Big Bend Analysis

Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project

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AUTHOR

Devi Glick
Bob Fagan
Jason Frost
David White

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

ERRATA SHEET

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This report has been revised to correct minor typographical errors only. No substantive changes were made.

1. Introduction and Summary

1.1. Focus of Synapse analysis

Synapse Energy Economics has conducted an analysis of the economics of Tampa Electric Company's (TECO or the Company) site certification application for its Big Bend Power Station (Big Bend). Big Bend's units are currently fired by gas (Units 1 and 2)[1] and coal (Units 3 and 4).[2] This analysis[3] focuses on TECO's proposal in the SCA to add two gas-fired combustion turbines), refurbish one of its gas-fired steam turbines, and retire the remaining steam turbine (collectively, the Gas Project).

As proposed, the Gas Project would result in a new combined-cycle power plant (the "proposed plant"), with a net capacity increase of 285 megawatts (MW) in the summer (net summer capability), and 329 MW in the winter (net winter capability), relative to Big Bend's existing configuration. The Gas Project is estimated to cost $895 million,[4] plus substantial ongoing annual fuel and operations and maintenance (O&M) costs.

In this report, Synapse analyzes the electrical energy needs of TECO's customers and cleaner, lower-cost methods available to meet them. The principal sections of this report are as follows:

Section 2 describes the context for the analysis of needs, options, and relative costs, including an overview of TECO's proposed Gas Project.

Section 3 summarizes TECO customers' actual capacity and energy needs.

Section 4 analyzes Big Bend's current cost and operation, and future cost and operation of the proposed plant.

Section 5 identifies several reasonable and available methods to cost-effectively avoid the proposed plant and reduce overall emissions across TECO's service area.

1.2. Key conclusions

TECO's Gas Project would be expensive, environmentally harmful, and would unnecessarily lock customers into almost one *billion* dollars in capital spending. Synapse found that the Company's claims

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1 Units 1 and 2 are considered dual fuel units (gas and coal) but currently operate on natural gas.

2 As discovery in this matter is ongoing, Synapse reserves the right to supplement this report.

3 This analysis was all conducted by the primary author, Devi Glick of Synapse Energy Economics, Inc, and under her direct supervision.

4 Tampa Electric Company, DOHA Case No. 18-2124EPP, Sierra Club's First Request for Production of Documents 2, December 6, 2018. Page 4.

about both the need for the Gas Project, and the economic and environmental benefits it would produce for its customers, are false and unsupported. Here is a summary of our findings:

1. ***TECO uses a faulty baseline to make unsupported claims about the Gas Project's benefits, both economic and environmental.*** Specifically, TECO compares the cost and emissions of the Gas Project to a "baseline" of Units 1 and 2 operating on coal and at a high capacity factor. Units 1 and 2 have been converted to gas since 2017 and operate at exceptionally low (less than 20 percent) capacity factors. There is no plausible future in which TECO runs Units 1 and 2 at high capacity factors on coal, therefore the Company has no justification for using that as a baseline.

2. ***TECO's need claim is based on systematic over-projection of peak and load growth, technically unsupported winter peak modeling, and an unnecessarily high planning reserve margin.*** TECO has a history of over-projecting demand to justify capacity additions. The Company continues to do so in its most recent Ten-Year Site Plan.[5] TECO's winter peak demand is driving the Company's claim around capacity need. However, the assumptions used in the site certification application to develop the forecast deviate significantly from historical norms and are not supported or justified by the Company. TECO also plans its system to a 20 percent reserve margin above what the Company projects it will need to meet peak load. That is exceptionally high. In fact, even the Florida Reliability Coordinating Council (FRCC) uses only a 15 percent reserve margin threshold for peninsular Florida.

3. **TECO has historically underinvested in energy efficiency and demand-side management, and continues to lag nationally in planned investment over the next decade.** There is zero justification for building a billion-dollar plant without first ramping up investment in highly cost-effective energy efficiency, at least to a level approaching the national average.

4. **TECO actually has ZERO capacity need over the next decade, between incremental efficiency investment, a reasonable (lower) demand forecast, and a corrected winter peak.** Even with more conservative assumptions, TECO's winter capacity need is hundreds of megawatts less than the Company claims in the site certification application.

5. **TECO does not need the energy from the Gas Project.** The Company's own data indicate that TECO plans to significantly ramp down operations at its existing three combined cycle plants when the proposed combined cycle plant would come online at Big Bend. Eighty to ninety percent of the generation projected to come from Big Bend could be generated from the Company's existing plants operating at current levels.

6. **TECO fails to consider maintaining Units 1 and 2 as peaking capacity resources.** If the Company really only needs winter peaking capacity, and it does not in fact need energy, there is no reason not to consider maintaining the existing units for that purpose.

7. **TECO fails to consider any alternative resource options.** Utility-scale solar can provide TECO with significant summer peaking capacity and reduce emissions from running a gas or coal-

[5] The Ten-Year Site Plan is Florida's version of a long-term resource plan. This document summarizes 1) the energy needs of TECO's customers over the next ten years; 2) the Company's current resource portfolio; and 3) the Company's future resource plan to meet the electrical energy needs of TECO's customers over the next ten years.

fired plan. Battery storage can firm up solar capacity and provides a crucial winter (and also summer) peaking resource. Energy efficiency is and continues to be the lowest-cost resource option for TECO. But none of these reasonable and available (and less environmentally harmful) methods appear to be considered by TECO.

8. **TECO can save customers as much as $1.8 billion over the life of the proposed plant and reduce carbon dioxide (CO_2) emissions by 21 to 31 percent by investing in alternative resource portfolios. These portfolios offer reasonable and available methods to minimize adverse effects to the environment.** By deploying smaller, optimally sized resources such as energy efficiency investment—spread out to align with actual capacity needs—the Company will be able to take advantage of plummeting supply costs of solar photovoltaics ("PV") and battery technology. The incremental nature of energy efficiency, solar, and battery storage capacity provides a hedge against future load growth uncertainties. Additionally, these carbon-free resources substantially reduce both emissions and fuel costs.

In short, TECO has provided no reasonable justification for locking its customers into an almost billion-dollar capital expense. The Company should not be allowed to proceed with the Gas Project without first establishing need and robustly evaluating alternative resource options based on cost and environmental impact, in a transparent public process.

2. CONTEXT

2.1. TECO proposes to continue its reliance on gas and coal-fired generation

TECO has submitted to the Florida Department of Environmental Quality (and other agencies) a site certification application for what it refers to as the "Big Bend Unit 1 Modernization Project"[6] (referred to here as the Gas Project). The Gas Project would occur at the Big Bend Power Station (Big Bend) in Hillsborough County, Florida, at the current site of Units 1-4, and combustion turbine 4. Units 1 and 2 are 1970's era gas-fired steam turbines; Units 3 and 4 are coal-fired steam turbines—see Table 1 for full details.

Table 1: Current Big Bend Units 1-4

	Big Bend Unit 1	Big Bend Unit 2	Big Bend Unit 3	Big Bend Unit 4
Primary Fuel	Gas	Gas	Coal	Coal
Capacity (Summer / Winter MW)	385 / 395	385 / 395	385 / 400	437 / 443
Year Built	1970	1973	1976	1985

[6] TECO, Cover Letter to Big Bend Site Certification Application, April 18, 2018.

During the first phase of the Gas Project, TECO proposes to construct two new 360/392 MW (net summer/winter capability) gas combustion turbines and to take off-line Units 1 and 2, which are two 385/395 MW (net summer/winter capability) steam turbines. The new combustion turbines would only operate at 330/350 MW (summer/winter) capacity during this first phase of the project. The combustion turbines would be scheduled to come online in June 2021.[7]

In the second phase of the Gas Project, TECO would refurbish the steam turbine from Unit 1 and configure it to receive steam produced from two new heat-recovery steam generators powered by the exhaust of the newly installed gas-fired combustion turbines.[8] In other words, the steam turbine would become a heat-recovery steam turbine. TECO would also retire Unit 2. The Company would begin operating the proposed 2x1 combined-cycle facility in January 2023.[9] The proposed plant would be larger than the existing steam turbines, with a total of 1,090 MW of capacity (nominal), including 740 MW from two 370 MW combustion turbines and 350 MW from the heat-recovery steam turbine.[10]

The net capability of the proposed plant would be 1,055/1,119 MW (summer/winter).[11] Existing capability of Units 1 and 2 combined is 770/790 (summer/winter). Thus, **the Gas Project would result in a net increase of 285/329 MW (summer/winter) of capacity**.

In addition to the Gas Project, TECO's application also seeks certification of Unit 3 to remain a coal-fired steam turbine.[12] By omitting any proposal to phase out coal from Units 3 and 4, TECO in effect proposes to continue to operate these units on coal indefinitely.

2.2. TECO relies on a faulty baseline that misrepresents the current operation of Big Bend Units 1 and 2

TECO relies on outdated historical operational assumptions—from when the units were operating on coal at high capacity factors—to define the baseline of current operation at Big Bend Units 1 and 2. As a general principal, TECO's baseline for comparison in its SCA should reflect the present or what the future is reasonably expected to look like "but for" the Gas Project—that is, how things would look if Big Bend continued to operate as it does now. Instead, TECO cherry-picks a historical range that provides the Company a more favorable baseline for comparison.

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7 TECO Ten-Year Site Plan, Schedules 1, 8.1, 9 (pages 11-12 of 15).

8 TECO DOAH Case No. 18-2124EPP, Sierra Club First Set of Interrogatories, No 3. January 2, 2019.

9 Op. Cit., Schedule 9 (page 13 of 15).

10 Big Bend 1 Modernization Site Certification Application. April 2018. Page 1-9.

11 Net summer/winter capability is the firm capacity that the generating equipment can supply to meet the system load at peak in each season.

12 Unit 4 is not seeking certification. Unit 4 was built after the Florida Electrical Power Plan Siting Act (PPSA) became effective, and therefore is subject to the PPSA. Units 1-3 were built prior to the PPSA and are subject to different certification processes.

Units 1 and 2 currently run on gas and operate at very low capacity factors—neither of which TECO's analysis recognizes. While the two steam turbines did historically run on coal and at high capacity factors (78 percent and 76 percent in 2014),[13] in 2015 construction was completed to allow them both to co-fire on coal or gas.[14] Since then, these units have been operating at declining levels. As of June and October 2017, both units were operating exclusively on gas.[15] In 2018, they operated at only 16 percent and 20 percent capacity factors.[16] These data (all reported by TECO) make it highly unlikely that there is a future "baseline" in which Units 1 and 2 operate on coal or at high capacity factors. Despite this, the Company repeatedly categorizes both units as coal-burning in its Ten-Year Site Plan[17] and its site certification application.

The Gas Project would substantially increase emissions relative to current operation of Units 1 and 2.

TECO's claim that the Gas Project would result in a net emissions reduction of CO_2 and other pollutants is based on the Company's misleading characterization of Units 1 and 2 as high capacity factor coal units. It is inappropriate to compare Units 1 and 2 running on coal (and often) to the proposed plant's future operations because **TECO has already abandoned coal as a fuel source at Units 1 and 2**. In fact, CO_2 emissions from Units 1 and 2 were a combined 85 percent lower in 2018—by which time they were already gas-fired—than the "baseline" emission values that TECO presents in the site certification application.[18]

The "baseline" coal emissions values in the Company's site certification application come from TECO's air permit application for the Gas Project (permit no. 0570039-119-AC), where TECO evaluated the highest average annual emissions over any two-year period for each of Units 1 and 2. However, the two-year periods TECO selected are both several years old, spanning from 2013 to 2015. This is back when the units were coal-fired and running at substantially higher capacity factors.[19] Such values might have been acceptable for the air permit application,[20] but they are irrelevant and misleading as used in the site certification application.

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13 EIA form 923, Monthly Generating Unit Net Generation Time Series files for years 2013-2018.

14 TECO DOAH Case No. 18-2124EPP, Sierra Club Second Request for Production of Documents, No 15, page 2. January 16, 2019.

15 EIA form 923, Monthly Generation and Fuel Consumption Time Series files for years 2013 – 2018.

16 EIA form 923, Monthly Generating Unit Net Generation Time Series files for years 2013-2018. 2018 data was available only through October.

17 Unless otherwise noted, "Ten-Year Site Plan" refers to the Company's plan of that name dated April 2, 2018.

18 EPA Air Markets Program. Available at https://ampd.epa.gov/ampd/.

19 Big Bend 1 Modernization Project Air Construction Permit Application. April 2018. Appendix D.

20 Under New Source Review laws, a plant can calculate emission for any 24 months period in the past 5 years.

The Company should be using the emissions level from the current gas-fired operation of Units 1 and 2 as the baseline for comparison. TECO projects that the proposed plant (in the final combined-cycle phase) would emit a maximum of 3,559,465 tons of CO_2 annually.[21] This is more than four times as much as Units 1 and 2 emitted in 2018.[22] Emissions for sulfur dioxide (SO_2) and nitrogen oxides (NO_X)—two criteria pollutants under the Clean Air Act that pose serious health risks—would also be much higher from the proposed plant than the actual proper baseline, as shown in Table 2.

Table 2: Net Emissions from Big Bend Units 1 and 2

Annual Emissions	CO_2	SO_2	NO_x
Maximum historical emissions from Big Bend Units 1 &2	5,586,827	5,214	2,546
2018 historical emissions from Big Bend Units 1 & 2	860,346	7	413
Potential emission from the Gas Project under combined cycle operation	3,559,465	176	1,650

Sources: EPA Air Markets Program, Big Bend 1 Modernization Project Air Construction Permit Application Appendices C and D
Note: TECO's net emissions analysis was not performed on a generation-normalized basis, therefore we did not attempt to normalize emissions based on generation levels either.

TECO's inappropriate comparison of its proposed plant to Units 1 and 2 when they were coal-fired should be replaced by a comparison that is more plausible and generation-normalized. TECO's own data show that the Company would operate the Gas Project at a high capacity factor, while ramping down production at the Company's other combined cycle plants. There would be a minimal net change in emissions associated with this swapping out of energy between the existing combined cycle plants and the proposed plant in the Gas Project. However, TECO also plans to meet future load with energy from the proposed plant. Doing so would cause a significant increase in emissions relative to emission levels from the Company's existing combined cycle fleet and is unnecessary because load growth should be met by solar and energy efficiency as discussed below.

TECO makes the unsupported claim that the Gas Project would result in significant customer savings.

TECO states that the Gas Project would cost $895 million[23] and produce a net customer benefit of $747 million.[24] By comparing a future scenario with Units 1 and 2 operating on coal to a future scenario with the Gas Project, TECO seems to be once again using a faulty baseline in an effort to make the project appear more attractive than it actually is—this time financially.

[21] Big Bend 1 Modernization Project Air Construction Permit Application. April 2018. Appendix C.

[22] EPA Air Markets Program. Available at https://ampd.epa.gov/ampd/.

[23] Tampa Electric Company, DOHA Case No. 18-2124EPP, Sierra Club's First Request for Production of Documents 2, December 6, 2018. Page 4.

[24] Emera Investor Luncheon Presentation, Toronto, ON. November 27, 2018.

TECO has refused to provide a clear explanation of how the Company calculated this, except to reveal that the net savings are calculated relative to a baseline of Units 1 and 2 continuing to operate on coal.[25] Coal operations provide TECO a more expensive, and therefore more favorable, baseline for comparison than gas. The operating costs of running steam turbines on coal are substantially higher than the operating costs of running a unit as a gas-steam-peaking resource. This is significant because operating costs such as fuel account for the majority of a fossil-fuel powered plant's lifetime cost. In our analysis of the proposed Gas Project, for example, operating costs accounted for over 80 percent of the plant's lifetime cost.

TECO should be calculating the cost of the proposed Gas Project relative to the costs of continuing to operate Units 1 and 2 as gas-fired peaking units. For the reasons discussed above, this correction would considerably reduce, if not eliminate, the claimed cost savings from the proposed Gas Project.

3. TECO's Generation and Capacity Need

TECO claims its Gas Project at the Big Bend site is designed to meet the needs of its current and future customers. Specifically, the Company states that the plan is designed to meet needs, as determined by the process that is summarized in the integrated resource planning (IRP) section of its Ten-Year Site Plan.[26]

TECO's Ten-Year Site Plan provides a high-level summation of the Company's planning process. However, the Ten-Year Site Plan provides insufficient detail about the actual analysis, including calculations and inputs used for the load forecasts (peak and net load) and resource availability projections (supply- and demand-side, energy and capacity). The opaqueness of the Ten-Year Site Plan invites a challenge to TECO's presumption of need for the proposed Gas Project.

We have supplemented available data from TECO's site certification application with the discovery responses TECO has provided to date. This body of information has revealed inaccuracies in TECO's methodologies and illustrates why the proposed plant is not needed.

3.1. What capacity does TECO already have? Plenty of capacity and a high planning reserve margin.

TECO currently has 5,196 MW of winter capacity and 4,793 MW of summer capacity installed on its system, along with interconnections to adjacent systems to allow for imports and exports as warranted.

[25] TECO DOAH Case No. 18-2124EPP, Sierra Club Second Request for Production of Documents, No 26, page 2. January 16, 2019. The two scenarios are labeled as "Reference BB 1-4 on Coal with 600 MW of Solar" and "Staged Modernization with 600 MW of Solar."

[26] TECO DOAH Case No. 18-2124EPP, Sierra Club First Set of Interrogatories, No 1, page 1. December, 6, 2018.

Most of TECO's capacity is coal- or gas-fired, with a small amount of solar PV (22.4 MW) and very small reported energy efficiency gains (16.1 MW in the winter; 15.1 MW in the summer in 2017), and limited demand response.[27] The Company recently added 460 MW of combined cycle gas-fired capacity to its Polk Power Station.[28]

TECO's system has historically been summer peaking, driven by peak air-conditioning demand on the hottest days and hours of the year. The Company maintains a 20 percent planning reserve margin[29] over and above the capacity it projects that it will need to meet normal peak demand[30] loads. TECO assigns solar a zero percent firm capacity contribution in the winter and a 50 percent firm capacity contribution in the summer.[31]

3.2. What does TECO claim it needs? Over a billion dollars in new gas-fired assets.

TECO has 600 MW of solar projects coming online between now and 2021.[32] In addition to the capacity from the proposed Big Bend Gas Project, TECO includes two un-sited 245 MW combustion turbines in its Ten-Year Site Plan. The first would come online in 2023 and the second in 2026.

TECO is not required to publish a standard IRP that might preview and defend its current resource planning, therefore our understanding of the Company's future capacity plans was developed based on a combination of the Company's Ten-Year Site Plan, site certification application, and various responses to discovery (Table 10 and Table 11).

To assess TECO customers' need, we looked at what the summer and winter capacity and energy gap would be "but for" the Gas Project and the two un-sited combustion turbines.[33]

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[27] According to the Federal Energy Regulatory Commission, demand response is defined as "[c]hanges in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp

[28] TECO website: https://www.tampaelectric.com/company/ourpowersystem/powergeneration/polk/.

[29] According to the North American Electric Reliability Corporation, "A planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in planning horizon." A demand projection is generally based on a 50/50 forecast. A reserve margin is a percentage of excess capacity needed to maintain reliability operation while meeting unforeseen increases in demand (eg extreme weather) and unexpected outage of existing capacity. https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx

[30] Peak demand is the highest level of demand for electricity that a utility experiences over a defined period of time . Because a utility must keep the lights on at all times, Utilities plan their system to ensure they can meet peak demand needs.

[31] This was determined based on the total capacity available and reserve margins listed on Schedules 7.1 in the Ten-Year Site Plan.

[32] Tampa Electric Company Ten-Year Site Plan, April 2, 2018. Page 60.

[33] Under the "but for" scenario, Units 1 and 2 are assumed not to retire until their capital recovery years in 2035 and 2038.

Table 3: TECO's baseline capacity need

	Winter			Summer		
	Total Capacity Need	Incremental Capacity Need	Reserve Margin	Total Capacity Need	Incremental Capacity Need	Reserve Margin
2017	-	-	83%	-	-	26%
2018	-	-	30%	-	-	26%
2019	-	-	25%	-	-	27%
2020	-	-	23%	-	-	26%
2021	-	-	21%	-	-	25%
2022	-	-	22%	-	-	24%
2023	394	394	11%	165	165	16%
2024	468	74	10%	234	68	14%
2025	541	73	8%	300	66	13%
2026	617	76	7%	367	67	12%
2027	691	74	5%	436	70	10%

Source: Synapse analysis, based on TECO 2018 Ten-Year Site Plan and Company discovery responses.

3.3. What is wrong with TECO's need claim? It is based on unsubstantiated assumptions and technically inaccurate methodologies.

There are four inaccuracies associated with TECO's need claim.

First, the Company has historically over-projected energy sales, peak demand, and customer growth. TECO once again forecasts increasing load growth in the latest Ten-Year Site Plan, and there is no evidence that it has corrected the methodological errors that caused over-projection in the past. Critically related to this first problem is TECO's exaggeration of projected winter peak load, which now (in TECO's forecast) exceeds summer peak load even though this is not reflective of historical trends.

Second, TECO has invested minimally in energy efficiency and is currently in the midst of an energy efficiency goal-setting process. This means that the base load forecast from the Ten-Year Site Plan does not reflect the actual level of energy efficiency in which the Company can and should achieve going forward.

Third, TECO relies on a minimum reserve margin of 20 percent, which is markedly higher than the 15 percent that the Florida Reliability Coordinating Council say is necessary to maintain reliability.[34] Finally,

[34] *See, e.g.*, Florida Reliability Coordinating Council 2017 Load & Resource Reliability Assessment Report, "Reserve margins for the FRCC Region for the summer and winter peak hours are projected to meet or exceed 20% for each year in the ten-year period which is above the FRCC's minimum Reserve Margin Planning Criterion of 15%." Executive Summary, page 5. Available at: https://www.frcc.com/Reliability/Shared%20Documents/FRCC%20Reliability%20Assessments/FRCC%202017%20Load%20and%20Resource%20Reliability%20Assessment%20Report%20Approved%20062717.pdf.

TECO has recently revealed that the Company plans to install an additional 600 MW of solar PV, which is not included in the Company's most recent site plan.

In different combinations, these four inaccuracies, when corrected, reveal no need for TECO's proposed Gas Project.

TECO has a long record of over-projecting demand.

TECO has been systematically over-projecting electricity sales and demand for the past two decades (see Figure 1, at the end of the report). TECO's current load growth projections (Figure 1, below) are driving the purported need for significant capacity investment over the next decade.

Electricity sales have been essentially flat for the past decade.

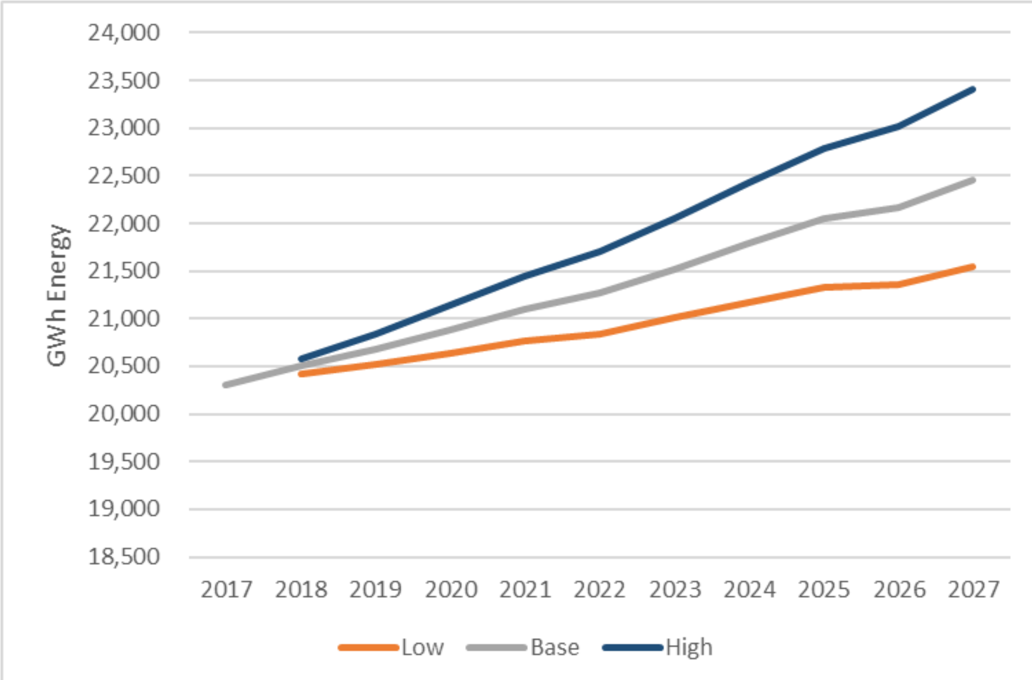
TECO has projected annual average growth rates for electricity sales greater than 1 percent (reaching as high as 3.1 percent) in every year since 2002 with the exception of 2012.[35] In reality, TECO sales have grown a total of only 7 percent since 2002 (5.35 percent on a weather-normalized basis). This is equivalent to an annual growth rate of around 0.85 percent. And most of that growth occurred prior to 2007. Focusing on just the 10 years from 2007–2017, sales have remained relatively flat. Indeed, they have actually fallen 1.78 percent relative to 2007 levels.

Despite a clear history of over-projection, the Company continues to forecast significant load growth in its Base Case load forecast in the 2018 Ten-Year Site Plan. For the period 2018–2027, TECO projects that retail energy sales will rise at an average annual rate of 1 percent, and base retail firm peak demand will increase at an average annual rate of 1.3 percent in the summer and 1.4 percent in the winter. The Company attributes this increase in electricity demand to projected future population growth in the region, and an accompanying increase in demand for services from the commercial sector.[36] This seemingly modest growth projection is driving the Company's need for hefty new capacity additions even after the proposed Gas Project would be complete in 2023. The Company's Low Demand forecast is more realistic than its baseline forecasts given the actual trends seen in TECO's service area.

[35] Projections were evaluated only though 2022. In 2012, TECO projected only a 0.85% growth rate over the years 2012–2021.

[36] Tampa Electric Company Ten-Year Site Plan, April 2, 2018. Page 18.

Figure 1: TECO net energy for load demand forecast



Source: TECO 2018 TYSP.

TECO's winter peak demand forecast relies on a technically unsupported assumption…this assumption is driving the majority of the Company's future capacity need.

TECO presumes that net firm winter demand (net peak load) will be higher than net firm summer demand for this winter (2018/2019) and every winter through 2026/2027.[37] By summer 2023, TECO's forecasts indicate the winter peak is higher than the summer peak, by between 224 MW (previous winter) and 286 MW (following winter). This winter/summer difference and the implication that winter rather than summer peak will drive resource need is inaccurate, because TECO incorrectly forecasts winter peak demand. Thus, going forward, resource needs will continue to revolve around summer peak load, and solar PV resources will continue to provide capacity towards meeting customers' needs.

TECO's weather-normalized net winter peak demand has been roughly flat or declining for the recent years in which data was provided. TECO's weather-normalized net summer peak demand has also been relatively flat, for the past decade (see Figure 6 and Figure 7). In every year since 2011, winter peak demand has been significantly lower than weather-normalized levels. On a non-weather-normalized basis, winter peak demand has reached the lowest levels in nearly a decade, while summer peak demand has steadily increased. Notably, TECO does not need to consider extreme winter weather events, such as the abnormal effects of a Polar Vortex, when projecting normal winter peak levels and

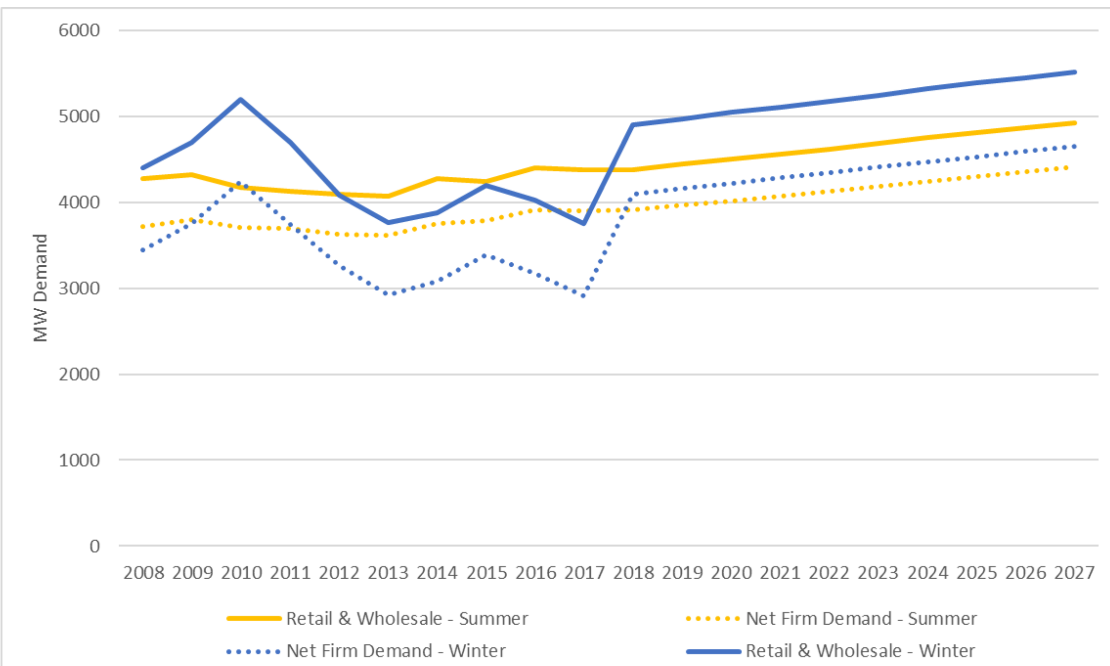
[37] TECO 2018 Ten-Year Site Plan, Schedule 3.1 and 3.2, column 10.

associated winter resource need; they only need consider “normal” low temperature periods, as prescribed by the FRCC.[38]

The biggest question about TECO’s demand forecast precedes the Company’s 2018–2027 forecasts. The Company’s actual 2017 winter net firm peak demand is 2,905 MW, however projected winter demand for 2018 jumps to 4,096 MW, reflecting TECO’s weather-normalization methodology (see Figure 2). This jump of more than 1,000 MW is more or less single-handedly driving the purported demand for the entire Big Bend Gas Project. Thus, the accuracy of TECO’s winter peak projection process is of crucial importance.

We reviewed TECO’s winter peak forecasting methodology and found technically unsupported, key assumptions in its regression model used to estimate winter peak demand. The Company (1) uses a much higher heating degree day value (for two regression components) than the historical average for the peak load days in January and February, and it also (2) presumes a relatively lower-than-normal temperature value on the peak winter day to project winter peak demand.

Figure 2: TECO's peak demand forecasts



Source: TECO 2018 TYSP.

[38] *See, e.g.*, FRCC 2017 Load & Resource Reliability Assessment Report, page 22. https://www.frcc.com/Reliability/Shared%20Documents/FRCC%20Reliability%20Assessments/FRCC%202017%20Load%20and%20Resource%20Reliability%20Assessment%20Report%20Approved%20062717.pdf.

In exploring the peak model spreadsheet provided by the Company we discovered an apparent disparity in the projected heating degree day data (HDD) used to derive the peak forecast. The forecast model uses three parameters to determine the winter peak. These are "Average of HDD65_Filled," "Average of LagHDD65_Filled," and "HDD50_filled." These appear to be based on the average temperature of the coldest day(s) in a given month. However, the details of that calculation are not provided, and the assumptions used for projecting future peak load—normally based on the historical patterns seen—are unsupported.

The spreadsheet contains historical data for 2007 through 2017, and also projected values for those parameters. The "normalized" values used in the forecast period are much higher than the historical average values, about 60 percent on the average. While normalized values might differ some from the recent historical averages, such extreme differences require a good explanation. TECO fails to provide this. It is the use of these higher future HDD values that is a major factor in the Company's higher winter peak load forecasts for 2018 through 2027.

Using TECO's model but substituting historical data for HDD values to reflect a "normalized" projection, we estimated a winter peak forecast that is at least 300 MW and perhaps as much as 700 MW lower than TECO's projection, depending on whether we adjust two (HDD65_Filled, and LagHDD65_Filled) or all three (HDD65_Filled, LagHDD65_Filled, and HDD50) of the key driving temperature-related variables. All three of these HDD variables used in TECO's specification are associated with low-temperature winter peak days, either historical or projected. In either case (adjusting the projection of just two variables or adjusting all three variables) the newly projected winter peak load is lower than the projected summer peak load.

In summary, TECO has forecasted a significant jump in winter peak demand without explaining or justifying the methodology or the result. This supposed jump in demand is the basis for TECO's entire capacity need-claims over the next decade. TECO's should provide a clear explanation of how the Company performed the calculations and why it is justified in relying on above-average values to develop an average demand forecast.

TECO underinvests in energy efficiency (which the Florida Public Service Commission is currently examining).

TECO has very low energy efficiency goals, and the Company has invested very little in energy efficiency programs historically. In TECO's last demand-side management (DSM) docket, where the Company set its 2015–2014 DSM goals, TECO witness Howard Bryant touted the Company's DSM accomplishments and claimed that the Company ranked highly among utilities.[39] Those claims were demonstrably false.

[39] Direct Testimony and Exhibits of Howard T. Bryant, FPSC Docket No. 130201-EI, Commission review of numeric conservation goals (Tampa Electric Company). April 2, 2014, p 9-10. Bryant claimed that TECO's DSM accomplishments are "significantly greater than most other utilities in the US" and that "[t]he magnitude of these continuing efforts by Tampa Electric, as well as other utilities in Florida, is demonstrated by the continued high rankings Florida utilities achieve as identified in the data available from the Energy Information Administration of the Department of Energy."

Synapse consultant Tim Woolf testified in that docket about the reasonableness of the utility's DSM goals. His testimony discussed how TECO's goals have dropped dramatically relative to past DSM savings, which were already well below industry averages.[40]

The Florida Public Service Commission is currently reviewing TECO's energy efficiency and DSM goals in Docket 20190021. This means that the load forecast that TECO uses as the basis for its need assessment in the Ten-Year Site Plan (and therefore plans to meet with the proposed Gas Project), has not even been set yet.

Table 4 shows how low TECO's energy efficiency goals are, and how little the Company has invested historically in energy efficiency programs. In 2017, the national average for first-year, incremental energy efficiency savings as a percent of retail sales was 0.72 percent.[41] TECO's actual energy efficiency savings were 70 percent below the national average (0.22 percent of retail sales); however this savings level was considerably better than the Company's commission-approved goal, which required a savings of only 0.06 percent of retail sales, more than 90 percent below the national average.

In fact, in every year since its last DSM plan was published in 2015, TECO's energy efficiency savings have exceeded Commission goals. Despite this pattern, TECO still projects future load using the Commission's exceptionally low goals. By doing this, the Company is overstating future demand relative to not just the energy efficiency levels that the Company *should* achieve, but also levels that the Company *can* achieve.

Table 4: Incremental annual energy efficiency goals and savings

	Commission Goal (GWh)	Total Achieved (GWh)	Goal as % of Sales	Savings Achieved as % of Sales
2015	5.7	33.7	0.03%	0.17%
2016	9.5	31	0.05%	0.15%
2017	12.8	45.2	0.06%	0.22%
2018	15.3		0.07%	
2019	16.8		0.08%	
2020	17.7		0.08%	
2021	181		0.86%	
2022	17.1		0.08%	
2023	16.2		0.08%	
2024	15.1		0.07%	

[40] Direct Testimony and Exhibits of Tim Woolf, FPSC Docket No.130201-EI, Commission review of numeric conservation goals (Tampa Electric Company). May 19, 2014. Mr. Woolf's testimony covered all Florida utilities. He did not directly call out TECO, but his analysis outlined when TECO fell without the pool of utilities that he was generally discussing.

[41] ACEEE, the 2018 State Energy Efficiency Scorecard, October 2018.

In addition to energy efficiency, TECO omits residential demand response from its future load forecast and resource plans. Residential demand response programs have achieved savings as high as 130 MW in the winter and 69 MW in the summer.[42] The Company does not explain why this demand response resource is omitted from future load forecasts. This omission allows the Company to overstate its future demand forecast.

TECO's planning reserve margin is unjustifiably high.

TECO uses a 20 percent planning reserve margin based on a 1999 stipulation approved by the Florida Public Service Commission.[43] However, that two-decades-old figure was developed based on staff evaluation of a reality that no longer exists. By continuing to plan to a 20 percent reserve margin, TECO is overbuilding its system and saddling its customers with the costs of excess capacity (especially in the winter).

In Docket No. 150196-EI,[44] the state's Office of Public Counsel (OPC) challenged the reserve margin for being excessively high and recommended Commission re-visit the issue in a generic proceeding. The OPC went on to recommend that the Commission apply a 15 percent reserve margin to the investor-owned utilities such as TECO, stating that "Planning to the minimum 15 [percent] reserve margin would not only meet the equitable sharing of energy reserve, but it would also avoid uneconomic and unnecessary overbuilding of generation and the resulting increase in rates to customers."[45] This recommendation is in line with the 15 percent reserve margin used by the Florida Reliability Coordinating Council (FRCC) for Peninsular Florida,[46] and was cited by OPC in making its recommendation. TECO has not justified why it needs a higher reserve margin than the regional reliability entity uses for the entire Florida peninsula.

TECO plans to add a second 600 MW block of solar in the next five years.

TECO has recently revealed that the Company plans to install a second 600 MW block of solar PV projects by 2023 (incremental to the first 600 MW of projects that will be online by 2021).[47] This will

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[42] Schedules 3.2 in the 2018 Ten-Year Site Plan.

[43] Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, December 22, 1999.

[44] This docket related to Florida Power and Light specifically, but the Counsel's challenge to the reserve margin applied to all three investor-owned utilities, including TECO.

[45] Docket No. 150196-EI, Citizen's Post Hearing Brief. December 9, 2015.

[46] North American Reliability Council, 2018 Summer Reliability Assessment, page 15.

[47] Florida Department of Environmental Protection Project Analysis Report, In Re: Tampa Electric Company Big Bend 1 Modernization Project, Case No. 18-2124, at 189 (Jan. 28, 2019) (Transcript of the Jan. 24, 2019 meeting of the Board of County Commissioners Regarding Tampa Electric's Big Bend Unit 1 Modernization Project).

provide TECO with 300 MW of additional firm summer capacity,[48] highly notable for a summer peaking system such as TECOs because this solar significantly reduces TECO incremental summer capacity needs.

3.4. What does TECO actually "need"? No new capacity additions over the next decade.

Given all the flaws in TECO's need claim, it is difficult to determine exactly how much energy and capacity the Company really needs to maintain reliability between now and 2027. However, there is very strong evidence that the Company is greatly overstating demand and will need much less energy and capacity than it claims (see Table 5), and possibly even zero capacity additions.

- With a 15 percent reserve margin instead of 20 percent, TECO's winter capacity need drops by 233 MW, and its summer capacity need drops by 216 MW.
- With reasonable investment in demand response and energy efficiency, TECO's winter capacity need drops by 222 MW, and its summer capacity need drops by 226 MW.
- With more realistic and flatter demand and capacity projections (TECO's low load growth projection, for example), TECO's winter and summer need drops by 355 MW.
- With the second 600 MW of solar projects by 2023, TECO's summer capacity need drops to zero MW.
- Most importantly, when TECO's winter peak load forecast is corrected, the Company's winter capacity need falls by between roughly 300 MW and 700 MW, depending on how many of the regression parameters are adjusted to account for TECO's unsupported assumptions concerning normal low temperatures in January.
- And when any of these factors are combined, need drops even more. Any reasonable combination of factors results in no need for the proposed plant that would increase TCO's system's net summer capacity by roughly 285 MW.

If TECO corrects its winter peak projection (and builds the second 600 MW block of solar) and ramps up energy efficiency investment to reach a level near the current national average by 2024, the Company can eliminate *all* future capacity need between now and 2027. This bears repeating. If TECO corrects its load forecast and ramps energy efficiency investment up to only moderate levels relative to the national average energy efficiency improvements, **the Company will need no new capacity over the next 10 years.**

If TECO is permitted to plan its system around its inaccurate winter peak demand forecast, and TECO builds an additional 600 MW of solar PV by 2023[49] and experiences low demand growth (reflecting a

[48] Assuming 50% summer firm capacity based on TECO's 2018 TYS Ten-Year Site Plan.

[49] This second 600 MW is not included in the Ten-Year Site Plan but has been mentioned by a TECO executive, and was referenced in confidential discovery materials.

more reasonable trajectory), TECO would require zero summer capacity additions, and only 300 MW of winter capacity additions between now and 2027.

Given the strong evidence that TECO has no near-term capacity needs, and at the most conservative end has a small near-term capacity need, TECO should consider smaller and more flexible resource options. There are less expensive and more environmentally benign ways to meet small incremental demand growth than a large gas-fired generation project. These options include energy efficiency, solar, and storage investments as well as winter capacity purchase opportunities. The latter option remains a viable and relatively low-cost insurance policy against any concern of falling short of meeting winter needs.

Table 5: TECO capacity need: 2018–2027

Scenario	Winter Capacity (MW)		Summer Capacity (MW)	
	Need	Diff from Baseline	Need	Diff from Baseline
Baseline (without 2nd 600 MW Solar)	691		436	
Baseline with 2nd 600 MW Solar	691	-	136	300
with Low Demand growth	444	247	-	436
with Low Demand growth + 15% Reserve Margin	222	470	-	436
with Low Demand growth + additional EE investment	104	587		436
Winter peak load corrected w/ 2nd 600 MW Solar	307	385	136	300
with additional EE investment	-	691	-	436

Note: We evaluate need for the proposed 1,090 MW Gas Project and the additional two un-sited 245 MW CT's by assuming that Units 1 and 2 do not retire in 2021, and looking at the capacity and energy gap that would occur "but for" those planned capacity additions. The corrected winter peak load scenario evaluates TECO's capacity need with the two HDD 65 variables corrected in its peak load forecast. When we also correct the HDD 50 variable, the Company's need drops even more.

4. BIG BEND'S COSTS AND OPERATION

4.1. Units 1 and 2 are gas-fired peaking resources that can continue to provide valuable winter (and summer) peaking capacity

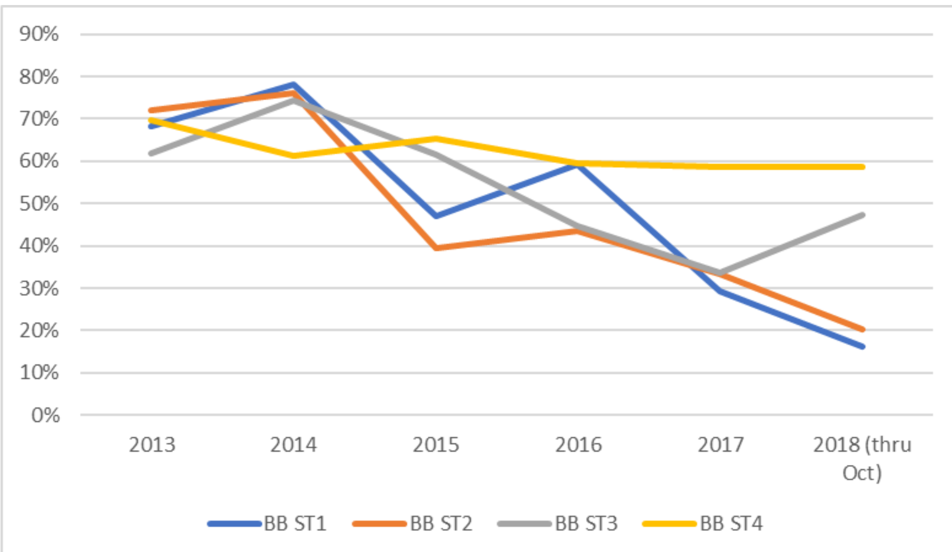
Units 1 and 2 are 1970's-era steam turbines that are currently being run as gas peaking plants. Up until 2014 the plants operated at relatively high capacity factors, on coal, but in recent years the units have been operated at significantly lower levels (see Figure 3). In 2017, Unit 1 operated at only a 29 percent capacity factor and Unit 2 at a 33 percent capacity factor. In 2018, the capacity factors fell further to 16 percent for Unit 1 and 20 percent for Unit 2 (based on data available through October).[50] As was discussed in Section 2.2, both units were converted to have dual-firing capabilities in 2015, and both

[50] EIA form 923 data from 2017 and 2018.

have run exclusively on gas since 2017. Unit 1 has a capital recovery year of 2035 and Unit 2 has a capital recovery year of 2038.[51]

TECO plans to retire both units in 2021 when the two new combustion turbines come online, well in advance of when their capital recovery period otherwise indicates. However, TECO should consider maintaining these units as peaking capacity resources, since the Company's capacity need claim is based on winter peaking capacity, rather than investing in unnecessary baseload resources. The resources would also be available for summer peaking purposes if necessary.

Figure 3: Capacity factors of the Big Bend units



Source: EIA Form 923

4.2. The Gas Project would cost around one billion dollars just to build, and TECO doesn't need any of the project's energy in the near term

TECO claims that the Gas Project (excluding the two un-sited CT's) will cost $895 million and result in net savings to customers of $746 million. As discussed in Section 2.2, the $746 million net savings was calculated based on a faulty baseline comparison of the expanded plant relative to continued operations of Units 1 and 2 on coal. It is not clear how the Company calculated the $895 million, what financial assumptions were used, and what components were included in that cost.

We calculated an installed cost of $818 million for the combined cycle plant in $2017 based on the cost information provided in the 2018 Ten-Year Site Plan (Table 6).[52] Adding in the fuel and O&M cost

[51] TECO 2011 Depreciation Study.

[52] Tampa Electric Company Ten-Year Site Plan, April 2, 2018. Page 71-73.

information provided by TECO,[53] we calculated a net present value (NPV) revenue requirement[54] of $6.2 billion for just the combined cycle plant over its 30-year lifetime. Adding in the other two un-sited CT's, we calculated a total cost of $6.6 billion for the entire proposed Gas Project (see Table 7).

Table 6: Total installed cost of the Big Bend Gas Project

Unit	Capacity (MW)	Total Installed Cost ($/kW)	Total Cost ($2017)
Big Bend CT 5	370	$ 533.17	$ 197,272
Big Bend CT 6	370	$ 533.17	$ 197,272
Big Bend ST	350	$ 1,266.28	$ 424,203
Total Big Bend combined cycle plant	**1,090**	**$ 715.15**	**$ 818,749**
Two Un-sited CT's	245	$616.00	$309,456

Note: The total installed cost on a per-kW basis would be more than three times the indicated value in the table above if considering just the incremental system capacity provided by the proposed Gas Project.

Table 7: Revenue requirement of the Big Bend Gas Project 2023–2052

Big Bend Gas Project Cost ($000 Nominal)	NPV
Fixed O&M	$227,577
Variable O&M	$397,700
Fuel	$4,745,059
Total Operations	$5,370,337
Annualized Capital Cost	$1,268,941
Total RR	$6,639,278

Notes: TECO did not provide the Company's weighted average cost of capital (WACC), so we assumed a 7 percent WACC. TECO also did not indicate whether the O&M costs provided were in real or nominal terms, so we assumed that they were nominal.

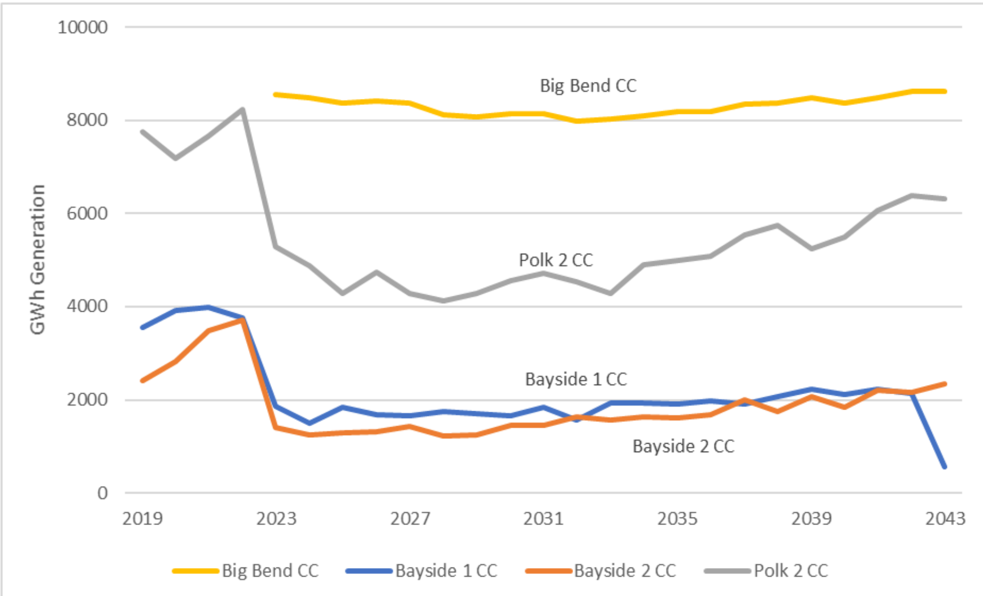
TECO models the proposed plant operating at between 82.9 percent and 91.4 percent capacity factors. Concurrent with this proposed combined cycle plant coming online, TECO's modeling ramps down operations of the rest of its gas fleet. The fleet average capacity factor for all other gas units would drop from 55 percent before the proposed Gas Project to below 30 percent after the proposed Gas Project. Generation from the three existing combined cycle plants (Bayside 1 and 2 and Polk 2) would drop from 15,714 GWh before the proposed Gas Project to 8,566 MW directly following the proposed Gas Project (see Figure 4). This is especially surprising considering that the Polk 2 combined cycle plant was just expanded in 2017 and the two combined cycle plants at Bayside (1 and 2) are only around 15 years

[53] TECO DOAH Case No. 18-2124EPP, Sierra Club Second Request for Production of Document No 13 Confidential Supplemental response. January, 9, 2019.

[54] The revenue requirement is the total amount of money a utility must collect from customers to pay all costs including a reasonable return on investment. https://pubs.naruc.org/pub.cfm?id=5376DE70-2354-D714-51BA-736C233E4185

old.[55] TECO's existing combined cycle fleet has more than sufficient "energy headroom"[56] to meet TECO's needs without the proposed plant.

Figure 4: Generation from TECO combined cycle (CC) plants before and after the Gas Project



Source: 2018 TYSP, IRR 7

As shown in Table 8, 84 percent of the energy output from Big Bend in 2023 can be matched by simply continuing to operate the existing combined cycle plants at 2022 levels. In 2024 this number jumps to 95 percent. This indicates that TECO does not need the energy from the Gas Project for at least the next 10 years, as it could simply continue operating the existing combined cycle plants at current or higher capacity factors and meet its full energy need. It makes no sense for the Company to spend almost a billion dollars on a combined cycle unit, when it does not have a significant energy need.

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[55] Polk 2 was expanded in 2017, and Bayside 1 and 2 were built in 2003 and 2004.

[56] Ability to increase generation

Table 8: Generation from TECO's existing combined (CC) cycle plants

GWh Generation	2022	2023	2024
Bayside 1 CC	3,756	1,871	1,500
Bayside 2 CC	3,719	1,407	1,256
Polk 2 CC	8,239	5,288	4,869
Total from Existing CC's	**15,714**	**8,566**	**7,626**
Decrease in GWh from existing CC's after the Gas Project		7,148	8,089
Projected generation from the new Big Bend CC	**-**	**8,559**	**8,489**
% of Big Bend GWh that would displace generation from existing CC's		84%	95%

5. Alternative Resource Options to Meet Need

5.1. Alternative clean resource portfolios can meet TECO's energy and capacity needs at a lower cost and with lesser environmental impact

TECO's Gas Project would cost customers on the order of a billion dollars in capital costs alone. When adding fuel and ongoing O&M, the Gas Project would result in a roughly **$6.6 billion** revenue requirement over the life of the proposed plant. This is an enormous sum to spend on a project, and pass on to customer, when the Company has not established a legitimate need.

Assuming for the moment that TECO had established a need for additional energy and capacity (it has not), below we review alternative resource options that can meet various levels of the Company's claimed need at a considerably lower cost and with a lower environmental impact than the proposed Gas Project.

Utility-scale solar can provide valuable summer peaking capacity and reduce emissions from running a gas- or coal-fired plant.

TECO is currently building 600 MW of solar projects set to come online by 2021, and the Company has indicated that it plans to build a second block of 600 MW of solar projects by 2023. Solar PV provides an incredibly valuable resource for TECO's summer-peaking system as it can reduce the generation requirements, and therefore emissions, from the Company's other gas and coal-fired units. With solar costs falling, and the strong alignment between solar production and TECO's summer peaking period, TECO should view solar as its primary supply-side resource choice to meet both annual energy and summer capacity needs.

TECO claims that solar PV provides zero firm winter capacity. However, depending on the exact hour of winter morning peak, solar PV could provide some contribution to peak needs in the early hours of the day (as the solar generation is ramping up). TECO has not sufficiently supported its contention that the capacity contribution from solar during the morning of the winter peak day is zero, rather than some level reflecting solar output at, say, 8-9 AM. Nonetheless, we have incorporated this conservative assumption by TECO into our analysis and will demonstrate other resources that can provide firm winter capacity. Solar PV continues to provide winter energy.

Battery storage can firm up solar capacity and provides a crucial winter (and also summer) peaking resource.

TECO currently has no large-scale battery storage on its system. As TECO ramps up its investment in solar capacity, the Company could integrate battery storage to firm up its solar resources, or in general allow for winter capacity with stand-alone battery storage. These options can be deployed by pairing battery storage with solar, or on a system level by installing utility-controlled battery storage as a peaking replacement option. Grid-connected battery storage can provide TECO flexibility and ancillary grid services, in addition to providing firm winter (and summer) capacity.

Battery storage costs have fallen substantially over the past few years and are projected to continue falling at around 8 percent a year for at least the next five years (for a total cost decline of nearly 30 percent by 2022). Lazard's industry-standard 2018 cost-of-storage report lists capital costs for peaker-replacement (4-hour duration capacity) battery storage systems at $1,140–$1,814/kW, and capital cost for utility-scale storage (to be paired with PV) at $1,559–$2,2162/kW.[57]

Energy efficiency is and continues to be the lowest cost resource option for TECO.

As discussed in Section 0 above, TECO's investment in energy efficiency programs is very low, and the Company has projected very minimal growth in energy efficiency programs over the next 10 years. It is concerning that TECO is proposing its second major capital project in five years[58] without any effort to first increase efficiency investment. TECO currently ranks towards the bottom among U.S. utilities for energy efficiency investment.

We have modeled energy efficiency investment for TECO, with the goal of reaching the 2017 national average (as measured by incremental energy efficiency savings as a percent of retail sales) by 2024. We allowed TECO to slowly ramp up from its current level of incremental energy efficiency savings at 0.22 percent of retail sales until it reached the 2017 national average of 0.72 percent in 2024. After 2024, we maintained incremental energy efficiency savings in each year at this level. This savings level of 0.72 percent is a very reasonable step-up from current investment levels. However, this is still well below national leaders, which achieve incremental annual energy efficiency savings as high as 3 percent of retail sales.[59]

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[57] Lazard Levelized Cost of Storage, Version 4, November 2018.

[58] The Polk station expansion was just completed in 2017.

[59] ACEEE 2018 Scorecard, available at https://aceee.org/research-report/u1808.

5.2. Economic and environmental savings from resource alternatives

We modeled several alternative scenarios for TECO that can meet the Company's energy and capacity needs (up to the level that would have been met by the proposed Big Bend Gas Project) at a lower cost. **We used fairly conservative assumptions, and we still found considerable savings for TECO's customers under a variety of scenarios.** There are several factors driving these savings:

1. Energy efficiency is, and will continue to be, the lowest cost resource for the Company. There is no economically valid reason why TECO's customers should support a billion-dollar utility Gas Project for a capacity need that can be more economically met with higher levels of incremental energy efficiency investment.

2. Battery storage and solar PV capital costs are falling rapidly. This means that building a solar PV and/or battery storage project later is cheaper for the customers than building one today. If TECO deploys smaller, optimally sized (to need) resources such as energy efficiency investment—spread out to align with actual capacity needs—the Company will then be able to capture falling solar PV and battery technology costs on the supply side. When the Company builds lumpy, unneeded large combined cycle and combustion turbined resources, it locks the customers in for the entire capital cost at the current price.

3. In addition to lower technology costs associated with alternative resources, there is also the time value of money. Every year that an unnecessary capital project is deferred results in customer savings by deferring any required return on (and return of, through depreciation) shareholder's capital investments.

4. Gas fuel costs are much lower under the alternative scenarios. Some of the energy that would have otherwise been provided by TECO will come from the existing combined cycle plants (assuming they continue to operate at current levels), but a large amount of energy will also come from zero-emission solar PV. This is also why all alternative scenarios result in significantly lower emissions.

5. TECO's baseline demand forecast is the basis for the Company's claim that it needs the proposed Gas Project. We evaluated TECO's energy and capacity needs using the Company's low-demand forecast. This forecast more closely aligns with the Company's historical growth trends and reduces the Company's winter capacity needs.

6. The proposed Big Bend Gas Project locks TECO's customers into the project's entire capital cost, regardless of if and when the capacity is actually needed. The alternative scenarios that we designed breaks out the portion of capital cost expenditures that are associated with capacity additions beyond 2027. The incremental nature of the capacity additions in the alternative scenarios provide a hedge against future load growth uncertainties.

TECO can save customers hundreds of millions of dollars by exploring cleaner, alternative resource portfolios.

Our results for all scenarios are shown in Table 9. We included the second 600 MW of planned utility-scale solar PV in all scenarios discussed here (including the baseline) to evaluate operational and planning impacts of solar. However, we did not include the solar project cost, or any other common project costs, in our results. All of our non-baseline scenarios are "but for" scenarios, meaning we evaluate TECO's energy and capacity needs "but for" the proposed Gas Project.[60]

Table 9: Scenario cost and emission differences (2023-2052)

	Big Bend Gas Project including 2 CT's (Baseline)	Low Demand, No Gas Project		Low Demand + EE, No Gas Project	
		Result	Reduction from Baseline	Result	Reduction from Baseline
Total Revenue Requirement	$6,639,278	$5,895,188	$744,091	$4,832,918	$1,806,360
Portion of Revenue Requirement for post-2027 capacity and program costs		$837,756		$630,349	
Emissions (short tons CO_2)	98,750,394	77,860,346	20,890,048	67,855,633	30,894,761
Total Generation (GWh)	255,104	155,137	99,967	134,989	120,115
Un-met generation (GWh)	103,613	92,179	11,435	92,087	11,526

Note: The second 600 MW of solar is common to all scenarios. Therefore, the cost and GWh are not reflected here.

The Gas Project (Baseline) would cost the most and would emit the most CO_2.

As a baseline we modeled the proposed plant (1,090 MW) with the two additional un-sited 245 MW combustion turbines that the Company plans to add in 2023 and 2026. Based on the cost and operational information provided by TECO, we found that the proposed Gas Project will cost customers a total of $6.64 billion (NPV) over the life of the project (from 2023–2052). This cost includes $5.4 billion in operating costs and $1.3 billion in annualized capital costs. The proposed plant and combustion turbines will produce just around 99 million short tons of carbon dioxide emissions over the life of the project.[61]

The low-demand scenario reduces emissions by 21 percent and costs $744 million less than the baseline.

The first alternative scenario we modeled is a low-demand scenario. We removed the proposed plant and the combustion turbines, kept Units 1 and 2 online as capacity peaking resources, and replaced the baseline demand forecast with TECO's more realistic low-demand forecast. We filled in the energy balance by ramping up TECO's existing combined cycle plants (Bayside 1, Bayside 2, and Polk 2) to current operational levels, and filling in winter capacity needs with 100–200 MW of in-state firm

[60] We did not try to fill TECO's energy and capacity needs beyond what the Company plans to meet with its Gas Project. This means that there are similar levels of unmet energy and capacity in both plans.

[61] Our emissions analysis assumed that the new plants will operate at the capacity factors provided by TECO.

capacity purchases and 2,320 MW of battery storage.[62] We used 980 MW of incremental utility-scale solar PV to fill unmet energy needs in the later years (the first year with unmet energy needs is 2039).

This scenario leads to $744 million in customer savings (relative to the proposed Gas Project) and reduces emissions 21 percent relative to the proposed Gas Project. Additionally, a large portion of the project cost is for capacity additions investments more than 10 years away (post-2027), as well as sustained investment in EE beyond the ramp-up that we model over the next decade This means that TECO is not locked into spending this money if the Company's capacity needs change. In the baseline scenario TECO is locked into the entire Gas Project cost once the project is constructed.

Adding energy efficiency to the low-demand scenarios substantially reduces costs and emissions.

The second alternative scenario we modeled is a low-demand scenario with incremental energy efficiency investment. This scenario is set up with the same assumptions as the first, with the addition of incremental energy efficiency. We filled in winter capacity needs with 40-200 MW of in-state firm capacity purchases and 660 MW of battery storage. We used 400 MW of incremental utility-scale solar to fill unmet energy needs in later years (the first year with unmet energy needs is 2039).

This scenario is $1.8 billion cheaper for customers and lowers emissions 31 percent relative to the proposed Gas Project. Once again, much of the project cost is for capacity additions and energy efficiency investments more than 10 years away (post-2027). This scenario demonstrates the additional value gained from investing in incremental energy efficiency to manage peak and energy needs.

6. CONCLUSION

TECO has provided no reasonable justification for locking the customers into an almost billion-dollar capital investment. The Company should not be allowed to proceed with the Gas Project. Instead, TECO should be required to establish need and robustly evaluate alternative resource options based on relative costs and environmental impacts, in a transparent and public process. The Gas Project would be unattractive compared to any number of feasible, cleaner, cheaper options.

As we have shown, there is considerable uncertainty around TECO's actual future need. In fact, TECO may have zero future capacity need for the next decade. The Company should be required to explain its forecasting methodology and winter peaking assumptions, especially where its assumptions deviate from the norm, and reevaluate its plan using corrected and updated forecasts. The Company should also be required to adopt a lower and more regionally standard reserve margin.

[62] The majority of the battery storage (all but 300 MW) is needed beyond 2027, when ratepayers can benefit from lower technology costs.

Moreover, even if the Company could justify its claimed need, TECO should be required to defend its proposal to build a gas-fired combined cycle plant if it only needs winter peaking capacity. The Company should consider other reasonable and available methods to minimize adverse effects to the environment, which include: maintaining Units 1 and 2 as capacity resources; investing in energy efficiency to bring TECO at least up to the national average of efficiency investment; deploying incremental blocks of solar PV and battery storage when capacity needs occur in the future; and buying in-state firm capacity resources from neighboring utilities.

Failing to do so would burden the customers with a $6.6 billion[63] Gas Project that would produce nearly one hundred million short tons of CO_2 emissions over its lifetime. TECO can and must do better for its customers.

[63] Lifetime project cost

Table 10: TECO's baseline firm winter capacity

Winter Firm Capacity (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Fossil Resources											
Big Bend 1	395	395	395	395	395	-	-	-	-	-	-
Big Bend 2	395	395	395	395	395	-	-	-	-	-	-
Big Bend 3*	400	400	400	400	400	400	257	257	257	257	257
Big Bend 4*	442	442	442	442	442	442	285	285	285	285	285
Big Bend 4 CT	61	61	61	61	61	61	61	61	61	61	61
Big Bend CT 5	-	-	-	-	-	350	-	-	-	-	-
Big Bend CT 6	-	-	-	-	-	350	-	-	-	-	-
Big Bend CC	-	-	-	-	-	-	1,090	1,090	1,090	1,090	1,090
Future CT 1	-	-	-	-	-	-	245	245	245	245	245
Future CT 2	-	-	-	-	-	-	-	-	-	245	245
All other Existing Natural Gas & Coal	3,503	3,503	3,503	3,503	3,503	3,503	3,503	3,503	3,503	3,503	3,503
Total Fossil Resources	**5,196**	**5,196**	**5,196**	**5,196**	**5,196**	**5,106**	**5,441**	**5,441**	**5,441**	**5,686**	**5,686**
Renewable Resources	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Existing Solar	-	-	-	-	-	-	-	-	-	-	-
New Solar from Ten-Year Site Plan	-	-	-	-	-	-	-	-	-	-	-
Second 600 MW of Solar PV	-	-	-	-	-	-	-	-	-	-	-
Total Renewable Resources	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Resources Available	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TECO Total Resources	5,196	5,196	5,196	5,196	5,196	5,106	5,441	5,441	5,441	5,686	5,686
Firm Capacity Imports	121	121	-	-	-	100	-	-	-	-	-
Total Capacity Available	5,317	5,317	5,196	5,196	5,196	5,206	5,441	5,441	5,441	5,686	5,686
Demand-Side	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Base Case Demand	**3,749**	**4,903**	**4,972**	**5,043**	**5,111**	**5,172**	**5,245**	**5,318**	**5,388**	**5,443**	**5,515**
Interruptible Load	137	94	88	88	88	77	77	78	77	60	60
Load Management	96	95	96	97	97	98	98	99	100	100	101
Conservation	611	618	626	635	644	653	662	671	680	689	698
Net Firm Demand	**2,905**	**4,096**	**4,162**	**4,223**	**4,282**	**4,344**	**4,408**	**4,470**	**4,531**	**4,594**	**4,656**
Reserve Margin	83.0%	29.8%	24.8%	23.0%	21.3%	19.8%	23.4%	21.7%	20.1%	23.8%	22.1%

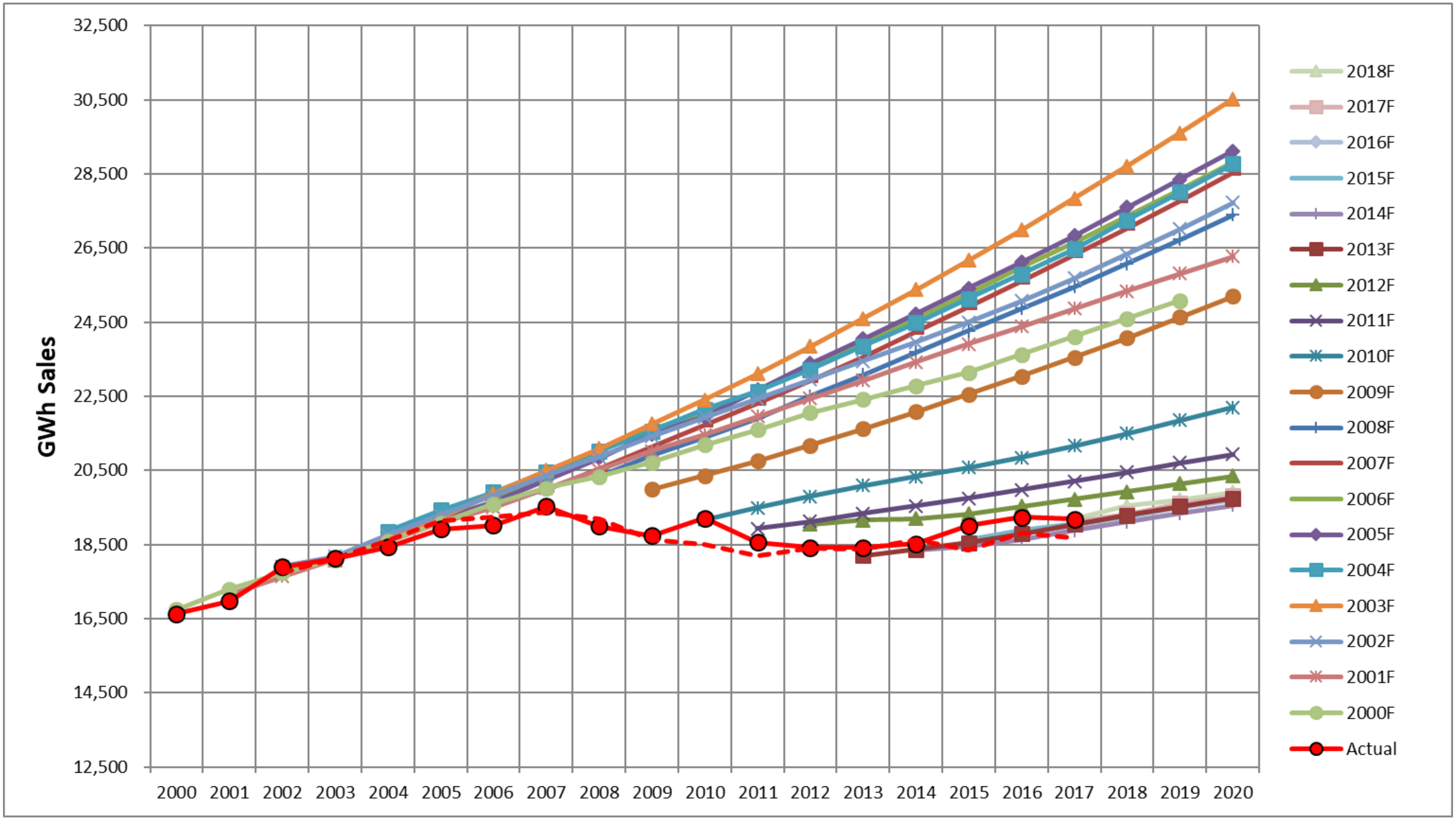
**Schedule 1 of the 2018 Ten-Year Site Plan states that for Big Bend Units 3 and 4 the "Combined net capability will be limited effective January 2023." No further information is given. The values here reflect our best guest of the net capacity available from each.*

Table 11: TECO's baseline firm summer capacity

Summer Firm Capacity (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Fossil Resources											
Big Bend 1	385	385	385	385	-	-	-	-	-	-	-
Big Bend 2	385	385	385	385	-	-	-	-	-	-	-
Big Bend 3*	395	395	395	395	395	395	278	278	278	278	278
Big Bend 4*	437	437	437	437	437	437	305	305	305	305	305
Big Bend 4 CT	56	56	56	56	56	56	56	56	56	56	56
Big Bend CT 5	-	-	-	-	330	330	-	-	-	-	-
Big Bend CT 6	-	-	-	-	330	330	-	-	-	-	-
Big Bend CC	-	-	-	-	-	-	1,055	1,055	1,055	1,055	1,055
Future CT 1	-	-	-	-	-	-	229	229	229	229	229
Future CT 2	-	-	-	-	-	-	-	-	-	229	229
All other Existing Natural Gas & Coal	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135
Total Fossil Resources	**4,793**	**4,793**	**4,793**	**4,793**	**4,683**	**4,683**	**5,058**	**5,058**	**5,058**	**5,287**	**5,287**
Renewable Resources											
Existing Solar	11	11	11	11	11	11	11	11	11	11	11
New Solar from Ten-Year Site Plan	-	-	213	276	300	300	300	300	300	300	300
Second 600 MW of Solar PV	-	-	-	-	-	-	300	300	300	300	300
Total Renewable Resources	**11**	**11**	**224**	**287**	**312**	**312**	**612**	**612**	**612**	**612**	**612**
Total Resources Available											
TECO Total Resources	4,804	4,804	5,017	5,080	4,995	4,995	5,670	5,670	5,670	5,899	5,899
Firm Capacity Imports	121	121	-	-	-	-	-	-	-	-	-
Total Capacity Available	4,925	4,925	5,017	5,080	4,995	4,995	5,670	5,670	5,670	5,899	5,899
Demand-Side											
Base Case Demand	**4,373**	**4,383**	**4,441**	**4,502**	**4,564**	**4,619**	**4,685**	**4,750**	**4,814**	**4,862**	**4,929**
Interruptible Load	110	115	109	109	110	98	98	98	97	81	81
Load Management	100	100	100	100	101	101	102	102	103	103	103
Conservation	253	258	266	275	284	292	301	309	317	327	335
Net Firm Demand	**3,905**	**3,910**	**3,966**	**4,018**	**4,069**	**4,128**	**4,184**	**4,241**	**4,296**	**4,352**	**4,410**
Reserve Margin	26.1%	26.0%	26.5%	26.4%	22.7%	21.0%	35.5%	33.7%	32.0%	35.5%	33.8%

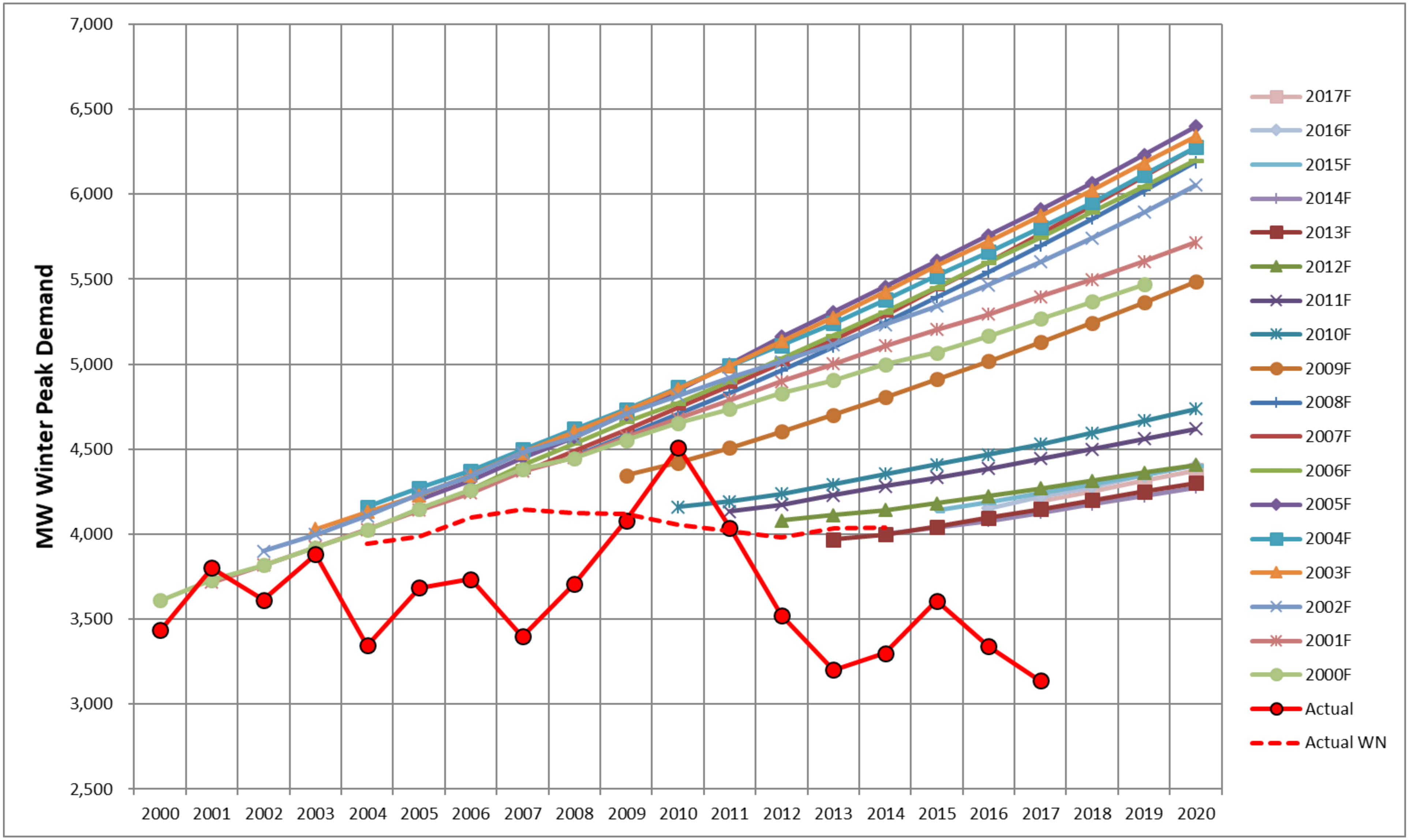
**Schedule 1 of the 2018 Ten-Year Site Plan states that for Big Bend Units 3 and 4 the "Combined net capability will be limited effective January 2023." No further information is given. The values here reflect our best guest of the net capacity available from each.*

Figure 5: Total retail sales for TECO: forecast vs actual



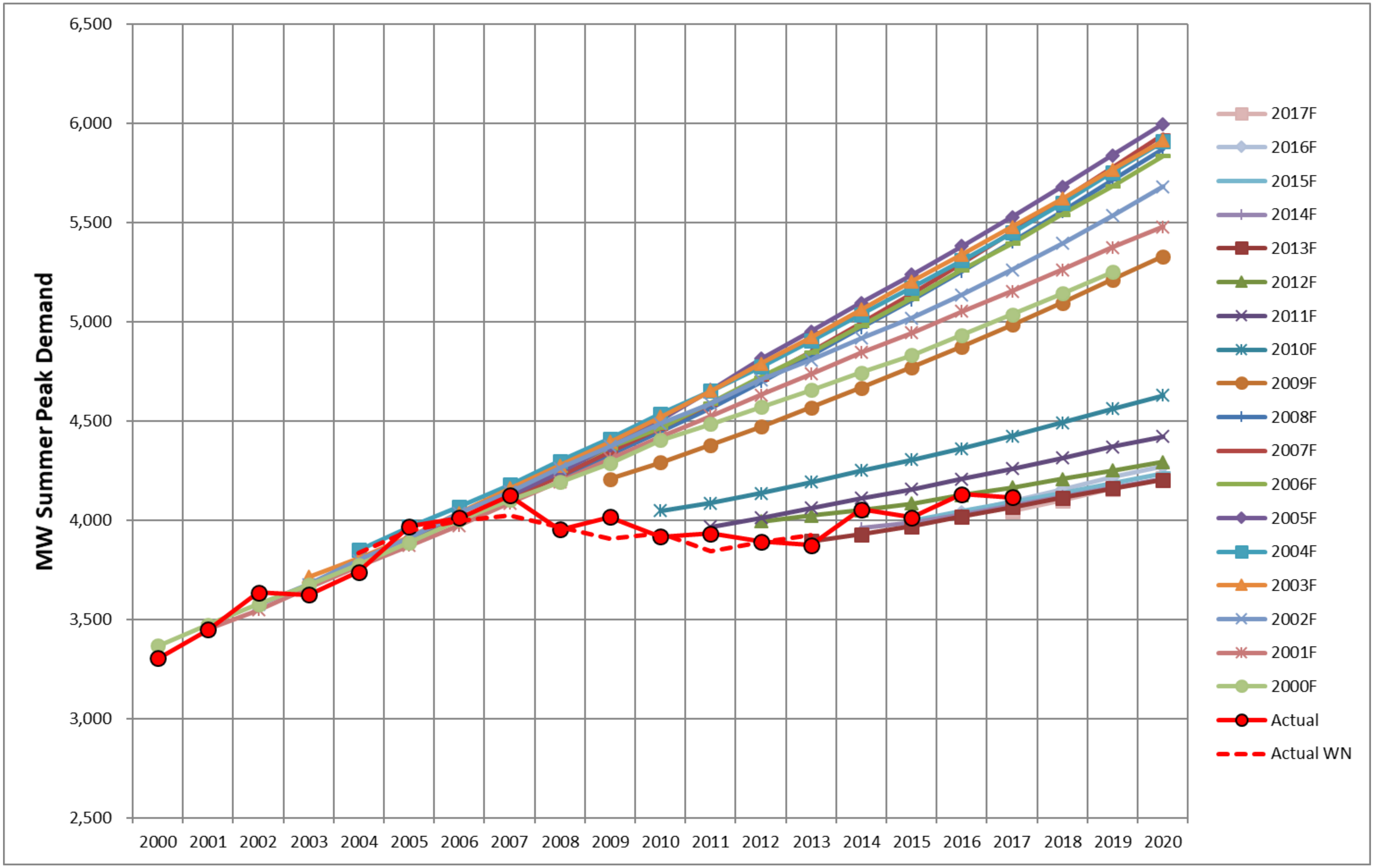
Source: Tampa Electric Company, Undocketed: Review of TYSP's, Supplemental Data Request No. 8., May 18, 2018.

Figure 6: Winter peak MW demand for TECO: projection vs actual



Source: Tampa Electric Company, Undocketed: Review of TYSP's, Supplemental Data Request No. 8., May 18, 2018.

Figure 7: Summer MW peak demand: projection vs actual



Source: Tampa Electric Company, Undocketed: Review of TYSP's, Supplemental Data Request No. 8., May 18, 2018.

Table 12: TECO Baseline Generation (GWh)

GWh Generation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Natural Gas											
Existing Units	13,685	14,911	14,756	14,876	15,571	14,939	8,814	7,963	7,872	8,113	7,865
Big Bend 1	984	452	223	243	4	-	-	-	-	-	-
Big Bend 2	1,127	568	349	275	32	-	-	-	-	-	-
Other Existing Units: - Big Bend Units 3,4 and CT 4 - Bayside Units 1-6 - Polk Units 1&2	11,574	13,891	14,183	14,358	15,535	14,939	8,814	7,963	7,872	8,113	7,865
New Units	-	-	-	-	185	564	8,643	8,573	8,462	8,555	8,514
Big Bend CT 5	-	-	-	-	128	370	-	-	-	-	-
Big Bend CT 6	-	-	-	-	57	194	-	-	-	-	-
Big Bend CC	-	-	-	-	-	-	8,559	8,489	8,377	8,419	8,378
Future CT 1	-	-	-	-	-	-	85	85	85	85	85
Future CT 2	-	-	-	-	-	-	-	-	-	52	52
Total	13,685	14,911	14,756	14,876	15,756	15,503	17,457	16,536	16,334	16,668	16,379
Dual (Coal & NG)											
Existing Units: - Big Bend 3 & 4 - Polk Unit 1	4,949	3,950	3,463	3,256	2,705	2,997	1,283	2,574	2,944	2,752	3,430
Total	**4,949**	**3,950**	**3,463**	**3,256**	**2,705**	**2,997**	**1,283**	**2,574**	**2,944**	**2,752**	**3,430**
Renewables											
Existing Solar	44	41	47	46	46	46	45	45	45	44	44
New Solar	-	98	929	1,226	1,376	1,370	1,365	1,363	1,354	1,349	1,343
Total	**45**	**139**	**976**	**1,272**	**1,422**	**1,416**	**1,410**	**1,408**	**1,399**	**1,393**	**1,387**
Total Energy Generated	**18,679**	**19,000**	**19,195**	**19,404**	**19,883**	**19,916**	**20,150**	**20,518**	**20,677**	**20,813**	**21,196**
Annual Firm Interchange	122	161	-	-	-	-	-	-	-	-	-
PC (Purchased Cogen)	1,064	1,033	1,220	1,224	1,118	1,220	1,195	1,119	1,220	1,220	1,115
Net Interchange	244	216	172	167	12	40	86	58	57	41	50
Purchased Energy from Non-Utility Generators	188	90	90	90	90	90	90	90	90	90	90
Net Energy for Load	**20,297**	**20,500**	**20,677**	**20,885**	**21,103**	**21,266**	**21,521**	**21,785**	**22,044**	**22,164**	**22,451**