuel forecast performed by a third party, the CME/NYMEX prices were relied on as the basis for the fuel forecasts submitted to the FPSC in the 2019 TYSP. At the time TAL prepared the TYSP forecast, the latest public fuel forecast available was from the Energy Information Administration's (EIA) 2019 Annual Energy Outlook released in January 2019. TAL reviewed the EIA data before the TYSP forecast was prepared and found the EIA natural gas prices, for the ten-year period, to track over 15% higher than TAL's CME/NYMEX based natural gas forecast. EIA's Distillate fuel forecast was much closer, averaging only 2% lower than the TAL's CME/NYMEX diesel forecast. Because market prices solicited from TAL suppliers mirror the CME/NYMEX, TAL used the CME/NYMEX as the basis for the TYSP fuel forecasts for natural gas and distillate fuel oil. Since suppliers specifically quote the CME/NYMEX as a basis for fixed price term deals, TAL believes the CME/NYMEX provides a better basis for fuel forecasting than the EIA forecasts.

74. Please identify and discuss expected industry trends and factors for each fuel type (coal, natural gas, nuclear fuel, oil, etc.) that may affect the Company during the period 2019–2028.

a. Coal

TAL does not have coal generating resources and is not planning to add coal plants within the ten-year time horizon. Therefore, TAL has limited insight into expected industry trends for coal.

b. Natural Gas

The expansion of shale gas production in the United States (US) has significantly contributed to lower and more stable natural gas prices in recent years. Improvements in fracking and directional drilling technology have decreased production costs and increased supply. There is some potential for upward pressure on prices as the US exports increasing volumes of LNG and conventional gas supplies to Mexico. Fracking is still exposed to regulatory risk, either from state legislation or citizen referendums which advocate for banning the practice or increasing setbacks which limits available drilling sites. Since shale gas production comes from on-shore sources, potential interruptions and price volatility related to hurricanes in the Gulf of Mexico are reduced. If shale gas production continues to grow TAL should have reasonably priced and stable natural gas supplies for the ten-year planning horizon.

c. Nuclear (if applicable)

Not applicable.

d. Fuel Oil

Since the re-powering of Hopkins Unit 2 in 2008 TAL no longer uses or stores residual fuel oil on site. Due to the higher price of distillate compared to natural gas and environmental permit limits, TAL uses distillate fuel oil primarily for reliability purposes and testing. Distillate and residual fuel oils are likely to remain volatile and subject to the forces of supply, demand, speculative interests and geo-political influences.

e. Other (please specify each, if any)

Not applicable.

75. Please identify and discuss steps that the Company has taken to ensure natural gas supply availability and transportation over the 2019–2028 planning period.

Over the past several years, TAL has added pipeline capacity and levelized natural gas consumption through the addition of more efficient generating resources and retirement of less efficient units. In 2011, Florida Gas Transmission (FGT) expanded its natural gas pipeline system with the addition of 820,000 MMBtu/day of additional firm transportation capacity. TAL contracted for 6,000 MMBtu/day (year-round) of additional pipeline capacity from this expansion to enhance reliability. TAL also negotiated with FGT to acquire additional FTS-1 turn-back capacity during the summer and winter months as part of the 2015 rate case settlement. The additional pipeline capacity volumes will enable TAL to meet customer needs based on load growth forecasts for the ten-year planning horizon.

76. Please identify and discuss any existing or planned natural gas pipeline expansion project(s), including new pipelines and those occurring or planned to occur outside of Florida that would affect the Company for the period 2019–2028.

Sabal Trail Transmission, LLC (Sabal Trail), a joint venture of Duke, Spectra Energy and NextEra, constructed a nearly 515-mile interstate natural gas pipeline to provide transportation services for the power generation needs of Florida Power and Light (FPL), Duke Energy of Florida (DEF) and others beginning in July 2017. The Sabal Trail pipeline terminates at the new central Florida hub south of Orlando. The hub also provided a point of interconnect with Gulf Stream Natural Gas and FGT. Additional pipeline infrastructure will benefit the greater Southeastern region of the United States by making available additional supplies and to support the growing demand for clean-burning natural gas. Transco pipeline will be able to supply gas from the Barnett, Haynesville, Fayetteville, Eagle Ford and Marcellus supply areas to the Florida gas market through Sabal Trail. Sabal Trail will increase energy diversity, security and reliability for the Southeastern markets. Although TAL is not connected to Sabal Trail, the additional pipeline capacity will benefit the entire State of Florida.

77. Please identify and discuss expected liquefied natural gas (LNG) industry factors and trends that will impact the Company, including the potential impact on the price and availability of natural gas, for the period 2019–2028.

TAL does not expect that the current industry factors and trends in LNG to adversely impact the price and supply of natural gas use for electric power generation for the period 2019 through 2028. The increased use of LNG as an over-the-road, rail, and water borne transportation fuel is not expected to impact the availability or price of natural gas. The market indications are that due to the low prices of liquid fuels and the advances in PEVs the conversion of fleets to LNG has declined to a near halt.

78. Please identify and discuss the Company's plans for the use of firm natural gas storage for the period 2019–2028.

TAL has contracts for firm underground storage capacity in Mississippi and Louisiana for a total of 70,781 MMBtus, located along the Southern Natural Gas pipeline which serves TAL's Gas Utility. TAL does not have any firm plans for additional underground natural gas storage but will continue to evaluate the economic viability of all storage options.

79. Please identify and discuss expected coal transportation industry trends and factors, for transportation by both rail and water that will impact the Company during the period 2019–2028. Please include a discussion of actions taken by the Company to promote competition among coal transportation modes, as well as expected changes to terminals and port facilities that could affect coal transportation.

Since TAL doesn't have any existing or planned coal fired generation, we have no informed opinions on coal industry trends and transportation challenges.

80. Please identify and discuss any expected changes in coal handling, blending, unloading, and storage for any planned changes and construction projects at coal generating units for the period 2019–2028.

Since TAL doesn't have any existing or planned coal fired generation, we have no informed opinions on coal handling, etc.

81. **[DEF & FPL Only]** Please identify and discuss the Company's plans for the storage and disposal of spent nuclear fuel for the period 2019–2028. As part of this discussion, please include the Company's expectation regarding short-term and long-term storage, dry cask storage, litigation involving spent nuclear fuel, and any relevant legislation.

    Not applicable.

82. **[FPL Only]** Please identify and discuss expected uranium production industry trends and factors that will affect the Company during the period 2019–2028.

    Not applicable.

Tables included in file “Data Request #1 (2019) - Excel Tables Rev 1.xls”

Historic Peak Demand Timing & Temperature

Year	Month	Actual Peak Demand (MW)	Demand Response Activated (MW)	Estimated Peak Demand (MW)	Day	Hour	System-Average Temperature (Degrees F)
2018	1	621	0	621	1/18/2018	800	36
	2	433	0	433	2/1/2018	900	61
	3	416	0	416	3/15/2018	900	49
	4	390	0	390	4/23/2018	1800	72
	5	494	0	494	5/31/2018	1700	82
	6	596	0	596	6/20/2018	1600	88
	7	560	0	560	7/13/2018	1600	84
	8	558	0	558	8/28/2018	1600	84
	9	581	0	581	9/14/2018	1600	85
	10	507	0	507	10/3/2018	1800	82
	11	457	0	457	11/28/2018	800	42
	12	505	0	505	12/12/2018	800	43
2017	1	533	0	533	1/9/2017	800	40
	2	378	0	378	2/17/2017	800	53
	3	444	0	444	3/16/2017	800	44
	4	477	0	477	4/28/2017	1800	78
	5	510	0	510	5/16/2017	1700	80
	6	550	0	550	6/23/2017	1500	83
	7	584	0	584	7/28/2017	1600	85
	8	598	0	598	8/18/2017	1600	88
	9	522	0	522	9/29/2017	1700	81
	10	528	0	528	10/10/2017	1500	83
	11	404	0	404	11/6/2017	1600	69
	12	501	0	501	12/11/2017	800	45
2016	1	511	0	511	1/20/2016	800	44
	2	505	0	505	2/11/2016	800	51
	3	402	0	402	3/16/2016	1800	80
	4	471	0	471	4/29/2016	1700	80
	5	496	0	496	5/31/2016	1500	82
	6	560	0	560	6/13/2016	1700	87
	7	563	0	563	7/29/2016	1700	87
	8	597	0	597	8/23/2016	1800	89
	9	526	0	526	9/20/2016	1700	85
	10	469	0	469	10/8/2016	1800	84
	11	423	0	423	11/4/2016	1700	75
	12	390	0	390	12/10/2016	900	45

Notes

(Include Notes Here)

Electric Vehicle Charging Impacts

Year	Number of PEVs	Number of Public PEV Charging Stations	Number of Public "Quick-charge" PEV Charging Stations	Cumulative Impact of PEVs		
				Summer Demand	Winter Demand	Annual Energy
				(MW)	(MW)	(GWh)
2018	1,379	1,412	2	N/A		
2019	1,392	1,412	2			
2020	1,406	1,413	2			
2021	1,420	1,421	4			
2022	1,435	1,435	4			
2023	1,449	1,449	4			
2024	1,463	1,463	6			
2025	1,478	1,478	6			
2026	1,493	1,495	6			
2027	1,508	1,510	8			
2028	1,524	1,526	8			

Notes

Due to the low expected penetration of EVs within the service area, TAL has not performed any formal analysis of the impact on system load and energy requirements.

[Demand Response Source or All Demand Response Sources]										
Year	**Beginning Year: Number of Customers**	**Available Capacity (MW)**		**New Customers Added**	**Added Capacity (MW)**		**Customers Lost**	**Lost Capacity (MW)**		
		Sum	Win		Sum	Win		Sum	Win	
2009	NA. TAL is not a FEECA utility.									
2010										
2011										
2012										
2013										
2014										
2015										
2016										
2017										
2018										
Notes										
(Include Notes Here)										

[Demand Response Source or All Demand Response Sources]												
Year	**Summer**						**Winter**					
	Number of Events	**Average Event Size**		**Maximum Event Size**			**Number of Events**	**Average Event Size**		**Maximum Event Size**		
		(MW)	Number of Customers	(MW)	Number of Customers			(MW)	Number of Customers	(MW)	Number of Customers	
2009	NA. TAL is not a FEECA utility.											
2010												
2011												
2012												
2013												
2014												
2015												
2016												
2017												
2018												
Notes												
(Include Notes Here)												

[Demand Response Source or All Demand Response Sources]							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak?	Number of Customers Activated	Capacity Activated	Activated During Peak?	Number of Customers Activated	Capacity Activated
		(Y/N)		(MW)	(Y/N)		(MW)
2009	NA. TAL is not a FEECA utility.						
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
Notes							
(Include Notes Here)							

Existing Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Net Firm Capacity (MW)		Capacity Factor	In-Service Date
			Sum	Win	Sum	Win	(%)	(MM/YYYY)
TAL	PV	SUN	0.232	0.232	0	0	15	1/1993
Notes								
(Include Notes Here)								

Planned Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Net Firm Capacity (MW)		Capacity Factor	In-Service Date
			Sum	Win	Sum	Win	(%)	(MM/YYYY)
Unsited	PV	SUN	0.1	0.1	0.0	0.0	15	12/2020

Notes
(Include Notes Here)

Existing Renewable Purchased Power Agreements

Seller Name	Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Contracted Firm Capacity (MW)		In-Service Date	Contract Term (MM/YY)	
				Sum	Win	Sum	Win	(MM/YY)	Start	End
FL Solar 1, LLC	SF1	PV	SUN	20	20	0	0	12/17	12/17	12/37
Notes										
(Include Notes Here)										

Renewable Purchased Power Agreements

Seller Name	Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Contracted Firm Capacity (MW)		In-Service Date	Contract Term (MM/YY)	
				Sum	Win	Sum	Win	(MM/YY)	Start	End
FL Solar 4, LLC	SF2	PV	SUN	40	40	0	0	12/19	12/19	12/39
Notes										
(Include Notes Here)										

Renewable Generation by Source

Renewable Source	Annual Renewable Generation (GWh)										
	Actual	Projected									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Utility - Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utility - Non-Firm[1]	22.5	7.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Utility - Co-Firing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Purchase - Firm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Purchase - Non-Firm	37.5	40.7	122.8	121.8	121.2	120.6	120.3	119.4	118.8	118.2	118.0
Purchase - Co-Firing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer - Owned	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	60.3	48.7	124.1	123.1	122.5	121.9	121.6	120.7	120.1	119.5	119.3
Notes											
[1]City-owned solar PV and former Corn Hydro generation. Corn Hydro Plant decommissioned February 2019.											

Candidate Sites -Solar

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues
A. B. Hopkins	75	10	The land may be needed for other uses or other requirements.

Candidate Sites -Wind

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues
NA			

Project Name	Pilot Program (Y/N)	In-Service/ Pilot Start Date	Max Capacity Output (MW)	Max Energy Stored (MWh)
TAL does not have energy storage technologies that are currently either part of the system portfolio or are part of a pilot program .				
Notes				
(Include Notes Here)				

As-Available Energy Rates

Year		As-Available Energy ($/MWh)	On-Peak Average ($/MWh)	Off-Peak Average ($/MWh)
Actual	2009	NA. TAL is a municipal utility.		
	2010			
	2011			
	2012			
	2013			
	2014			
	2015			
	2016			
	2017			
	2018			
Projected	2019			
	2020			
	2021			
	2022			
	2023			
	2024			
	2025			
	2026			
	2027			
	2028			
Notes				
(Include Notes Here)				

Planned Unit Additions

Generating Unit Name	Summer Capacity (MW)[1]	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions				
NA				
Combustion Turbine Unit Additions				
NA				
Combined Cycle Unit Additions				
NA				
Steam Turbine Unit Additions				
NA				
Reciprocating Internal Combustion Engine (RICE) Unit Additions				
Hopkins IC 5	18	NA	NA	6/1/2020
Notes				
[1]Reflects the summer net capacity				

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hopkins	2	CC	NG	46.3%	50.9%	51.9%	43.7%	50.6%	50.5%	49.2%	51.0%	51.2%	44.8%	52.9%
Hopkins	CT3	GT	NG	30.2%	2.1%	2.9%	2.5%	1.3%	1.5%	2.6%	1.4%	1.4%	3.2%	2.3%
Hopkins	CT4	GT	NG	21.8%	2.3%	3.3%	2.4%	1.0%	1.7%	2.6%	1.7%	1.6%	3.3%	2.7%
Hopkins	IC1	IC	NG	0.1%	13.0%	17.6%	20.7%	11.3%	11.9%	20.6%	12.9%	12.7%	23.0%	18.0%
Hopkins	IC2	IC	NG	0.1%	13.1%	17.9%	18.4%	11.2%	11.0%	19.4%	12.3%	12.7%	21.9%	16.7%
Hopkins	IC3	IC	NG	0.2%	13.1%	16.0%	19.4%	10.4%	11.7%	19.0%	12.1%	12.7%	21.4%	16.9%
Hopkins	IC4	IC	NG	0.1%	13.1%	18.0%	18.9%	10.7%	11.5%	18.7%	12.3%	12.6%	21.3%	16.3%
Hopkins	IC5	IC	NG	NA	NA	7.5%	19.3%	11.2%	12.4%	18.8%	12.1%	12.1%	21.0%	16.2%
Purdom	8	CC	NG	61.5%	70.9%	63.6%	73.9%	70.5%	70.5%	68.6%	71.1%	71.4%	75.3%	68.0%
Sub 12	IC1	IC	NG	3.0%	7.1%	8.4%	8.8%	5.9%	5.7%	8.8%	6.2%	6.9%	9.6%	9.0%
Sub 12	IC2	IC	NG	3.7%	6.7%	8.8%	9.2%	6.5%	7.0%	9.4%	6.6%	6.5%	10.3%	8.7%
Notes														
Hopkins IC 1-4 were not commercially available until Spring 2019. All 2018 generation associated with these units was during testing. Hopkins IC 5 is expected to be in service by June 2020.														

Repowering Candidate Units - Steam

Plant Name	Fuel Type	Summer Capacity (MW)	In-Service Date	Potential Conversion	Potential Issues
Hopkins 2	NG	300	6/2008	2 x 1 Combined Cycle	See notes

Notes

Potential issues include balancing the repowered unit's output with load requirements (minimum unit loading would exceed TAL's minimum load requirements), adding a catalyst layer to existing selective catalytic reduction (SCR) system to accommodate the higher NOx emissions associated with the addition of a second combustion turbine (CT) , and expansion of the Hopkins switchyard to interconnect the second CT.

Existing Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Capacity	Description
	Begins	Ends	Summer	Winter	(%)			
NA								
Notes								
(Include Notes Here)								

Planned Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Capacity	Description
	Begins	Ends	Summer	Winter	(%)			
NA								
Notes								
(Include Notes Here)								

Existing Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter	(%)			
NA								
Notes								
(Include Notes Here)								

Planned Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter	(%)			
NA								
Notes								
(Include Notes Here)								

Transmission Projects Requiring TLSA Approval

Transmission Line	Line Length	Nominal Voltage	Date Need Approved	Date TLSA Certified	In-Service Date
	(Miles)	(kV)			
NA					
Notes					
(Include Notes Here)					

Emissions of Registered Air Pollutants & CO2

Year		SOX		NOX		Mercury		Particulates		CO2	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	**2009**	0.00600	8	0.30900	434	NA	NA	0.05100	72	851	1,193,491
	2010	0.03500	52	0.35000	512	NA	NA	0.05000	74	830	1,217,028
	2011	0.04000	6	0.20400	282	NA	NA	0.05000	69	847	1,174,318
	2012	0.05000	7	0.33600	423	NA	NA	0.05000	68	991	1,246,444
	2013	0.04000	8	0.30600	411	NA	NA	0.05000	73	959	1,288,759
	2014	0.00492	7	0.29500	415	NA	NA	0.05000	56	984	1,381,137
	2015	0.00490	7	0.31100	424	NA	NA	0.05700	77	958	1,302,973
	2016	0.00500	7	0.29970	400	NA	NA	0.05495	73	918	1,223,680
	2017	0.00464	6	0.31200	431	NA	NA	0.05380	74	892	1,229,914
	2018	0.00470	7	0.28189	397	NA	NA	0.05168	73	863	1,217,442
Projected	**2019**	0.00470	7	0.28189	403	NA	NA	0.05168	74	863	1,232,984
	2020	0.00470	7	0.28189	406	NA	NA	0.05168	74	863	1,242,481
	2021	0.00470	7	0.28189	407	NA	NA	0.05168	75	863	1,247,230
	2022	0.00470	7	0.28189	409	NA	NA	0.05168	75	863	1,254,138
	2023	0.00470	7	0.28189	411	NA	NA	0.05168	75	863	1,258,455
	2024	0.00470	7	0.28189	414	NA	NA	0.05168	76	863	1,267,089
	2025	0.00470	7	0.28189	415	NA	NA	0.05168	76	863	1,270,975
	2026	0.00470	7	0.28189	417	NA	NA	0.05168	76	863	1,277,019
	2027	0.00470	7	0.28189	419	NA	NA	0.05168	77	863	1,283,063
	2028	0.00470	7	0.28189	422	NA	NA	0.05168	77	863	1,292,561
Notes											
(Include Notes Here)											

Year	Estimated Cost of Mercury and Air Toxics Standards (MATS) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	NA			
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

Year	Estimated Cross-State Air Pollution Rule (CSAPR) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	NA			
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

Year	Estimated Cost of Cooling Water Intake Structures Rule (CWIS) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	NA			
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

Year	Estimated Coal Combustion Residuals Rule (CCR) Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	NA			
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

Year	Estimated Cost of Standards of Performance for Greenhouse Gas Emissions Rule for New Sources Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	NA			
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

Estimated Impacts of EPA's Rules on Generating Units

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Type of New and Proposed EPA Rule Impacts					Anticipated Impacts
				MATS	CSAPR/ CAIR	CWIS	CCR		
							Non-Hazardous Waste	Special Waste	
Hopkins 2A	CT	NG	300		X				Note 1
Purdom 8	CT	NG	222		X				Note 1
Purdom GT2	GT	NG	10			X			Note 2
Hopkins 1	ST	NG	76		X				Notes 1, 3
Hopkins GT 3	GT	NG	46		X				Note 1
Hopkins GT 4	GT	NG	46		X				Note 1
Hopkins IC 1	IC	NG	18						Note 1
Hopkins IC 2	IC	NG	18						Note 1
Hopkins IC 3	IC	NG	18						Note 1
Hopkins IC 4	IC	NG	18						Note 1
Substation 12 IC 1	IC	NG	9						Note 1
Substation 12 IC 2	IC	NG	9						Note 1

Notes

[1]As of 2017, Florida will not be subject to CSAPR/CAIR. However, if Ozone standard changes, the impact will be a shortfall of allowances. Must purchase additional allowances.

[2]No impact from this Rule. Purdom GT 2 was retired on 10/26/2018 and the Sam O. Purdom Generation Station does not meet the established requirements under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities.

[3]Hopkins 1 retired November 2018.

Estimated Unit Cost of EPA's Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Cost of EPA Rules Impacts (2019 $ millions)						
				MATS	CSAPR/ CAIR	CWIS	CCR		Anticipated Impacts	Total Cost
							Non-Hazardous Waste	Special Waste		
Hopkins 2A	CT	NG	300		Note 1					
Purdom 8	CT	NG	222		Note 1					
Purdom GT2	GT	NG	10		Note 1	Note 2				
Hopkins 1	ST	NG	76		Notes 1, 3					
Hopkins GT 3	GT	NG	46		Note 1					
Hopkins GT 4	GT	NG	46		Note 1					
Hopkins IC 1	IC	NG	18		Note 1					
Hopkins IC 2	IC	NG	18		Note 1					
Hopkins IC 3	IC	NG	18		Note 1					
Hopkins IC 4	IC	NG	18		Note 1					
Substation 12 IC 1	IC	NG	9		Note 1					
Substation 12 IC 2	IC	NG	9		Note 1					
Notes										

[1]As of 2017, Florida will not be subject to CSAPR/CAIR. However, if Ozone standard changes, the impact will be a shortfall of allowances. Must purchase additional allowances.

[2]No impact from this Rule. Purdom GT 2 was retired on 10/26/2018 and the Sam O. Purdom Generation Station does not meet the established requirements under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities.

[3]Hopkins 1 retired November 2018.

Estimated Timing of Unit Impacts of EPA's Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Timing of EPA Rule Impacts (Month/Year - Duration)				
				MATS	CSAPR/ CAIR	CWIS	CCR	
							Non-Hazardous Waste	Special Waste
Purdom GT2	GT	NG	10		Note 1	Note 2		
Hopkins 1	ST	NG	76		Notes 1, 3			

Notes

[1]As of 2017, Florida will not be subject to CSAPR/CAIR. However, if Ozone standard changes, the impact will be a shortfall of allowances. Must purchase additional allowances.

[2]No impact from this Rule. Purdom GT 2 was retired on 10/26/2018 and the Sam O. Purdom Generation Station does not meet the established requirements under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities.

[3]Hopkins 1 retired November 2018.

Average Fuel Price Comparison

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	2009	NA	NA	NA	NA	2,612	8.57	0	9.32	4	18.66
	2010	NA	NA	NA	NA	2,614	7.69	6	9.08	3	22.15
	2011	NA	NA	NA	NA	2,703	6.96	2	9.08	0	20.86
	2012	NA	NA	NA	NA	2,509	5.54	NA	NA	0	18.86
	2013	NA	NA	NA	NA	2,662	4.51	NA	NA	2	23.58
	2014	NA	NA	NA	NA	2,788	4.82	NA	NA	10	23.57
	2015	NA	NA	NA	NA	2,704	4.44	NA	NA	0	NA
	2016	NA	NA	NA	NA	2,562	3.92	NA	NA	76	22.54
	2017	NA	NA	NA	NA	2,635	3.79	NA	NA	0	NA
	2018	NA	NA	NA	NA	2,808	3.79	NA	NA	1	23.09
Projected	2019	NA	NA	NA	NA	2,829	3.48	NA	NA	0	12.19
	2020	NA	NA	NA	NA	2,769	3.49	NA	NA	0	12.53
	2021	NA	NA	NA	NA	2,772	3.42	NA	NA	0	12.54
	2022	NA	NA	NA	NA	2,805	3.43	NA	NA	0	12.62
	2023	NA	NA	NA	NA	2,814	3.49	NA	NA	0	12.92
	2024	NA	NA	NA	NA	2,823	3.60	NA	NA	0	13.24
	2025	NA	NA	NA	NA	2,843	3.69	NA	NA	0	13.57
	2026	NA	NA	NA	NA	2,857	3.83	NA	NA	0	13.91
	2027	NA	NA	NA	NA	2,855	3.93	NA	NA	0	14.26
	2028	NA	NA	NA	NA	2,889	4.03	NA	NA	0	14.62

Notes

(Include Notes Here)

Tables included in file “Data Request #1 (2019) – Appendix A Rev 1.xls”

History and Forecast of Summer Peak Demand
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
FORECAST:									
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									

Please see Schedule 3.1.2 (Table 2.5) in the City's Ten Year Site Plan report.

History and Forecast of Summer Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
FORECAST:									
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									

Please see Schedule 3.1.3 (Table 2.6) in the City's Ten Year Site Plan report.

History and Forecast of Winter Peak Demand
High Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) C / I Load Management	(9) C / I Conservation	(10) Net Firm Demand
HISTORY:									
2009/10									
2010/11									
2011/12									
2012/13									
2013/14									
2014/15									
2015/16									
2016/17									
2017/18									
2018/19									
FORECAST:									
2019/20									
2020/21									
2021/22									
2022/23									
2023/24									
2024/25									
2025/26									
2026/27									
2027/28									
2028/29									

Please see Schedule 3.2.2 (Table 2.8) in the City's Ten Year Site Plan report.

History and Forecast of Winter Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2009/10									
2010/11									
2011/12									
2012/13									
2013/14									
2014/15									
2015/16									
2016/17									
2017/18									
2018/19									
FORECAST:									
2019/20									
2020/21									
2021/22									
2022/23									
2023/24									
2024/25									
2025/26									
2026/27									
2027/28									
2028/29									

Please see Schedule 3.2.3 (Table 2.9) in the City's Ten Year Site Plan report.

History and Forecast of Annual Net Energy for Load - GWH
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	C / I Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor (%)
HISTORY:								
2009								
2010								
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
FORECAST:								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								

Please see Schedule 3.3.2 (Table 2.11) in the City's Ten Year Site Plan report.

History and Forecast of Annual Net Energy for Load - GWH
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	C / I Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor (%)
HISTORY:								
2009								
2010								
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
FORECAST:								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								

Please see Schedule 3.3.3 (Table 2.12) in the City's Ten Year Site Plan report.

Existing Generating Unit Operating Performance

(1)	(2)		(3)		(4)		(5)		(6)	
			Planned Outage Factor (POF) [1]		Forced Outage Factor (FOF)		Equivalent Availability Factor (EAF)		Average Net Operating Heat Rate (ANOHR)	
Plant Name	Unit No.		Historical	Projected	Historical	Projected	Historical	Projected	Historical	Projected
Existing Units										
C. H. Corn	1	[2]	NA	NA	NA	NA	NA	NA	NA	NA
C. H. Corn	2	[2]	NA	NA	NA	NA	NA	NA	NA	NA
C. H. Corn	3	[2]	NA	NA	NA	NA	NA	NA	NA	NA
A. B. Hopkins	ST 1 [3]		4.14%	NA	0.09%	NA	95.77%	NA	12,565	NA
A. B. Hopkins	CC 2		4.59%	8.03%	0.19%	2.48%	95.17%	85.00%	7,907	7,881
A. B. Hopkins	GT 3	[4]	1.83%	3.05%	2.69%	4.20%	95.48%	88.23%	10,021	9,938
A. B. Hopkins	GT 4	[4]	18.49%	3.05%	1.16%	4.20%	80.35%	88.23%	9,896	9,943
A. B. Hopkins	IC 1-4	[5]	NA	2.06%	NA	1.68%	NA	93.87%	NA	8,140
S. O. Purdom	CC 8		7.70%	8.03%	7.99%	2.48%	84.31%	85.00%	7,795	7,552
S. O. Purdom	GT 2 [3]	[4]	1.82%	NA	1.19%	NA	96.99%	NA	22,201	NA
Substation 12	IC 1-2		0.07%	2.06%	0.00%	1.68%	99.93%	93.87%	8,429	8,323
Future Units										
A. B. Hopkins	IC 5		NA	2.06%	NA	1.68%	NA	93.87%	NA	8,140

NOTE: Historical - average of past three years (taken from Electric Utility's "Operational Recap" report for 2015-17)
Projected - average of next ten years (POF/FOF/EAF taken from NERC GADS "2013-2017 Generating Unit Statistical Brochure - All Units Reporting")

[1] Historical values reflect sum of scheduled and maintenance outage factors. Projected values are NERC GADS planned outage factors (POF) for peer units.
[2] The City did not track the historical factors for the Corn Hydro units. No "Projected" data provided. These units were retired in February 2019.
[3] No "Projected" data provided for these units. They were retired in the Fall of 2018.
[4] Historical data reflects average gross operating heat rate (Btu/kWh).
[5] These units became commercially operational in the Spring of 2019.

Nominal, Delivered Residual Oil Prices [1]
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
HISTORY:									
2016	NA	NA	NA	NA	NA	NA	NA	NA	NA
2017	NA	NA	NA	NA	NA	NA	NA	NA	NA
2018	NA	NA	NA	NA	NA	NA	NA	NA	NA
FORECAST:									
2019	NA	NA	NA	NA	NA	NA	NA	NA	NA
2020	NA	NA	NA	NA	NA	NA	NA	NA	NA
2021	NA	NA	NA	NA	NA	NA	NA	NA	NA
2022	NA	NA	NA	NA	NA	NA	NA	NA	NA
2023	NA	NA	NA	NA	NA	NA	NA	NA	NA
2024	NA	NA	NA	NA	NA	NA	NA	NA	NA
2025	NA	NA	NA	NA	NA	NA	NA	NA	NA
2026	NA	NA	NA	NA	NA	NA	NA	NA	NA
2027	NA	NA	NA	NA	NA	NA	NA	NA	NA
2028	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS: heat content, ash content

[1] Residual fuel oil is not currently nor is it expected in the future to be a part of the City's generation fuel mix.

Nominal, Delivered Residual Oil Prices [1]
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
HISTORY:									
2016	NA	NA	NA	NA	NA	NA	NA	NA	NA
2017	NA	NA	NA	NA	NA	NA	NA	NA	NA
2018	NA	NA	NA	NA	NA	NA	NA	NA	NA
FORECAST:									
2019	NA	NA	NA	NA	NA	NA	NA	NA	NA
2020	NA	NA	NA	NA	NA	NA	NA	NA	NA
2021	NA	NA	NA	NA	NA	NA	NA	NA	NA
2022	NA	NA	NA	NA	NA	NA	NA	NA	NA
2023	NA	NA	NA	NA	NA	NA	NA	NA	NA
2024	NA	NA	NA	NA	NA	NA	NA	NA	NA
2025	NA	NA	NA	NA	NA	NA	NA	NA	NA
2026	NA	NA	NA	NA	NA	NA	NA	NA	NA
2027	NA	NA	NA	NA	NA	NA	NA	NA	NA
2028	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS: heat content, ash content

[1] Residual fuel oil is not currently nor is it expected in the future to be a part of the City's generation fuel mix.

Nominal, Delivered Residual Oil Prices [1]
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
HISTORY:									
2016	NA	NA	NA	NA	NA	NA	NA	NA	NA
2017	NA	NA	NA	NA	NA	NA	NA	NA	NA
2018	NA	NA	NA	NA	NA	NA	NA	NA	NA
FORECAST:									
2019	NA	NA	NA	NA	NA	NA	NA	NA	NA
2020	NA	NA	NA	NA	NA	NA	NA	NA	NA
2021	NA	NA	NA	NA	NA	NA	NA	NA	NA
2022	NA	NA	NA	NA	NA	NA	NA	NA	NA
2023	NA	NA	NA	NA	NA	NA	NA	NA	NA
2024	NA	NA	NA	NA	NA	NA	NA	NA	NA
2025	NA	NA	NA	NA	NA	NA	NA	NA	NA
2026	NA	NA	NA	NA	NA	NA	NA	NA	NA
2027	NA	NA	NA	NA	NA	NA	NA	NA	NA
2028	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS: heat content, ash content

[1] Residual fuel oil is not currently nor is it expected in the future to be a part of the City's generation fuel mix.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil [2]			Natural Gas [3]		
			Escalation			Escalation
Year	$/BBL	c/MBTU	%	c/MBTU	$/MCF	%
HISTORY[1]:						
2016	131.31	2,254	NA	392	4.01	NA
2017	0.00	0	NA	379	3.87	-3.4%
2018	134.53	2,309	NA	379	3.88	0.0%
FORECAST:						
2019	70.99	1,219	-47.2%	367	3.75	-3.2%
2020	73.00	1,253	2.8%	348	3.56	-5.0%
2021	73.07	1,254	0.1%	343	3.51	-1.5%
2022	73.51	1,262	0.6%	346	3.54	0.8%
2023	75.26	1,292	2.4%	353	3.61	2.0%
2024	77.14	1,324	2.5%	361	3.69	2.3%
2025	79.07	1,357	2.5%	370	3.79	2.6%
2026	81.04	1,391	2.5%	384	3.93	3.8%
2027	83.07	1,426	2.5%	394	4.03	2.6%
2028	85.15	1,462	2.5%	405	4.14	2.6%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.825 MMBtu/BBL, ash content - NA, sulfur content - < 15 ppm

[1] Actual average cost of distillate oil and gas burned. No distillate burned in CY 2017.
[2] Forecast values reflected expected delivered prices for New York Harbor ULSD (HO).
[3] Delivered gas price reflects cost at Henry Hub increased by compression losses, basis and firm transportation cost.

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil [2]			Natural Gas [3]		
			Escalation			Escalation
Year	$/BBL	c/MBTU	%	c/MBTU	$/MCF	%
HISTORY[1]:						
2016	131.31	2,254	NA	392	4.01	NA
2017	0.00	0	NA	379	3.87	-3.4%
2018	134.53	2,309	NA	379	3.88	0.0%
FORECAST[4]:						
2019	70.99	1,219	-47.2%	367	3.75	-3.2%
2020	74.78	1,284	5.3%	357	3.66	-2.5%
2021	76.72	1,317	2.6%	361	3.69	1.0%
2022	79.10	1,358	3.1%	373	3.82	3.3%
2023	82.95	1,424	4.9%	390	3.99	4.5%
2024	87.10	1,495	5.0%	408	4.18	4.8%
2025	91.45	1,570	5.0%	429	4.39	5.1%
2026	96.03	1,649	5.0%	456	4.67	6.3%
2027	100.83	1,731	5.0%	480	4.91	5.1%
2028	105.87	1,818	5.0%	504	5.16	5.1%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.825 MMBtu/BBL, ash content - NA, sulfur content - < 15 ppm

[1] Actual average cost of distillate oil and gas burned. No distillate burned in CY 2017.
[2] Forecast values reflected expected delivered prices for New York Harbor ULSD (HO).
[3] Delivered gas price reflects cost at Henry Hub increased by compression losses, basis and firm transportation cost.
[4] For the high case, compound annual escalation rates (CAER) are assumed to be 2.5% higher than the base case CAERs.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil [2]			Natural Gas [3]		
			Escalation			Escalation
Year	$/BBL	c/MBTU	%	c/MBTU	$/MCF	%
HISTORY[1]:						
2016	131.31	2,254	NA	392	4.01	NA
2017	0.00	0	NA	379	3.87	-3.4%
2018	134.53	2,309	NA	379	3.88	0.0%
FORECAST[4]:						
2019	70.99	1,219	-47.2%	367	3.75	-3.2%
2020	71.23	1,223	0.3%	339	3.47	-7.5%
2021	69.52	1,193	-2.4%	325	3.33	-4.0%
2022	68.20	1,171	-1.9%	320	3.27	-1.7%
2023	68.11	1,169	-0.1%	318	3.26	-0.5%
2024	68.11	1,169	0.0%	318	3.25	-0.2%
2025	68.11	1,169	0.0%	318	3.26	0.1%
2026	68.11	1,169	0.0%	322	3.30	1.3%
2027	68.11	1,169	0.0%	323	3.30	0.1%
2028	68.11	1,169	0.0%	323	3.30	0.1%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.825 MMBtu/BBL, ash content - NA, sulfur content - < 15 ppm

[1] Actual average cost of distillate oil and gas burned. No distillate burned in CY 2017.
[2] Forecast values reflected expected delivered prices for New York Harbor ULSD (HO).
[3] Delivered gas price reflects cost at Henry Hub increased by compression losses, basis and firm transportation cost.
[4] For the low case, compound annual escalation rates (CAER) are assumed to be 2.5% lower than the base case CAERs.

Nominal, Delivered Coal Prices [1]
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
HISTORY:												
2016	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2017	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2018	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
FORECAST:												
2019	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2020	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2021	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2022	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2023	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2024	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2025	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2026	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2027	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2028	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS: type of coal, heat content, ash content

[1] Coal is not currently nor is it expected in the future to be a part of the City's generation fuel mix.

Nominal, Delivered Coal Prices [1]
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
HISTORY:												
2016	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2017	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2018	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
FORECAST:												
2019	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2020	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2021	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2022	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2023	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2024	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2025	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2026	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2027	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2028	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS: type of coal, heat content, ash content

[1] Coal is not currently nor is it expected in the future to be a part of the City's generation fuel mix.

Nominal, Delivered Coal Prices [1]
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
HISTORY:												
2016	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2017	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2018	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
FORECAST:												
2019	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2020	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2021	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2022	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2023	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2024	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2025	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2026	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2027	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2028	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS: type of coal, heat content, ash content

[1] Coal is not currently nor is it expected in the future to be a part of the City's generation fuel mix.

Nominal, Delivered Nuclear Fuel and Firm Purchases

(1)	(2)	(3)	(4)	(5)
	Nuclear [1]		Firm Purchases [2]	
		Escalation		Escalation
Year	c/MBTU	%	$/MWh	%
HISTORY:				
2016	NA	NA	87.41	NA
2017	NA	NA	87.29	-0.1%
2018	NA	NA	90.42	3.6%
FORECAST:				
2019	NA	NA	90.42	0.0%
2020	NA	NA	90.42	0.0%
2021	NA	NA	90.42	0.0%
2022	NA	NA	90.42	0.0%
2023	NA	NA	90.42	0.0%
2024	NA	NA	90.42	0.0%
2025	NA	NA	90.42	0.0%
2026	NA	NA	90.42	0.0%
2027	NA	NA	90.42	0.0%
2028	NA	NA	90.42	0.0%

[1] Nuclear fuel is not currently nor is it expected in the future to be a part of the City's generation fuel mix.

[2] Reflects actual and projected firm retail purchases from Talquin Electric Cooperative.

Financial Assumptions
Base Case

AFUDC RATE	5.90%	%	[1]
CAPITALIZATION RATIOS:			
DEBT	55.65%	%	[2]
PREFERRED	N/A	%	
EQUITY	181.58%	%	[2]
RATE OF RETURN			
DEBT	6.02%	%	[3]
PREFERRED	N/A	%	
EQUITY	9.12%	%	[4]
INCOME TAX RATE:			
STATE	N/A	%	
FEDERAL	N/A	%	
EFFECTIVE	N/A	%	
OTHER TAX RATE:		%	
Sales Tax ($5,000 or less)	7.50	%	
Sales Tax (>$5,000)	6.00	%	
DISCOUNT RATE:	5.50	%	[5]
TAX DEPRECIATION RATE:	N/A	%	

[1] Equals 2018 Capitalized Interest divided by Amount subject to interest (see Accounting Services Cap Interest workpapers)
[2] Per 2018 CAFR for electric fund
[3] Equals FY2018 "Income before Contibutions and Transfers" divided total debt
[4] Equals FY2018 "Income before Contibutions and Transfers" divided total net position
[5] WSJ prime rate at 4/16/19

Financial Escalation Assumptions

(1)	(2)	(3)	(4)	(5)
Year	General Inflation %	Plant Construction Cost %	Fixed O&M Cost %	Variable O&M Cost %
2019	2.2%	2.2%	2.2%	2.2%
2020	2.4%	2.5%	2.5%	2.5%
2021	2.5%	2.6%	2.6%	2.6%
2022	2.5%	2.6%	2.6%	2.6%
2023	2.4%	2.5%	2.5%	2.5%
2024	2.4%	2.5%	2.5%	2.5%
2025	2.4%	2.5%	2.5%	2.5%
2026	2.4%	2.5%	2.5%	2.5%
2027	2.4%	2.5%	2.5%	2.5%
2028	2.4%	2.5%	2.5%	2.5%

Source: Congressional Budget Office

Loss of Load Probability, Reserve Margin, and Expected Unserved Energy
Base Case Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Annual Isolated			Annual Assisted		
Year	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)
2019	13.4	17.1	6,263.4	0.45	17.1	183.1
2020	8.5	20.1	7,702.7	0.72	20.1	267.9
2021	17.8	20.1	8,506.1	0.69	20.1	299.7
2022	7.5	20.0	4,759.8	0.23	20.0	121.6
2023	10.3	20.2	5,250.5	0.38	20.2	152.6
2024	12.0	20.1	7,681.3	0.60	20.1	247.7
2025	10.6	19.6	5,379.6	0.41	19.6	142.6
2026	8.0	19.2	5,233.8	0.30	19.2	129.3
2027	16.4	18.8	9,140.6	0.76	18.8	312.9
2028	10.0	18.4	6,765.1	0.45	18.4	181.0