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April 30, 2020

VIA: ELECTRONIC FILING

Mr. Adam J. Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: NEW DOCKET; In re: Petition of Tampa Electric Company to True-up First and Second SoBRAs

Dear Mr. Teitzman:

Attached for filing in the above docket are the following documents:

1. Tampa Electric Company's Petition for Limited Proceeding to True-up First and Second SoBRAs

2. Prepared Direct Testimony and Exhibit of Mark D. Ward

3. Prepared Direct Testimony and Exhibit of Jose A. Aponte

4. Prepared Direct Testimony and Exhibit of Jeffrey S. Chronister

5. Prepared Direct Testimony and Exhibit of William R. Ashburn

Thank you for your assistance in connection with this matter.

Sincerely,

J. Jeffry Wahlen

JJW/bmp
Attachments

cc: All Parties of Record (w/attachment)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Tampa Electric Company	)	
To True-Up First and Second SoBRAs	)	Docket No. 2020____-EI
____	)	Filed: April 30, 2020

TAMPA ELECTRIC COMPANY'S PETITION
FOR LIMITED PROCEEDING TO
TRUE-UP FIRST AND SECOND SOBRAs

Pursuant to Sections 366.076, 120.57 and 366.06(3), Florida Statutes, and Rule 28-106.301, F.A.C., Tampa Electric Company ("Tampa Electric" or "the company") petitions the Florida Public Service Commission ("FPSC" or "the Commission") to true-up its First and Second SoBRAs, and states:

I. Introduction

A. 2017 Agreement

1. Tampa Electric is currently operating under its 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement") approved by the Commission.[1] Paragraph 6 of the company's 2017 Agreement contains a provision that authorizes the company to recover the costs of certain qualifying solar generating projects through a solar base rate adjustment mechanism based on projected costs and estimated in-service dates, with a true-up for both.

2. The Commission has approved three SoBRAs totaling 550 MW of solar capacity for Tampa Electric. The First SoBRA was approved by Order No. PSC-2018-0288-FOF-EI, issued June 5, 2018, in Docket No. 20170260-EI ("First SoBRA Order"). The Second SoBRA was approved by Order No. PSC-2018-0571-FOF-EI, issued December 7, 2018, in Docket No.

[1] The Commission approved the 2017 Agreement by Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket Nos. 20170210-EI and 20160160-EI.

20180133-EI ("Second SoBRA Order"). The annual revenue requirement for the solar projects in both SoBRAs and the resulting base rate changes were calculated using projected costs and the SoBRA rates went into effect based on estimated in-service dates. The Third SoBRA is not addressed in this petition.

3. Paragraph 6(c) of the 2017 Agreement states:

> The Rate Change and In-Service Dates specified in the chart in Subparagraph 6(b) are "no sooner than" dates, and the SoBRA rate changes for each Tranche will be implemented effective on the earliest In-Service Date for that Tranche identified in such chart <u>and subsequently trued up to reflect and correct for (1) any delay in the actual In-Service Dates of any of the projects in a particular Tranche beyond the applicable In-Service date for that Tranche and (2) the extent to which the actual installed costs of any project or projects vary from the projected costs used to set the SoBRA rate change</u>…. (emphasis added)

4. Paragraph 6(n) of the 2017 Agreement states:

> In order to determine the amount of each annual cost true-up, a revised SoBRA will be computed using the same data and methodology incorporated in the initial SoBRA, with the exception that the actual capital expenditures after sharing and the actual in-service date will be used in lieu of the capital expenditures on which the annualized revenue requirement was based. The difference between the cumulative base revenues since the implementation of the initial SoBRA factor and the cumulative base revenues that would have resulted if the revised SoBRA factor (for cost and In-Service date true-ups) had been in place during the same time period will be trued up with interest at the AFUDC rate shown in Exhibit B used for the projects, and will be made through a one-time, twelve-month adjustment through the CCR clause. On a going forward basis, the base rates will be adjusted to reflect the revised SoBRA factors.

5. Thus, for the First and Second SoBRAs, the 2017 Agreement requires the company to do the following for Commission approval:

(a) determine the actual installed cost per kW_{ac} of the seven projects;

(b) recalculate the projected annual revenue requirement for the seven projects using the actual installed capital costs for the projects, but otherwise using the same data and methodology used for the projections;

(c) identify the actual in-service dates for the seven projects;

(d) develop final customer SoBRA rate factors to implement the SoBRA that reflect the actual annual revenue requirement for the seven projects ("Final SoBRA Factors") and implement them on a date certain;

(e) calculate a SoBRA revenue true-up amount equal to the difference between (i) the cumulative base revenues from the implementation of the initial First and Second SoBRA factors beginning on the projected in-service dates through the date the Final SoBRA Factors will be implemented and (ii) the cumulative base revenues that would have been generated had the Final SoBRA Factors been in effect from the actual in-service dates of the projects through the date the Final SoBRA Factors, to be implemented from the date the projects went in service through the Final SoBRA Factors implementation date ("True-Up Amount"); and

(f) refund or credit the True-Up Amount with interest at the AFUDC rate shown in the 2017 Agreement through a one-time, twelve-month adjustment through the Capacity Cost Recovery Clause.

B. First SoBRA

6. Tampa Electric's First SoBRA provided cost recovery for two solar projects: a 74.4 MW project in Hillsborough County called Balm Solar and a 70.3 MW project in Polk County called Payne Creek Solar. The First SoBRA Order found that these two projects were cost-effective within the meaning of the 2017 Agreement and approved estimated installed costs for Balm Solar and Payne Creek Solar of $1,480 per kW_{ac} and $1,324 per kW_{ac}, respectively. It also approved a

projected annual revenue requirement for the two projects of $24,245,000 (with 25% incentive[2]) and tariff revisions to recover that amount with a September 1, 2018 effective date.

7. The Balm Solar project actually went into service on September 27, 2018 at an actual cost of $1,478 per kW_{ac}. The annual revenue requirement for Balm Solar is $12,879,000 calculated using its actual costs, without the 25% incentive and per the guidelines in the 2017 Agreement. The actual annual revenue requirement with incentive is $12,926,000.

8. The Payne Creek project actually went into service on September 1, 2018 at an actual cost of $1,342 per kW_{ac}. The annual revenue requirement for Payne Creek is $11,105,000 calculated using its actual costs, without the 25% incentive and the per guidelines in the 2017 Agreement. The actual annual revenue requirement with incentive is $11,416,000.

9. The combined actual annual revenue requirement with incentive for the two First SoBRA projects is $24,342,000 or $97,000 more than the projected revenue requirement.

C. Tampa Electric's Second SoBRA

10. The company's Second SoBRA recovered costs associated with five solar projects totaling 260.3 MW with a projected in-service date of January 1, 2019 for all five. The Second SoBRA Order found that the five projects were cost-effective within the meaning of the 2017 Agreement and the approved projected installed costs as follows:

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[2] Paragraph 6(m) of the 2017 states: "If Tampa Electric's actual installed cost for a project is less than the Installed Cost Cap, the company's customers and the company will share in the beneficial difference with 75% of the difference inuring to the benefit of customers and 25% serving as an incentive to the company to seek such cost savings over the life of this 2017 Agreement." For purposes of this document, the term "with incentive" refers to the cost of a project including the 25% incentive in paragraph 6(m).

Project	MW	Cost per kW_{ac}
Lithia	74.5	$1,494
Grange Hall	61.1	1,437
Peace Creek	55.4	1,492
Bonnie Mine	37.5	1,464
Lake Hancock	31.8	1,494
	260.3	

11. The Second SoBRA Order also approved a projected total annual revenue requirement for all five projects of $46,045,000, broken down as follows:

Project	Estimated Revenue Requirement
Lithia	13,291
Grange Hall	10,611
Peace Creek	9,868
Bonnie Mine	6,601
Lake Handcock	5,674

12. The Lithia project actually went into service on January 1, 2019 at an actual cost of $1,481 per kW_{ac}. The annual revenue requirement with incentive for Lithia is $13,211,000 calculated using its actual costs and the guidelines in the 2017 Agreement.

13. The Grange Hall project actually went into service on January 2, 2019 at an actual cost of $1,430 per kW_{ac}. The annual revenue requirement with incentive for Grange Hall is $10,570,000 calculated using its actual costs and the guidelines in the 2017 Agreement.

14. The Peace Creek project actually went into service on March 1, 2019 at an actual cost of $1,479 per kW_{ac}. The annual revenue requirement with incentive for Peace Creek is $9,808,000 calculated using its actual costs and the guidelines in the 2017 Agreement.

15. The Bonnie Mine project actually went into service on January 23, 2019 at an actual cost of $1,496 per kW_{ac}. The annual revenue requirement with incentive for Bonnie Mine is $6,704,000 calculated using its actual costs and the guidelines in the 2017 Agreement.

16. The Lake Hancock project actually went into service on April 25, 2019 at an actual cost of \$1,459 per kW_{ac}. The annual revenue requirement for Lake Hancock is \$5,578,000 calculated using its actual costs and the guidelines in the 2017 Agreement.

17. The combined actual annual revenue requirement with incentive for the five Second SoBRA projects is \$45,871,000 or \$174,000 less than the projected revenue requirement.

18. The combined actual revenue requirement with incentive for the seven projects in the First and Second SoBRAs is \$70,213,000, which is \$77,000 less than the projected total revenue requirement with incentive.

II. Preliminary Information

19. The Petitioner's name and address are:

Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

20. Any pleading, motion, notice, order or other document required to be served upon Tampa Electric or filed by any party to this proceeding shall be served upon the following individuals:

James D. Beasley
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21. Tampa Electric is an investor-owned public utility regulated by the Commission pursuant to Chapter 366, Florida Statutes, and is a wholly-owned subsidiary of Emera, Inc. Tampa

Electric's principal place of business is located at 702 North Franklin Street, Tampa, Florida 33602.

22. Tampa Electric serves more than 750,000 retail customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties, Florida.

23. This Petition represents an original pleading and is not in response to any proposed action by the Commission. Accordingly, the Petitioner is not responding to any proposed agency action.

III. Tampa Electric's Proposed Base Rate True-Up and Credit

24. Tampa Electric seeks approval to include the final base rate true-up with its Fourth SoBRA base rate change, subject to Commission approval, since the revenue requirement true-up is not large enough to change any of the base rates. The company plans to submit a petition for approval of the Fourth SoBRA charges in the summer of 2020 for implementation with the first billing cycle for January 2021 or another date to be decided by the Commission. The company also requests that the FPSC approve the company's proposed revenue true-up credit as described in paragraph 5(e), above, in the amount of $5,096,041. An estimated true-up credit of $ 4,856,329 was included in the company's approved 2020 mid-course capacity factors, and Tampa Electric also requests that the FPSC allow the company to credit the difference between these two amounts, the $239,712 final true-up amount to customers through the Capacity Cost Recovery Clause during 2021.

IV. Statement on Disputed Issues of Material Fact

25. Tampa Electric is not aware of any disputed issues of material fact at this time, and does not believe any disputed issues of material fact will arise in this docket.

V. Statement of Ultimate Facts Alleged and Providing the Basis for Relief

26. The ultimate facts that entitle Tampa Electric to the relief requested herein are:

(a) The facts specified in paragraphs 1 through 18, above.

(b) The actual installed cost per kW_{ac} of the seven projects in the First and Second SoBRAs are:

Project	Cost per kW_{ac}
Balm	$1,478
Payne Creek	1,342
Lithia	1,481
Grange Hall	1,430
Peace Creek	1,479
Bonnie Mine	1,496
Lake Hancock	1,459

(c) The recalculated annual revenue requirement for the seven projects in the First and Second SoBRA using the actual installed capital costs for the projects, but otherwise using the same data and methodology used for the projections are:

Project	Annual Revenue Requirement
Balm	$12,926,000
Payne Creek	11,416,000
Lithia	13,211,000
Grange Hall	10,570,000
Peace Creek	9,808,000
Bonnie Mine	6,704,000
Lake Hancock	5,578,000

(d) The actual in-service dates for the seven projects in the First and Second SoBRAs are:

Project	Date
Balm	September 27, 2018
Payne Creek	September 1, 2018
Lithia	January 1, 2019
Grange Hall	January 2, 2019
Peace Creek	March 1, 2019
Bonnie Mine	January 23, 2019
Lake Hancock	April 25, 2019

(e) The First and Second SoBRA revenue true-up amount is a credit of $5,096,041 and is equal to the difference between (i) the cumulative base revenues from the implementation of the initial First and Second SoBRAs beginning on their projected in-service dates through the first billing cycle in January 2021 and (ii) the cumulative base revenues that would have been generated had the Final SoBRA Factors been in effect from the actual in-service dates of each of the projects through the first billing cycle in January 2021 ("True-Up Amount"). A schedule showing the calculation of this amount, including interest at the AFUDC rate, is provided in Exhibit ___ (JSC-1) of witness Jeffrey S. Chronister, attached to this petition and is incorporated herein by reference.

VI. <u>Relief Requested</u>

27. For the reasons set forth above, Tampa Electric requests that the Commission:

(a) approve the actual installed cost per kW_{ac} of the First and Second SoBRA projects as specified herein;

(b) approve the final annual revenue requirement for the First and Second SoBRA Projects as specified herein;

(c) allow the company to include the base rate changes necessary to reflect actual installed costs for the First and Second SoBRAs with the changes to be made for its Fourth SoBRA effective for the first billing cycle in January 2021;

(d) approve the First and Second SoBRA revenue true-up credit of $5,096,041 and authorize the company to credit the net final true-up amount of $239,712 to customers through the Capacity Cost Recovery Clause during 2021; and

(e) grant other such relief as is reasonable and proper.

28. Tampa Electric is entitled to the relief requested pursuant to Chapters 366 and 120, Florida Statutes.

29. The relief requested herein is consistent with the 2017 Agreement and FPSC Order No. PSC-2017-0456-S-EI.

VII. Conclusion

30. For the reasons shown above, Tampa Electric Company respectfully requests that the Commission grant this Petition and the relief requested herein.

DATED this 30th day of April, 2020.

Respectfully submitted,

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J. JEFFRY WAHLEN
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(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 30th day of April, 2020 to the following:

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Jeff Wahlen

Attorney

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2020____-EI

IN RE: PETITION BY TAMPA ELECTRIC COMPANY FOR A LIMITED PROCEEDING TO TRUE-UP FIRST AND SECOND SOBRAS

REDACTED

PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

MARK D. WARD

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARK D. WARD

Q. Please state your name, address, occupation and employer.

A. My name is Mark D. Ward. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Renewables.

I. <u>Introduction</u>

Q. Please provide a brief outline of your educational background and business experience.

A. I earned a Bachelor of Science in Mechanical Engineering from University of Alabama in Huntsville in 1984. I have thirty-six years of combined professional experience as a Department of Defense contractor and working for public utilities and independent power producers. Twenty-four years of my experience has been with electric utilities and independent power producers.

I worked for Tampa Electric from 1996 to 2001, where I served as Manager of Generation Planning and provided management support for the development of Tampa Electric’s Bayside Power project. From 2001 to 2007, I served in mid- to senior level management positions at various companies involved in the power industry. These companies included Entergy Asset Management, an unregulated subsidiary of Entergy, the Shaw Group, an engineering and construction firm, and TXU, a regulated electric utility. From 2007 to 2014, I served as President of the Mesa Power Group. Mesa Power was a renewable energy developer with a primary focus in large scale wind development. From 2014 to 2016, I managed an energy consulting practice with clients primarily in solar, wind and combined heat and power.

I was re-hired by Tampa Electric in December 2016 as Director of Renewables. My responsibilities in this position include management oversight with respect to Tampa Electric’s renewable energy strategies and projects. This includes the execution of Tampa Electric’s 600 MW of utility scale solar projects described in the 2017 Amended and Restated Stipulation and Settlement Agreement (“2017 Agreement”) that was approved by the Commission in Order No. PSC-2017-0456-S-EI, issued in

Docket Nos. 20170210-EI and 20160160-EI on November 27, 2017.

Q. Have you previously testified or submitted written testimony before the Florida Public Service Commission ("Commission")?

A. Yes. I submitted direct and rebuttal testimony on behalf of Tampa Electric in Docket No. 19981890-EI (In re: Generic Investigation into Aggregate Electric Utility Reserve Margins Planned for Peninsular Florida). I submitted direct and rebuttal testimony on behalf of Tampa Electric on the prudency of replacement fuel and purchased power costs in Docket No. 19990001-EI (In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor). I submitted direct testimony on behalf of Tampa Electric regarding the Gannon Repowering Project in Docket No. 19992014-EI (In re: Petition by Tampa Electric Company to Bring Generating Units into Compliance with Clean Air Act).

In addition, while working for Mesa Power Group, LLC, I submitted direct testimony before the Minnesota Public Utilities Commission on behalf of AWA Goodhue, LLC in MPUC Docket No. IP6701/WS-08-1233 (In the matter of the

Application by AWA Goodhue Wind, LLC for a Site Permit for a Large Wind Energy Conversion System for a 78 MW Wind Project in Goodhue County).

I also served as a member of a panel of witnesses during the November 6, 2017 hearing on the 2017 Agreement, and most recently, I testified before this Commission in Docket No. 20170260-EI, petition for limited proceeding to approve First Solar Base Rate Adjustment ("First SoBRA"), effective September 1, 2018, by Tampa Electric Company. I submitted direct testimony in Docket No. 20180133-EI, petition for limited proceeding to approve Second Solar Base Rate Adjustment, effective January 1, 2019, by Tampa Electric Company ("Second SoBRA) and in Docket No. 20190136-EI, petition for limited proceeding to approve Third Solar Base Rate Adjustment, effective January 1, 2020, by Tampa Electric Company.

Q. What are the purposes of your direct testimony?

A. My testimony serves two purposes. My testimony shows that the actual installed costs for the seven solar projects in the company's first two tranches of utility scale solar, which were part of the company's First and Second SoBRAs ("Seven Projects"), are below the $1,500 per kilowatt alternating current (“kW_{ac}”) installed cost cap contained in the 2017 Agreement. I also describe the actual in-service dates for the Seven Projects and explain why five of them did not enter service on their planned in-service dates. My description of the actual costs for the Seven Projects discusses how and why the company received liquidated damages for some of the Seven Projects and how those amounts were determined.

I discuss the two First and five Second SoBRA projects in a section dedicated to each SoBRA.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. Exhibit No. _____ (MDW-1) was prepared under my direction and supervision. It consists of the following seven documents:

Document No. 1	Payne Creek Solar Project Actual and Estimated Installed Costs by Category
Document No. 2	Balm Solar Project Actual and Estimated Installed Costs by Category
Document No. 3	Lithia Solar Project Actual and Estimated Installed Costs by Category
Document No. 4	Grange Hall Solar Project Actual and

	Estimated Installed Costs by Category
Document No. 5	Peace Creek Solar Project Actual and Estimated Installed Costs by Category
Document No. 6	Bonnie Mine Solar Project Actual and Estimated Installed Costs by Category
Document No. 7	Lake Hancock Solar Project Actual and Estimated Installed Costs by Category

Q. How does your prepared direct testimony relate to the prepared direct testimony of the company's other three witnesses?

A. My prepared direct testimony describes the Seven Projects in the company's First and Second SoBRAs, as well as their actual in-service dates and installed cost per kW_{ac}. Tampa Electric witness Jeffrey S. Chronister discusses how liquidated damages associated with the projects were apportioned among the Seven Projects and reduced the company's project installed costs, as well as the true-up credit required by the 2017 Agreement. Witness Jose A. Aponte uses the final actual installed project cost, net of liquidated damages, to calculate the true-up for the annual revenue requirements for the First and Second SoBRAs. The company's cost of service and rate design witness, William R. Ashburn, uses the trued-up to actual revenue requirement to develop the proposed permanent customer rates for the First and Second SoBRAs and proposes a way to implement those changes.

II. First SoBRA Projects: Payne Creek Solar and Balm Solar

Q. Do the two projects in the company's First SoBRA differ from the specifications mentioned in your direct testimony in Docket No. 20170260-EI?

A. No, the project design and specifications do not differ materially from planned and are as described in my Direct Testimony submitted in Docket No. 20170260-EI. The initial costs were estimates; therefore, there is a cost difference for each project. In addition, while Payne Creek Solar was fully operational and placed in service on September 1, 2018 as contemplated in the 2017 Agreement, Balm Solar became fully operational and was placed in service on September 27, 2018.

Q. What do you mean by the term "placed in service?"

A. The solar project is considered to be placed in service when the project has all modules installed and electrically connected, all inverters have been installed and commissioned, and the project substation is energized and transmitting the solar power to the Tampa Electric transmission system. Tampa Electric notified the Florida Public Service Commission when the projects were placed in service and eligible for cost recovery through the Solar Base Rate Adjustments.

Q. Please explain why Balm Solar was placed in service later than originally expected.

A. Balm Solar received its environmental and construction permits almost two months later than expected, and the contractor was not able to start construction on the project until the last week in May 2018. The contractor was able to mitigate some of the delay by working weekends, which allowed the project to begin commercial service on September 27, 2018.

Q. How did the company manage the actual costs of the two First SoBRA projects?

A. Payne Creek Solar and Balm Solar were turnkey EPC projects. The cost for each project was fixed by the terms of the contract, and any cost increases were submitted as change orders.

Actual costs were managed by Tampa Electric's project management and accounting teams. The contractor sent invoices to Tampa Electric monthly for work completed. Prior to paying the invoice, Tampa Electric inspected the project to verify the work had been completed and additional costs were justified.

Q. What are the total actual and estimated installed costs for the two First SoBRA Projects?

A. The estimated installed costs of the Payne Creek and Balm Solar Projects are \$1,324 per kW_{ac} and \$1,480 per kW_{ac}, respectively. The actual installed costs are \$1,342 per kW_{ac} for the Payne Creek Solar project and \$1,478 per kW_{ac} for the Balm Solar Project. The weighted-average cost for First SoBRA projects is \$1,412 per kW_{ac}.

Q. What costs were included in the actual costs for purposes of this true-up filing?

A. The actual total installed cost broken down by major category for the First SoBRA Projects is shown on Document Nos. 1 and 2 of my exhibit. The actual costs included are the same categories or types of costs as those included in the company's estimated costs, as submitted in Docket No.

20170260-EI and in accordance with the 2017 Agreement. These include the types of costs that traditionally have been allowed in rate base and are eligible for cost recovery via a SoBRA. These costs include: EPC costs; development costs including third party development fees, if any; permitting and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection cost and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters and modules; Allowance for Funds Used During Construction ("AFUDC") at the weighted average cost of capital from Exhibit B of the 2017 Agreement; owner's costs and other traditionally allowed rate base costs.

Q. Are all of the costs incurred to make the two First SoBRA projects fully operational included in the actual total installed cost amounts presented in your exhibit?

A. Yes. All costs incurred to bring the First SoBRA projects into service are included in the installed costs presented in my exhibit.

Q. Did the company receive liquidated damages for either of the two First SoBRA projects, and if so, how were liquidated damages reflected in the actual installed costs for the projects?

A. Yes. The company received liquidated damages for, and used them (1) to offset the lost revenue associated with the project's in-service date and (2) to reduce the actual installed capital cost of the projects, as applicable. The manner in which the company accounted for liquidated damages for the projects in the First and Second SoBRAs is explained by company witness Chronister in his direct testimony. The actual installed costs for the two First SoBRA projects described in my testimony reflect the application of liquidated damages as applicable.

Q. What are liquidated damages?

A. For more than 30 years, I have been involved in negotiation and administration of business contracts and have practical, work experience with liquidated damages. As used in this context, the term "liquidated damages" refers to the pre-arranged dollar amounts in the contracts Tampa Electric executed with solar developers or EPC contractors to compensate Tampa Electric for "damages" associated with performance delays. In general, the contracts contained provisions that compensated Tampa Electric for delays beyond the planned "commercial operation (in-service)" or "substantial completion" date as defined in the contracts.

Q. Did the company receive liquidated damages from the solar developers who built the Seven Projects?

A. Yes.

Q. How was the amount of liquidated damages paid by each developer determined?

A. The amounts ultimately were determined through negotiation for the number of days the project was delayed. The amounts were calculated pursuant to the liquidated damages provisions in the contracts as a starting point for the negotiations.

Once the amounts were determined and paid, Tampa Electric's accounting department apportioned the amounts between reimbursement for lost revenues and then to reduce the capital costs of the projects. This process is described in the testimony of witness Chronister.

Q. What is the difference between the estimated and actual installed costs for the two projects in the First SoBRA?

A. Payne Creek Solar total installed costs are approximately \$18 per kW_{ac} greater, and Balm Solar total installed costs are about \$2 per kW_{ac} lower than the estimated project costs.

Q. Please explain the variances between actual and estimated costs by category for the Payne Creek project.

A. The module, major equipment, balance of system, and development costs for each project are components of the turnkey contract price.

Payne Creek Solar's estimated turnkey contract price is \$84,650,369. The turnkey contract price is the sum of the modules, major equipment, balance of system, and development costs as listed in the "Estimated" column shown in Document No. 1 of my exhibit.

The Payne Creek Solar actual cost is the sum of the modules, major equipment, balance of system, and development costs and is \$85,588,779. These costs are listed in Document No. 1 of my exhibit in the column entitled "Actual". The variance between the actual and estimated EPC contract costs for Payne Creek Solar is \$938,410. The variance is due to change orders for additional modules needed as "breakage spares" and additional costs to provide more durable roads.

The owner's costs variance is approximately $1.1 million greater than estimated, due to additional Tampa Electric project management and safety personnel required to monitor workmanship and contractor safety practices on the project site.

The Payne Creek total all-in cost variance is approximately $1.3 million or $18 per kW_{ac} greater than expected.

Q. Please explain the variances between actual and estimated costs by category for the Balm project.

A. As is the case for Payne Creek, the module, major equipment, balance of system, and development costs for each project are components of the turnkey EPC contract price.
Balm Solar's estimated turnkey EPC contract price with First Solar is $86,238,085. Balm Solar's turnkey EPC contract price is the sum of the modules, major equipment, balance of system, and development costs listed in the "Estimated" column in Document No. 2 of my exhibit.

The Balm Solar actual EPC contract cost is the sum of the modules, major equipment, balance of system, and development costs and is $86,733,554. The costs are listed in the column entitled “Actual” shown in Document No. 2 of my exhibit The Balm development costs are included in the actual balance of system costs.

The variance between the actual and estimated turnkey contract costs for Balm Solar is $495,469. Most of this variance is due to change orders resulting from constructing more durable roads and retaining the Florida Highway Patrol to manage traffic at the project’s entrance. The owner’s costs variance is approximately $1.3 million. The higher owner’s costs are primarily due to additional Tampa Electric project management and safety personnel required to monitor workmanship and contractor safety practices on the project site. The land cost variance is approximately $1.7 million less than estimated.

The variance between the actual and estimated total all-in cost for Balm Solar is approximately $(127,000) or $2 per kW_{ac} lower than the estimated all-in cost.

Q. How are owner’s costs determined for the two First SoBRA projects?

A. Owner's costs include costs of work performed by Tampa Electric employees assigned to the solar projects who were not employed prior to the last rate case, consultants that were retained by the company to assist in development, project management, and safety activities, and legal support.

III. <u>Second SoBRA Projects: Lithia, Grange Hall, Peace Creek, Bonnie Mine and Lake Hancock Solar</u>

Q. Do the five projects in the company's Second SoBRA differ from the specifications mentioned in your direct testimony in Docket No. 20180133-EI?

A. No, the project design and specifications do not differ materially from planned and are as described in my Direct Testimony submitted in Docket No. 20180133-EI. The initial costs were estimates; therefore, there is a cost difference for each project. I explain these differences later in my testimony.

Q. Were the five Second SoBRA projects placed in service on or before the dates projected in Docket No. 20180133-EI?

A. No. All five of the projects were projected to be in-service on January 1, 2019. One of the projects was placed in service on January 1, 2019 as projected, and one was placed in service a day later. The other three projects were placed in service more than three weeks after the projected January 1, 2019 date; however, our customers will be made whole for the delays, even the one-day delay, via the revenue true-up described by company witness Chronister.

The actual in-service dates for the five Second SoBRA projects are:

Project	Actual In-Service Date
Lithia	January 1, 2019
Grange Hall	January 2, 2019
Peace Creek	March 1, 2019
Bonnie Mine	January 23, 2019
Lake Hancock	April 25, 2019

Q. Please explain why Grange Hall Solar was placed in service a day later than projected.

A. The contractor damaged a medium voltage cable late in the commissioning process. This required replacing the entire length of the cable. This installation and commissioning pushed the schedule out by one day.

Q. Please explain why Peace Creek Solar was placed in service later than projected.

A. Peace Creek Solar's in-service date was delayed due to the lack of a qualified labor pool to perform work needed to meet the contract schedule. This hindered daily production and caused delays to the project. The EPC contractor was not able to recover from the shortage of qualified labor. This resulted in a two-month delay.

Q. Please explain why Bonnie Mine Solar was placed in service later than projected.

A. Bonnie Mine Solar's Environmental Resource and County permits were issued one month later than what the EPC contractor had planned. In addition, site conditions caused additional delays with the project's civil work for the project contractor. The permit delay and additional civil work caused Bonnie Mine Solar to be placed in service three weeks later than planned.

Q. Please explain why Lake Hancock Solar was placed in service later than projected.

A. Lake Hancock Solar replaced Mountain View Solar when

Mountain View's county approval was appealed. Lake Hancock Solar was delayed because it received its permits later than planned, and a smaller than expected qualified labor pool delayed the construction of the project.

Q. How did the company manage the actual costs of the five Second SoBRA projects?

A. All five projects are turnkey projects. The cost of each project was fixed by the terms of the EPC contract, and any cost increases were submitted as change orders.

Actual costs were managed by Tampa Electric's project management and accounting teams. Contractors sent invoices to Tampa Electric monthly for work completed. Prior to paying each invoice, Tampa Electric inspected the project to verify the work had been completed and additional costs were justified.

Q. What are the total actual and estimated installed costs for the five Second SoBRA Projects?

A. The actual installed costs for four of the five Second SoBRA projects are lower than their projected costs. The estimated and actual installed costs per kW_{ac} of the five

Second SoBRA projects are:

Project	Estimated	Actual
Lithia	$1,494	$1,481
Grange Hall	$1,437	$1,430
Peace Creek	$1,492	$1,479
Bonnie Mine	$1,464	$1,496
Lake Hancock	$1,494	$1,459

The weighted-average cost for Second SoBRA projects is $1,468 per kW_{ac}.

Q. What costs were included in the actual costs for the five Second SoBRA projects for purposes of this true-up filing?

A. The actual total installed cost broken down by major category for the Second SoBRA Projects is shown on Document Nos. 3 through 7 of my exhibit. The actual costs included are the same categories or types of costs as those included in the company's estimated costs, as submitted in Docket No. 20180133-EI and in accordance with the 2017 Agreement.

As is the case with the First SoBRA projects, they include the types of costs that traditionally have been allowed in rate base and are eligible for cost recovery via a SoBRA.

Specifically, the installed costs include: EPC costs; development costs including third party development fees, if any; permitting and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection cost and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters and modules; Allowance for Funds Used During Construction (“AFUDC”) at the weighted average cost of capital from Exhibit B of the 2017 Agreement, owner’s costs; and other traditionally allowed rate base costs.

Q. Are all of the costs incurred to make the five Second SoBRA projects fully operational included in the actual total installed cost amounts presented in your exhibit?

A. Yes. All costs incurred to bring the Second SoBRA projects into service are included in the actual installed costs presented in my exhibit.

Q. Did the company receive liquidated damages for any of the five Second SoBRA projects, and if so, how are liquidated damages reflected in the actual installed costs for the projects?

A. Yes. The company received liquidated damages for, and used them (1) to offset the lost revenue associated with the project's later in-service date and (2) to reduce the actual installed capital cost of, all five of the projects in the Second SoBRA. The manner in which the company accounted for liquidated damages for the projects in the First and Second SoBRAs is explained by company witness Chronister in his direct testimony. The actual installed costs for the five Second SoBRA projects described in my testimony reflect the application of liquidated damages as applicable.

Q. Taking liquidated damages into account, what is the difference between the estimated and actual installed costs for the five Second SoBRA projects?

A. The actual installed cost for the Lithia, Grange Hall, Peace Creek, and Lake Hancock solar projects are \$13, \$7, \$13, and \$35 per kW_{ac} lower than projected, respectively. The actual installed cost of the Bonnie Mine project is \$32 per kW_{ac} higher than projected.

Q. Please explain the variances between actual and estimated costs by category for the Lithia project.

A. The modules, major equipment, balance of system, and development costs for each project are components of the turnkey EPC contract price.

Lithia Solar's estimated turnkey contract price is $90,200,000. The turnkey contract price is the sum of the modules, major equipment, balance of system, and development costs as listed in the "Estimated" column shown in Document No. 3 of my exhibit.

Lithia Solar's actual cost is the sum of the modules, major equipment, balance of system and development costs, which is $89,293,223. These costs are listed in Document No. 3 of my exhibit in the column entitled "Actual".

The variance between the actual and estimated contract costs for Lithia Solar is $(906,777). The variance is due to the liquidated damages applied to EPC costs.

The owner's costs variance is $650,184. The higher owner's costs are primarily due to the relocation of more than 200 gopher tortoises, site management, and safety oversight at the project site. The land cost variance is $447,022 less than estimated.

The variance between the actual and estimated total all-in

cost for Lithia Solar is approximately $(935,179) or $13 per kW_{ac} lower than the estimated all-in cost.

Q. Please explain the variances between actual and estimated costs by category for the Grange Hall project.

A. The modules, major equipment, balance of system, and development costs for each project are components of the turnkey EPC price.

Grange Hall Solar’s estimated turnkey contract price is $73,300,000. The turnkey EPC contract price is the sum of the modules, major equipment, balance of system, and development costs as listed in the “Estimated” column shown in Document No. 4 of my exhibit.

Grange Hall Solar’s actual cost is the sum of the modules, major equipment, balance of system, and development costs, which is $72,643,452. These costs are listed in Document No. 4 of my exhibit in the column entitled “Actual”.

The variance between the actual and estimated contract costs for Grange Hall is $(656,548). The variance is due to applying the liquidated damages to the contract cost.
The variance between the actual and estimated total all-in

cost for Grange Hall Solar is $(452,974), or $7 per kW_{ac} lower than the estimated all-in cost.

Q. Please explain the variances between actual and estimated costs by category for the Peace Creek project.

A. The modules, major equipment, balance of system, and development costs for each project are components of the turnkey contract price.

Peace Creek Solar's estimated turnkey contract price is $64,500,000. The turnkey EPC contract price is the sum of the modules, major equipment, balance of system, and development costs as listed in the "Estimated" column shown in Document No. 5 of my exhibit.

Peace Creek Solar's actual cost is the sum of the modules, major equipment, balance of system, and development costs, which is $64,540,841. These costs are listed in Document No. 5 of my exhibit in the column entitled "Actual".

The variance between the actual and estimated contract costs for Peace Creek is $40,841, or less than one tenth of one percent greater than the estimated cost.

The transmission interconnection cost variance is

$(1,728,866), and the owner's costs variance is $559,812. The higher owner's costs are primarily due to having construction and safety site managers to ensure workmanship and safety protocols were followed by the contracts.

The variance between the actual and estimated total all-in cost for Peace Creek Solar is $(656,362), or $13 per kW_{ac} lower than the estimated all-in cost.

Q. Please explain the variances between actual and estimated costs by category for the Bonnie Mine project.

A. The modules, major equipment, balance of system, and development costs for each project are components of the turnkey contract price.

Bonnie Mine Solar's estimated turnkey contract price is $48,600,000. The turnkey contract price is the sum of the modules, major equipment, balance of system, and development costs as listed in the "Estimated" column shown in Document No. 6 of my exhibit.

Bonnie Mine Solar's actual cost is the sum of the modules, major equipment, balance of system, and development costs, which is $48,409,422. These costs are listed in Document

No. 6 of my exhibit in the column entitled “Actual”.

The variance between the actual and estimated contract costs for Bonnie Mine Solar is $(190,578), or 0.4 percent less than the estimated costs.

The transmission interconnection cost variance is $(361,837), and the owner’s costs variance is $1,128,941. The higher owner’s costs are primarily due to using additional construction and safety managers to ensure workmanship and safety protocols were followed during project construction.

The variance between the actual and estimated total all-in cost for Bonnie Mine Solar is approximately $1,202,532, or $32 per kW_{ac} higher than the estimated all-in cost.

Q. Please explain the variances between actual and estimated costs by category for the Lake Hancock project.

A. The modules, major equipment, balance of system, and development costs for each project are components of the turnkey contract price.

Lake Hancock Solar’s estimated turnkey contract price for the 31.8 MW of capacity included in the SoBRA is $38,802,424. The turnkey contract price is the sum of the modules, major equipment, balance of system, and development costs as listed in the “Estimated” column shown in Document No. 7 of my exhibit.

Lake Hancock Solar’s actual cost is the sum of the modules, major equipment, balance of system, and development costs, which is $37,110,412. These costs are listed in Document No. 7 of my exhibit in the column entitled “Actual”.

The variance between the actual and estimated contract costs for Lake Hancock Solar is $(1,692,012). The variance is due to the liquidated damages applied to the actual EPC contract costs.

The transmission interconnection cost variance is $(355,295), and the owner’s costs variance is $1,020,143. The higher owner’s costs are primarily due to required vegetation buffer costs and the additional construction and safety managers needed to ensure workmanship and safety protocols were followed during the construction of the project.

The variance between the actual and estimated total all-in

cost for Lake Hancock Solar is $(1,072,140), or $35 per kW_{ac} lower than the estimated all-in cost.

Q. How are owner's costs determined for the five Second SoBRA projects?

A. As is the case for the two First SoBRA projects, owner's costs for the five Second SoBRA projects include costs of work performed by Tampa Electric employees assigned to the solar projects who were not employed prior to the last rate case, consultants retained by the company to assist in development, project management, safety activities, and legal support.

IV. Summary

Q. Please summarize your direct testimony.

A. Tampa Electric's Payne Creek Solar (70.3 MW) and Balm Solar (74.4 MW) became fully operational and were placed in service on September 1, 2018 and September 27, 2018, respectively.

The Lithia (74.5 MW), Grange Hall (61.1 MW), Peace Creek (55.4 MW), Bonnie Mine (37.5 MW) and Lake Hancock (31.8

MW), projects were placed in service on January 1, January 2, January 23, March 1 and April 25, 2019, respectively.

Balm Solar’s actual installed cost is $1,478 per kW_{ac}, which is $2 per kW_{ac} less than the estimated cost of $1,480 per kW_{ac}.

Payne Creek Solar’s actual installed cost is $1,432 per kW_{ac}, which is $18 per kW_{ac} more than the estimated all-in cost. The variance is primarily due to constructing more durable roads and including costs for breakage or “spare” modules.

Lithia Solar’s actual installed cost is $1,481 per kW_{ac}, which is $13 per kW_{ac} less than the estimated cost of $1,494 per kW_{ac}.

Grange Hall Solar’s actual installed cost is $1,430 per kW_{ac}, which is $7 per kW_{ac} less than the estimated cost of $1,437 per kW_{ac}.

Peace Creek Solar’s actual installed cost is $1,479 per kW_{ac}, which is $13 per kW_{ac} less than the estimated cost of $1,492 per kW_{ac}.

Bonnie Mine Solar's actual installed cost is $1,496 per kW_{ac}, which is $32 per kW_{ac} more than the estimated cost of $1,464 per kW_{ac}. The variance is primarily due to costs for additional construction and safety site managers to oversee construction.

Lake Hancock Solar's actual installed cost is $1,459 per kW_{ac}, which is $35 per kW_{ac} less than the estimated cost of $1,494 per kW_{ac}. The variance is primarily due to liquidated damages that offset the actual EPC contract cost.

The actual installed cost of each of the Seven Projects falls below the SoBRA cost cap of $1,500 per kW_{ac}. The weighted average of the Seven Projects is $1,448 per kW_{ac}.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

EXHIBIT

OF

MARK D. WARD

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REDACTED

Payne Creek Solar Actual and Estimated Costs

	Actual	Estimated	Difference
Project Output (MW_{ac})	70.3	70.3	-
EPC Contract Costs:			
Major Equipment	[redacted]	[redacted]	$ (107,664)
Balance of System	[redacted]	[redacted]	2,356,859
Development	282,837.8	1,593,623	(1,310,785)
Total EPC Contract	85,588,779	84,650,369	938,410
Trans. Interconnect	4,011,698	4,400,000	(388,302)
Land	1,345,839	1,408,400	(62,561)
Owner's Costs	1,562,235	419,383	1,142,852
Total Installed Cost	92,508,551	90,878,151	1,630,400
AFUDC	1,851,033	2,195,318	(344,285)
Total All-in Cost	$ 94,359,584	$ 93,073,469	$ 1,286,115
Total ($/$kW_{ac}$)	1,342	1,324	18

Notes:
[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

REDACTED

Balm Solar Actual and Estimated Costs

	Actual	Estimated	Difference
Project Output (MW_{ac})	74.4	74.4	-
EPC Contract Costs:			
Major Equipment	[redacted]	[redacted]	$ (1,059,555)
Balance of System	[redacted]	[redacted]	2,879,854
Development	362,124	1,686,953	(1,324,829)
Total EPC Contract	86,733,554	86,238,085	495,469
Trans. Interconnect	1,662,086	2,500,000	(837,914)
Land	17,022,515	18,720,128	(1,697,613)
Owner's Costs	1,760,273	443,970	1,316,303
Total Installed Cost	107,178,428	107,902,183	(723,755)
AFUDC	2,784,955	2,188,259	596,696
Total All-in Cost	$ 109,963,383	$ 110,090,442	$ (127,059)
Total ($/$kW_{ac}$)	1,478	1,480	(2)

Notes:
[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

REDACTED

Lithia Solar Actual and Estimated Costs

	Actual	Estimated	Difference
Project Output (MW_{ac})	74.5	74.5	-
EPC Contract Costs:			
Major Equipment	[redacted]	[redacted]	$ (3,603,118)
Balance of System	[redacted]	[redacted]	4,663,481
Development	432,860	2,400,000	(1,967,140)
Total EPC Contract	89,293,223	90,200,000	(906,777)
Trans. Interconnect	3,287,123	4,000,000	(712,877)
Land	13,352,978	13,800,000	(447,022)
Owner's Costs	1,550,184	900,000	650,184
Total Installed Cost	107,483,507	108,800,000	(1,316,493)
AFUDC	2,881,314	2,500,000	381,314
Total All-in Cost	$ 110,364,821	$ 111,300,000	$ (935,179)
Total ($/$kW_{ac}$)	1,481	1,494	(13)

Notes:
[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

REDACTED

Grange Hall Solar Actual and Estimated Costs

	Actual	Estimated	Difference
Project Output (MW_{ac})	61.1	61.1	-
EPC Contract Costs:			
Major Equipment	[redacted]	[redacted]	$ (725,323)
Balance of System	[redacted]	[redacted]	1,512,962
Development	355,813	1,800,000	(1,444,187)
Total EPC Contract	72,643,452	73,300,000	(656,548)
Trans. Interconnect	3,402,187	4,600,000	(1,197,813)
Land	8,252,433	8,400,000	(147,567)
Owner's Costs	978,840	500,000	478,840
Total Installed Cost	85,276,912	86,800,000	(1,523,088)
AFUDC	2,070,114	1,000,000	1,070,114
Total All-in Cost	$ 87,347,026	$ 87,800,000	$ (452,974)
Total ($/$kW_{ac}$)	1,430	1,437	(7)

Notes:
[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

Peace Creek Solar Actual and Estimated Costs

	Actual	Estimated	Difference
Project Output (MW_{ac})	55.4	55.4	-
EPC Contract Costs:			
Major Equipment	[redacted]	[redacted]	$ (33,558)
Balance of System	[redacted]	[redacted]	1,606,438
Development	267,962	1,800,000	(1,532,038)
Total EPC Contract	64,540,841	64,500,000	40,841
Trans. Interconnect	2,971,134	4,700,000	(1,728,866)
Land	11,577,007	11,700,000	(122,993)
Owner's Costs	959,812	400,000	559,812
Total Installed Cost	80,048,794	81,300,000	(1,251,206)
AFUDC	1,894,844	1,400,000	494,844
Total All-in Cost	$ 81,943,638	$ 82,600,000	$ (656,362)
Total ($/$kW_{ac}$)	1,479	1,492	(13)

Notes:
[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

REDACTED

Bonnie Mine Solar Actual and Estimated Costs

	Actual	Estimated	Difference
Project Output (MW_{ac})	37.5	37.5	-
EPC Contract Costs:			
Major Equipment	[redacted]	[redacted]	$ 7,029,294
Balance of System	[redacted]	[redacted]	(6,137,509)
Development	317,638	1,400,000	(1,082,362)
Total EPC Contract	48,409,422	48,600,000	(190,578)
Trans. Interconnect	538,163	900,000	(361,837)
Land	4,157,276	4,300,000	(142,724)
Owner's Costs	1,428,941	300,000	1,128,941
Total Installed Cost	54,533,803	54,100,000	433,803
AFUDC	1,568,729	800,000	768,729
Total All-in Cost	$ 56,102,532	$ 54,900,000	$ 1,202,532
Total ($/$kW_{ac}$)	1,496	1,464	32

Notes:
[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

REDACTED

Lake Hancock Solar Actual and Estimated Costs

	Actual	Estimated	Difference
Project Output (MW_{ac})	31.8	31.8	-
EPC Contract Costs:			
Major Equipment	[redacted]	[redacted]	$ (1,002,221)
Balance of System	[redacted]	[redacted]	127,967
Development	210,121	1,027,879	(817,758)
Total EPC Contract	37,110,412	38,802,424	(1,692,012)
Trans. Interconnect	2,278,645	2,633,939	(355,295)
Land	5,801,085	5,846,061	(44,975)
Owner's Costs	1,212,870	192,727	1,020,143
Total Installed Cost	46,403,012	47,475,152	(1,072,140)
AFUDC	-	-	-
Total All-in Cost	$ 46,403,012	$ 47,475,152	$ (1,072,140)
Total ($/$kW_{ac}$)	1,459	1,494	(34)

Notes:
[1] Major Equipment includes modules, inverters, and transformers
[2] Balance of System includes racking, posts, collection cables, EPC contractor and project management

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2020___-EI

IN RE: PETITION BY TAMPA ELECTRIC COMPANY FOR A LIMITED PROCEEDING TO TRUE-UP FIRST AND SECOND SOBRAS

PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

JOSE A. APONTE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOSE A. APONTE

Q. Please state your name, address, occupation and employer.

A. My name is Jose A. Aponte. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager of Resource Planning. My primary responsibilities include identifying the need for future resource additions and analyzing the economic and other operational impacts to Tampa Electric's system associated with the addition of resource options.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from the University of South Florida with a Bachelor's degree and a Master of Science degree in Mechanical Engineering. I am a registered Project Management Professional ("PMP").

In 1999, I was employed by Tampa Electric as an engineer in the Inventory Management and Supply Chain Logistics team. In 2004, I became supervisor for the Materials and Quality Assurance Department at the Big Bend Power Station. Since 2008, I have held several positions in the Resource Planning department at Tampa Electric.

I have twenty-one years of accumulated electric utility experience working in the areas of planning, systems integration, data analytics, project economic analysis, and engineering. I was appointed to my current position, Manager of Resource Planning, in December 2017.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to sponsor and explain the calculation of the revenue requirement based on actual installed project costs for the seven projects in the company’s first and second SoBRA tranches. i.e., its First and Second SoBRAs.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, Exhibit No. ____(JAA-1) was prepared by me or under my direction and supervision. It is titled “Revenue

Requirement True-Up for First and Second SoBRAs."

Q. How does your testimony relate to the prepared direct testimony of Tampa Electric's other witnesses?

A. Tampa Electric witness Ward's direct testimony describes the actual in-service dates and installed cost per kilowatt alternating current ("kW_{ac}") for (1) the two projects, Payne Creek Solar and Balm Solar, for which cost recovery was granted by the Commission via the company's First SoBRA in Docket No. 20170260-EI and (2) the five projects (Lithia Solar, Grange Hall Solar, Peace Creek Solar, Bonnie Mine Solar, and Lake Hancock Solar) for which cost recovery was granted by the Commission via the Second SoBRA in Docket No. 20180133-EI.

I will refer to the Balm, Payne Creek, Lithia, Grange Hall, Peace Creek, Bonnie Mine, and Lake Hancock solar projects collectively as the "Seven Projects" throughout my testimony.

I use the actual installed project costs of the Seven Projects in witness Ward's direct testimony to calculate the actual revenue requirement for the First and Second SoBRAs and compare them to the estimated revenue requirement determined in Docket Nos. 20170260-EI and 20180133-EI.

The company’s cost of service and rate design witness, William Ashburn, uses the actual revenue requirement described in my direct testimony to develop final customer rates for the First and Second SoBRAs. The company proposes that these rates become effective with the first billing cycle in January 2021.

The testimony of witness Chronister describes the revenue true-up for the period the estimated First and Second SoBRA rates were charged to customers to reflect actual project in-service dates and costs, which is passed along to customers through the capacity clause. Mr. Chronister also explains how the liquidated damages paid by solar developers were apportioned among the Seven Projects and reduced the actual installed costs of certain of those projects.

Annual Revenue Requirement True-Up

Q. What is the annual revenue requirement authorized to recover the costs associated with the First and Second SoBRAs?

A. The estimated annual revenue requirement for the First SoBRA is $24,245,000. The estimated annual revenue requirement for the Second SoBRA is $46,045,000.

These amounts were calculated using the projected installed costs for the seven projects in the First and Second SoBRAs as described in witness Ward's direct testimony in Docket Nos. 20170260-EI and 20180133-EI, and in accordance with the revenue requirement cost recovery provisions in the 2017 Agreement.

Q. What are the total estimated annual revenue requirement for each of the seven projects?

A. The total estimated annual revenue requirements by project for the First and Second SoBRAs as approved by the Commission are:

Project	Revenue Requirement
Balm	$12,937,000
Payne Creek	11,308,000
Lithia	13,291,000
Grange Hall	10,611,000
Peace Creek	9,868,000
Bonnie Mine	6,601,000
Lake Handcock	5,674,000

Q. Are these estimated annual revenue requirements final amounts?

A. No. Subparagraph 6(g) of the 2017 Agreement specifies that the approved projected annual revenue requirement amount will be trued up to reflect the actual installed cost of the projects covered by the First and Second SoBRAs.

Q. What is the total actual cost annual revenue requirement for the First and Second SoBRAs?

A. The actual annual revenue requirement for the First and Second SoBRAs together is $70,213,000. This amount is calculated using the actual installed costs for the Seven Projects as described in witness Ward’s direct testimony in this docket, and in accordance with the revenue requirement cost recovery provisions in the 2017 Agreement. A summary of the annual revenue requirement calculation by project is shown in my exhibit, Exhibit No. ___ (JAA-1).

Q. Does the revised annual revenue requirement for the First and Second SoBRAs presented in Exhibit No. ___ (JAA-1) reflect an incentive savings adjustment?

A. Yes. Subparagraph 6(m) of the 2017 Agreement contains an incentive designed to encourage Tampa Electric to build solar projects for recovery under a SoBRA at the lowest possible cost. According to subparagraph 6(m), if Tampa Electric's actual installed cost for a project is less than the Installed Cost Cap, the company's customers and the company will share in the beneficial difference with 75 percent of the difference inuring to the benefit of customers and 25 percent serving as an incentive to the company to seek such cost savings over the life of this 2017 Agreement. The company has included the effect of the incentive in its actual revenue requirement for the First and Second SoBRAs.

Q. Does the 2017 Agreement include an example of how the incentive mechanism would work?

A. Yes. According to subparagraph 6(m), if the actual installed cost of a solar project is $1,400 per kW_{ac}, the final cost to be used for purposes of computing cost recovery under this 2017 Agreement and the true-up of the initial SOBRA would be $1,425 kW_{ac} [0.25 times ($1,500 - $1,400) + $1,400].

Q. Please describe the calculation of the incentive for the First and Second SoBRAs based on the company's actual installed costs.

A. Witness Ward provides the actual installed costs for the Seven Projects including interconnection, allowance for funds used during construction ("AFUDC"), and land costs. The calculation of the actual installed costs including the incentive for each project is as follows.

Project	Actual Costs Including Incentive per kW_{ac}
Balm Solar	0.25 * ($1,500 - $1,478) + $1,478 = $1,483
Payne Creek	0.25 * ($1,500 - $1,342) + $1,342 = $1,381
Lithia	0.25 * ($1,500 - $1,481) + $1,481 = $1,486
Grange Hall	0.25 * ($1,500 - $1,430) + $1,430 = $1,447
Peace Creek	0.25 * ($1,500 - $1,479) + $1,479 = $1,484
Bonnie Mine	0.25 * ($1,500 - $1,496) + $1,496 = $1,497
Lake Hancock	0.25 * ($1,500 - $1,459) + $1,459 = $1,469

Q. How does the revised incentive calculation differ from the estimated incentive calculation for the First and Second SoBRAs?

A. The formula is the same as that formula used in Docket Nos. 20170260-EI and 20180133-EI, but the estimated installed costs used in those dockets have been replaced with the actual installed costs provided by witness Ward.

Project	**Estimated Costs Including Incentive per kW_{ac}**
Balm Solar	0.25 * ($1,500 - $1,480) + $1,480 = $1,485
Payne Creek	0.25 * ($1,500 - $1,324) + $1,324 = $1,368
Lithia	0.25 * ($1,500 - $1,494) + $1,494 = $1,496
Grange Hall	0.25 * ($1,500 - $1,437) + $1,437 = $1,453
Peace Creek	0.25 * ($1,500 - $1,492) + $1,492 = $1,494
Bonnie Mine	0.25 * ($1,500 - $1,464) + $1,464 = $1,473
Lake Hancock	0.25 * ($1,500 - $1,494) + $1,494 = $1,496

Q. How do the projected and actual incentive amounts compare for each of the Seven Projects?

A. A comparison of the projected and actual incentive amounts for each of the Seven Projects is shown below:

Project	Estimated	Actual	Difference
Balm	5	5	0
Payne Creek	44	39	(5)
Lithia	2	5	3
Grange Hall	15	17	2
Peace Creek	2	5	3
Bonnie Mine	9	1	(8)
Lake Hancock	2	10	8

Q. Are investment tax credits included in the calculation of the actual First and Second SoBRA revenue requirement?

A. Yes. Thirty percent investment tax credits were applied in the calculation of the estimated and actual First and Second SoBRA annual revenue requirements.

Q. Did the company credit the value of liquidated damages received from solar developers to reduce the actual installed costs of certain of the Seven Projects?

A. Yes. The company apportioned liquidated damages to six of the Seven Projects. The amount of liquidated damages apportioned to the six projects and how they reduced the actual installed cost of those projects is shown in the direct testimony of witness Chronister. The rationale the company used to apportion the liquidated damages is explained in the direct testimony of witness Chronister.

Q. How is the actual annual revenue requirement you calculated for the First and Second SoBRAs to be applied?

A. The SoBRA rates are to be adjusted to reflect the revised revenue requirement based on actual costs. The actual First and Second SoBRA rates are described and explained in witness Ashburn’s testimony, but because the difference between the estimated and actual revenue requirements is small, the company proposes that the revenue difference be included in its Fourth SoBRA.

In addition, the 2017 Agreement requires the company to calculate a true-up to reflect differences between the actual and estimated installed cost and in-service dates for the projects, for the period of time the estimated SoBRA rates were in effect.

Q. Does the 2017 Agreement state how this revenue requirement true-up is to be calculated?

A. Yes. Subparagraph 6(n) of the 2017 Agreement states that a revised SoBRA will be computed using the same data and methodology incorporated in the initial SoBRA, with the exception that the actual capital expenditures after sharing and the actual in-service date will be used in lieu of the capital expenditures on which the annualized revenue requirement was based. The difference between the cumulative base revenues since the implementation of the initial SoBRA factor and the cumulative base revenues that would have resulted if the revised SoBRA factor (for cost and in-service date true-ups) had been in place during the same time period will be trued up with interest at the AFUDC rate used for the projects, and will be made through a twelve-month adjustment via the Capacity Clause. This true-up is described and explained in witness Chronister’s testimony.

Q. Please summarize your direct testimony.

A. The First and Second SoBRA estimated annual revenue requirements totaled $70,290,000. Using the actual installed costs provided by witness Ward, I calculated the actual annual revenue requirement for the First and Second SoBRAs to be $70,213,000, or $77,000 less than the estimated amount. These amounts include incentive and are calculated in accordance with the 2017 Agreement.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

JOSE A. APONTE

First SoBRA Actual Revenue Requirements

145 MW of Solar (Tranche 1)

($000)	2018
Balm Solar	10,434
Payne Creek	10,442
Capital RR	20,876
Balm Solar	533
Payne Creek	503
FOM	1,036
Land RR	2,073
TOTAL RR	23,985

First SoBRA Actual Revenue Requirements with Sharing Mechanism

145 MW of Solar (Tranche 1)
with 75%/25% Incentive
vs $1,500/kW Maximum

($000)	2018
Balm Solar	10,480
Payne Creek	10,753
Capital RR	21,233
Balm Solar	533
Payne Creek	503
FOM	1,036
Land RR	2,073
TOTAL RR	24,342

Second SoBRA Actual Revenue Requirements

260 MW of Solar (Tranche 2)

($000)	2019
Lithia	11,130
Grange Hall	9,074
Peace Creek	8,073
Bonnie Mine	5,959
Lake Hancock	4,658
Capital RR	38,894
Lithia	547
Grange Hall	448
Peace Creek	407
Bonnie Mine	275
Lake Hancock	233
FOM	1,911
Land RR	4,828
TOTAL RR	45,633

Second SoBRA Actual Revenue Requirements with Sharing Mechanism

260 MW of Solar (Tranche 2)
with 75%/25% Incentive
vs $1,500/kW Maximum

($000)	2019
Lithia	11,169
Grange Hall	9,198
Peace Creek	8,106
Bonnie Mine	5,964
Lake Hancock	4,695
Capital RR	39,132
Lithia	547
Grange Hall	448
Peace Creek	407
Bonnie Mine	275
Lake Hancock	233
FOM	1,911
Land RR	4,828
TOTAL RR	45,871

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2020___-EI
IN RE: PETITION BY TAMPA ELECTRIC COMPANY
FOR A LIMITED PROCEEDING TO TRUE-UP FIRST
AND SECOND SOBRAS

REDACTED

PREPARED DIRECT TESTIMONY AND EXHIBIT
OF
JEFFREY S. CHRONISTER

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEFFREY S. CHRONISTER

Q. Please state your name, address, occupation and employer.

A. My name is Jeffrey S. Chronister. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Vice President Finance and Controller, Tampa Electric.

I. Introduction

Q. Please describe your duties and responsibilities in that position?

A. I am responsible for maintaining the financial books and records of the company and for the determination and implementation of accounting policies and practices for Tampa Electric. I am also responsible for budgeting activities within the company.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from Stetson University in 1982 with a Bachelor of Business Administration degree in Accounting. Upon graduation I joined Coopers & Lybrand, an independent public accounting firm, where I worked for four years before joining the company in 1986. I started in Tampa Electric’s Accounting department, moved to TECO Energy’s Internal Audit department in 1987, and returned to the Accounting department in 1991. I am a Certified Public Accountant in the State of Florida and I am a member of both the American Institute of Certified Public Accountants (“AICPA”) and the Florida Institute of Certified Public Accountants (“FICPA”). I have served as Controller of Tampa Electric since July 2009, and in my current position since July 2018.

Q. Have you previously testified before the Florida Public Service Commission (“Commission”)?

A. Yes, I have testified or filed testimony before this Commission in several dockets. I testified for Tampa Electric in Docket No. 20130040-EI, which was Tampa Electric’s last base rate proceeding. I filed testimony in Docket No. 20080317-EI, Tampa Electric Company’s Petition for An Increase in Base Rates and Miscellaneous Service Charges, Docket No. 19960007-EI, Tampa Electric's Environmental Cost Recovery Clause, and Docket No. 19960688-EI, Tampa Electric's environmental compliance activities for purposes of cost recovery. I also filed testimony in Docket No. 20170271-EI, Petition for recovery of costs associated with named tropical systems during the 2015, 2016, and 2017 hurricane seasons and replenishment of storm reserve subject to final true-up, Tampa Electric Company.

Q. What are the purposes of your direct testimony?

A. All of my testimony relates to (1) the two projects, Payne Creek Solar and Balm Solar, for which cost recovery was granted by the Commission via the company's First SoBRA in Docket No. 20170260-EI and (2) the five projects (Lithia Solar, Grange Hall Solar, Peace Creek Solar, Bonnie Mine Solar, and Lake Hancock Solar) for which cost recovery was granted by the Commission via the Second SoBRA in Docket No. 20180133-EI. I will refer to the Balm, Payne Creek, Lithia, Grange Hall, Peace Creek, Bonnie Mine and Lake Hancock solar projects collectively as the "Seven Projects" throughout my testimony.

My testimony serves two purposes. My first purpose is to describe the calculation of two SoBRA true-ups – the timing true-up and the cost true-up. These true-ups are for the seven projects in the company’s First and Second SoBRAs. The timing true-up is related to the actual project in-service dates for the seven projects compared to the period that the company began charging customers the First and Second SoBRA rates. The cost true-up is related to the actual installed project costs for the seven projects compared to the estimated costs used to set SoBRA rates. These true-ups are passed through the capacity clause.

My second purpose is to explain how the liquidated damages paid by solar developers for projects in the First and Second SoBRAs were apportioned among those projects and reduced the actual installed costs of certain of those projects. The liquidated damage amounts I explain in my testimony were used by Tampa Electric witness Mark Ward in his calculation of the final installed costs for each of the Seven Projects.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, Exhibit No. ____(JSC-1) was prepared by me or under my direction and supervision. Document No. 1 reflects the calculation of the True-Up Amounts. Document No. 2 shows how the liquidated damages paid to the company by the developers involved in the First and Second SoBRA projects were apportioned to those projects.

Q. How does your testimony relate to the prepared direct testimony of Tampa Electric's other witnesses?

A. Tampa Electric witness Ward's direct testimony describes the actual in-service dates and installed cost per kilowatt alternating current ("kW_{ac}") for the Seven Projects in the First and Second SoBRAs. Witness Aponte uses the actual installed project costs in witness Ward's direct testimony to calculate the actual revenue requirement for the First and Second SoBRAs and compares it to the estimated revenue requirement determined in Docket Nos. 20170260-EI and 20180133-EI. The company's cost of service and rate design witness, William R. Ashburn, uses the actual revenue requirement described in witness Aponte's direct testimony to develop final customer rates for the First and Second SoBRAs that will be effective with the first billing cycle in January 2021. My testimony relates to the testimony of these witnesses in that the timing true-up I present reflects the in-service dates presented in Witness Ward’s testimony and the cost true-up I present reflects the installed cost and revenue requirements presented in Witness Ward and Witness Aponte’s testimonies, respectively.

II. True-Up Calculations

Q. Please provide perspective for the true-ups related to SoBRA revenues.

A. The first consideration is the applicability of the true-ups. Below I will describe how the 2017 Agreement provides for the true-up of SoBRA revenues. The next consideration is that there are two types of true-up involved. The timing true-up is related to the actual project in-service dates for the SoBRA projects compared to the period that the company began charging customers the SoBRA rates. The cost true-up is related to the actual installed project costs for the SoBRA projects compared to the estimated costs used to set SoBRA rates. The timing true-up is calculated for the period from the beginning of each tranche’s SoBRA billing to the project in-service dates, while the cost true-up applies to the period from the project in-service dates to January 2021, when the final

SoBRA rates are put in place.

Q. Does the 2017 Agreement provide for a true-up of SoBRA revenues?

A. Yes. The 2017 Agreement made room for the possibility that the estimated and actual annual revenue requirement and in-service dates for the Seven Project could end up being different and included provisions to protect customers should differences occur.

Subparagraph 6(n) of the 2017 Agreement states that a revised SoBRA will be computed using the same data and methodology incorporated in the initial SoBRA, with the exception that the actual capital expenditures after sharing will be used in lieu of the capital expenditures on which the estimated annualized revenue requirement was based. The difference between the cumulative base revenues since the implementation of the initial SoBRA factor and the cumulative base revenues that would have resulted if the revised SoBRA factor had been in place during the same time period will be trued up with interest at the AFUDC rate used for the projects, and will be made through a one-time, twelve-month adjustment. The true-up also reflects any differences between the actual and estimated in-service dates for the Seven Projects.

Q. Please describe the calculation of the timing true-up.

A. The timing true-up consists of the portion of the annual revenue requirement for each of the Seven Projects from the estimated in-service date to the actual in-service date. The company charged rates to customers based on the estimated annual revenue requirement for the Seven Projects beginning on the estimated in-service dates for the projects, and some of the projects did not go in-service until after the estimated date. The company owes its customers the ratable portion of the annual revenue requirement attributable to any period when the new SoBRA rates were in effect and the underlying projects were not in service. The company also owes its customers any applicable interest. The calculation of the timing true-up is shown on Page 3 of Document No. 1 in my exhibit.

Q. Please describe the calculation of the cost true-up.

A. The cost true-up consists of the difference between the estimated and actual (final) revenue requirement for the projects from the time when each project went in service to January 1, 2021, which is the date the company proposes that the base rate adjustment to reflect the final First and Second SOBRA rates will become effective. The company owes its customers this true-up plus any applicable interest. The calculation of the cost true-up is shown in Document No. 1 in my exhibit.

Q. What is the dollar amount of the timing true-up?

A. The dollar amount of the timing true-up is $(4,490,688), as shown on Line 10, Page 1 of Document No. 1 in my exhibit. At Page 3 of Document No. 1, I show the estimated revenue requirement for each of the Seven Projects as approved by the Commission and, using the daily average for the estimated annual revenue requirement for each project, show the revenue requirement attributable to the period of time the individual projects were not in service as estimated, if any. This schedule uses the actual in-service dates by project as described in the testimony of Mr. Mark Ward. The company calculated the interest due on the true-up amount using the AFUDC rate specified in the 2017 Agreement.

Q. What is the dollar amount of the cost true-up?

A. The dollar amount of the cost true-up is $(93,176), as shown on Line 9, Page 1 of Document No. 1 in my exhibit. The calculation compares the estimated annual revenue requirement for each project with the actual final annual revenue requirement and shows the difference for the period when a project was placed in service to January 1, 2021. This schedule uses the actual in-service dates by project as described in the testimony of witness Ward and the actual annual revenue requirements by project presented by witness Aponte. The company calculated the interest due on the true-up amount using the AFUDC rate specified in the 2017 Agreement.

The cost true-up is applicable beginning at the in-service date of the project. Since Tampa Electric returned the entire amount of revenue collected prior to the in-service date, a cost true-up amount is not needed for those days and would be double-counted. On Page 4 of Document 1 of my exhibit, I provide the calculation of adjusted monthly average true-up amounts to reflect the project in-service dates. The adjustment is calculated using the actual in-service dates and the daily average for the difference between estimated and actual annual revenue requirement for each project.

The company calculated the interest due on the true-up amount using the AFUDC rate specified in the 2017 Agreement.

Q. For what period will the true-up be applied to customer bills?

A. An estimated $4.9 million First and Second SoBRA true-up was included in the capacity clause in February 2020 and will be returned to customers in the company's mid-course capacity factors effective for the period June 2020 through December 2020. The final net true-up amount consisting of the difference between the estimated and actual true-up amounts, a credit of approximately $240,000, will be applied to customer bills beginning with the first billing cycle of January 2021 through the final billing cycle of December 2021.

Q. Although the true-ups are being provided to customers in two parts, what is the total amount of the true-ups?

A. The total true-up amount to be passed through the capacity clause is a credit of $5,096,041.

Q. If the total true-up was applied all in the same manner, what would be the effect of the true-up amount on a typical 1,000 kWh residential bill?

A. The total true-up amount would reduce a typical residential bill by $0.30 per 1,000 kWh. Since the greater portion of the true-up will be returned to customers in the 2020 mid-course capacity factors effective from June 2020 through December 2020, the remaining net true-up amount to be applied in the calculation of the 2021 capacity factors is a credit of $239,712, which represents a $0.01 reduction for a typical residential bill.

III. Liquidated Damages

Q. In general, what are liquidated damages?

A. The term “liquidated damages” refers to the pre-arranged dollar amounts established in construction contracts to compensate the paying party for deficient performance by the construction contractor. Tampa Electric includes liquidated damage provisions in construction contracts to mitigate the risk of financial burden that would result from a construction contractor not performing their duties properly. Liquidated damages protect customers from bearing negative financial impact and help keep project costs at appropriate levels. Customers benefit by being protected from rate burdens that would result from deficient contractor performance.

Q. Please describe liquidated damages related to the SoBRA solar projects.

A. Tampa Electric included liquidated damage provisions in the contracts with the First and Second SoBRA solar developers to compensate Tampa Electric for damages associated with performance delays. In general, the contracts contained provisions that compensated Tampa Electric for delays beyond the planned “substantial completion” or “commercial operation” dates as defined in the contracts. The process by which the company received payments as liquidated damages is discussed in the testimony of witness Ward.

Q. How did the company apportion liquidated damages for the Seven Projects?

A. Liquidated damages were first applied to the revenue impact of performance delays by the developers. The developers’ construction delays caused revenue losses – for which the developers were contractually responsible. Any liquidated damages over and above the revenue impacts were applied to capital cost – which lowered the total installed cost of the seven projects. In total, the company received about $9.2 million of liquidated damages from the developers. Of that total, about $4.5 million was applied to revenue losses, and about $4.7 million was credited against project costs.

Q. How did the company apportion liquidated damages for the Seven Projects to the individual projects?

A. Liquidated damages for revenue losses were applied according to the revenue losses associated with each project. The remaining liquidated damages were applied using consideration of developer performance and contract terms, amounts paid to each developer and factors associated with the delays.

Q. Have you prepared a schedule showing the amount of liquidated damages apportioned to each project?

A. Yes. Document No. 2 of my exhibits shows how liquidated damages were apportioned between lost revenues and capital costs and how amounts were apportioned to each of the individual projects. This data was presented to and discussed with the company’s external auditors in their review of the application of the liquidated damages.

Q. Is it possible for the company to receive liquidated damages for a project which was placed in service on its estimated in-service date?

A. Yes. Liquidated damages could be paid if a developer did not meet the conditions established in the contract that equated to substantial completion. A project could be properly placed in service if the facility were putting power to the grid according to regulatory guidance in FERC and FPSC regulatory plant accounting rules. However, the developer still could have several requirements to satisfy after the in-service date to be considered substantially complete and released from contractual obligations.

IV. <u>Summary</u>

Q. Please summarize your direct testimony.

A. In my testimony I have explained the true-ups associated with Tranche 1 and Tranche 2 of SoBRA solar. I explained that there is both a timing true-up and a cost true-up. I discussed the regulatory support for the true-ups as well as the way in which each true-up was calculated. I also explained liquidated damages and how SoBRA solar liquidated damages were apportioned to the Seven Projects.

Q. Does this conclude your direct testimony?

A. Yes.

EXHIBIT

OF

JEFFREY S. CHRONISTER

CALCULATION OF TRUE-UP AMOUNTS

TAMPA ELECTRIC COMPANY
DOCKET NO. 2020_____-EI
EXHIBIT NO. ___ (JSC-1)
WITNESS: CHRONISTER
DOCUMENT NO. 1
PAGE 1 OF 4
FILED: 04/30/2020

Tampa Electric
First and Second SoBRA True-Up Calculation
($)

	(A)	(B) Sep-2018	(C) Oct-2018	(D) Nov-2018	(E) Dec-2018	(F) Jan-2019	(G) Feb-2019	(H) Mar-2019	(I) Apr-2019	(J) May-2019	(K) Jun-2019	(L) Jul-2019	(M) Aug-2019	(N) Sep-2019	(O) Oct-2019	(P) Nov-2019	(Q) Dec-2019	(R) Total
(1)	Total Installed Cost True-up	7,148	8,083	8,083	8,083	5	4,387	232	(861)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(16,176)
(2)	In-Service Date Timing True-up	(1,100,102)	-	-	-	(3,390,586)	-	-	-	-	-	-	-	-	-	-	-	(4,490,688)
(3)	Total Installed Cost and Timing True-Up	(1,092,954)	(1,084,871)	(1,076,788)	(1,068,705)	(4,459,286)	(4,454,899)	(4,454,667)	(4,455,528)	(4,461,945)	(4,468,362)	(4,474,779)	(4,481,196)	(4,487,613)	(4,494,030)	(4,500,447)	(4,506,864)	(4,506,864)
(4)	Annual Interest Rate	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	
(5)	Monthly Interest Rate[1]	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	
(6)	Interest Adjustment	(5,884)	(5,915)	(5,904)	(5,892)	(5,880)	(24,164)	(24,271)	(24,400)	(24,536)	(24,703)	(24,871)	(25,039)	(25,208)	(25,379)	(25,550)	(25,722)	(303,318)
(7)	Total Installed Cost and Timing True-Up with Interest	(1,098,838)	(1,096,671)	(1,094,491)	(1,092,300)	(4,488,761)	(4,508,539)	(4,532,578)	(4,557,839)	(4,588,792)	(4,619,912)	(4,651,200)	(4,682,656)	(4,714,281)	(4,746,077)	(4,778,043)	(4,810,182)	(4,810,182)
(8)						Jan-2020	Feb-2020	Mar-2020	Apr-2020	May-2020	Jun-2020	Jul-2020	Aug-2020	Sep-2020	Oct-2020	Nov-2020	Dec-2020	Total
(9)	Total Installed Cost True-up				(16,176)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	(6,413)	(93,176)
(10)	In-Service Date Timing True-up				(4,490,688)	-	-	-	-	-	-	-	-	-	-	-	-	(4,490,688)
(11)	Total Installed Cost and Timing True-Up				(4,506,864)	(4,513,281)	(4,519,698)	(4,526,115)	(4,532,532)	(4,538,949)	(4,545,366)	(4,551,783)	(4,558,200)	(4,564,617)	(4,571,034)	(4,577,451)	(4,583,864)	(4,583,864)
(12)	Estimated True-Up Included in Mid-Course Factors[2]					-	-	-	-	-	693,761	693,761	693,761	693,761	693,761	693,761	693,763	4,856,329
(13)	Annual Interest Rate					6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	6.460000%	
(14)	Monthly Interest Rate[1]					0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	0.538333%	
(15)	Interest Adjustment				(303,318)	(25,929)	(25,964)	(25,998)	(26,033)	(26,068)	(22,367)	(18,667)	(14,967)	(11,267)	(7,567)	(3,866)	(166)	(512,177)
(16)	Total Installed Cost and Timing True-Up for Interest Calculation[3]				(4,810,182)	(4,816,599)	(4,823,016)	(4,829,433)	(4,835,850)	(4,842,267)	(4,154,923)	(3,467,579)	(2,780,235)	(2,092,891)	(1,405,547)	(718,203)	(30,853)	(30,853)
(17)	Total Installed Cost and Timing True-Up with Interest				(4,810,182)	(4,842,528)	(4,874,909)	(4,907,324)	(4,939,774)	(4,972,259)	(5,001,043)	(5,026,127)	(5,047,511)	(5,065,195)	(5,079,179)	(5,089,462)	(5,096,041)	(5,096,041)
(18)	Less Estimated True-Up Included in Mid-Course Factors[2]					-	-	-	-	-	693,761	693,761	693,761	693,761	693,761	693,761	693,763	4,856,329
(19)	**Final Net True-Up Amount to Be Collected in the Capacity Clause in 2021**																	**(239,712)**
(20)																		

(21) [1] Calculated at the AFUDC rate for the projects, 6.46%.

(22) [2] Estimated true-up amount of $4,856,329 included in the capacity clause in February 2020 and in June through December 2020 mid-course capacity factors.

(23) [3] Amount for interest calculation reflects return of estimated true-up through the 2020 mid-course capacity factors.

Tampa Electric
Installed Cost Revenue Requirement True-up

	(A)	(B) Annual ($)	(C) Monthly ($)
(1)	First SoBRA[1]	97,000	8,083
(2)	Second SoBRA[2]	(174,000)	(14,500)
(3)	Net First and Second SoBRA[2]	(77,000)	(6,417)

[1] Effective September 2018
[2] Effective January 2019

Tampa Electric
In-Service Date (Timing) True-Up

		($)
(4)	First SoBRA[1]	(1,100,102)
(5)	Second SoBRA[2]	(3,390,586)
(6)	Net First and Second SoBRA[2]	(4,490,688)

[1] Effective September 2018
[2] Effective January 2019

Tampa Electric
In-Service Date (Timing) True-Up Calculation

First SoBRA

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Project	Estimated Annual Revenue Requirements	Portion of SoBRA Revenue Requirements	Estimated In-Service Date	Actual In-Service Date	# Days Delayed	September 2018 Estimated Revenue	Revenue Requirement True-Up
		($MM)					($)	($)
(1)	Balm Solar	12.937	53.4%	9/1/2018	9/27/2018	26	1,269,349	1,100,102
(2)	Payne Creek Solar	11.308	46.6%	9/1/2018	9/1/2018	0	1,109,515	-
(3)								
(4)	**Total**	**24.245**	**100%**				**2,378,864**	**1,100,102**
(5)								
(6)								
(7)								

Second SoBRA

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
(8)	**Second SoBRA**														
(9)							2019 Estimated Revenue				Revenue Requirement True-Up				
(10)	Project	Estimated Annual Revenue Requirements	Portion of SoBRA Revenue Requirements	Estimated In-Service Date	Actual In-Service Date	# Days Delayed	January	February	March	April	January	February	March	April	Total
(11)		($MM)					($)	($)	($)	($)	($)	($)	($)	($)	($)
(12)	Lithia Solar	13.291	28.9%	1/1/2019	1/1/2019	0	1,013,548	920,576	902,450	953,932	-	-	-	-	-
(13)	Grange Hall Solar	10.611	23.0%	1/1/2019	1/2/2019	1	809,150	734,928	720,457	761,557	26,102	-	-	-	26,102
(14)	Peace Creek Solar	9.868	21.4%	1/1/2019	3/1/2019	59	752,461	683,439	669,981	708,202	752,461	683,439	-	-	1,435,900
(15)	Bonnie Mine Solar	6.601	14.3%	1/1/2019	1/23/2019	22	503,356	457,184	448,181	473,749	357,220	-	-	-	357,220
(16)	Lake Hancock Solar	5.674	12.3%	1/1/2019	4/25/2019	114	432,645	392,959	385,222	407,198	432,645	392,959	385,222	360,538	1,571,364
(17)															
(18)	**Total**	**46.045**	**100%**				**3,511,161**	**3,189,085**	**3,126,291**	**3,304,638**	**1,568,429**	**1,076,398**	**385,222**	**360,538**	**3,390,586**

TAMPA ELECTRIC COMPANY
DOCKET NO. 2020_____-EI
EXHIBIT NO. ___ (JSC-1)
WITNESS: CHRONISTER
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Tampa Electric
Actual Installed Cost True-Up Calculation

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		Estimated Annual Revenue Requirements	Actual Annual Revenue Requirements	Difference		Estimated In-Service Date	Actual In-Service Date	# Days Delayed		September 2018 Estimated Revenue	Portion of Estimated Annual Revenue Requirements	Difference	Cost True-Up Already Returned in Timing True-Up
		($MM)	($MM)	($)						($)		($)	($)
(1)	**First SoBRA**												
(2)	Balm Solar	12.937	12.926	(11,000)		9/1/2018	9/27/2018	26		1,269,349	9.8%	(1,079)	(935)
(3)	Payne Creek Solar	11.308	11.416	108,000		9/1/2018	9/1/2018	-		1,109,515	9.8%	10,597	-
(4)	Total	24.245	24.342	97,000						2,378,864			
(5)	**Second SoBRA**												
(6)	Lithia Solar	13.291	13.217	(74,000)		1/1/2019	1/1/2019	-					
(7)	Grange Hall Solar	10.611	10.570	(41,000)		1/1/2019	1/2/2019	1					
(8)	Peace Creek Solar	9.868	9.808	(60,000)		1/1/2019	3/1/2019	59					
(9)	Bonnie Mine Solar	6.601	6.704	103,000		1/1/2019	1/23/2019	22					
(10)	Lake Hancock Solar	5.674	5.578	(96,000)		1/1/2019	4/25/2019	114					
(11)	Total	46.045	45.871	(174,000)									(935)
(12)	Monthly True-Up Amount Prior to Consideration of the Timing True-Up												8,083
(13)	**Monthly True-Up Amount with Timing True-Up Adjustment**												**7,148**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
		January 2019 Estimated Revenue	Portion of Estimated Annual Revenue Requirements	Difference	Cost True-Up Already Returned in Timing True-Up	February 2019 Estimated Revenue	Portion of Estimated Annual Revenue Requirements	Difference	Cost True-Up Already Returned in Timing True-Up	March 2019 Estimated Revenue	Portion of Estimated Annual Revenue Requirements	Difference	Cost True-Up Already Returned in Timing True-Up	April 2019 Estimated Revenue	Portion of Estimated Annual Revenue Requirements	Difference	Cost True-Up Already Returned in Timing True-Up
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
(14)	**Second SoBRA**																
(15)	Lithia Solar	1,013,548	7.6%	(5,643)	-	920,576	6.9%	(5,125)	-	902,450	6.8%	(5,025)	-	953,932	7.2%	(5,311)	-
(16)	Grange Hall Solar	809,150	7.6%	(3,126)	(101)	734,928	6.9%	(2,840)	-	720,457	6.8%	(2,784)	-	761,557	7.2%	(2,943)	-
(17)	Peace Creek Solar	752,461	7.6%	(4,575)	(4,575)	683,439	6.9%	(4,155)	(4,155)	669,981	6.8%	(4,074)	(131)	708,202	7.2%	(4,306)	-
(18)	Bonnie Mine Solar	503,356	7.6%	7,854	5,574	457,184	6.9%	7,134	-	448,181	6.8%	6,993	-	473,749	7.2%	7,392	-
(19)	Lake Hancock Solar	432,645	7.6%	(7,320)	(7,320)	392,959	6.9%	(6,649)	(6,649)	385,222	6.8%	(6,518)	(6,518)	407,198	7.2%	(6,889)	(5,556)
(20)	Total	3,511,161		(12,811)	(6,422)	3,189,085		(11,635)	(10,804)	3,126,291		(11,406)	(6,649)	3,304,638		(12,057)	(5,556)
(21)	Monthly True-Up Amount Prior to Consideration of the Timing True-Up				(6,417)				(6,417)				(6,417)				(6,417)
(22)	**Monthly True-Up Amount with Timing True-Up Adjustment**				**5**				**4,387**				**232**				**(861)**

LIQUIDATED DAMAGES APPORTIONED TO FIRST AND SECOND SOBRA PROJECTS

REDACTED

Tampa Electric
SoBRA Projects Liquidated Damages Summary

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Project Timing Summary:		MW	Planned In-Service Date	Actual In-Service Date	Planned Substantial Completion	Actual Substantial Completion	Planned Commercial Operation	Actual Commercial Operation
(1)	**First SoBRA**								
(2)	Payne Creek	[redacted]	70.3	9/1/2018	9/1/2018	[redacted]			
(3)	Balm		74.4	9/1/2018	9/27/2018				
(4)									
(5)	**Second SoBRA**								
(6)	Lithia		74.5	1/1/2019	1/1/2019				
(7)	Grange Hall		61.1	1/1/2019	1/2/2019				
(8)	Bonnie Mine[1]		37.5	1/1/2019	1/23/2019				
(9)	Peace Creek		55.4	1/1/2019	3/1/2019				
(10)	Lake Hancock[2]		31.8	1/1/2019	4/25/2019				

(11)
(12) *1 - Bonnie Mine contractual liquidated damages start past commercial operation date.*
(13) *2 - Total Lake Hancock is 49.6 MW. The SoBRA portion is 31.8 MW. The Community Solar portion is 17.8 MW.*
(14)
(15) **Liquidated Damages Received:**
(16)

	Date	Counterparty	Assignment Location	Amount
(17)	**Date**	**Counterparty**	**Assignment Location**	**Amount**
(18)	12/10/2018	[redacted]		
(19)	3/4/2019			
(20)	3/4/2019			
(21)	3/28/2019			
(22)	4/12/2019			
(23)	3/26/2019			
(24)	5/14/2019			
(25)	**Total**			$ 9,170,565

(26)
(27)
(28) **Liquidated Damages Assigned:**

		Liquidated Damages Assigned	Sub-Assignment: Offset Lost Revenue	Sub-Assignment: Reduce Capital
(29)				
(30)				
(31)	**Tranche 1**			
(32)	Payne Creek	-	-	-
(33)	Balm	[redacted]		
(34)				
(35)				
(36)	**Tranche 2**			
(37)	Lithia			
(38)	Grange Hall			
(39)	Bonnie Mine[1]			
(40)	Peace Creek			
(41)	Lake Hancock[2]			
(42)				
(43)				
(44)	**Total**	9,170,565	4,450,245	4,720,320

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 2020______-EI

IN RE: PETITION BY TAMPA ELECTRIC COMPANY FOR A LIMITED PROCEEDING TO TRUE-UP FIRST AND SECOND SOBRAS

PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

WILLIAM R. ASHBURN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM R. ASHBURN

Q. Please state your name, address, occupation and employer.

A. My name is William R. Ashburn. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Pricing and Financial Analysis.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from Creighton University with a Bachelor of Science degree in Business Administration. Upon graduation, I joined Ebasco Business Consulting Company where my consulting assignments included the areas of cost allocation, computer software development, electric system inventory and mapping, cost of service filings and property record development. I joined Tampa Electric in 1983 as a Senior Cost Consultant in the Rates and Customer Accounting Department. At Tampa Electric I have held a series of positions with responsibility for cost of service studies, rate filings, rate design, implementation of new conservation and marketing programs, customer surveys and various state and federal regulatory filings. In March 2001, I was promoted to my current position of Director, Pricing and Financial Analysis in Tampa Electric's Regulatory Affairs Department. I am a member of the Rate and Regulatory Affairs Committee of the Edison Electric Institute ("EEI").

Q. Have you previously testified before the Commission?

A. Yes. I have testified or filed testimony before this Commission in several dockets. Most recently I testified for Tampa Electric in Docket No. 20170260-EI during the hearing on the company's First Solar Base Rate Adjustment ("SoBRA"). I testified in Docket No. 20170210-EI as a member of a panel of witnesses during the November 6, 2017 hearing on the 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement"). I submitted direct testimony in Docket No. 20180133-EI, petition for limited proceeding to approve Second Solar Base Rate Adjustment, effective January 1, 2019, by Tampa Electric Company ("Second SoBRA"). I also submitted testimony in Docket No. 20190136-EI, petition for limited proceeding to approve Third Solar Base Rate Adjustment, effective January 1, 2020, by Tampa Electric Company.

I testified on behalf of Tampa Electric in Docket No. 20130040-EI regarding the company’s Petition for an Increase in Base Rates and Miscellaneous Service Charges and in Docket No. 20080317-EI which was Tampa Electric’s previous base rate proceeding. I testified in Docket No. 20020898-EI regarding a self-service wheeling experiment and in Docket No. 20000061-EI regarding the company’s Commercial/Industrial Service Rider. In Docket Nos. 20000824-EI, 20001148-EI, 20010577-EI and 20020898-EI, I testified at different times for Tampa Electric and as a joint witness representing Tampa Electric, Florida Power & Light Company (“FP&L”) and Progress Energy Florida, Inc. (“PEF”) regarding rate and cost support matters related to the GridFlorida proposals. In addition, I represented Tampa Electric numerous times at workshops and in other proceedings regarding rate, cost of service and related matters. I have also provided testimony and represented Tampa Electric before the Federal Energy Regulatory Commission (“FERC”) in rate and cost of service matters.

Q. What is the purpose of your prepared direct testimony?

A. The purpose of my prepared direct testimony is to sponsor and explain the proposed rate treatment for the company's First and Second SoBRA Revenue Requirement True-Up, which the company proposes to be effective with the first billing cycle in January 2021.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, Exhibit No. ____ (WRA-1) was prepared under my direction and supervision. It demonstrates how the revenue requirement of the First and Second SoBRA Revenue Requirement True-Up would be allocated to rate classes.

Q. How does your prepared direct testimony relate to the prepared direct testimony of the company's other three witnesses?

A. Tampa Electric witness Mark D. Ward's direct testimony describes the actual in-service dates and installed cost for the Seven Projects in the company's First and Second SoBRAs. Tampa Electric witness Jose A. Aponte uses the actual installed project costs to calculate the revised annual revenue requirement for the First and Second SoBRAs. In my direct testimony, I explain how the revised revenue requirement is allocated to customer rate classes and discuss the impact of that allocation to permanent customer rates. Tampa Electric witness Jeffrey S. Chronister describes the True-up Credit related to: (1) timing differences between the estimated and actual in-service dates for the projects and (2) estimated and actual installed costs. The final True-Up Amount will be flowed through the capacity clause in 2021 pursuant to the 2017 Agreement.

2017 Agreement Guidance for SoBRA

Q. Did you allocate the actual First and Second SoBRA revenue requirements to rate classes as you did when calculating the estimated First and Second SoBRA rates?

A. No. While in Docket Nos. 20170260-EI and 20180133-EI I allocated the estimated First and Second SoBRA total revenue requirements to rate classes using a method that complies with the 2017 Agreement, as described in detail in my direct testimony submitted in Docket Nos. 20170260-EI, 20180133-EI and 20190136-EI, in the case of the true-up a slight difference from that method was employed.

Q. What was that difference?

A. While the methodology employed was the same, I applied the net revenue requirement difference between the estimated and actual true-up revenue requirements, summed together, to the method.

Q. Do you provide an exhibit that shows the results of applying the allocation methodology called for in the 2017 Agreement?

A. Yes. My exhibit is provided for that purpose. That document, titled "Development of First and Second SoBRA Base Revenue Increases by Rate Class," shows how the revenue requirements associated with the annual revenue requirement true ups described in witness Aponte's direct testimony were allocated to the rate classes. The document shows how the net $(77,000) difference from the combination of SoBRA Tranche 1 and 2 true ups are allocated across rate classes.

Proposed Rates and Tariffs for SoBRA

Q. Having completed the allocation of the First and Second SoBRA true-up revenue requirement to rate classes, what is the next step to derive the proposed impact to base rates?

A. As shown in my Document No. 1, the $77,000 reduction is spread over all the rate classes as required by the 2017 Settlement Agreement. The $(77,000) true-up difference represents a *de minimis* amount. The true-up amount is so small that there is not enough increase in any rate class to result in a change to any of the least digits of the rate levels from the original filed rates. For example, the residential class allocation is $(43,000). The residential energy rate utilizes five significant digits and the $(43,000) divided by the applicable residential billing determinants would only change that energy rate beyond the fifth significant digit. This same effect occurs for all the other rate classes.

Given this result, and because Tampa Electric expects to file its Fourth SoBRA petition in July 2020 to take effect with customer bills beginning in January 2021 (the same time as this First and Second SoBRA true-up is planned to go into effect) the company proposes that the $(77,000) revenue requirement difference for the First and Second SoBRA revenue requirement change be deducted from the revenue requirement calculated for the Fourth SoBRA and thus be reflected in the Fourth SoBRA base rates according to the class revenue allocations shown in my exhibit.

Summary

Q. Please summarize your direct testimony.

A. I have performed the cost of service components of the First and Second SoBRA base rate true-up adjustment in accordance with the provisions of the 2017 Agreement. I allocated the revised revenue requirements to rate classes and proposed no base rate changes by rate class in this docket. The company proposes that the $(77,000) revenue requirement change for the First and Second SoBRA true-up be included in the revenue requirement recovery and rate design for the Fourth SoBRA.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

WILLIAM R. ASHBURN

Development of First and Second SoBRA True-Up Base Revenue Increase by Rate Class

TAMPA ELECTRIC COMPANY
DOCKET NO. 2020_____-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 1
PAGE 1 OF 2
FILED: 04/30/2020

TAMPA ELECTRIC COMPANY
DEVELOPMENT OF COST ALLOCATION FOR TRUE-UP OF SoBRA TRANCHE 1 AND 2 BY CLASS

($000)

TRUE-UP TRANCHE 1 AND 2
12CP &1/13 - All Demand

Line		Rate Class	(A) Adjusted Revenue Requirement(1)	(B) Present Base Revenue(2)	(C) Base Revenue Deficiency $ (A) - (B)	(D) Base Revenue Deficiency % (C) / (B)	(E) Proposed Base Rev. Increase $	(F) Proposed Base Rev. Increase % (E) / (B)	(G) 2020 Targeted Base Revenue (B) + (E)	
1	I.	Residential (RS,RSVP)	$ 646,653	$ 646,696	$ (43)	-0.01%				
2										
3	II.	General Service								
4		Non-Demand (GS,CS)	68,471	68,475	(4)	-0.01%				
5										
6										
7		Sub-Total: I. + II.	$ 715,124	$ 715,171	$ (47)	-0.01%	$ (47)	-0.01%	$ 715,124	$ 715,086
8										
9										
10	III.	General Service								
11		Demand (GSD, SBF)	343,281	343,308	(27)	-0.01%	$ (27)	-0.01%	343,281	$ 351,807
12										
13	IV.	Interruptible Service (IS/SBI)	24,270	24,272	(2)	-0.01%	$ (2)	-0.01%	24,270	$ 24,961
15										
16										
19	V.	Lighting (LS-1)								
20		A. - Energy	$ 3,882	3,882	(0)	0.00%	$ (0)	0.00%	$ 3,882	$ 3,900
21		B. - Facilities	43,545	43,545	-	0.00%	$ -	0.00%	$ 43,545	$ 43,545
22										
23										
24		Total	$ 1,130,101	$ 1,130,178	$ (77)	-0.01%	$ (77)	-0.01%	$ 1,130,101	$ 1,139,299
25										
26				$ (77)						
27										

28 (1) The Adjusted Revenue Requirement column reflects a decrease of $77,000 net true-up for SoBRA 1 and 2 revenues based on each class's percentage
29 of 12 CP & 1/13th allocator and a 40% allocation to lighting service.
30 .

2020
12 CP &1/13 Allocation

(77)

Lighting allocation spread over other classes

(0)		0.286%
	60.00%	
0		
	40.00%	
0		

$000	%	Lighting Share Reallocation $000	%	FINAL RR $000	Lighting Share Reallocation $000	%	FINAL RR $000
(43)	56.411%	(0)	56.53%	(44)	(0)	56.53%	(43)
(4)	5.157%	(0)	5.17%	(4)	(0)	5.17%	(4)
	61.568%						
(27)	35.640%	(0)	35.71%	(27)	(0)	35.71%	(27)
(2)	2.590%	(0)	2.60%	(2)	(0)	2.60%	(2)
(0)	0.201%						0
(77)	100.00%	(0)	100%	(77)	(0)	100%	(77)