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Tampa Electric's Response to Staff's Tenth Data Request Nos. 1-6

(Nos. 4, 5 have attachments)

1. Paragraph 1 of the 2021 Settlement Agreement states that the agreement "will become effective upon the date of the Commission's vote approving it." What impact, if any, would an effective date occurring prior to the first billing cycle of January 2022 have on TECO and/or its customers?

A. If the Commission approves the 2021 Agreement prior to January 1, 2022, the entire agreement will be "in effect," but some provisions would immediately become operative and others would not. Many of the key provisions of the 2021 Agreement do not become operative until January 1, 2022, or later, even if the 2021 Agreement is approved prior to that date. Consequently, an effective date prior to January 2022 would not affect the impact of these provisions. Those paragraphs are:

- Paragraph 2 (Return on Equity and Equity Ratio) applies beginning January 1, 2022, except that the "clock" starts on the running six-month commercial paper rate predicate for the ROE "trigger." This provision would not impact customers prior to January 1, 2022 since its effect – if any – cannot change rates or the authorized ROE until at least six months after any Commission vote approving the agreement. Furthermore, the 30-year United States Treasury Bond yield rate for purposes of the trigger is calculated on the date the Commission votes to approve the 2021 Agreement.
- Paragraph 3 (2022 Revenue Increase) applies with the first billing cycle of January 2022.
- Paragraph 4 (Generation Base Rate Adjustments) applies with the first billing cycles of January 2023 and January 2024.
- Paragraph 5 (Clean Energy Transition Mechanism) applies with the first billing cycle of 2022.
- Paragraph 9 (Depreciation) applies beginning January 1, 2022.
- Paragraph 12 (Asset Optimization Mechanism) applies for a three-year period beginning January 1, 2022.

Two paragraphs in the 2021 Agreement will be in effect upon approval but will not become operative until an additional qualifying event occurs. Thus, an effective date prior to January 2022 would not change the impact of these provisions:

- Paragraph 8 (Storm Damage) – Once it goes into effect upon Commission approval, this provision does not become operative until: (1) there is a named tropical storm that impacts Tampa Electric; and (2) Tampa Electric seeks cost recovery for that storm. If there is a storm before December 31, 2021, the storm provisions in the 2017 Agreement will apply.

- Paragraph 11 (Tax Changes) – Once it goes into effect upon Commission approval, this provision does not become operative until Tax Changes are enacted. The Tax Reform provisions in the 2017 Agreement remain in effect until December 31, 2021.

The remaining paragraphs would go into effect and become operative in whole or in part immediately upon Commission approval, with varying effects on Tampa Electric and/or its customers:

- Approval of the 2021 Agreement will allow the company to make the balance sheet adjustments associated with the CETM by the end of 2021.

- Paragraph 6 (Cost of Service Study, Billing Determinants, Rate Design) requires the company to file updated factors for certain cost recovery clauses upon approval of the 2021 Agreement. Thus, an effective date prior to January 2022 would trigger filing requirements in certain clauses for Tampa Electric. The updated clause factors, however, will not go into effect until the first billing cycle of January 2022 and the earlier effective date would have no impact on customers in 2021.

- Paragraph 7 (Other Cost Recovery) would go into effect upon Commission approval. Specifically, the company would be immediately subject to a “base rate freeze” with certain specified exceptions.

- Paragraph 10 (Earnings) works in tandem with paragraph 2, so while it would become effective upon approval, the return on equity and equity ratio established in the 2021 Agreement do not change until January 1, 2022, so the return on equity and equity ratio in the 2017 Agreement will remain operative until December 31, 2021 and this provision will not become operative until January 1, 2022.

- Paragraph 13 (Other) becomes effective upon Commission approval of the 2021 Agreement, but its provisions would have no significant impact on the company or the customers, because these provisions (with minor changes) are already in effect through December 31, 2021 in the 2017 Agreement. First, the company would immediately be prohibited from entering into new natural gas financial hedging contracts. Second, the company would be immediately barred from seeking cost recovery for investments in natural gas exploration, reserves, acreage, and/or production. Third, the company will immediately begin crediting the fuel clause for an amount equal to the incremental cost of generating or purchasing energy sold in non-separated or non-stratified wholesale energy sales.

- Paragraph 14 (New Tariffs) takes effect upon Commission approval. It permits the company to file certain new or revised tariff provisions or rate schedules as soon as the 2021 Agreement goes into effect. This would not likely affect Tampa Electric's customers in 2021 as it is unlikely that the company could file, and obtain Commission approval of, new tariffs before January 1, 2022, and in any event, the 2017 Agreement contains a similar provision.

- Paragraph 15 (Application of 2021 Agreement) would apply immediately if the Commission granted approval prior to January 1, 2022. This would affect Tampa Electric by prohibiting the company from requesting, supporting, or seeking to impose a change to any term or provision of the 2021 Agreement.

- Paragraph 16 (Commission Approval) would take effect concurrently upon Commission approval, but with no material impact Tampa Electric.

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REQUEST NO. 2
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2. Please refer to Paragraph 5(a) of the 2021 Settlement. Please identify the reason(s) why the Parties to the 2021 Settlement propose moving the cost recovery of the net book value of Big Bend Units 1-3 and AMR from base rates to the Clean Energy Transition Mechanism cost recovery factors.

A. Almost every settlement agreement considered and approved by the Commission reflects give and take among the parties and reflects an integrated package of exchanged agreements and consideration. The answer to why any particular provision was included in a settlement always boils down to a simple answer, namely, because the parties, notwithstanding their diverse and often competing interests, agreed to it. In virtually every settlement, every party likely would have objected to some feature(s) of the settlement if offered individually and not as a part of a larger integrated package, but nonetheless every party agreed to the settlement in its totality. The 2021 Agreement is no different in this regard.

Without divulging the dynamics of the negotiating process, the Parties considered two approaches to retired asset cost recovery: the CETM and a traditional rate-making approach under which the remaining undepreciated net book value would be recovered through base rates on a declining balance basis. The Parties agreed to the CETM, each for their own reasons, and generally based on these considerations:

1. The early retirement of portions of Big Bend Units One, Two, and Three and the AMR assets facilitates the timely introduction of three major projects that will provide important benefits to both current and future customers, namely Big Bend Modernization, 600 MW of Future Solar, and Automated Metering Infrastructure ("AMI"). The benefits of these projects are discussed in the prepared direct testimony of David Pickles, Brent Caldwell, Jose Aponte, David Sweat, and Regan Haines filed by the company. Levelized recovery of the costs associated with early retirement of these assets prospectively over a reasonable period, from the customers who will benefit from Big Bend Modernization[1], at least 600 MW of Future Solar, and AMI implementation, appropriately matches these costs with the new, transformational cleaner generating and state-of-the-art project benefits accruing to current and future

[1] The prepared direct testimony of Brent Caldwell shows that the Big Bend Modernization Project (The repowering of Big Bend Unit One by retiring portions of Big Bend One and all of Big Bend Two) will over the lives of the projects generate approximately $750 million of CPVRR net benefits/savings for customers. The calculation of this amount included recovery of the remaining NBV of the Big Bend Unit One and Two assets to be retired as a "cost," so the estimated $750 million CPVRR benefit of Big Bend Modernization are net of the costs of retiring the Big Bend One and Two assets.

customers. This cost/benefit matching mitigates potential inter-generational cost recovery concerns.

2. The CETM is transparent in the sense that customers will be able to see how the costs of the assets being retired to enable Big Bend Modernization, 600 MW of Future Solar, and AMI will be recovered on customers' bills. This CETM cost recovery will not be bundled with other costs to be recovered through base rates.

3. The levelized nature of the CETM provides a measure of rate stability for customers and certainty of cost recovery for the company and mitigates the regulatory lag that can occur between rate cases when traditional declining-balance cost recovery methods are employed.

4. As shown on Exhibit J to the 2021 Agreement, the net present value ("NPV") cost recovery under the CETM equals the NPV of cost recovery under traditional declining balance/bundled base rate ratemaking if base rates are reset every year to reflect the declining balance, which, of course, does not usually happen.

5. The CETM contains true-up provisions that will ensure that the costs incurred will be recovered - no more and no less.

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3. Please refer to Paragraph 5(a) of the 2021 Settlement. Please explain the expected potential benefits and harms, if any, to TECO ratepayers related to moving the recovery of the net book value of Big Bend Units 1-3 and AMR from base rates to the Clean Energy Transition Mechanism cost recovery factors.

A. The benefits associated with the CETM are identified in the response to Request No. 2, above. The Parties have not identified any "harms" to ratepayers associated with the CETM. The Parties do not view the 15-year recovery period for the CETM to be a "harm," because: (a) extending cost recovery from 10 years as proposed in the company's initial filing to 15-years moderates the rate impact to customers and (b) the 15-year recovery period reasonably matches the costs of retiring the assets covered by the CETM with the benefits associated with the Big Bend Modernization, 600 MW of Future Solar, and the AMI project, which were enabled by the early retirement of (1) Big Bend Units One, Two, and Three, and (2) the company's AMR system.

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4. Referring to paragraph 5(a)(i) of the Settlement, please respond to the following questions:

a. Show the calculation of the proposed 2022 CETM charges, including the allocation of total cost to the rate classes and the billing determinants used.

b. Explain why the CETM revenue requirement was allocated to the rate classes using allocation factors approved in the most recent base rate proceeding as opposed to allocation factors proposed in this proceeding.

A. a. Please see Excel file "(BS 8) Final Clean Energy Transitions Mechanism Draft Calc.xlsx".

b. That provision was negotiated, and the Parties may have agreed to it for different reasons; however, since the CETM recovers costs associated with assets being retired to make way for and match the timing of the value of implementation of more efficient generation and a more advanced metering system that will provide long-term benefits for customers, the idea of using the allocation factors in effect when those assets were in service can logically assumed to have been part of the discussions among the Parties.

5. The 2021 Settlement, at Paragraph 5(c), proposes to extend the recovery period for the net book value of the Big Bend Retirement Assets, AMR, and Big Bend Retirement Assets dismantlement reserve deficiency to 15 years, rather than 10 years as proposed by TECO in its Base Case (Witness Avellan Direct Testimony, Pages 32-35).

a. What reason(s) do the Parties have for further extending the recovery period of TECO's retiring assets?

b. What is the dollar impact to TECO's customers, in terms of Net Present Value, of extending the recovery period of these assets from 10 years to 15 years? Please provide all calculations in Excel format with cell formulas included.

A. a. The 15-year recovery period was negotiated, and the Parties may have agreed to it for different reasons; however, the Parties considered these reasons for extending the recovery period from 10 to 15 years: (1) extending cost recovery from 10 years as proposed in the company's initial filing to 15 years moderates the rate impact to customers and (2) the 15-year recovery period reasonably matches the costs of retiring the assets covered by the CETM with the benefits associated with the Big Bend Modernization, 600 MW of Future Solar, and the AMI project, which were enabled by the early retirement of (1) Big Bend Units 1 and 2 and (2) the company's AMR system.

b. The CETM assumes that the discount rate used for NPV calculation purposes equals the authorized grossed up rate of return for cost-of-service calculation purposes. For that reason, mathematically the NPV would be equal no matter what amortization period is used as long as the NPV and the return on rate base are computed based on the same time periods. In the case of the CETM, the NPV calculation is based on revenue requirement dollars for each entire year while the return on rate base is computed based on average rate base during the year. Thus, the computed NPV will be slightly different if different amortization periods are utilized. Excel file "(BS 11) 5b - CETM Rider Calculation-15 and 10 year Amort.xlsx" computes the NPV for the CETM calculation assuming both the 15-year amortization period and the 10-year amortization period. The NPV of all recoveries calculated for the 15-year period is $593.989 million and the NPV of all recoveries calculated for the 10-year period is $591.589 million. Those amounts are very close and are different only due to the use of average rate base to compute the annual return on rate base in the quantification of the

CETM. To prove that the NPV would be mathematically equal no matter what amortization were to be selected, BS 12 “CETM Rider Calculation-15 and 10 year Amort – test” shows the calculations of the NPV for both amortization periods if the return on rate base were computed at the beginning of each year. These calculations show that the NPV is exactly the same for both amortization periods.

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6. According to Paragraph 5(i) and Exhibit J of the 2021 Settlement, the 2021 Settlement would shift a portion of the cost recovery of the net book value of Big Bend Retirement Assets, AMR, and the Big Bend Retirement Assets dismantlement reserve deficiency to the latter half of the 15-year CETM cost recovery period compared to the traditional revenue requirement calculation. Given the proposed expanded cost recovery period for these retiring assets (i.e. 15 years rather than 10 years), please explain the Parties' rationale for further shifting these assets' cost recovery out in time using the levelized recovery method.

A. Please see the response to Request 5(a).