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Docket No. 20170210-EI
Comprehensive Exhibit List for Entry into Hearing Record
November 6, 2017

EXH #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
STAFF– (DIRECT)					
2			Tampa Electric Company's (TECO) petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement. *[Bates Nos. 000001- 000055]*		
3			TECO's responses to Staff's First Data Requests (Nos. 1-27) with revised page 101. *[Bates Nos. 000056 - 000170]*		
4			TECO's responses to Staff's Second Data Requests (Nos. 28-37) **Additional file "(BS 13) Staff 2nd DR No. 35.xlsx" provided separately.** *[Bates Nos. 000171 - 000188]*		

2

Tampa Electric Company's petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170210-EI EXHIBIT: 2
PARTY: STAFF– (DIRECT)
DESCRIPTION: Tampa Electric Company's (TECO) petition for limited proceeding to

AUSLEY MCMULLEN
ATTORNEYS AND COUNSELORS AT LAW

123 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

September 27, 2017

VIA E-FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Petition by Tampa Electric Company for a limited proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement, Docket No. 2017 _____-EI; Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism, Docket No. 20160160-EI

Dear Ms. Stauffer:

Enclosed for filing in the above-styled matter is Tampa Electric Company's Petition for a limited proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement.

Thank you for our assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosure

cc: All Parties of Record (w/enc.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Tampa Electric Company for a limited proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement	)	DOCKET NO. 2017 _____-EI
In re: Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism	)	DOCKET NO. 20160160-EI FILED: September 27, 2017

TAMPA ELECTRIC COMPANY'S PETITION FOR LIMITED PROCEEDING TO APPROVE 2017 AMENDED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT

Tampa Electric Company ("Tampa Electric" or "the company"), pursuant to Sections 366.076, 120.57(2) and 366.06(3), Florida Statutes, and Rule 28-106.301, F.A.C., respectfully petitions the Florida Public Service Commission ("FPSC" or "the Commission") for a limited proceeding to approve the 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement") attached as an exhibit to this Petition and incorporated and made a part hereof.

BACKGROUND

On September 8, 2013, Tampa Electric and the Consumer Parties (Office of Public Counsel or "OPC", Florida Industrial Power User's Group or "FIPUG", Florida Retail Federation or "FRF", Federal Executive Agencies or "FEA" and West Central Florida Hospital Utility Alliance or "HUA") filed a Stipulation and Settlement Agreement ("2013 Agreement") that resolved all of the issues in Tampa Electric's 2013 base rate case (Docket No. 20130040-EI). Therein, among other things, Tampa Electric agreed that the general base rates provided for in the 2013 Agreement would remain in effect through December 31, 2017, and thereafter until the company's next general base rate case. The 2013 Agreement also specified that Tampa Electric would forego seeking future general base rate increases with an effective date prior to January 1, 2018, except in limited circumstances. The FPSC approved the 2013 Agreement and memorialized its decision in Order No. PSC-2013-0443-FOF-EI, issued September 30, 2013 ("2013 Agreement Order").

In late 2016, recognizing that the period in which Tampa Electric agreed to refrain from seeking general base rate increases would expire at the end of 2017, Tampa Electric and OPC began discussing whether the company would be willing and able to (a) refrain from seeking a general base rate increase beyond December 31, 2017 and (b) extend the terms of the 2013 Agreement for an additional period of time. During those discussions, OPC requested and Tampa Electric provided extensive financial and other information to OPC regarding its financial condition and future business plans. FIPUG, FRF, FEA, and HUA later joined the discussions and made their own requests for information which was provided by Tampa Electric. As a result of this extensive and time-consuming process, Tampa Electric and the Consumer Parties (collectively, "the Parties") have reached an agreement to extend the 2013 Agreement with limited amendments, subject to Commission approval.

The 2017 Agreement continues and advances Tampa Electric's long-standing commitment to clean energy. It amends and restates the 2013 Agreement, extends the general base rate freeze included in the 2013 Agreement, limits fuel hedging and investments in natural gas reserves, protects customers if federal tax reform occurs and replaces the Generation Base Rate Adjustment ("GBRA") mechanism in the 2013 Agreement with a Solar Base Rate Adjustment ("SoBRA") mechanism that includes a strict cost-effectiveness test and a $1,500 per kilowatt alternating current (kW_{ac}) installed cost cap to protect customers. The SoBRA mechanism allows the company to install and receive cost recovery for up to 600 MW of photovoltaic solar generation. Using the SoBRA mechanism, the company plans to install over 6 million solar panels into various projects in its service territory. These projects and the SoBRA mechanism will allow the company to transition power generation to less carbon intensity while keeping prices for electricity affordable for its customers. When the projects are complete, about 6 percent of Tampa Electric's energy will come from the sun.

This significant addition of solar energy is part of the company's strategy to reduce its carbon footprint, which started in 1999 with the repowering of the former Gannon Station to natural gas-fired Bayside Power Station, and most recently included the expansion of the Polk Power Station's combined cycle generation. This strategy will reduce the company's exposure to financial and other risks associated with burning carbon-based fuels, and because the fuel cost of solar generation is zero, will provide an important measure of price stability to customers. The 2017 Agreement also allows the company to take advantage of the existing 30% solar investment tax credit for the benefit of customers while the credit remains in effect.

Approval of the 2017 Agreement in this limited proceeding, under Section 366.076, Florida Statutes, is appropriate because the 2017 Agreement is in the public interest, fairly reflects a compromise of the competing viewpoints among the Parties, reduces the risks and costs of pursuing litigation before the FPSC, avoids the substantial time and costs associated with a traditional base rate proceeding and provides certainty and predictability for customers, the Consumer Parties and the company for a period of four years through 2021. The 2017 Agreement addresses numerous base rate, infrastructure and clean energy matters that all Parties support as timely, appropriate and reasonable. Ultimately, the 2017 Agreement between Tampa

Electric and the Consumer Parties (who represent customers' interests before the Commission) is a fair, reasonable, and comprehensive resolution of matters that is in the best interests of Tampa Electric and its customers, and that is, therefore, in the public interest.

The Parties have agreed to the terms and conditions of the 2017 Agreement as a comprehensive and interdependent package, such that disapproval of any portion of the 2017 Agreement would negate the effectiveness of such an agreement. Accordingly, for all the reasons set forth in this Petition, Tampa Electric requests and moves the Commission to grant this Petition and approve the 2017 Agreement in its entirety.

I. Preliminary Information

1. The Petitioner's name and address are:

Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

2. 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
jbeasley@ausley.com
J. Jeffry Wahlen
jwahlen@ausley.com
Ausley McMullen
Post Office Box 391
Tallahassee, FL 32302
(850) 224-9115
(850) 222-7560 (Fax)

3. Tampa Electric, the Petitioner, is an investor-owned electric utility regulated by the Commission pursuant to Chapter 366, Florida Statutes, and is a wholly-owned subsidiary of Emera. The company's principal place of business is located at: 702 North Franklin Street, Tampa, Florida 33601.

4. Tampa Electric serves more than 745,000 retail customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties in Florida.

5. 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.

II. Approval of the 2017 Agreement

6. The 2017 Agreement presents a base rate plan that will establish rates through the end of 2021. The specific terms are set forth in more detail in the 2017 Agreement attached as an exhibit and incorporated in this Petition. Additionally, inasmuch as the Parties have engaged in extensive informal - but highly detailed - discovery in a general exchange of information over a period of nine (9) months, the provisions of the 2017 Agreement, coupled with the base rate freeze and solar generation additions, represent both a short-term and longer-term moderation of future rate impacts that would otherwise likely occur as the result of a conventional base rate proceeding in or after 2018.

7. Tampa Electric believes, and represents that the Consumer Parties believe, that the 2017 Agreement in its totality is fair, just, and reasonable and that it is in the public interest. The 2017 Agreement provides the company, the Consumer Parties and the company's customers represented by the numerous parties, a comprehensive extension of the 2013 Agreement with limited amendments that are in the public interest. As a result, the 2017 Agreement fairly and reasonably balances the various positions of the Parties on the issues resolved by the 2017 Agreement and serves the best interests of the customers they represent and the public interest in general. Approval of the 2017 Agreement will promote administrative efficiency and avoid the time and expense associated with litigating the settled issues that would otherwise have to be

taken up in other dockets before the Commission. The 2017 Agreement is consistent with the Commission's long-standing practice of encouraging parties to settle contested proceedings whenever possible.[1]

8. Section 366.076(1), Florida Statutes, provides that the Commission may conduct a limited proceeding to consider and act upon any issue within its jurisdiction, including any such issue which, once resolved, requires a public utility to adjust its rates. Approval of the 2017 Agreement through a limited proceeding under Section 366.076, Florida Statutes, provides the Commission and the Consumer Parties a single proceeding in which all issues related to the matters addressed in the 2017 Agreement will be resolved. Accordingly, Tampa Electric requests and moves the Commission to grant this Petition and approve the 2017 Agreement in its entirety.

III. Statement of No Disputed Issues of Material Fact

9. Tampa Electric believes and represents that the other Parties believe that there are no disputed issues of material fact that must be resolved in order for the Commission to grant this Petition and approve the 2017 Agreement.

[1] See In re: Request for approval of amendment to connection/transfer sheets, increase in returned check charge, amendment to miscellaneous service charges, increase in meter installation charges, and imposition of new tap-in fee in Marion County by East Marion Sanitary Systems Inc., Order No. PSC-11-0566-AS-WU, Docket No. 080562-WU, (P.S.C. Dec. 11, 2011); In re: Application of staff-assisted rate case in Lee County by Mobile Manor Water Company, Inc., Order No. PSC-10-0299-AS-WU, Docket No. 090170-WU, (P.S.C. May 10, 2010); In re: Application for increase in water and wastewater rates in Pasco County by Labrador Utilities, Inc., Order No. PSC-09-0711-AS-WS, Docket No. 080249-WS (P.S.C. Oct. 26, 2009); In re: Petition of Tampa Electric Company to close Rate Schedules IS-3 and IST-3 and approve new Rate Schedules GSLM-2 and GSLM-3, Order No. PSC-00-0374-S-EI, Docket No. 990037-EI (P.S.C. Feb. 22, 2000); In re: Application for staff-assisted rate case in Pasco County by Orangeland Water Supply, Order No. PSC-08-0640-AS-WU, Docket No. 070601-WU, (P.S.C. Oct. 3, 2008); and In re: Application for increase in water and wastewater rates in Lake County by Utilities, Inc. of Pennbrooke, Order No. PSC-07-0534-AS-WS, Docket No. 060261-WS (P.S.C. June 26, 2007).

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

10. The ultimate facts that entitle Tampa Electric to the relief requested herein, i.e., the Commission granting the Petition and approving the 2017 Agreement, are that the 2017 Agreement represents a fair and reasonable resolution of all issues related to the matters addressed therein, that the rates resulting from approval of the Petition and the 2017 Agreement will be fair, just and reasonable, and that the 2017 Agreement is in the public interest. Tampa Electric is entitled to the relief requested pursuant to Chapter 366, Florida Statutes, and Chapter 120, Florida Statutes.

V. Effective Date, Notice, and Final Hearing

11. Tampa Electric requests that the Commission provide public notice of this Petition for the approval of the 2017 Agreement in the dockets affected by the 2017 Agreement, and set the Petition for approval of the 2017 Agreement for final hearing. Tampa Electric asks that the Commission's consideration of the proposed 2017 Agreement be decided by bench vote at the conclusion of the requested final hearing. Tampa Electric has conferred with the other Parties to the 2017 Agreement, and represents that those Parties support this approach.

12. The Parties to the 2017 Agreement include OPC, who represents all customers, the organizations that represent the major customer groups served by the company and, thus, the interests of all customers and customer classes are fairly represented by the signatories to the 2017 Agreement. Tampa Electric, therefore, requests that the Commission proceed expeditiously to issue the public notice of the hearing of this Petition for approval of the 2017 Agreement and set the date for the requested final hearing at least fourteen (14) days after issuance of the public notice of the hearing consistent with Rule 28-106.302(2), F.A.C. As

reflected in the 2017 Agreement, it is the Parties' intent that the tariff sheets reflected in Exhibit A of the 2017 Agreement become effective January 1, 2018. Accordingly, the Parties respectfully request that the final hearing be set not later than November 15, 2017, such that the new and revised rates and tariffs can be implemented with the first billing cycle of January 2018.

13. In the alternative, because Tampa Electric is filing the proposed amended tariff sheets for approval, this Petition should be considered by the Commission as a "file and suspend" rate filing pursuant to Section 366.06(3), Florida Statutes. Accordingly, if the Commission does not set a final hearing such that the 2017 Agreement will be approved before the first billing cycle of January 2018, Tampa Electric respectfully requests that the Commission authorize the implementation of Tampa Electric's tariff sheet changes, effective with the first billing cycle of January 2018, subject to refund, pending the outcome of the final hearing. Tampa Electric is authorized to represent that the Parties to the 2017 Agreement affirmatively agree that in this event, the Commission should either vote to approve the tariffs attached as Exhibit A to the 2017 Agreement or allow them to go into effect by operation of law with revenues held subject to refund pursuant to Section 366.06, Florida Statutes.

VI. Conclusion

14. For all the reasons provided in this Petition, and the supporting 2017 Agreement, complete with amended tariff sheets and other exhibits to the 2017 Agreement filed with this Petition, Tampa Electric respectfully requests that the Commission promptly schedule the consideration of the 2017 Agreement for final hearing, grant this Petition, and approve the 2017 Agreement pursuant to Section 366.076(1), Florida Statutes.

DATED this 27th day of September, 2017

Respectfully submitted,

JAMES D. BEASLEY
J. JEFFRY WAHLEN
Ausley McMullen
Post Office Box 391
Tallahassee, Florida 32302
(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 27th day of September, 2017 to the following:

Office of Public Counsel
J. R. Kelly
Public Counsel
Charles Rehwinkle
Associate Public Counsel
c/o The Florida Legislature
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Tallahassee, FL 32399-1400

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Florida Retail Federation
Mr. Robert Scheffel Wright
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Bowden, Bush, Dee, LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, FL 32308

ATTORNEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Tampa Electric Company for a limited proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement	)))	DOCKET NO. 2017 _____-EI
In re: Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism	))))	DOCKET NO. 20160160-EI FILED: September 27, 2017

2017 AMENDED AND RESTATED
STIPULATION AND SETTLEMENT AGREEMENT

THIS AGREEMENT is dated this 27th day of September, 2017 and is by and between Tampa Electric Company ("Tampa Electric" or the "company"), the Office of Public Counsel ("OPC" or "Citizens"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), the Federal Executive Agencies ("FEA"), and the WCF Hospital Utility Alliance ("HUA"). Collectively, Tampa Electric, OPC, FIPUG, FRF, FEA, and HUA shall be referred to herein as the "Parties" and the term "Party" shall be the singular form of the term "Parties." OPC, FIPUG, FRF, FEA, and HUA will be referred to herein as the "Consumer Parties." This document shall be referred to as the "2017 Agreement."

Background

On September 8, 2013, Tampa Electric and the Consumer Parties filed a Stipulation and Settlement Agreement ("2013 Stipulation") that resolved all the issues in Tampa Electric's 2013 base rate case (Docket No. 20130040-EI). Therein, among other things, Tampa Electric agreed that the general base rates provided for in the 2013 Stipulation would remain in effect through December 31, 2017, and thereafter, until the company's next general base rate case. The 2013

Stipulation also specified that Tampa Electric would forego seeking future general base rate increases with an effective date prior to January 1, 2018, except in limited circumstances. The Florida Public Service Commission ("FPSC" or "Commission") approved the 2013 Stipulation and memorialized its decision in Order No. PSC-2013-0443-FOF-EI, issued September 30, 2013 ("2013 Stipulation Order").

In late 2016, recognizing that the period in which Tampa Electric agreed to refrain from seeking general base rate increases would expire at the end of 2017, Tampa Electric and the Consumer Parties began discussing whether the company would be willing and able to (a) refrain from seeking a general base rate increase beyond December 31, 2017 and (b) extend the terms of the 2013 Stipulation for an additional period of time. The Parties also discussed the company's desire to build 600 MW of solar photovoltaic generation with cost recovery via a solar base rate adjustment mechanism ("SoBRA").

The Parties have entered into this 2017 Agreement in compromise of positions taken in accord with their rights and interests under Chapters 350, 366 and 120, Florida Statutes, as applicable, and as part of a negotiated exchange of consideration among the Parties to this 2017 Agreement, each Party has agreed to concessions to the others with the expectation, intent, and understanding such that all provisions of the 2017 Agreement, upon approval by the Commission, will be enforced by the Commission as to all matters addressed herein with respect to all Parties.

NOW, THEREFORE, in light of the mutual covenants of the Parties and the benefits accruing to all Parties through this 2017 Agreement, and for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties agree as follows:

1. Term.

This 2017 Agreement will become effective upon the date of the Commission's vote approving it (the "Effective Date") and continue through and including December 31, 2021, such that, except as specified in this 2017 Agreement, no base rates, charges, or credits (including the credits that are specifically the subject of this 2017 Agreement) or rate design methodologies will be changed before January 1, 2022. The period from the Effective Date through December 31, 2021 (subject to Paragraph 7(c)) shall be referred to herein as the "Term". The Parties reserve all rights, unless such rights are expressly waived or released, under the terms of this 2017 Agreement.

2. Return on Equity and Equity Ratio.

(a) Subject to the adjustment Trigger provisions in Subparagraph 2(b), Tampa Electric's authorized return on common equity ("ROE") shall be within a range of 9.25% to 11.25%, with a mid-point of 10.25%, except under the conditions specifically provided in this 2017 Agreement in Paragraphs 2(b) and 7. Tampa Electric's authorized ROE range and mid-point shall be used for all regulatory purposes during the Term, together with an equity ratio as follows: (a) a 54% equity ratio for the SoBRA revenue requirement calculations, (b) the company's actual equity ratio for earnings surveillance reporting, and (c) the actual equity ratio up to a cap of 54% for purposes of setting cost recovery clause rates, triggering an exit from this 2017 Agreement pursuant to paragraph 7, or calculating interim rates.

(b) ROE Trigger Mechanism. The purpose of the provisions in this Subparagraph 2(b) is to provide Tampa Electric with rate relief in the event that market capital costs, as indicated by the interest rate on U.S. Treasury bonds, rise above the level specified herein; these provisions are generically referred to as the "Trigger" mechanism or the "Trigger provisions," or simply as the "Trigger." If at any time during the Term, the average 30-year United States Treasury Bond yield rate for any period of six (6) consecutive months is at least 4.6039% (the "Trigger Point")[1], Tampa Electric's authorized ROE shall be increased by 25 basis points to be within a range of 9.50% to 11.50%, with a mid-point of 10.50% ("Revised Authorized ROE") from the Trigger Effective Date defined below for and through the remainder of the Term, and thereafter until the Commission resets the Company's rates and its authorized ROE. The Trigger Criterion Value ("Trigger Value") shall be calculated by summing the reported 30-year U.S. Treasury Bond rates for each day over a consecutive six-month period for which rates are reported, and dividing the resulting sum by the number of reporting days in such period. The effective date of the Revised Authorized ROE ("Trigger Effective Date") shall be the first day of the month following the day in which the Trigger Value reaches the Trigger Point. If the Trigger Point is reached and the Revised Authorized ROE becomes effective, Tampa Electric's Revised Authorized ROE range and mid-point shall be used for the remainder of the Term for all regulatory purposes, and thereafter until changed by a final non-appealable order ("Final Order") of the Commission.

(c) The ROE in effect at the expiration of the Term of this 2017 Agreement shall continue in effect until the company's ROE is next reset by a Final Order of the Commission whether by operation of Paragraph 7 or otherwise.

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[1] This value was derived as provided for in the 2013 Stipulation and reflected in Late Filed Hearing Exhibit 246, in Docket No. 130040-EI as follows: "The Trigger shall be calculated by summing the reported 30-year U.S. Treasury Bond rates for each day over any six-month period, e.g. January 1, 2014 through July 1, 2014, or March 17, 2014 through September 17, 2014, for which rates are reported, and dividing the resulting sum by the number of reporting days in such period."

3. Customer Rates.

(a) Except as specified in this 2017 Agreement, the company's general base rates, charges, credits, and rate design methodologies, for retail electric service in effect on December 31, 2017, shall remain in effect for service rendered and charges imposed through and including December 31, 2021, and thereafter until revised by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as the result of a future general base rate proceeding.

(b) Except as specified in this 2017 Agreement, the company may not petition to change any of its general base rates, charges, credits, or rate design methodologies for retail electric service with an effective date for the new rates, charges, credits, or rate design methodologies earlier than January 1, 2022.

(c) Notwithstanding Subparagraphs 3(a) and 3(b), the company shall be authorized to change its base rates as set forth in Paragraphs 6 and 9, below, in accordance with procedures identified for the SoBRA mechanism and to reduce rates in accordance with Federal Income Tax Reform that may occur during the Term of this 2017 Agreement.

(d) The current lock period for the Contracted Credit Value ("CCV") shall remain 72 months (6 years).

(e) The company's standby generator credit shall be increased from $4.75/kW/month to $5.35/kW/month, concurrent with meter reads for the first billing cycle of January 2018. The CCV credit shall be increased from $9.98/kW/month to $10.23/kW/month for secondary, $9.88/kW/month to $10.13/kW/month for primary, and $9.78/kW/month to $10.03/kW/month for sub-transmission voltage customers, concurrently with meter readings for the first billing cycle of January 2018. To the extent that implementation of these revised credits results in an under-recovery or over-recovery of revenues that are subject to the Energy Conservation Cost Recovery ("ECCR") clause, the company shall be authorized to make an adjustment to remedy any such under-recovery or over-recovery in its ECCR charges for 2019 and thereafter. The level of these credits will not change during the Term and will remain in effect after the expiration of the Term until changed, if at all, by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding. The credit modifications addressed in this Subparagraph 3(e) are reflected in the revised tariff sheets set forth in Exhibit A to this 2017 Agreement, the approval of which shall constitute approval of the revised tariff sheets.

(f) The company's Economic Development Rider, which is set forth in Rate Schedule ECONOMIC DEVELOPMENT RATE – EDR of the company's retail tariff, shall remain in effect during the Term and thereafter until modified or terminated by order of the Commission. The Parties intend that the Commission's approval of this 2017 Agreement shall constitute continuing approval of the Economic Development Rider and that such approval shall satisfy the requirements of Rule 25-6.0426(3) - (6), F.A.C., and accordingly, the reductions afforded in Rate Schedule EDR shall be included as a cost in the company's cost of service for all ratemaking purposes and surveillance reporting. The rates in the Economic Development Rider shall be open for new customers and for new applications by existing customers through December 31, 2021, unless the maximum amount of economic development expenditures as specified in Rule 25-6.0426, F.A.C., is met, at which time the Economic Development Rider will be closed to new customers and to new applications by existing customers until the amount again falls below the maximum allowed.

(g) The provisions of this Paragraph 3 shall remain in effect during the Term except as otherwise permitted or provided for in this 2017 Agreement and shall continue in effect until changed by unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding.

4. Other Cost Recovery. Nothing in this 2017 Agreement shall preclude the company from requesting the Commission to approve the recovery of costs that are: (a) of a type which traditionally or historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) incremental costs not currently recovered in base rates which the Legislature expressly requires shall be clause recoverable subsequent to the approval of this 2017 Agreement. It is the intent of the Parties that, in conjunction with the provisions of Subparagraph 3(a), the company shall not seek to recover, nor shall the company be allowed to recover, through any cost recovery clause or charge, or through the functional equivalent of such cost recovery clauses and charges, costs of any type or category that have historically or traditionally been recovered in base rates, unless such costs are: (i) the direct and unavoidable result of new governmental impositions or requirements; or (ii) new or atypical costs that were unforeseeable and could not have been contemplated by the Parties resulting from significantly changed industry-wide circumstances directly affecting the company's operations. As a part of the base rate freeze agreed to herein, the company will not seek Commission approval to defer for later recovery in rates, any costs incurred or reasonably expected to be incurred from the Effective Date through and including December 31, 2021, which are of the type which historically or traditionally have been or would be recovered in base rates, unless such deferral and subsequent recovery is expressly authorized herein or otherwise agreed to by each of the Parties. The Parties are not precluded from participating in any proceedings pursuant to this

Paragraph 4, nor is any Party precluded from raising any issues pertinent to any such proceedings.

5. Storm Damage.

(a) Nothing in this 2017 Agreement shall preclude Tampa Electric from petitioning the Commission to seek recovery of costs associated with any tropical systems named by the National Hurricane Center or its successor without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings. Consistent with the rate design methods approved in this 2017 Agreement, the Parties agree that recovery of storm costs from customers will begin, on an interim basis (subject to refund following a hearing or a full opportunity for a formal proceeding), sixty days following the filing of a cost recovery petition and tariff with the Commission and will be based on a 12-month recovery period if the storm costs do not exceed $4.00/1,000 kWh on monthly residential customer bills. In the event the company's reasonable and prudent storm costs exceed that level, any additional costs in excess of $4.00/1,000 kWh shall be recovered in a subsequent year or years as determined by the Commission, after hearing or after the opportunity for a formal proceeding has been afforded to all substantially affected persons or parties. All storm related costs shall be calculated and disposed of pursuant to Rule 25-6.0143, F.A.C., and shall be limited to (i) costs resulting from a tropical system named by the National Hurricane Center or its successor, (ii) the estimate of incremental storm restoration costs above the level of storm reserve prior to the storm, and (iii) the replenishment of the storm reserve to $55,860,642. The Parties to this 2017 Agreement are not precluded from participating in any such proceedings and opposing the amount of Tampa Electric's claimed costs (for example, and without limitation, on grounds that such claimed costs were not reasonable or were not prudently incurred) or whether the proposed recovery is consistent with this Paragraph 5, but not the mechanism agreed to herein.

(b) The Parties agree that the $4.00/1,000 kWh cap in this Paragraph 5 shall apply in aggregate for a calendar year; provided, however, that Tampa Electric may petition the Commission to allow Tampa Electric to increase the initial 12 month recovery at rates greater than $4.00/1,000 kWh or for a period longer than 12 months if Tampa Electric incurs in excess of $100 million of storm recovery costs that qualify for recovery in a given calendar year, inclusive of the amount needed to replenish the storm reserve to $55,860,642. All Consumer Parties reserve their right to oppose such a petition.

(c) The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of Tampa Electric and shall not apply any form of earnings test or measure or consider previous or current base rate earnings. Such issues may be fully addressed in any subsequent Tampa Electric base rate case.

(d) The provisions of this Paragraph 5 shall remain in effect during the Term except as otherwise permitted or provided for in this 2017 Agreement and shall continue in effect until the company's base rates are next reset by the Commission. For clarity, this means that if this 2017 Agreement is terminated pursuant to Paragraph 7 hereof, the company's rights regarding storm cost recovery under this 2017 Agreement are terminated at the same time, except that any Commission-approved surcharge then in effect shall remain in effect until the costs subject to that surcharge are fully recovered. A storm surcharge in effect without approval of the Commission shall be terminated at the time this 2017 Agreement is terminated pursuant to Paragraph 7 hereof.

6. Solar Base Rate Adjustment Mechanism ("SoBRA").

(a) Notwithstanding the general base rate freeze specified in Paragraph 2, the company shall be allowed to recover the cost of its investment in, and operation of, certain new solar generation facilities and to make solar base rate adjustments consistent with this Paragraph 6. If the applicable federal or state income tax rate for the Company changes before any of the increases provided for in in this Paragraph 6, the Company will adjust the amount of the base rate increase to reflect the new tax rate before the implementation of such increase, pursuant to the applicable methodology in Exhibit C.

(b) Subject to the conditions in Subparagraph 6(c), the planned capacity amounts, earliest in-service and rate adjustment dates, and associated maximum annual revenue requirements (calculated at the Installed Cost Cap specified herein) are as follows:

Year	Earliest Rate Change And In-Service Date	Maximum Incremental SoBRA MW	Maximum Incremental Annualized SoBRA Revenue Requirements (millions)	Maximum Cumulative SoBRA MW	Maximum Cumulative Annualized SoBRA Revenue Requirements (millions)
2018	September 1	150	$30.6[2]	150	$30.6
2019	January 1	250	$50.9	400	$81.5
2020	January 1	150	$30.6	550	$112.1
2021	January 1	50	$10.2	600	$122.3[3]

(c) The company will seek approval of and cost recovery for specific solar generation projects in SoBRA Tranches up to the amounts as specified in this Paragraph 6. Nothing in this 2017 Agreement requires Tampa Electric to build the full amount of solar generating capacity

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[2] The annual revenue requirement is approximately $30.6 million, however, since the first 150 MW Tranche is scheduled to come online September 1, 2018, the revenue requirements collected would be four months of the annual revenue requirements, or $10.2 million.

[3] The 2021 Tranche can be included in and its costs recovered under the SoBRA mechanism only if the projects constituting the 2018 and 2019 Tranches in this table are in-service and operating per design specifications as of December 31, 2019, and were constructed at an average capital cost of no more than $1475 per kW_{ac}.

allowed by this 2017 Agreement for any year or in total over the Term of this 2017 Agreement. Commission action may occur before or after expiration of the Term, but to qualify for cost recovery pursuant to these SoBRA provisions, any Tranche must be fully operational and providing service no later than December 31, 2022. A SoBRA Tranche may consist of a single project or may include multiple individual solar projects, which may be located throughout the company's retail service territory. Tampa Electric will construct and bring into full commercial operation, the full Maximum Incremental SoBRA MW for each year's Tranche by the dates shown in the table above. 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 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 but may not exceed the Maximum Incremental Annualized SoBRA Revenue Requirements or Maximum Cumulative Annualized SoBRA Revenue Requirements set forth in Subparagraph 6(b) or the Installed Cost Cap set forth in Subparagraph 6(d). Each SoBRA revenue increase shall be calculated based on the projected In-Service date, operating capacity, and estimated cost of the solar projects to which it corresponds, subject to being trued up as described in this Subparagraph 6(c). The 2021 SoBRA will only be available to the company if (i) for all projects in the 2018 and 2019 Tranches (totaling 400MW subject to the two percent (2%) variance allowance described in the following sentence), the actual average installed cost necessary to make such projects fully operational is less than or equal to \$1,475 per kW_{ac} and (ii) the 2018 and 2019 Tranches in the amount of 400

MW (subject to the 2% variance) are installed and operating at design specifications as of December 31, 2019. The SoBRA Tranches of solar generation capacity and the associated revenue requirements shown in Subparagraph 6(b) are "up to" or maximum amounts; however, the amount of revenues and MW in the 2019 SoBRA Tranche or Tranches may vary by up to 2 percent of the 2019 total (5 MW variance, either greater than or less than the specified maximum for 2019) to accommodate efficient planning and construction of the associated individual solar projects, and the 2019 Tranche or Tranches remain subject to the cost cap contained herein. Tampa Electric shall make a filing with the Commission by February 28, 2020, reflecting whether it has met the requirements to qualify for the 2021 SoBRA Tranche.

(d) For the solar projects that are approved by the Commission for cost recovery pursuant to this Paragraph 6, Tampa Electric's base rates will be increased by the incremental annualized base revenue requirement in steps, one step for each SoBRA Tranche. Each such base rate adjustment will be referred to as a SoBRA, and shall be authorized for solar projects for which Tampa Electric files for Commission approval pursuant to this Paragraph 6. Each project qualifying for SoBRA treatment must consist of either single axis tracking or other solar electric generating equipment or tracking technology that yields greater efficiency or higher capacity value, or both, for the benefit of customers all within the cost caps stated in this Paragraph 6. The types of costs of solar projects that traditionally have been allowed in rate base (including Engineering, Procurement and Construction ("EPC") costs; development costs including third party development fees, if any; permitting fees and costs; actual land costs and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection costs; installation labor and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters, and modules; AFUDC at the weighted average cost of capital from Exhibit B of this 2017 Agreement; and other traditionally allowed rate base costs) shall be eligible for SoBRA cost recovery. The total installed capital cost of a project eligible for cost recovery through a SoBRA shall not exceed \$1,500 per kW_{ac} (the "Installed Cost Cap"). This Installed Cost Cap shall apply on a per project basis, and includes all costs required to make each of the projects in a Tranche fully operational. Each SoBRA will be based on a 10.25% ROE, except under the conditions specifically provided in this 2017 Agreement in Subparagraph 2(b), a 54% equity ratio (based on investor sources of capital), and the incremental capital structure components of long-term debt, short-term debt (if any), common equity, and tax credits, adjusted to reflect the inclusion of investment tax credits on a normalized basis. The debt rate utilized to calculate the revenue requirements associated with the SoBRA projects will be updated to reflect the incremental costs of prospective long-term debt issuances during the first 12 months of operation of each project. The SoBRA Installed Cost Cap is an amount agreed to by and between the Parties that reflects their negotiations regarding all relevant factors affecting or determining the installed cost of each project, including but not limited to capital costs, costs of capital, capital structure, and the other costs and expenses associated with the project.

(e) The Installed Cost Cap is not a "safe harbor" or a "build to" number for the company. The company will use reasonable efforts to design and build solar projects at installed costs below the cap. The Installed Cost Cap will limit the cost recovery of projects under a SoBRA, so if a project costs more than \$1,500 per kW_{ac}, the company can recover through a SoBRA only the installed cost up to the Installed Cost Cap, but may use the actual installed cost for purposes of preparing its periodic earnings surveillance reports; however, during the company's next general base rate proceeding, the depreciated net book value of any SoBRA project included in rate base for the test year may not exceed the Installed Cost Cap.

(f) The individual solar generation projects contemplated in this 2017 Agreement are not subject to the Florida Electrical Power Plant Siting Act, because each project will be smaller than 75 MW, and accordingly, the projects contemplated herein will be subject to the process and FPSC approval as specified herein. For each SoBRA and associated SoBRA Tranche, Tampa Electric will file a petition for approval of each SoBRA, provided that the SoBRA rate change for each Tranche shall not take effect before the dates specified in the aforementioned chart. Each petition for approval of a SoBRA or SoBRAs shall be filed in a separate stand-alone docket. The petition for approval of the first SoBRA (September 1, 2018) shall be made as soon as reasonably possible after the Commission vote to approve this 2017 Agreement. The petition for approval of each of the remaining SoBRAs shall be made in a separate stand-alone docket; the company may file the petitions for each Tranche for the following year at the time of the company's projection filings in the 2018, 2019 and 2020 Fuel and Purchased Power Cost Recovery Clause dockets ("Fuel Docket(s)") for the 2019, 2020 and 2021 factors, respectively, or the company may file each SoBRA petition at a convenient time throughout each year. The Parties contemplate that there will be a final true-up for the 2021 SoBRA, if needed. The Parties agree to request that, to the extent practicable, the deadlines and schedules in the Fuel Dockets apply to the petitions for approval of SoBRAs, so that the amount of solar generation approved for recovery through a SoBRA and related fuel cost savings can be synchronized with the Fuel Dockets.

(g) The issues for determination in each proceeding for approval of a SoBRA shall be limited to: (1) the cost effectiveness of the solar projects in the Tranche, (2) whether the installed cost of each project in the Tranche is projected to be under the Installed Cost Cap, (3) the amount of revenue requirements and appropriate increase in base rates needed to collect the estimated annual revenue requirement for the projects in a Tranche, (4) a true-up of previously approved SoBRAs for the actual cost of the previously approved projects, subject to the sharing provisions in Subparagraph 6(m), and (5) a true-up through the Capacity Cost Recovery Clause ("CCR") of previously approved SoBRAs to reflect the actual in service dates and actual installed cost for each of the previously-approved projects. The cost effectiveness for the projects in a Tranche shall be evaluated in total by considering only whether the projects in the Tranche will lower the company's projected system cumulative present value revenue requirement ("CPVRR") as compared to such CPVRR without the solar projects.

(h) The Parties expect and intend that the first SoBRA will be effective as of September 1, 2018, based on the Parties' expectation and the company's intent that all projects in the 2018 Tranche will be fully operational and providing service as of September 1, 2018. To accommodate efficient planning and construction by the company, the Consumer Parties agree that Tampa Electric may request the Commission to consider approval of the 2018 Tranche as soon as practicable following approval of this 2017 Agreement. The Parties further intend that Commission action on the remaining SoBRAs will be resolved, to the extent practicable, on a schedule that is contemporaneous with the annual, regularly scheduled Fuel and Purchased Power Cost Recovery Docket hearings, provided, however, that the Commission on its own initiative or upon good cause shown by any Party to this 2017 Agreement or any other entity satisfying the standing requirements of Florida law may set Tampa Electric's request for approval of any SoBRA or SoBRA Tranche for a separate hearing to be held at any convenient time to permit timely resolution before the company's projected In-Service date for the SoBRA Tranche that is the subject of such petition and hearing.

(i) The SoBRA increases approved pursuant to this 2017 Agreement shall be calculated based upon Tampa Electric's billing determinants used in the company's then-most-current ECCR Clause filings with the Commission for the twelve months following the effective date of any respective SoBRA. To the extent necessary, this will include projections of such billing determinants into a subsequent calendar year so as to cover the same 12 months as the first 12 months of each Tranche of solar projects' operations. The exception to this will be the first Tranche of SoBRA, which is to go into effect on September 1, 2018. In the case of this Tranche, the billing determinants used will be from the 2017 ECCR Clause filing for the 12 months of 2018 and the base rate adjustment derived on an annual basis but only applied to bills for the four months from September 2018 through December 2018 and then for the 12 months of 2019. The revenue requirement for each SoBRA Tranche shall be allocated to the rate classes using the 12 CP and 1/13th method of allocating production plant and shall be applied to existing base rates, charges and credits using the following principles:

(i) 40% of the revenue requirements that would otherwise be allocated to the lighting class under the 12 CP and 1/13th methodology shall be allocated to the lighting class for recovery through an increase in the lighting base energy rate and the remaining 60% shall be allocated ratably to the other customer classes.

(ii) The revenue requirement associated with a SoBRA will be recovered through increases to demand charges where demand charges are part of a rate schedule, and through energy charges where no demand charge is used in a rate schedule.

(iii) Within the GSD and IS rate classes, recovery of SoBRA revenue requirements allocated to those rate classes will be borne by non-standby demand charges only within a rate class, which methodology will not impact RS and GS rate classes.

(j) The solar capacity amounts specified in Subparagraphs 6(b) and 6(c) shall limit the maximum amount of solar capacity for which the company may recover costs through a SoBRA during each year of the Term, which may include recovery during 2022 for any SoBRA that satisfies the capacity and cost caps provided herein; provided, however, if Tampa Electric receives approval for SoBRA recovery for capacity amounts below the capacity amounts specified in Subparagraphs 6(b) and 6(c) in any year, the company can seek recovery of the unused capacity in a future petition for approval up to the Maximum Cumulative SoBRA for the applicable year as set forth in Subparagraph 6(b), provided such request is filed with the Commission during the Term of this 2017 Agreement. A SoBRA may become effective at any time during the Term or within one year after expiration of the Term, as limited by Subparagraph 6(d) and subject to the termination of the company's rights to seek SoBRA recovery if this 2017 Agreement is terminated pursuant to Paragraph 7 hereof.

(k) For each of the SoBRAs specified in Subparagraphs 6(b) and 6(c), the increased base rates shall be reflected on Tampa Electric's customer bills as specified herein. Tampa Electric will begin applying the increased base rate charges for each SoBRA concurrently with meter readings for the first billing cycle of September 2018 for the first SoBRA, subject to true-up as provided in Subparagraph 6(c). Tampa Electric will begin applying each subsequent SoBRA concurrently with meter readings for the first billing cycle of the month the Tranche is projected to go in service, subject to true-up as provided in Subparagraph 6(c). The Parties contemplate and intend that the final true-up for the 2021

SoBRA, if any, would be made to the CCR as soon as practicable following implementation of the 2021 SoBRA, if any.

(l) Subject to the revenue requirement limits in Subparagraph 6(b), the SoBRA for a Tranche will be calculated using the company's projected installed cost per kW_{ac} for each project (subject to the Installed Cost Cap); reasonable estimates for depreciation expense (based on an initial average service life of 30 years for depreciable plant), property taxes and fixed O&M expenses; an incremental capital structure reflecting the then current midpoint ROE and a 54% equity ratio adjusted to reflect the inclusion of investment tax credits on a normalized basis.

(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% 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. By way of illustration, 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 shall be $1,425 per kW_{ac} [0.25 times ($1,500 - $1,400) + $1,400].

(n) 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.

(o) Tampa Electric agrees to file monthly reports that will provide the same information as that filed with the Commission in Docket No. 20170007-EI by another utility for its solar projects, in order to reflect the performance of the solar projects after they have been placed in service.

(p) Tampa Electric's base rate and credit levels applied to customer bills, including the effects of the SoBRAs implemented pursuant to this 2017 Agreement, shall continue in effect until next reset by future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding. Any incentive attributed to the company during the term of this 2017 Agreement under Subparagraph 6(m) above will not be included in rate base in the company's next general base rate proceeding, meaning that when a solar asset plant balance is moved to base rates in the company's next general base rate case, only the actual cost -- not any incentive -- will be included.

(q) For all new solar generation assets that Tampa Electric places in service during the Term, the lowest total installed cost per-kW solar energy resources up to the capacity amounts associated with the SoBRA mechanism will be attributed to the SoBRA mechanism in the event the company constructs more solar generation capacity than is subject to the SoBRA mechanism.

(r) Nothing in this 2017 Agreement shall preclude any Party to this 2017 Agreement or any other lawful party from participating, consistent with the full rights of an intervenor, in any proceeding that addresses any matter or issue concerning the SoBRA provisions of this 2017 Agreement.

7. <u>Earnings.</u>

(a) Notwithstanding Paragraph 2 and subject to the Trigger provisions in Subparagraph 2(b) above, if Tampa Electric's earned return on common equity falls below 9.25% during the Term on a monthly earnings surveillance report stated on an actual Commission thirteen-month average adjusted basis, Tampa Electric may petition the Commission to amend its base rates either through a general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, or through a limited proceeding under Section 366.076, Florida Statutes. Nothing in this 2017 Agreement shall be construed as an agreement by the Consumer Parties that a limited proceeding would be appropriate, and Tampa Electric acknowledges and agrees that the Parties reserve and retain all rights to challenge the propriety of any limited proceeding or to assert that any request for base rate changes should properly be addressed through a general base rate case, as well as to challenge any substantive proposals to change the company's rates in any such future proceeding. This floor of 9.25% shall be subject to adjustment in accordance with the Trigger provision in Subparagraph 2(b). For purposes of this 2017 Agreement, "Commission actual adjusted basis" and "actual adjusted earned return" shall mean results reflecting all adjustments to Tampa Electric's books required by the Commission by rule or order, but excluding pro forma adjustments. No Consumer Parties shall be precluded from participating in any proceeding initiated by Tampa Electric to increase base rates pursuant to this Paragraph 7, and no Consumer Party is precluded from opposing Tampa Electric's request.

(b) Notwithstanding Paragraph 2 and subject to the Trigger in Subparagraph 2(b) above, if Tampa Electric's earned return on common equity exceeds 11.25% during the Term on a monthly earnings surveillance report stated on an actual Commission thirteen-month average adjusted basis, no Consumer Party shall be precluded from petitioning the Commission for a review of Tampa Electric's base rates. In any case initiated by Tampa Electric or any other Party pursuant to Paragraph 7, all Parties will retain full rights conferred by law. The ceiling of 11.25% set forth in this Subparagraph shall be subject to adjustment in accordance with the Trigger provision in Subparagraph 2(b).

(c) Notwithstanding Paragraph 2 and subject to the Trigger provisions in Subparagraph 2(b) above, this 2017 Agreement shall terminate upon the effective date of any Final Order of the Commission issued in any proceeding pursuant to Paragraph 7 that changes Tampa Electric's base rates prior to the last billing cycle of December 2021.

(d) This Paragraph 7 shall not: (i) be construed to bar Tampa Electric from requesting any recovery of costs otherwise contemplated by this 2017 Agreement; (ii) apply to any request to change Tampa Electric's base rates that would become effective after the expiration of the Term of this 2017 Agreement; (iii) limit any Party's rights in proceedings concerning changes to base rates that would become effective subsequent to the Term of this 2017 Agreement to argue that Tampa Electric's authorized ROE range should be different than as set forth in this 2017 Agreement; or (iv) affect the provisions of Subparagraphs 3(d) and 3(e) of this 2017 Agreement.

(e) Notwithstanding any other provision of this 2017 Agreement, the Parties fully and completely reserve all rights available to them under the law to challenge the level or rate structure (or the cost of service methodologies underlying them) of Tampa Electric's base rates, charges, credits, and rate design methodologies effective as of January 1, 2022 or thereafter. It is specifically understood and agreed that this 2017 Agreement does not preclude any Consumer Party from filing before January 1, 2022, an action to challenge the level or rate structure (or the cost of service methodologies underlying them) of Tampa Electric's base rates, charges and credits effective as of January 1, 2022 or thereafter.

8. Depreciation.

(a) The Parties agree and intend that, notwithstanding any requirements of Rules 25-6.0436 and 25-6.04364, F.A.C., the company shall not be required during the Term of this 2017 Agreement to file any depreciation study or dismantlement study. The depreciation and amortization accrual rates approved by the FPSC and currently in effect as of the Effective Date of this 2017 Agreement shall remain in effect during the Term or the company's next depreciation study, whichever is later. The Parties further agree that the provisions of Rules 25-6.0436 and 25-6.04364, F.A.C., which otherwise require depreciation and dismantlement studies to be filed at least every four years, will not apply to the company during the Term, and that the Commission's approval of this 2017 Agreement shall excuse the company from compliance with the filing requirement of these rules during the Term.

(b) Notwithstanding the non-deferral language in Paragraph 4, unless the company proposes a special capital recovery schedule and the Commission approves it, if coal-fired generating assets or other assets are retired or planned for retirement of a magnitude that would ordinarily or otherwise require a special capital recovery schedule, such assets will continue to be depreciated using their then existing depreciation rates and special capital recovery issues will be addressed in conjunction with the company's next depreciation study. If the company installs Automated Meter Infrastructure ("AMI") meters and retires Automated Meter Reading ("AMR") meters during the Term, such assets will continue to be depreciated using their then existing depreciation rates and special capital recovery issues will be addressed in conjunction with the company's next depreciation study.

(c) Notwithstanding the provisions of Subparagraph 8(a) above, the company shall file a depreciation and dismantlement study or studies no more than one year nor less than 90 days before the filing of its next general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, such that there is a reasonable opportunity for the Consumer Parties to review, analyze and potentially rebut depreciation rates or other aspects of such depreciation and dismantlement studies contemporaneously with the company's next general rate proceeding. The depreciation and dismantlement study period shall match the test year in the company's MFRs, with all supporting data in electronic format with links, cells and formulae intact and functional, and shall be served upon all Consumer Parties and all intervenors in such subsequent rate case.

9. Federal Income Tax Reform.

(a) Changes in the rate of taxation of corporate income by federal or state taxing authorities ("Tax Reform") could impact the effective tax rate recognized by the company in FPSC adjusted reported net operating income and the measurement of existing and prospective deferred federal income tax assets and liabilities reflected in the FPSC adjusted capital structure.

When Congress last reduced the maximum federal corporate income tax rate in the Tax Reform Act of 1986, it included a transition rule that, as an eligibility requirement for using accelerated depreciation with respect to public utility property, provided guidance regarding returning to customers the portion of the resulting excess deferred income taxes attributable to the use of accelerated depreciation. To the extent Tax Reform includes a transition rule applicable to excess deferred federal income tax assets and liabilities ("Excess Deferred Taxes"), defined as those that arise from the re-measurement of those deferred federal income tax assets and liabilities at the new applicable corporate tax rate(s), those Excess Deferred Taxes will be governed by the Tax Reform transition rule, as applied to most promptly and effectively reduce Tampa Electric's rates consistent with the Tax Reform rules and normalization rules.

(b) If Tax Reform is enacted before the company's next general base rate proceeding, the company will quantify the impact of Tax Reform on its Florida retail jurisdictional net operating income thereby neutralizing the FPSC adjusted net operating income of the Tax Reform to a net zero. The company's forecasted earnings surveillance report for the calendar year that includes the period in which Tax Reform is effective will be the basis for determination of the impact of Tax Reform. The company will also adjust any SoBRAs that have not yet gone into effect to specifically account for Tax Reform. The impacts of Tax Reform on base revenue requirements will be flowed back to retail customers within 120 days of when the Tax Reform becomes law, through a one-time adjustment to base rates upon a thorough review of the effects of the Tax Reform on base revenue requirements consistent with Subparagraph 9(a). This adjustment shall be accomplished through a uniform percentage decrease to customer, demand and energy base rate charges for all retail customer classes. Any effects of Tax Reform on retail revenue requirements from the Effective Date through the date of the one-time base rate adjustment shall be flowed back to customers through the ECCR Clause on the same basis as used in any base rate adjustment. An illustration is included as Exhibit C. If Tax Reform results in an increase in base revenue requirements, the company will utilize deferral accounting as permitted by the Commission, thereby neutralizing the FPSC adjusted net operating income impact of the Tax Reform to a net zero, through the Term. In this situation, the company shall defer the revenue requirement impacts to a regulatory asset to be considered for prospective recovery in a change to base rates to be addressed in the company's next base rate proceeding or in a limited scope proceeding before the Commission no sooner than the end of the Term.

(c) All Excess Deferred Taxes shall be deferred to a regulatory asset or liability which shall be included in FPSC adjusted capital structure and flowed back to customers over a term consistent with law. If the same Average Rate Assumption Method used in the Tax Reform Act of 1986 is prescribed, then the regulatory asset or liability will be flowed back to customers over the remaining life of the assets associated with the Excess Deferred Taxes subject to the provisions related to FPSC adjusted operating income impacts of Tax Reform noted above. If the Tax Reform law or act is silent on the flow-back period, and there are no other statutes or rules that govern the flow-back period, then there shall be a rebuttable presumption that the following flow-back period(s) will apply: (1) if the cumulative net regulatory liability is less than $100 million, the flow-back period will be five years; or (2) if the cumulative net regulatory liability is greater than $100 million, the flow-back period will be ten years. The company reserves the right to demonstrate by clear and convincing evidence that such five or ten-year maximum period (as applicable) is not in the best interest of the company's customers and should be increased to no greater than 50 percent of the remaining life of the assets associated with the Excess Deferred Taxes ("50 Percent Period"). The relevant factors to support the company's demonstration include, but are not limited to, the impact the flow-back period would have on the company's cash flow and credit metrics or the optimal capitalization of the company's jurisdictional operations in Florida. If the company can demonstrate, by clear and convincing evidence, that limiting the flow-back period to the 50 Percent Period, in conjunction with the other Tax Reform provisions related to deferred taxes within this 2017 Agreement, will be the sole basis for causing a full notch credit downgrade by each of the major rating agencies (i.e. Standard & Poor's and Moody's), as expressly reflected in a publicly available report of the agencies, it may file to seek a longer flow-back period.

10. Incentive Plan. The Parties consent to the FPSC's approval of and request that the Commission approve the company's Asset Optimization/Incentive Program as set forth in its Petition in Docket No. 160160-EI, dated June 30, 2016, for a four-year period beginning January 1, 2018, but with the following sharing thresholds: (a) up to $4.5MM/year, 100% gain to customers; (b) greater than $4.5MM/year and less than $8.0MM/year, 60% to shareholders and 40% to customers; and (c) greater than $8.0MM/year, 50% to shareholders and 50% customers.

11. Other.

(a) Except as specified in this 2017 Agreement, the company will enter into no new natural gas financial hedging contracts for fuel through December 31, 2022.

(b) The company agrees that it will not seek to recover any costs from its customers related to investments in oil and/or natural gas exploration, reserves, acreage and/or production, including but not limited to investments in gas or oil exploration or production projects that utilize "fracking" (hydraulic fracturing) or similar technology, for a period of no less than five years after the Effective Date.

(c) The company may not make separated/stratified sales from energy generated by solar assets being recovered through a SoBRA during the Term.

(d) For any non-separated or non-stratified wholesale energy sales during the Term, the company will credit its fuel clause for an amount equal to the company's incremental cost of generating or purchasing the amount of energy sold during the hours that any such sale was made.

(e) The full benefits of solar renewable energy credits ("RECs") (including any and all rights attaching to environmental attributes) associated with the solar projects subject to this 2017 Agreement, if any, will be retained for, and flowed through to, retail customers through the Environmental Cost Recovery Clause.

(f) All dollar values, asset determinations, rate impact values and revenue requirements in this 2017 Agreement are intended by the Parties to be retail jurisdictional in amount or formulation basis, unless otherwise specified.

12. New Tariffs. Nothing in this 2017 Agreement shall prelude Tampa Electric from filing and the Commission from approving any new or revised tariff provisions or rate schedules requested by Tampa Electric, provided that any such tariff request does not increase any existing base rate component of a tariff or rate schedule, or any other charge imposed on customers during the Term unless the application of such new or revised tariff, rate schedule, or charge is optional to Tampa Electric's customers.

13. Application of 2017 Agreement. No Party to this 2017 Agreement will request, support, or seek to impose a change to any term or provision of this 2017 Agreement. Except as provided in Paragraph 7, no Party to this 2017 Agreement will either seek or support any reduction in Tampa Electric's base rates, charges, or credits, including limited, limited-scope,

interim, or any other rate decreases, or changes to rate design methodologies, that would take effect prior to the first billing cycle for January 2022, except for any such reduction in base rates or charges (but not credits) requested by Tampa Electric or as otherwise provided for in this 2017 Agreement. Tampa Electric shall not seek interim, limited, or general base rate relief during the Term except as provided for in Paragraphs 6 or 7 of this 2017 Agreement. Tampa Electric is not precluded from seeking interim, limited or general base rate relief that would be effective during or after the first billing cycle in January 2022, nor are the Consumer Parties precluded from opposing such relief. Such interim relief may be based on time periods before January 1, 2022, consistent with Section 366.071, Florida Statutes, and calculated without regard to the provisions of this 2017 Agreement. Tampa Electric will not seek to adjust either the standby generator credit or the CCV credit either during the Term of this 2017 Agreement or thereafter, except by unanimous Agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding.

14. Commission Approval.

(a) The provisions of this 2017 Agreement are contingent on approval of this 2017 Agreement in its entirety by the Commission without modification. The Parties further agree that this 2017 Agreement is in the public interest, that they will support this 2017 Agreement and that they will not request or support any order, relief, outcome, or result in conflict with the terms of this 2017 Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this 2017 Agreement or the subject matter hereof.

(b) No Party will assert in any proceeding before the Commission that this 2017 Agreement or any of the terms in the 2017 Agreement shall have any precedential value. The

Parties' agreement to the terms in the 2017 Agreement shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving this 2017 Agreement. The Parties further expressly agree that no individual provision, by itself, necessarily represents a position of any Party in any future proceeding, and the Parties further agree that no Party shall assert or represent in any future proceeding in any forum that another Party endorses any specific provision of this 2017 Agreement by virtue of that Party's signature on, or participation in, this 2017 Agreement. It is the intent of the Parties to this 2017 Agreement that the Commission's approval of all the terms and provisions of this 2017 Agreement is an express recognition that no individual term or provision, by itself, necessarily represents a position, in isolation, of any Party or that a Party to this 2017 Agreement endorses a specific provision, in isolation, of this 2017 Agreement by virtue of that Party's signature on, or participation in, this 2017 Agreement.

(c) The Parties intend, and agree to request that the Commission's order state that approval of this 2017 Agreement in its entirety will resolve all matters in Docket No. 20160160-EI pursuant to and in accordance with Section 120.57(4), Florida Statutes, and that Docket No. 20160160-EI will be closed effective on the date the Commission's order approving this 2017 Agreement becomes final. The Parties further agree to request that Docket No. 20170057-EI be closed upon approval of this 2017 Agreement or as soon thereafter as is reasonably practical.

(d) No Party shall seek appellate review of any Commission order approving this 2017 Agreement.

15. Disputes. To the extent a dispute arises among the Parties about the provisions, interpretation, or application of this 2017 Agreement, the Parties agree to meet and confer in an effort to resolve the dispute. To the extent that the Parties cannot resolve any dispute, the matter may be submitted to the Commission for resolution.

16. Execution. This 2017 Agreement is dated as of September 27, 2017. It may be executed in counterpart originals and a facsimile of an original signature shall be deemed an original.

[Remainder of page intentionally left blank]

IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this 2017 Agreement by their signature(s):

Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33601

By ______________________
Gordon L. Gillette, President

Signature Page to 2017 Agreement

Office of Public Counsel
J. R. Kelly, Esquire
Public Counsel
Charles Rewinkle, Esquire
Associate Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400

By: ______________________
J.R. Kelly

Signature Page to 2017 Agreement

The Florida Industrial Power Users Group
Jon C. Moyle, Jr., Esquire
Moyle Law Firm
The Perkins House
118 North Gadsden Street
Tallahassee, FL 32301

By: ______________________ Sept. 27, 2017
Jon C. Moyle, Jr.

Signature Page to 2017 Agreement

WCF Hospital Utility Alliance
Mark F. Sundback, Esquire
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1350 I Street, N.W., Suite 1100
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Kenneth L. Wiseman

Signature Page to 2017 Agreement

Federal Executive Agencies
Lanny L. Zieman, Capt, USAF, Esquire
AFLOA/JACL-ULFSC
139 Barnes Drive, Suite 1
Tyndall Air Force Base, FL 32403

By: ______________________________
Lanny L. Zieman

Signature Page to 2017 Agreement

Florida Retail Federation
Robert Scheffel Wright
Gardner, Bist, Bowden, Bush, Dee, LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, FL 32308

By: Robert Scheffel Wright
Robert Scheffel Wright

Tampa Electric Company

2017 Agreement

Exhibit A

Tariffs

TECO
TAMPA ELECTRIC

~~NINTH~~ TENTH REVISED SHEET NO. 3.200
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 3.200

STANDBY GENERATOR RIDER

SCHEDULE: GSSG-1

AVAILABLE: At the option of the customer, available to commercial and industrial customers on rate schedule GSD, GSDT, SBF, and SBFT who sign a Tariff Agreement for the Provision of Standby Generator Transfer Service.

CHARACTER OF SERVICE: Upon notification by Tampa Electric Company, electric service to all or a portion of the customer's firm load will be transferred by the customer to a standby generator(s) for service.

MONTHLY CREDITS: Credits will be applied each billing period to the regular bill submitted under the GSD, GSDT, SBF, or SBFT rate schedule, for credits generated in the previous billing period.

Credit:

$~~4.75~~5.35/KW/Month payment for Average Transferable Demand of a customer's load to a standby generator(s).

INITIAL TRANSFERABLE DEMAND: To begin participation under this tariff, Initial Transferable Demand will be determined by Tampa Electric in the field at the customer's site by transferring the customer's normal load to the standby generator(s).

AVERAGE TRANSFERABLE DEMAND: For a control month, Transferable Demand is calculated by totaling the KWH produced by the standby generator(s) during all the control(s) in the month divided by the total control hours in the month (less the 30 minute customer response time to transfer load per control). This demand is then averaged with the calculated Transferable Demands from the previous service months (for a maximum of eleven) to determine the Average Transferable Demand. For non-control months, the Average Transferable Demand is the average of the calculated Transferable Demands of the previous twelve months.

NOTIFICATION SCHEDULE: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight savings time and vice versa.)

Normally the Company will notify customers to transfer load to standby generator(s) during the prime hours. These periods are:

Continued to Sheet No. 3.201

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~November 1, 2013~~

TECO TAMPA ELECTRIC
AN EMERA COMPANY

ADDITIONAL BILLING CHARGES

TOTAL FUEL AND PURCHASED POWER COST RECOVERY CLAUSE: The total fuel and purchased power cost recovery factor shall be applied to each kilowatt-hour delivered, and shall be computed in accordance with the formula prescribed by the Florida Public Service Commission. The following fuel recovery factors by rate schedule have been approved by the Commission:

RECOVERY PERIOD
(January ~~2017~~ 2018 through December ~~2017~~2018)

Rate Schedules	Fuel ¢/kWh Standard	Fuel ¢/kWh Peak	Fuel ¢/kWh Off-Peak	¢/kWh Energy Conservation	¢/kWh Capacity	¢/kWh Environmental
RS (up to 1,000 kWh)	2.642	-	-	~~0.225~~0.246	0.088	0.389
RS (over 1,000 kWh)	3.642	-	-	~~0.225~~0.246	0.088	0.389
RSVP-1 (P1)	2.956	-	-	~~(2.501)~~(3.002)	0.088	0.389
(P2)	2.956	-	-	~~(0.719)~~(1.058)	0.088	0.389
(P3)	2.956	-	-	~~7.054~~6.906	0.088	0.389
(P4)	2.956	-	-	~~28.645~~40.852	0.088	0.389
GS, GST	2.956	3.166	2.865	~~0.203~~0.232	0.076	0.388
CS	2.956	-	-	~~0.203~~0.232	0.076	0.388
LS-1	2.916	-	-	~~0.099~~0.125	0.017	0.381
GSD Optional						
Secondary	2.956	-	-	~~0.180~~0.201	0.063	0.386
Primary	2.926	-	-	~~0.178~~0.199	0.062	0.382
Subtransmission	2.897	-	-	~~0.176~~0.197	-	0.378

Rate Schedules	Fuel ¢/kWh Standard	Fuel ¢/kWh Peak	Fuel ¢/kWh Off-Peak	$/kW Energy Conservation	$/kW Capacity	¢/kWh Environmental
GSD, GSDT, SBF, SBFT						
Secondary	2.956	3.166	2.865	~~0.77~~0.87	0.27	0.386
Primary	2.926	3.134	2.836	~~0.76~~0.86	0.27	0.382
Subtransmission	2.897	3.103	2.808	~~0.75~~0.85	0.26	0.378
IS, IST, SBI						
Primary	2.926	3.134	2.836	~~0.48~~0.67	0.14	0.375
Subtransmission	2.897	3.103	2.808	~~0.47~~0.66	0.14	0.371

Continued to Sheet No. 6.021

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~December 30, 2016~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~THIRTY-THIRD~~THIRTY-FOURTH REVISED SHEET NO. 6.021
CANCELS ~~THIRTY-SECOND~~THIRTY-THIRD REVISED
SHEET NO. 6.021

Continued from Sheet No. 6.020

CONTRACT CREDIT VALUE (CCV): This incentive is applicable to any commercial or industrial customer with interruptible loads of 500 kW or greater who qualify to participate in the company's GSLM 2 & 3 load management programs. The credit is updated annually. The ~~2017~~ 2018 and prior six years of historical CCVs per kW reduction at secondary voltage are:

Year	Secondary	Primary	Subtransmission
~~2017~~2018	~~9.98~~10.23	~~9.88~~10.13	~~9.78~~10.03
~~2016~~2017	~~8.81~~9.98	~~8.72~~9.88	~~8.63~~9.78
~~2015~~2016	~~8.14~~8.81	~~8.06~~8.72	~~7.98~~8.63
~~2014~~2015	~~7.72~~8.14	~~7.64~~8.06	~~7.57~~7.98
~~2013~~2014	~~6.81~~7.72	~~6.74~~7.64	~~6.67~~7.57
~~2012~~2013	~~9.82~~6.81	~~9.72~~6.74	~~9.62~~6.67
~~2011~~2012	~~9.21~~9.82	~~9.12~~9.72	~~9.03~~9.62

Refer to Tariff sheets 3.210 and 3.230 for additional contract details.

FUEL CHARGE: Fuel charges are adjusted annually by the Florida Public Service Commission, normally in January.

ENERGY CONSERVATION COST RECOVERY CLAUSE: Energy conservation cost recovery factors recover the conservation related expenditures of the Company. The procedure for the review, approval, recovery and recording of such costs and revenues is set forth in Commission Rule 25-17.015, F.A.C. For rate schedules, RS, RSVP, GS, GST, and GSD Optional, cost recovery factors shall be applied to each kilowatt-hour delivered. For rate schedules, GSD, GSDT, IS, IST, SBF, SBFT, and SBI, cost recovery factors shall be applied on a kilowatt basis to the billing demand or supplemental billing demand and to the greater of the standby demand times 12% or the actual standby demand times 4.76%.

CAPACITY COST RECOVERY CLAUSE: In accordance with Commission Order No. 25773, Docket No. 910794-EQ, issued February 24, 1992, the capacity cost recovery factors shall be applied to each kilowatt-hour delivered for rate schedules, RS, RSVP, GS, GST, and GSD Optional. For rate schedules, GSD, GSDT, IS, IST, SBF, SBFT, and SBI the cost recovery factors shall be applied to each kilowatt of billing demand and supplemental billing demand and to the greater of the standby demand times 12% or the actual standby demand times 4.76%.

ENVIRONMENTAL COST RECOVERY CLAUSE: In accordance with Commission Order No. PSC-96-1048-FOF-EI, Docket No. 960688-EI, issued August 14, 1996, the environmental cost recovery factors shall be applied to each kilowatt-hour delivered.

Continued to Sheet No. 6.022

ISSUED BY: G. L. Gillette, President **DATE EFFECTIVE:** ~~December 30, 2016~~

Tampa Electric Company

2017 Agreement

Exhibit B

AFUDC

TAMPA ELECTRIC COMPANY, INC.
Capital Structure Used for AFUDC Calculation
FPSC Order No. PSC-14-0176-PAA-EI

	Capital Ratio	Cost Rates	AFUDC Weighted Average Cost of Capital
Long Term Debt	36.2860%	5.61%	2.04%
Short Term Debt	0.0000%	0.60%	0.00%
Customer Deposits	2.7010%	2.24%	0.06%
Common Equity	42.6030%	10.25%	4.37%
Deferred Income Taxes	18.2040%	-	0.00%
Tax Credits -Weighted Cost	0.2060%	-	0.00%
Total	100.00%		6.46%

Tampa Electric Company

2017 Agreement

Exhibit C

Tax Reform Illustration

Methodology of Income Tax Change (Illustrative)

			Scenario A	Scenario B	Scenario C	Scenario D
1	INCOME TAX INPUTS AND ASSUMPTIONS					
2	New federal statutory tax rate	Input	35%	30%	30%	20%
3	Current federal statutory tax rate	Given	35%	35%	35%	35%
4	Current State statutory tax rate	Given	5.5%	5.5%	5.5%	5.5%
5	New combined feredal & state statutory tax rate	Line 2 + Line 4 - (Line 2 x Line 4)	38.6%	33.9%	33.9%	24.4%
6	Current combined federal & state statutory tax rate	Line 3 + Line 4 - (Line 3 x Line 4)	38.6%	38.6%	38.6%	38.6%
7	Disallowed Interest (or other) expense deduction	Input	-	100.0	-	-
8						
9	PARAGRAPH 9 - TAX REFORM SHARING					
10	Step 1 - Calculate Income tax expense BEFORE tax reform					
11	FPSC adjusted NOI before tax (per Forcasted Surveillance)	Input	500	500	500	500
12	Less interest expense	Input	(100)	(100)	(100)	(100)
13	Permanent differences	Input	5	5	5	5
14	FPSC adjusted taxable income	Sum of Lines 11 through 13	405	405	405	405
15	Current combined statutory tax rate	Line 6	38.6%	38.6%	38.6%	38.6%
16	Income tax expense	Line 14 x Line 15	156	156	156	156
17						
18	Step 2 - Calculate Income tax expense AFTER tax reform					
19	FPSC adjusted NOI before tax (per Forecasted Surveillence)	Input	500	500	500	500
20	Less interest expense	Input	(100)	-	(100)	(100)
21	Permanent differences	Input	5	5	5	5
22	FPSC adjusted taxable income	Sum of Lines 19 through 21	405	505	405	405
23	New combined statutory tax rate	Line 5	38.6%	33.9%	33.9%	24.4%
24	Income tax expense	Line 22 x Line 23	156	171	137	99
25						
26	Step 3 - Calculate impact on FPSC Adjusted NOI					
27	Income tax expense BEFORE tax reform - step 1	Line 16	156	156	156	156
28	Income tax expense AFTER tax reform - step 2	Line 24	156	171	137	99
29	Difference - FPSC Adjusted NOI increase/(decrease) from tax reform	Line 27 - Line 28	-	(15)	19	57
30						
31	Step 4 - Calculate adjustment for base increase implemented at new combined statutory tax rate					
32	Solar base rate adjustment - "All Tranches"	Input	tbd	tbd	tbd	tbd
33	Change in combined statutory tax rate	Line 5 - Line 6	0.0%	-4.7%	-4.7%	-14.2%
34	Adj. for base rate increases at new combined statutory tax rate	Line 32 x Line 33	-	-	-	-
35						
36	Step 5 - Calculate net favorable/(unfavorable) FPSC adjusted NOI Impact					
37	Impact on NOI - Step 3	Line 29	-	(15)	19	57
38	Impact on NOI - Step 4	Line 34	-	-	-	-
39	Net favorable/(nonfavorable) FPSC adjusted NOI import - after tax	Line 37 + Line 38	-	(15)	19	57
40	Divide by one minus new combined statutory tax rate	1 - Line 5	61.4%	66.2%	66.2%	75.6%
41	Net favorable/(nonfavorable) FPSC adjusted NOI import - pretax	Line 39/Line 40	-	(22)	29	76
42						
43	Step 6 - Calculate annual pretax impacts					
44	Annual flowback to customers	If line 41>0, then line 41	-	-	29	76
45	Annual deferral to Regulatory Asset	If line 41<0, then line 41	-	(22)	-	-
46	Total	Ln 44 + Ln 45	-	(22)	29	76

E-7

3

TECO's responses to Staff's First Data Requests (Nos. 1-27) with revised page 101.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170210-EI EXHIBIT: 3
PARTY: STAFF– (DIRECT)
DESCRIPTION: TECO's responses to Staff's First Data Requests (Nos. 1-27) with revised page 101.[Bates Nos. 000056...

AUSLEY MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

123 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

October 16, 2017

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Petition by Tampa Electric Company for a limited proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement, Docket No. 20170210-EI; Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism, Docket No. 20160160-EI

Dear Ms. Stauffer:

Attached are Tampa Electric Company's responses to Staff's First Data Requests (Nos. 1-27). As indicated in the responses, confidential portions of the responsive documents will be made available at Staff's convenience in the office of Ausley McMullen.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

cc:	Bill McNulty	(w/attachment)
	R. Kelly/Charles Rehwinkel	(w/attachment)
	Jon C. Moyle, Jr.	(w/attachment)
	Robert Scheffel Wright	(w/attachment)
	Thomas Jernigan	(w/attachment)
	Mark Sundback	(w/attachment)
	Kenneth L. Wiseman	(w/attachment)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Tampa Electric Company for a Limited Proceeding to Approve 2017 Amended and Restated Stipulation and Settlement Agreement	)	**DOCKET NO. 20170210-EI**
and		
Petition by Tampa Electric Company for Approval of Energy Transaction Optimization Mechanism	)	**DOCKET NO. 20160160-EI** **FILED: OCTOBER 16, 2017**

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST DATA REQUEST (NOS. 1-27)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files its Answers to Data Request (Nos. 1-27) propounded and served on October 11, 2017 by the Florida Public Service Commission Staff.

1. Please provide the assumptions used in calculating and the results of the three DSM cost-effectiveness models supporting the proposed program credits provided in Paragraph 3(e).

A. Tampa Electric used the results of the latest 2017 update to the cost-effectiveness model which included using 2016 actuals as directed by the Commission in responding to the Staff's 1st set of interrogatories, Interrogatory No. 1, which was filed with the Commission on July 31, 2017 within Docket No. 20170002-EG. The Rate Impact Measure Test ("RIM"), Total Resource Cost Test ("TRC") and Participant Cost Test ("PCT") cost-effectiveness test results for the three programs which would be affected by the Standby Generator Program credit increase and the Contracted Credit Value ("CCV") credit increase were updated with the proposed values and are included below. As an additional note, the credit that is paid to the participants of Tampa Electric's Commercial Demand Response Program is based on the Standby Generator credit. Below is a summary of the cost effectiveness results for each of the programs with the credit adjustments in the 2017 Agreement:

Standby Generator Program:

RIM:	1.93
TRC:	9.40
PCT:	1,317

Commercial Demand Response Program:

RIM:	1.40
TRC:	114.83
PCT:	2,067

CCV for the GSLM 2 & 3 Program:

RIM:	1.13
TRC:	31.14
PCT:	24,537

INPUT DATA - PART 1
PROGRAM TITLE: Standby Generator

PSC FORM CE 1.1
PAGE 1 OF 1
RUN DATE: October 14, 2017

PROGRAM DEMAND SAVINGS & LINE LOSSES

I.	(1) CUSTOMER KW REDUCTION AT THE METER	485.500	KW /CUST
I.	(2) GENERATOR KW REDUCTION PER CUSTOMER	540.417	KW GEN/CUST
I.	(3) KW LINE LOSS PERCENTAGE	7.00	%
I.	(4) GENERATION KWH REDUCTION PER CUSTOMER	51,213	KWH/CUST/YR
I.	(5) KWH LINE LOSS PERCENTAGE	5.20	%
I.	(6) GROUP LINE LOSS MULTIPLIER	1	
I.	(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0	KWH/CUST/YR
I.	(8)* CUSTOMER KWH REDUCTION AT METER	48,550	KWH/CUST/YR

ECONOMIC LIFE & K FACTORS

II.	(1) STUDY PERIOD FOR CONSERVATION PROGRAM	25	YEARS
II.	(2) GENERATOR ECONOMIC LIFE	25	YEARS
II.	(3) T & D ECONOMIC LIFE	25	YEARS
II.	(4) K FACTOR FOR GENERATION	1.4181	
II.	(5) K FACTOR FOR T & D	1.4181	
	(6)* SWITCH REV REQ(0) OR VAL-OF-DEF (1)	0	

UTILITY & CUSTOMER COSTS

III.	(1) UTILITY NONRECURRING COST PER CUSTOMER	6,304.00	$/CUST
III.	(2) UTILITY RECURRING COST PER CUSTOMER	386.00	$/CUST/YR
III.	(3) UTILITY COST ESCALATION RATE	2.40	%
III.	(4) CUSTOMER EQUIPMENT COST	0.00	$/CUST
III.	(5) CUSTOMER EQUIPMENT ESCALATION RATE	2.30	%
III.	(6) CUSTOMER O & M COST	4985.00	$/CUST/YR
III.	(7) CUSTOMER O & M ESCALATION RATE	2.30	%
III.	(8)* CUSTOMER TAX CREDIT PER INSTALLATION	0.00	$/CUST
III.	(9)* CUSTOMER TAX CREDIT ESCALATION RATE	0.00	%
III.	(10)* INCREASED SUPPLY COSTS	0.00	$/CUST/YR
III.	(11)* SUPPLY COSTS ESCALATION RATE	0.00	%
III.	(12)* UTILITY DISCOUNT RATE	0.06976	
III.	(13)* UTILITY AFUDC RATE	0.0646	
III.	(14)* UTILITY NON RECURRING REBATE/INCENTIVE	0.00	$/CUST
III.	(15)* UTILITY RECURRING REBATE/INCENTIVE	33,784.00	$/CUST/YR
III.	(16)* UTILITY REBATE/INCENTIVE ESCAL RATE	0.00	%

AVOIDED GENERATOR, TRANS. & DIST COSTS

IV.	(1) BASE YEAR	2017	
IV.	(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2021	
IV.	(3) IN-SERVICE YEAR FOR AVOIDED T & D	2018	
IV.	(4) BASE YEAR AVOIDED GENERATING UNIT COST	682.22	$/KW
IV.	(5) BASE YEAR AVOIDED TRANSMISSION COST	37.16	$/KW
IV.	(6) BASE YEAR DISTRIBUTION COST	69.64	$/KW
IV.	(7) GEN, TRAN, & DIST COST ESCALATION RATE	2.40	%
IV.	(8) GENERATOR FIXED O & M COST	12.27	$/KW/YR
IV.	(9) GENERATOR FIXED O&M ESCALATION RATE	2.40	%
IV.	(10) TRANSMISSION FIXED O & M COST	2.24	$/KW/YR
IV.	(11) DISTRIBUTION FIXED O & M COST	8.54	$/KW/YR
IV.	(12) T&D FIXED O&M ESCALATION RATE	2.40	%
IV.	(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.198	CENTS/KWH
IV.	(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	2.40	%
IV.	(15) GENERATOR CAPACITY FACTOR	13.20	%
IV.	(16) AVOIDED GENERATING UNIT FUEL COST	3.95	CENTS/KWH
IV.	(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	3.69	%
IV.	(18)* AVOIDED PURCHASE CAPACITY COST PER KW	0.00	$/KW/YR
IV.	(19)* CAPACITY COST ESCALATION RATE	0.00	%

NON-FUEL ENERGY AND DEMAND CHARGES

V.	(1) NON-FUEL COST IN CUSTOMER BILL	2.140	CENTS/KWH
V.	(2) NON-FUEL ESCALATION RATE	1.00	%
V.	(3) CUSTOMER DEMAND CHARGE PER KW	11.290	$/KW/MO
V.	(4) DEMAND CHARGE ESCALATION RATE	1.00	%
V.	(5)* DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL	0.00	

CALCULATED BENEFITS AND COSTS	
(1)* TRC TEST - BENEFIT/COST RATIO	**9.40**
(2)* PARTICIPANT NET BENEFITS (NPV)	**1,317**
(3)* RIM TEST - BENEFIT/COST RATIO	**1.93**

TOTAL RESOURCE COST TESTS
PROGRAM: Standby Generator

PSC FORM CE 2.3
Page 1 of 1
October 14, 2017

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) PARTICIPANT PROGRAM COSTS $(000)	(5) OTHER COSTS $(000)	(6) TOTAL COSTS $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)	(8) AVOIDED T & D BENEFITS $(000)	(9) PROGRAM FUEL SAVINGS $(000)	(10) OTHER BENEFITS $(000)	(11) TOTAL BENEFITS $(000)	(12) NET BENEFITS $(000)	(13) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2017	0	6	2	0	9	0	0	1	0	1	(8)	(8)
2018	0	7	8	0	15	0	22	2	0	24	9	0
2019	0	8	13	0	21	0	22	4	0	27	6	6
2020	0	8	19	0	27	0	23	6	0	29	2	7
2021	0	2	22	0	24	311	57	8	0	376	353	277
2022	0	2	22	0	24	304	56	8	0	368	344	522
2023	0	2	23	0	25	294	56	10	0	359	334	745
2024	0	2	23	0	25	284	55	6	0	345	320	944
2025	0	2	24	0	26	277	54	7	0	338	312	1,126
2026	0	2	24	0	26	271	54	11	0	335	309	1,295
2027	0	2	25	0	27	263	53	10	0	327	300	1,447
2028	0	2	26	0	28	258	53	11	0	322	295	1,588
2029	0	2	26	0	28	248	53	9	0	310	282	1,713
2030	0	2	27	0	29	243	52	11	0	306	277	1,828
2031	0	2	27	0	30	236	52	12	0	300	270	1,934
2032	0	2	28	0	30	232	52	12	0	295	265	2,030
2033	0	2	29	0	31	224	51	15	0	291	260	2,118
2034	0	2	29	0	32	219	51	16	0	286	254	2,199
2035	0	2	30	0	32	216	51	15	0	282	250	2,273
2036	0	2	31	0	33	218	51	13	0	282	249	2,342
2037	0	2	31	0	34	220	51	14	0	285	251	2,408
2038	0	3	32	0	35	221	51	14	0	286	251	2,469
2039	0	3	33	0	35	222	52	13	0	286	250	2,525
2040	0	3	34	0	36	226	52	15	0	294	257	2,580
2041	0	3	34	0	37	225	53	19	0	297	260	2,631
NOMINAL	0	75	623	0	698	5,210	1,178	262	0	6,650	5,952	
NPV:	0	45	269	0	313	2,304	534	106	0	2,945	2,631	

Discount Rate 0.06976 Benefit/Cost Ratio - [col (11)/col (6)]: 9.40

PARTICIPANT COSTS AND BENEFITS
PROGRAM: Standby Generator

PSC FORM CE 2.4

October 14, 2017

(1) YEAR	(2) SAVINGS IN PARTICIPANTS BILL $(000)	(3) TAX CREDITS $(000)	(4) UTILITY REBATES $(000)	(5) OTHER BENEFITS $(000)	(6) TOTAL BENEFITS $(000)	(7) CUSTOMER EQUIPMENT COSTS $(000)	(8) CUSTOMER O & M COSTS $(000)	(9) OTHER COSTS $(000)	(10) TOTAL COSTS $(000)	(11) NET BENEFITS $(000)	(12) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2017	1	0	17	0	18	0	2	0	2	16	16
2018	4	0	51	0	55	0	8	0	8	47	60
2019	7	0	84	0	92	0	13	0	13	79	128
2020	10	0	118	0	129	0	19	0	19	110	218
2021	12	0	135	0	147	0	22	0	22	125	314
2022	12	0	135	0	147	0	22	0	22	125	403
2023	13	0	135	0	148	0	23	0	23	125	486
2024	13	0	135	0	148	0	23	0	23	125	564
2025	14	0	135	0	149	0	24	0	24	125	637
2026	14	0	135	0	149	0	24	0	24	125	705
2027	14	0	135	0	149	0	25	0	25	124	768
2028	15	0	135	0	150	0	26	0	26	124	828
2029	15	0	135	0	150	0	26	0	26	124	883
2030	16	0	135	0	151	0	27	0	27	124	934
2031	16	0	135	0	151	0	27	0	27	124	983
2032	16	0	135	0	152	0	28	0	28	124	1,028
2033	17	0	135	0	152	0	29	0	29	123	1,070
2034	17	0	135	0	153	0	29	0	29	123	1,109
2035	18	0	135	0	153	0	30	0	30	123	1,145
2036	18	0	135	0	153	0	31	0	31	122	1,179
2037	18	0	135	0	153	0	31	0	31	122	1,211
2038	18	0	135	0	153	0	32	0	32	121	1,240
2039	19	0	135	0	154	0	33	0	33	121	1,267
2040	19	0	135	0	154	0	34	0	34	120	1,293
2041	19	0	135	0	154	0	34	0	34	120	1,317
NOMINAL	356	0	3,108	0	3,464	0	623	0	623	2,841	
NPV:	152	0	1,433	0	1,585	0	269	0	269	1,317	
In service year of gen unit:			2021		5.9030066						

RATE IMPACT TEST
PROGRAM: Standby Generator

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(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) INCENTIVES $(000)	(5) REVENUE LOSSES $(000)	(6) OTHER COSTS $(000)	(7) TOTAL COSTS $(000)	(8) AVOIDED GEN UNIT UNIT & FUEL BENEFITS $(000)	(9) AVOIDED T & D BENEFITS $(000)	(10) REVENUE GAINS $(000)	(11) OTHER BENEFITS $(000)	(12) TOTAL BENEFITS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)	(14) CUMULATIVE DISCOUNTED NET BENEFIT $(000)
2017	0	6	17	1	0	24	1	0	0	0	1	(23)	(23)
2018	0	7	51	2	0	59	2	22	0	0	24	(35)	(56)
2019	0	8	84	3	0	95	4	22	0	0	27	(68)	(116)
2020	0	8	118	4	0	130	6	23	0	0	29	(101)	(199)
2021	0	2	135	4	0	141	319	57	0	0	376	235	(19)
2022	0	2	135	4	0	141	312	56	0	0	368	227	143
2023	0	2	135	4	0	141	303	56	0	0	359	217	288
2024	0	2	135	4	0	141	290	55	0	0	345	204	415
2025	0	2	135	5	0	142	283	54	0	0	338	196	529
2026	0	2	135	5	0	142	281	54	0	0	335	194	635
2027	0	2	135	5	0	142	273	53	0	0	327	185	729
2028	0	2	135	5	0	142	269	53	0	0	322	180	815
2029	0	2	135	5	0	142	257	53	0	0	310	168	890
2030	0	2	135	5	0	142	254	52	0	0	306	164	958
2031	0	2	135	5	0	142	248	52	0	0	300	158	1020
2032	0	2	135	5	0	142	244	52	0	0	295	153	1075
2033	0	2	135	5	0	142	239	51	0	0	291	148	1126
2034	0	2	135	5	0	142	235	51	0	0	286	144	1171
2035	0	2	135	5	0	142	231	51	0	0	282	140	1213
2036	0	2	135	5	0	143	231	51	0	0	282	140	1252
2037	0	2	135	5	0	143	234	51	0	0	285	143	1289
2038	0	3	135	5	0	143	235	51	0	0	286	143	1323
2039	0	3	135	5	0	143	234	52	0	0	286	143	1356
2040	0	3	135	5	0	143	241	52	0	0	294	151	1388
2041	0	3	135	5	0	143	244	53	0	0	297	154	1418
NOMINAL	0	75	3,108	109	0	3,292	5,472	1,178	0	0	6,650	3,358	
NPV:	0	45	1,433	49	0	1,527	2,411	534	0	0	2,945	1,418	

Discount rate: 0.06976

Benefit/Cost Ratio - [col (12)/col (7)]: 1.93

INPUT DATA - PART 1
PROGRAM TITLE: Commercial Demand Response

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PROGRAM DEMAND SAVINGS & LINE LOSSES

I.	(1) CUSTOMER KW REDUCTION AT THE METER	470.590	KW /CUST
I.	(2) GENERATOR KW REDUCTION PER CUSTOMER	523.821	KW GEN/CUST
I.	(3) KW LINE LOSS PERCENTAGE	7.00	%
I.	(4) GENERATION KWH REDUCTION PER CUSTOMER	37,230	KWH/CUST/YR
I.	(5) KWH LINE LOSS PERCENTAGE	5.20	%
I.	(6) GROUP LINE LOSS MULTIPLIER	1	
I.	(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0	KWH/CUST/YR
I.	(8)* CUSTOMER KWH REDUCTION AT METER	35,294	KWH/CUST/YR

ECONOMIC LIFE & K FACTORS

II.	(1) STUDY PERIOD FOR CONSERVATION PROGRAM	25	YEARS
II.	(2) GENERATOR ECONOMIC LIFE	25	YEARS
II.	(3) T & D ECONOMIC LIFE	25	YEARS
II.	(4) K FACTOR FOR GENERATION	1.4181	
II.	(5) K FACTOR FOR T & D	1.4181	
	(6)* SWITCH REV REQ(0) OR VAL-OF-DEF (1)	0	

UTILITY & CUSTOMER COSTS

III.	(1) UTILITY NONRECURRING COST PER CUSTOMER	860.00	$/CUST
III.	(2) UTILITY RECURRING COST PER CUSTOMER	393.00	$/CUST/YR
III.	(3) UTILITY COST ESCALATION RATE	2.40	%
III.	(4) CUSTOMER EQUIPMENT COST	0.00	$/CUST
III.	(5) CUSTOMER EQUIPMENT ESCALATION RATE	2.30	%
III.	(6) CUSTOMER O & M COST	0.00	$/CUST/YR
III.	(7) CUSTOMER O & M ESCALATION RATE	2.30	%
III.	(8)* CUSTOMER TAX CREDIT PER INSTALLATION	0.00	$/CUST
III.	(9)* CUSTOMER TAX CREDIT ESCALATION RATE	0.00	%
III.	(10)* INCREASED SUPPLY COSTS	0.00	$/CUST/YR
III.	(11)* SUPPLY COSTS ESCALATION RATE	0.00	%
III.	(12)* UTILITY DISCOUNT RATE	0.06976	
III.	(13)* UTILITY AFUDC RATE	0.0646	
III.	(14)* UTILITY NON RECURRING REBATE/INCENTIVE	0.00	$/CUST
III.	(15)* UTILITY RECURRING REBATE/INCENTIVE	46,117.70	$/CUST/YR
III.	(16)* UTILITY REBATE/INCENTIVE ESCAL RATE	0.00	%

AVOIDED GENERATOR, TRANS. & DIST COSTS

IV.	(1) BASE YEAR	2017	
IV.	(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2021	
IV.	(3) IN-SERVICE YEAR FOR AVOIDED T & D	2018	
IV.	(4) BASE YEAR AVOIDED GENERATING UNIT COST	682.22	$/KW
IV.	(5) BASE YEAR AVOIDED TRANSMISSION COST	37.16	$/KW
IV.	(6) BASE YEAR DISTRIBUTION COST	69.64	$/KW
IV.	(7) GEN, TRAN, & DIST COST ESCALATION RATE	2.40	%
IV.	(8) GENERATOR FIXED O & M COST	12.27	$/KW/YR
IV.	(9) GENERATOR FIXED O&M ESCALATION RATE	2.40	%
IV.	(10) TRANSMISSION FIXED O & M COST	2.24	$/KW/YR
IV.	(11) DISTRIBUTION FIXED O & M COST	8.54	$/KW/YR
IV.	(12) T&D FIXED O&M ESCALATION RATE	2.40	%
IV.	(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.198	CENTS/KWH
IV.	(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	2.40	%
IV.	(15) GENERATOR CAPACITY FACTOR	13.20	%
IV.	(16) AVOIDED GENERATING UNIT FUEL COST	3.95	CENTS/KWH
IV.	(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	3.69	%
IV.	(18)* AVOIDED PURCHASE CAPACITY COST PER KW	0.00	$/KW/YR
IV.	(19)* CAPACITY COST ESCALATION RATE	0.00	%

NON-FUEL ENERGY AND DEMAND CHARGES

V.	(1) NON-FUEL COST IN CUSTOMER BILL	2.140	CENTS/KWH
V.	(2) NON-FUEL ESCALATION RATE	1.00	%
V.	(3) CUSTOMER DEMAND CHARGE PER KW	11.290	$/KW/MO
V.	(4) DEMAND CHARGE ESCALATION RATE	1.00	%
V.	(5)* DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL	0.00	

CALCULATED BENEFITS AND COSTS	
(1)* TRC TEST - BENEFIT/COST RATIO	**114.83**
(2)* PARTICIPANT NET BENEFITS (NPV)	**2,067**
(3)* RIM TEST - BENEFIT/COST RATIO	**1.40**

TOTAL RESOURCE COST TESTS
PROGRAM: Commercial Demand Response

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(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) PARTICIPANT PROGRAM COSTS $(000)	(5) OTHER COSTS $(000)	(6) TOTAL COSTS $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)	(8) AVOIDED T & D BENEFITS $(000)	(9) PROGRAM FUEL SAVINGS $(000)	(10) OTHER BENEFITS $(000)	(11) TOTAL BENEFITS $(000)	(12) NET BENEFITS $(000)	(13) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2017	0	1	0	0	1	0	0	0	0	0	(1)	(1)
2018	0	1	0	0	1	0	21	2	0	23	21	19
2019	0	2	0	0	2	0	22	3	0	25	23	39
2020	0	2	0	0	2	0	22	4	0	27	24	59
2021	0	2	0	0	2	301	55	6	0	363	361	335
2022	0	2	0	0	2	295	55	6	0	355	353	587
2023	0	2	0	0	2	284	54	7	0	345	343	816
2024	0	2	0	0	2	275	53	5	0	333	331	1,022
2025	0	2	0	0	2	268	53	5	0	326	324	1,211
2026	0	2	0	0	2	262	52	8	0	322	320	1,385
2027	0	2	0	0	2	255	52	7	0	314	312	1,544
2028	0	2	0	0	2	250	51	8	0	310	307	1,691
2029	0	2	0	0	2	241	51	7	0	298	296	1,823
2030	0	2	0	0	2	235	51	8	0	294	292	1,944
2031	0	2	0	0	2	229	50	9	0	288	286	2,055
2032	0	2	0	0	2	224	50	9	0	283	281	2,158
2033	0	2	0	0	2	217	50	11	0	278	276	2,251
2034	0	2	0	0	2	212	50	12	0	273	271	2,337
2035	0	2	0	0	2	210	49	11	0	270	267	2,417
2036	0	2	0	0	2	211	49	10	0	270	268	2,491
2037	0	3	0	0	3	213	49	10	0	273	270	2,561
2038	0	3	0	0	3	214	50	10	0	274	271	2,627
2039	0	3	0	0	3	215	50	9	0	274	271	2,689
2040	0	3	0	0	3	219	51	11	0	281	278	2,748
2041	0	3	0	0	3	218	51	14	0	283	280	2,803
NOMINAL	0	53	0	0	53	5,049	1,142	190	0	6,381	6,328	
NPV:	0	25	0	0	25	2,233	517	77	0	2,828	2,803	

Discount Rate 0.06976 Benefit/Cost Ratio - [col (11)/col (6)]: 114.83

PARTICIPANT COSTS AND BENEFITS
PROGRAM: Commercial Demand Response

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October 14, 2017

(1) YEAR	(2) SAVINGS IN PARTICIPANTS BILL $(000)	(3) TAX CREDITS $(000)	(4) UTILITY REBATES $(000)	(5) OTHER BENEFITS $(000)	(6) TOTAL BENEFITS $(000)	(7) CUSTOMER EQUIPMENT COSTS $(000)	(8) CUSTOMER O & M COSTS $(000)	(9) OTHER COSTS $(000)	(10) TOTAL COSTS $(000)	(11) NET BENEFITS $(000)	(12) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2017	1	0	23	0	24	0	0	0	0	24	24
2018	3	0	69	0	72	0	0	0	0	72	91
2019	5	0	115	0	120	0	0	0	0	120	197
2020	8	0	161	0	169	0	0	0	0	169	335
2021	9	0	184	0	193	0	0	0	0	193	482
2022	9	0	184	0	193	0	0	0	0	193	620
2023	9	0	184	0	194	0	0	0	0	194	749
2024	10	0	184	0	194	0	0	0	0	194	871
2025	10	0	184	0	194	0	0	0	0	194	984
2026	10	0	184	0	195	0	0	0	0	195	1,090
2027	10	0	184	0	195	0	0	0	0	195	1,189
2028	11	0	184	0	195	0	0	0	0	195	1,282
2029	11	0	184	0	196	0	0	0	0	196	1,369
2030	11	0	184	0	196	0	0	0	0	196	1,451
2031	12	0	184	0	196	0	0	0	0	196	1,527
2032	12	0	184	0	196	0	0	0	0	196	1,598
2033	12	0	184	0	197	0	0	0	0	197	1,665
2034	13	0	184	0	197	0	0	0	0	197	1,728
2035	13	0	184	0	197	0	0	0	0	197	1,787
2036	13	0	184	0	197	0	0	0	0	197	1,841
2037	13	0	184	0	197	0	0	0	0	197	1,893
2038	13	0	184	0	198	0	0	0	0	198	1,941
2039	14	0	184	0	198	0	0	0	0	198	1,986
2040	14	0	184	0	198	0	0	0	0	198	2,028
2041	14	0	184	0	199	0	0	0	0	199	2,067
NOMINAL	258	0	4,243	0	4,501	0	0	0	0	4,501	
NPV:	111	0	1,956	0	2,067	0	0	0	0	2,067	
In service year of gen unit:			2021		#DIV/0!						

RATE IMPACT TEST
PROGRAM: Commercial Demand Response

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(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) INCENTIVES $(000)	(5) REVENUE LOSSES $(000)	(6) OTHER COSTS $(000)	(7) TOTAL COSTS $(000)	(8) AVOIDED GEN UNIT UNIT & FUEL BENEFITS $(000)	(9) AVOIDED T & D BENEFITS $(000)	(10) REVENUE GAINS $(000)	(11) OTHER BENEFITS $(000)	(12) TOTAL BENEFITS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)	(14) CUMULATIVE DISCOUNTED NET BENEFIT $(000)
2017	0	1	23	0	0	24	0	0	0	0	0	(24)	(24)
2018	0	1	69	1	0	72	2	21	0	0	23	(49)	(70)
2019	0	2	115	2	0	119	3	22	0	0	25	(94)	(152)
2020	0	2	161	3	0	167	4	22	0	0	27	(140)	(267)
2021	0	2	184	3	0	189	308	55	0	0	363	173	(134)
2022	0	2	184	3	0	189	300	55	0	0	355	166	(16)
2023	0	2	184	3	0	189	291	54	0	0	345	156	88
2024	0	2	184	3	0	190	280	53	0	0	333	143	177
2025	0	2	184	3	0	190	273	53	0	0	326	136	256
2026	0	2	184	3	0	190	270	52	0	0	322	133	329
2027	0	2	184	3	0	190	262	52	0	0	314	124	392
2028	0	2	184	3	0	190	258	51	0	0	310	120	449
2029	0	2	184	3	0	190	247	51	0	0	298	108	497
2030	0	2	184	3	0	190	243	51	0	0	294	104	540
2031	0	2	184	3	0	190	237	50	0	0	288	98	578
2032	0	2	184	4	0	190	233	50	0	0	283	93	612
2033	0	2	184	4	0	190	228	50	0	0	278	88	642
2034	0	2	184	4	0	190	224	50	0	0	273	83	668
2035	0	2	184	4	0	190	220	49	0	0	270	79	692
2036	0	2	184	4	0	191	221	49	0	0	270	80	714
2037	0	3	184	4	0	191	224	49	0	0	273	82	735
2038	0	3	184	4	0	191	224	50	0	0	274	83	755
2039	0	3	184	4	0	191	224	50	0	0	274	83	774
2040	0	3	184	4	0	191	230	51	0	0	281	90	793
2041	0	3	184	4	0	191	232	51	0	0	283	92	812
NOMINAL	0	53	4,243	79	0	4,375	5,239	1,142	0	0	6,381	2,006	
NPV:	0	25	1,956	35	0	2,016	2,311	517	0	0	2,828	812	

Discount rate: 0.06976

Benefit/Cost Ratio - [col (12)/col (7)]: 1.40

INPUT DATA - PART 1
PROGRAM TITLE: Contracted Credit Value Calculation

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RUN DATE: October 14, 2017

PROGRAM DEMAND SAVINGS & LINE LOSSES

I.	(1) CUSTOMER KW REDUCTION AT THE METER	4,264.710	KW /CUST
I.	(2) GENERATOR KW REDUCTION PER CUSTOMER	4,550.705	KW GEN/CUST
I.	(3) KW LINE LOSS PERCENTAGE	7.00	%
I.	(4) GENERATION KWH REDUCTION PER CUSTOMER	1,049,268	KWH/CUST/YR
I.	(5) KWH LINE LOSS PERCENTAGE	5.20	%
I.	(6) GROUP LINE LOSS MULTIPLIER	1	
I.	(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0	KWH/CUST/YR
I.	(8)* CUSTOMER KWH REDUCTION AT METER	994,706	KWH/CUST/YR

ECONOMIC LIFE & K FACTORS

II.	(1) STUDY PERIOD FOR CONSERVATION PROGRAM	25	YEARS
II.	(2) GENERATOR ECONOMIC LIFE	25	YEARS
II.	(3) T & D ECONOMIC LIFE	25	YEARS
II.	(4) K FACTOR FOR GENERATION	1.4181	
II.	(5) K FACTOR FOR T & D	1.4181	
	(6)* SWITCH REV REQ(0) OR VAL-OF-DEF (1)	0	

UTILITY & CUSTOMER COSTS

III.	(1) UTILITY NONRECURRING COST PER CUSTOMER	122,946.00	$/CUST
III.	(2) UTILITY RECURRING COST PER CUSTOMER	4,104.00	$/CUST/YR
III.	(3) UTILITY COST ESCALATION RATE	2.40	%
III.	(4) CUSTOMER EQUIPMENT COST	42,000.00	$/CUST
III.	(5) CUSTOMER EQUIPMENT ESCALATION RATE	2.30	%
III.	(6) CUSTOMER O & M COST	0.00	$/CUST/YR
III.	(7) CUSTOMER O & M ESCALATION RATE	2.30	%
III.	(8)* CUSTOMER TAX CREDIT PER INSTALLATION	0.00	$/CUST
III.	(9)* CUSTOMER TAX CREDIT ESCALATION RATE	0.00	%
III.	(10)* INCREASED SUPPLY COSTS	0.00	$/CUST/YR
III.	(11)* SUPPLY COSTS ESCALATION RATE	0.00	%
III.	(12)* UTILITY DISCOUNT RATE	0.06976	
III.	(13)* UTILITY AFUDC RATE	0.0646	
III.	(14)* UTILITY NON RECURRING REBATE/INCENTIVE	0.00	$/CUST
III.	(15)* UTILITY RECURRING REBATE/INCENTIVE	508,623.60	$/CUST/YR
III.	(16)* UTILITY REBATE/INCENTIVE ESCAL RATE	0.00	%

AVOIDED GENERATOR, TRANS. & DIST COSTS

IV.	(1) BASE YEAR	2017	
IV.	(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2021	
IV.	(3) IN-SERVICE YEAR FOR AVOIDED T & D	2018	
IV.	(4) BASE YEAR AVOIDED GENERATING UNIT COST	682.22	$/KW
IV.	(5) BASE YEAR AVOIDED TRANSMISSION COST	37.16	$/KW
IV.	(6) BASE YEAR DISTRIBUTION COST	69.64	$/KW
IV.	(7) GEN, TRAN, & DIST COST ESCALATION RATE	2.40	%
IV.	(8) GENERATOR FIXED O & M COST	12.27	$/KW/YR
IV.	(9) GENERATOR FIXED O&M ESCALATION RATE	2.40	%
IV.	(10) TRANSMISSION FIXED O & M COST	2.24	$/KW/YR
IV.	(11) DISTRIBUTION FIXED O & M COST	8.54	$/KW/YR
IV.	(12) T&D FIXED O&M ESCALATION RATE	2.40	%
IV.	(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.198	CENTS/KWH
IV.	(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	2.40	%
IV.	(15) GENERATOR CAPACITY FACTOR	13.20	%
IV.	(16) AVOIDED GENERATING UNIT FUEL COST	3.95	CENTS/KWH
IV.	(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	3.69	%
IV.	(18)* AVOIDED PURCHASE CAPACITY COST PER KW	0.00	$/KW/YR
IV.	(19)* CAPACITY COST ESCALATION RATE	0.00	%

NON-FUEL ENERGY AND DEMAND CHARGES

V.	(1) NON-FUEL COST IN CUSTOMER BILL	2.140	CENTS/KWH
V.	(2) NON-FUEL ESCALATION RATE	1.00	%
V.	(3) CUSTOMER DEMAND CHARGE PER KW	11.290	$/KW/MO
V.	(4) DEMAND CHARGE ESCALATION RATE	1.00	%
V.	(5)* DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL	0.00	

CALCULATED BENEFITS AND COSTS	
(1)* TRC TEST - BENEFIT/COST RATIO	**31.14**
(2)* PARTICIPANT NET BENEFITS (NPV)	**24,537**
(3)* RIM TEST - BENEFIT/COST RATIO	**1.13**

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-EI
STAFF'S FIRST DATA REQUEST
FILED: OCTOBER 16, 2017

TOTAL RESOURCE COST TESTS
PROGRAM: Contracted Credit Value Calculation

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October 14, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	INCREASED SUPPLY COSTS $(000)	UTILITY PROGRAM COSTS $(000)	PARTICIPANT PROGRAM COSTS $(000)	OTHER COSTS $(000)	TOTAL COSTS $(000)	AVOIDED GEN UNIT BENEFITS $(000)	AVOIDED T & D BENEFITS $(000)	PROGRAM FUEL SAVINGS $(000)	OTHER BENEFITS $(000)	TOTAL BENEFITS $(000)	NET BENEFITS $(000)	CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2017	0	125	42	0	167	0	0	13	0	13	(154)	(154)
2018	0	132	43	0	175	0	191	43	0	234	59	(99)
2019	0	140	44	0	184	0	196	85	0	280	97	(14)
2020	0	147	45	0	192	0	200	119	0	319	127	90
2021	0	18	0	0	18	2,619	493	171	0	3,283	3,265	2,583
2022	0	18	0	0	18	2,560	488	162	0	3,210	3,191	4,860
2023	0	19	0	0	19	2,471	482	196	0	3,149	3,130	6,949
2024	0	19	0	0	19	2,388	476	131	0	2,996	2,977	8,806
2025	0	20	0	0	20	2,328	472	137	0	2,937	2,917	10,507
2026	0	20	0	0	20	2,278	468	219	0	2,965	2,944	12,111
2027	0	21	0	0	21	2,214	464	209	0	2,887	2,866	13,571
2028	0	21	0	0	21	2,170	461	233	0	2,864	2,843	14,925
2029	0	22	0	0	22	2,090	458	185	0	2,733	2,711	16,132
2030	0	22	0	0	22	2,044	455	223	0	2,722	2,699	17,256
2031	0	23	0	0	23	1,986	452	244	0	2,682	2,659	18,290
2032	0	23	0	0	23	1,950	449	245	0	2,645	2,622	19,244
2033	0	24	0	0	24	1,889	447	304	0	2,640	2,616	20,133
2034	0	25	0	0	25	1,841	445	332	0	2,618	2,593	20,957
2035	0	25	0	0	25	1,822	442	301	0	2,565	2,540	21,712
2036	0	26	0	0	26	1,836	441	272	0	2,549	2,524	22,413
2037	0	26	0	0	26	1,851	443	295	0	2,589	2,563	23,078
2038	0	27	0	0	27	1,859	446	283	0	2,588	2,561	23,699
2039	0	28	0	0	28	1,866	449	257	0	2,573	2,546	24,277
2040	0	28	0	0	28	1,903	453	317	0	2,673	2,644	24,837
2041	0	29	0	0	29	1,898	456	390	0	2,744	2,715	25,376
NOMINAL	0	1,030	174	0	1,204	43,867	10,226	5,366	0	59,459	58,256	
NPV:	0	685	157	0	842	19,403	4,633	2,181	0	26,218	25,376	

Discount Rate 0.06976 Benefit/Cost Ratio - [col (11)/col (6)]: 31.14

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-EI
STAFF'S FIRST DATA REQUEST
FILED: OCTOBER 16, 2017

PARTICIPANT COSTS AND BENEFITS
PROGRAM: Contracted Credit Value Calculation

PSC FORM CE 2.4
Page 1 of 1
October 14, 2017

(1) YEAR	(2) SAVINGS IN PARTICIPANTS BILL $(000)	(3) TAX CREDITS $(000)	(4) UTILITY REBATES $(000)	(5) OTHER BENEFITS $(000)	(6) TOTAL BENEFITS $(000)	(7) CUSTOMER EQUIPMENT COSTS $(000)	(8) CUSTOMER O & M COSTS $(000)	(9) OTHER COSTS $(000)	(10) TOTAL COSTS $(000)	(11) NET BENEFITS $(000)	(12) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2017	28	0	254	0	282	42	0	0	42	240	240
2018	81	0	763	0	844	43	0	0	43	801	989
2019	146	0	1,272	0	1,418	44	0	0	44	1,374	2,189
2020	211	0	1,780	0	1,992	45	0	0	45	1,947	3,780
2021	246	0	2,034	0	2,280	0	0	0	0	2,280	5,521
2022	252	0	2,034	0	2,286	0	0	0	0	2,286	7,153
2023	261	0	2,034	0	2,296	0	0	0	0	2,296	8,684
2024	271	0	2,034	0	2,306	0	0	0	0	2,306	10,122
2025	278	0	2,034	0	2,312	0	0	0	0	2,312	11,471
2026	284	0	2,034	0	2,318	0	0	0	0	2,318	12,734
2027	293	0	2,034	0	2,328	0	0	0	0	2,328	13,920
2028	300	0	2,034	0	2,334	0	0	0	0	2,334	15,032
2029	313	0	2,034	0	2,348	0	0	0	0	2,348	16,077
2030	321	0	2,034	0	2,355	0	0	0	0	2,355	17,057
2031	331	0	2,034	0	2,365	0	0	0	0	2,365	17,977
2032	337	0	2,034	0	2,371	0	0	0	0	2,371	18,840
2033	348	0	2,034	0	2,383	0	0	0	0	2,383	19,650
2034	358	0	2,034	0	2,392	0	0	0	0	2,392	20,410
2035	362	0	2,034	0	2,397	0	0	0	0	2,397	21,122
2036	362	0	2,034	0	2,397	0	0	0	0	2,397	21,787
2037	366	0	2,034	0	2,401	0	0	0	0	2,401	22,411
2038	373	0	2,034	0	2,408	0	0	0	0	2,408	22,995
2039	381	0	2,034	0	2,416	0	0	0	0	2,416	23,543
2040	384	0	2,034	0	2,419	0	0	0	0	2,419	24,056
2041	396	0	2,034	0	2,430	0	0	0	0	2,430	24,537
NOMINAL	7,284	0	46,793	0	54,077	174	0	0	174	53,903	
NPV:	3,120	0	21,575	0	24,695	157	0	0	157	24,537	
In service year of gen unit:			2021		156.98922						

RATE IMPACT TEST
PROGRAM: Contracted Credit Value Calculation

PSC FORM CE 2.5
Page 1 of 1
October 14, 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	INCREASED SUPPLY COSTS	UTILITY PROGRAM COSTS	INCENTIVES	REVENUE LOSSES	OTHER COSTS	TOTAL COSTS	AVOIDED GEN UNIT UNIT & FUEL BENEFITS	AVOIDED T & D BENEFITS	REVENUE GAINS	OTHER BENEFITS	TOTAL BENEFITS	NET BENEFITS TO ALL CUSTOMERS	CUMULATIVE DISCOUNTED NET BENEFIT
YEAR	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
2017	0	125	254	11	0	390	13	0	0	0	13	(377)	(377)
2018	0	132	763	32	0	927	43	191	0	0	234	(693)	(1025)
2019	0	140	1,272	54	0	1,466	85	196	0	0	280	(1,185)	(2060)
2020	0	147	1,780	77	0	2,004	119	200	0	0	319	(1,685)	(3437)
2021	0	18	2,034	89	0	2,141	2,790	493	0	0	3,283	1,142	(2565)
2022	0	18	2,034	89	0	2,142	2,722	488	0	0	3,210	1,067	(1803)
2023	0	19	2,034	90	0	2,144	2,667	482	0	0	3,149	1,005	(1132)
2024	0	19	2,034	91	0	2,145	2,520	476	0	0	2,996	851	(602)
2025	0	20	2,034	92	0	2,147	2,466	472	0	0	2,937	791	(141)
2026	0	20	2,034	93	0	2,148	2,497	468	0	0	2,965	817	304
2027	0	21	2,034	94	0	2,149	2,423	464	0	0	2,887	737	680
2028	0	21	2,034	95	0	2,151	2,403	461	0	0	2,864	713	1020
2029	0	22	2,034	96	0	2,152	2,275	458	0	0	2,733	580	1278
2030	0	22	2,034	97	0	2,154	2,267	455	0	0	2,722	568	1515
2031	0	23	2,034	98	0	2,155	2,230	452	0	0	2,682	527	1720
2032	0	23	2,034	99	0	2,157	2,196	449	0	0	2,645	488	1897
2033	0	24	2,034	100	0	2,158	2,193	447	0	0	2,640	482	2061
2034	0	25	2,034	101	0	2,160	2,173	445	0	0	2,618	458	2207
2035	0	25	2,034	102	0	2,162	2,123	442	0	0	2,565	403	2326
2036	0	26	2,034	103	0	2,163	2,108	441	0	0	2,549	386	2434
2037	0	26	2,034	104	0	2,165	2,146	443	0	0	2,589	425	2544
2038	0	27	2,034	105	0	2,166	2,142	446	0	0	2,588	422	2646
2039	0	28	2,034	106	0	2,168	2,124	449	0	0	2,573	405	2738
2040	0	28	2,034	107	0	2,170	2,220	453	0	0	2,673	503	2845
2041	0	29	2,034	108	0	2,172	2,288	456	0	0	2,744	572	2958
NOMINAL	0	1,030	46,793	2,233	0	50,056	49,233	10,226	0	0	59,459	9,403	
NPV:	0	685	21,575	1,000	0	23,259	21,585	4,633	0	0	26,218	2,958	

Discount rate: 0.06976

Benefit/Cost Ratio - [col (12)/col (7)]: 1.13

2. If Paragraph 3(e) is approved, what impact will this have on the 2019 factors requested by the company in Docket No. 20180002-EG? Please explain.

A. The proposed credit adjustments, if approved, will cause an incremental increase in the company's Energy Conservation Cost Recovery ("ECCR") Clause of approximately $1,766,450 in 2018. This was calculated by comparing the proposed credit adjustments being added to the current Standby Generator and Commercial Demand Response credits and the proposed CCV credit for 2018. Tampa Electric projects the annual incremental increase in credits to equate to an approximate increase in the ECCR Clause of 10.4 cents per 1,000 kWh for the 2019 factors that will be requested by the company in Docket No. 20180002-EG.

3. If the proposed Settlement is approved, does the company anticipate any additional impacts to the Energy Conservation Cost Recovery clause, including any material impacts to the clause factors? Please explain.

A. Tampa Electric does not anticipate any additional impacts to the ECCR Clause if the 2017 Agreement is approved.

4. Paragraph 3(e) states:

The level of these credits will not change during the Term and will remain in effect after the expiration of the Term until changed, if at all, by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding.

Does this preclude the Commission from considering the cost-effectiveness of these programs and/or changing the credits in a future DSM proceeding? Please explain.

A. This term was negotiated by the Parties to the 2017 Agreement, and is part of a comprehensive and interdependent settlement that fairly reflects a compromise of the competing viewpoints among the parties, reduces the risks and costs of pursuing litigation before the FPSC, avoids the substantial time and costs associated with a traditional base rate proceeding and provides certainty and predictability for customers, the Consumer Parties and the company for a period of four years through 2021 (hereinafter, “Negotiated Term”).

Pursuant to Paragraph 3(e), the SoBRA increases remain in effect after the expiration of the Term, until changed, if at all by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding, and the same applies to the credits. Nothing in the 2017 Agreement precludes the Commission from considering the cost-effectiveness of these two programs at any time; however, if the commission approves the 2017 Agreement, the quoted language in Paragraph 3(e) would limit the Commission’s ability to change the level of the credits for these two programs until the same time that all other base rates are changed, i.e. in a future Commission-approved settlement or through final Commission decisions in a general base rate proceeding for Tampa Electric.

5. Has TECO begun the process of soliciting bids/proposals for the various SoBRA Tranches? If yes, please provide a detailed narrative explaining the process to date, including deadlines for entities to submit their bids/proposals to TECO. Also, please provide a copy of TECO's request for bids/proposals.

A. Yes. The company used a competitive process to review qualifications and experience of, identify and select full service solar developers. Three full service solar developers were selected to enter into contract negotiations to provide project development and engineering, procurement and construction services for the 600 MW of Tampa Electric solar projects.

Tampa Electric employed a Request for Information ("RFI") process to collect information from the bidders with respect to their qualifications, capabilities and experience as full service solar developers. On April 12, 2017, the RFI was provided to more than 60 companies that Tampa Electric had met and/or discussed the development and construction of utility scale solar projects. On April 21, 2017, Tampa Electric received more than 30 responses from solar developers and/or solar engineering procurement and construction ("EPC") companies. The company used the information from the RFI responses to select a shortlist of four full service solar developers.

The shortlisted developers were asked to provide pricing for 7 PV solar projects that ranged in size from 20-74.5 MW_{AC}. The pricing information was broken out for engineering and permitting, equipment, balance of system, installation and interconnection. The projects were based on sites that Tampa Electric has purchased or for which the company has site control. During the pricing phase of the selection process one developer withdrew. The pricing evaluation was conducted during May 2017 and included interviews with each developer.

In early June 2017, Tampa Electric awarded the three-shortlisted full-service solar developers individual projects for sites that are planned for Tampa Electric's 600 MW of PV solar.

Tampa Electric and developers executed limited notice to proceed agreements in June 2017 for each site in the first two tranches to enable engineering and permitting to be initiated.

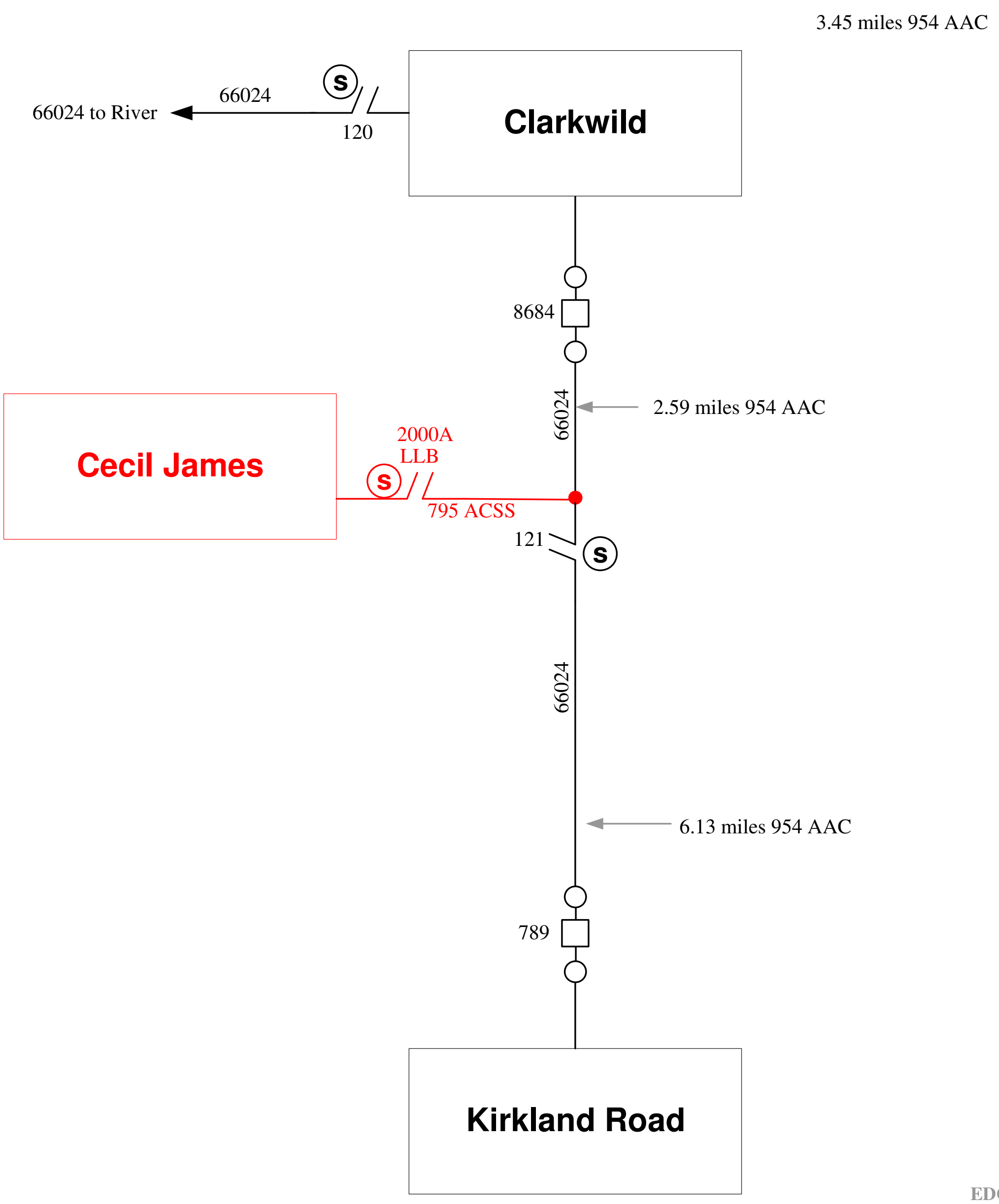
Tampa Electric expects to complete and execute the turn-key agreement for the first tranche projects in the month of October 2017.

Tampa Electric plans to negotiate and execute turn-key agreements for the remaining project tranches before the end of 2017.

The RFI used by the company is included as an attachment to this response.

TITLE: Cecil James Solar Facility	**2018**
DESCR: Tap circuit 66024 to connect to new Meter Station for Cecil James Solar Facility. Install a 2000A LLB supervisory transmission line switch on Circuit 66024 north of new tap.	**IN SVC BY:** **Jun** **See Construction Schedule**
NOTES: Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels	

Color Specifications:
Black: Existing Construction
Red: Proposed Construction



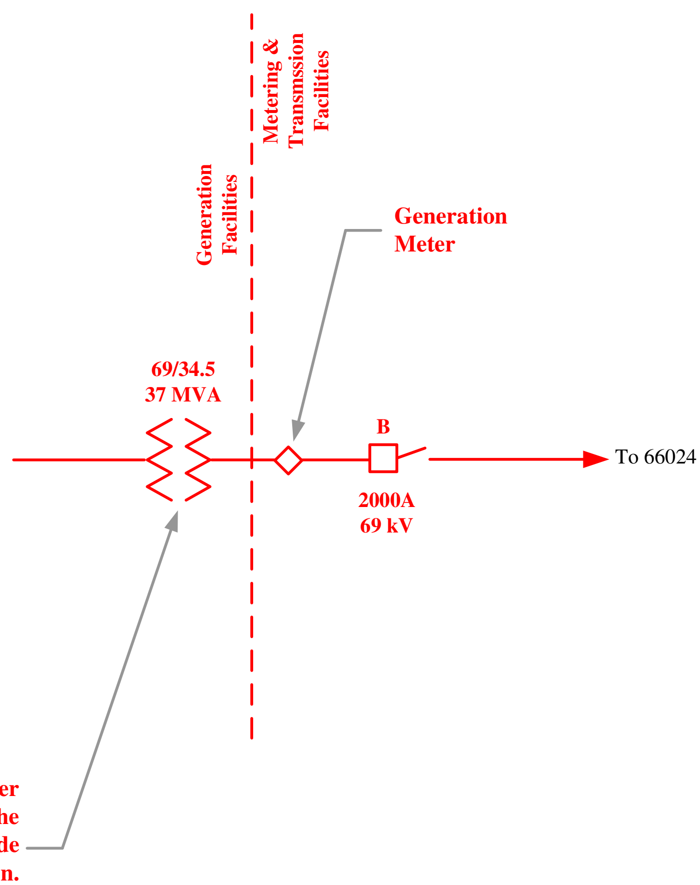
EDCP: PCA

TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:	ESTIMATE #: **1960.000**	**T**
	SUB #: ISSUE DATE: **04/18/2017**	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM		

TITLE: Cecil James Solar Facility	**2018**
DESCR: Metering station contains a 69/34.5 kV 37 MVA transformer. A 69 kV generation meter, CTs, PTs and 69 kV 2000A circuit switcher will also be installed in station.	**IN SVC BY:** **Jun** See Construction Schedule
NOTES: Cecil James Solar Facility will be tapped off 69 kV circuit 66024 and is expected to have an output of 33MW	N

Color Specifications:
Black: Existing Construction
Red: Proposed Construction

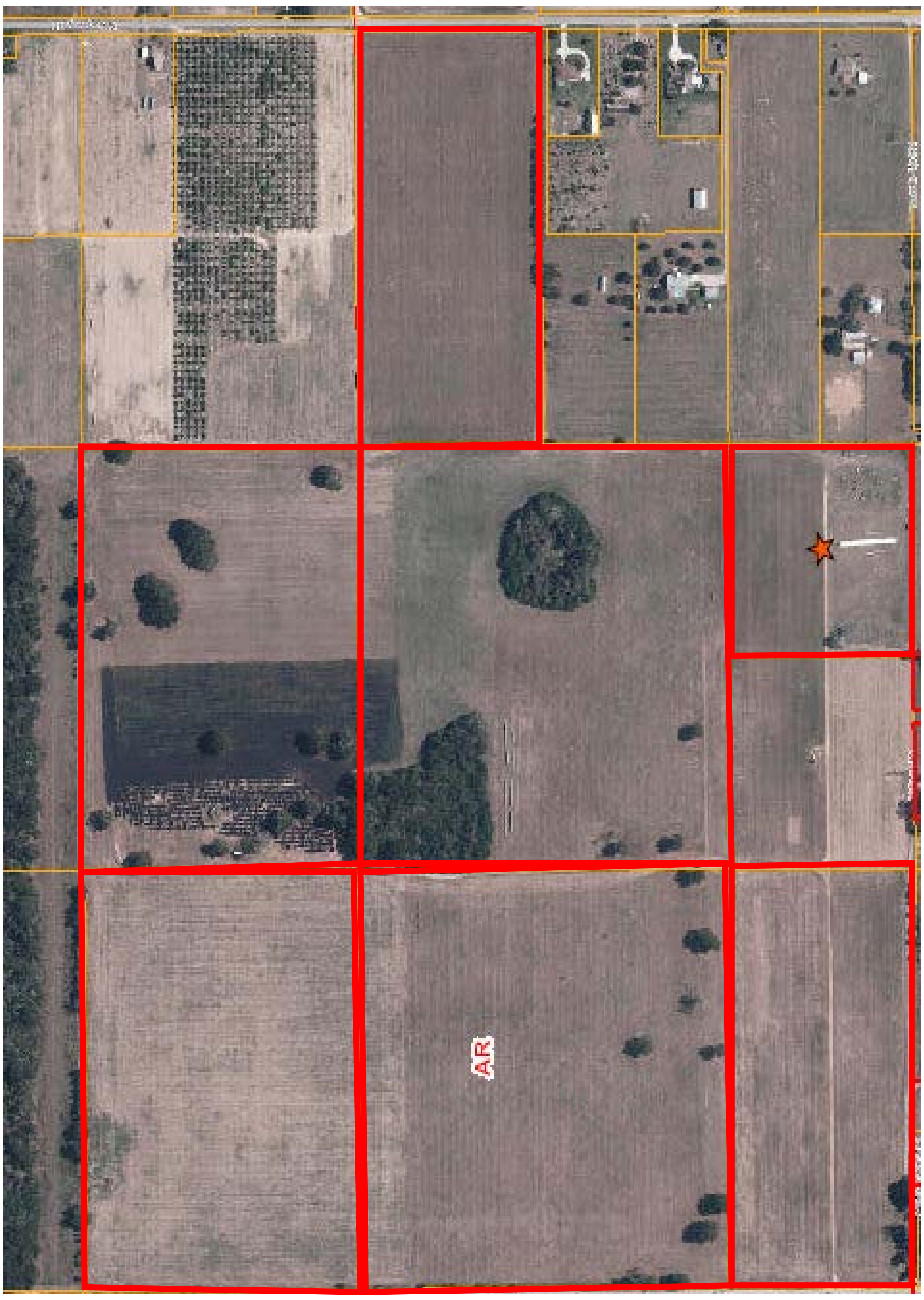
Cecil James



EDCP: PCA

TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:	ESTIMATE #: **1960.000**	**S**
	SUB #: ISSUE DATE: **04/18/2017**	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM		

Cecile B. James, Nancy Burnett and John W. James Jr.
199± Acres on Saddle Up Road
Existing Land Use - AR



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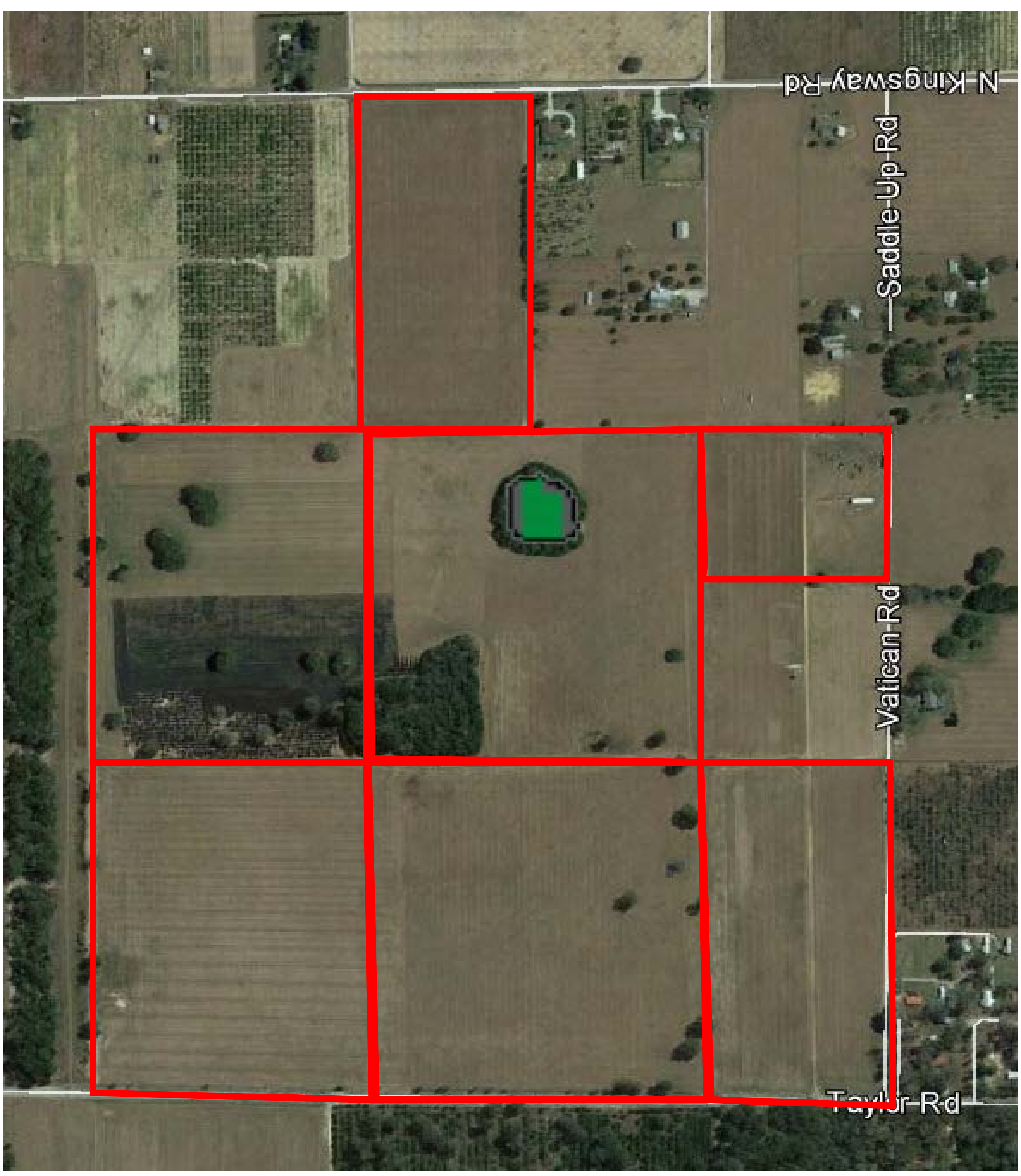
Cecile B. James, Nancy Burnett and John W. James Jr.
199± Acres on Saddle Up Road
Potential Wetlands Area



NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

DUE DILIGENCE REPORT

CECIL B. JAMES PROPERTY
SADDLE UP ROAD
THONOTOSASSA, HILLSBOROUGH COUNTY, FLORIDA

Prepared for:

SLA 75, LLC

Prepared by:

ECT Environmental Consulting & Technology, Inc.

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ECT No. 170265-0100

May 24, 2017

TABLE OF CONTENTS

DUE DILIGENCE

LAND USE PLANNING

Jurisdiction

The Cecil B. James property (also referred to as the subject property or the property) is located in the Thonotosassa area of unincorporated Hillsborough County. The subject property is located in the Thonotosassa Community Plan, according to the Livable Communities Element of the Hillsborough County Comprehensive Plan. There do not appear to be any goals or policies of the Community Plan that would potentially impact the construction and operation of a solar farm.

Hillsborough County Future Land Use Map (FLUM) Designation

The Future Land Use Map (FLUM) land use designation of the subject property is Agricultural/Rural-1/5 (AR-1/5) and Residential-1 (RES-1). The AR-1/5 land use designation allows up to one dwelling unit per five acres. Typical uses are identified as farms, ranches, residential uses, neighborhood commercial uses, office uses, and industrial uses related to agricultural uses. The specific intent of the land use category is to designate areas of agricultural uses or other rural uses. Solar farms are not listed as a use in the AR-1/5 land use designation. The RES-1 land use designation allows up to one dwelling unit per acre. Typical uses are identified as farms, ranches, residential uses, neighborhood commercial uses, office uses, and multi-purpose uses. The specific intent of the land use category is to designate areas for rural residential use compatible with short term agricultural uses. Solar farms are not listed as a use in the RES-1 land use designation.

Adjacent land use categories are:

- AR-1/5 to the north, east, and south; and
- Residential-2 to the west.

The subject property is not located within the Urban Service Area and it is not shown as overlain by major wetlands or significant wildlife habitat.

The Comprehensive Plan has a series of maps within the Future Land Use, Transportation, and Conservation Elements, among others. A review of the applicable maps indicates the following:

- The property does not appear to be located within the 100-year floodplain.
- There are no historic structures or archaeological resources shown onsite.
- Kingsway Road is identified as a scenic corridor.
- Kingsway Road, along the eastern property boundary, is currently identified as a local road and as a 2-lane road on the 2025 Corridor Preservation Plan.
- An extension of Joe Ebert Road (to the west) connecting to McIntosh Road (to the east) is shown transecting the subject property as a 2-lane road on the 2025 Corridor Preservation Plan.
- The subject property is not shown as a natural recharge area.
- The subject property is not located in a wellfield resource protection area.
- The subject property is not identified as environmentally sensitive relative to wetlands, natural systems, strategic habitat, and surface water protection areas.

Development of the subject property is potentially impacted by the planned 2-lane roadway extension across the southern portion. A typical section for a 2-lane, undivided, rural road depicts a minimum 96-foot right-of-way, according to the Hillsborough County Transportation Technical Manual (2015). Adjacent development is restricted to up to two dwelling units per acre to the west and one unit per five acres to the north, east, and south.

Hillsborough County Zoning District

The subject property is located in the Agricultural Rural (AR) zoning district. The purpose of the AR zoning district is to protect viable long-term agricultural lands from urban and suburban encroachment by encouraging agricultural and related uses. Solar energy production is listed as a conditional use.

The adjacent zoning district in all directions is AR. A Planned Development (PD 05-0960) is identified north of the transmission line corridor.

Existing Land Uses

The subject property is currently undeveloped and used as hay production.

The adjacent land uses are:

- Undeveloped transmission line corridor to the north followed by undeveloped land or land in agricultural use;
- Undeveloped land and land in agricultural use to the west;
- Residences and agricultural uses to the south; and
- Residences and agricultural uses to the east.

Discussion

While the Future Land Use Element of the Comprehensive Plan addresses electrical power generation facilities, the Land Development Code excludes solar generation less than 75 megawatts from the definition of electrical power generation facilities. The only land use category that lists solar farms as a typical use is Energy Industrial Park. The proposed use (solar energy generation) is not compatible with this land use category because at least two renewable energy technologies are required.

The proposed solar energy use can be accommodated within the existing land use category of AR-1/5 since the AR zoning district allows this use as a conditional use. A FLUM amendment and a rezoning are not required.

The Hillsborough County Land Development Code allows solar energy production facility as a conditional use. The conditional use standards for this use are:

Sec. 6.11.125. - Solar Energy Production Facility

A. In agricultural zoning districts, the host parcel shall be a minimum of five acres in size.

B. In agricultural zoning districts, a minimum setback of 50 feet shall be required from all boundaries of the site. This setback shall apply to all solar panels and other above-ground structures excluding transmission line poles.

1. In the M (Manufacturing) district, solar panels and other above-ground structures excluding transmission line poles shall conform with principal structure setback requirements.

C. In agricultural zoning districts, the solar panels shall be ground mounted and have a maximum height of 15 feet as measured when the panels are tilted to the design degree that creates the greatest overall height. All other structures shall conform with principal structure height requirements of this Code.

   1. In the M district, all structures including solar panels shall conform with principal structure height requirements of this Code.

D. Ground-mounted facilities shall be enclosed with a security fence with a minimum height of six feet to discourage unauthorized entry. The fence location and maximum height shall comply with the requirements of this Code. Clearly visible warning signs shall be placed on the fence and/or site perimeter advising of potential high voltage hazards.

E. In agricultural zoning districts, the facility shall be classified a Group 1 use for buffering and screening purposes under this Code. In the M district, ground-mounted facilities shall be classified a Group 6 use; however, buffering and screening shall be required only where abutting parcels have a Group 3 or lower intensity classification. Building-mounted facilities shall have the same intensity classification as the host use.

F. Where ground-mounted solar panels face abutting residentially developed or zoned parcels or public roadways and screening is not otherwise required under the provisions of this Code, the panels shall be made of glare reducing materials or shall be visually screened from said abutting parcels and roadways as follows:

   1. In agricultural districts, the screening shall be comprised of evergreen plants with a minimum opacity of 75 percent at the time of planting. The plants shall be six feet in height or the height of the solar panels, whichever is less. Alternatively, an increased setback of 100 feet may be provided in lieu of screening.
   2. In the M district, the screening shall be comprised of a solid fence or wall, chain link fence with opaque slates, or evergreen plants with a minimum opacity of 75

percent at the time of planting. The screening shall be six feet in height or the height of the solar panels, whichever is less.

The Administrator may waive these screening requirements in cases where equivalent or greater screening is provided by existing vegetation, fences or non-residential structures on the host parcel and/or abutting residential parcels or roadways.

G. Onsite power lines and interconnections shall be placed underground to the greatest extent possible.

H. Prior to preliminary site plan approval or construction plan where the preliminary process is waived, the applicant shall submit proof of notice to the utility company that operates the power grid where the solar energy production facility will be located of the intent to develop an interconnected power generation facility. Prior to site construction plan approval, the applicant shall submit proof of an executed interconnection agreement with the utility or other written proof of an agreement with the utility that construction can proceed.

I. A solar energy production facility shall be considered abandoned after a one-year period without energy production. The property owner shall be responsible for removing all energy production and transmission equipment and appurtenances within 120 days of abandonment.

J. Solar power generation facilities, which require certification under the Florida Electrical Power Plant Siting Act shall be allowed only in Planned Development districts, which specifically permit the use.

The applicable regulations are a minimum 50-foot setback from all property boundaries, a maximum height of 15 feet, security fencing along the perimeter and screening or a 100-foot setback along all perimeters. Due to the potential for a new road to be built across the subject property, an additional 50-foot setback may be required from both sides of the required 96-foot right-of-way.

ECOLOGICAL FINDINGS

An ecological assessment of the subject property (Figure 1) was conducted to determine the likelihood of the presence of listed floral and faunal species and to delineate and describe existing upland and wetland plant communities.

Desktop Review

Initially, a desktop review was conducted consisting of readily available information including recent aerial photography, the Soil Survey of Hillsborough County, Florida map (Figure 2), and the National Wetlands Inventory (NWI) map (Figure 3). An initial "aerial signature" map was created using aerial photo-interpretation. After the field survey of the subject property, a final map depicting the plant communities and land use was completed using the *Florida Land Use, Cover, and Forms Classification System* (FLUCFCS), Level III, of the Florida Department of Transportation (1999). The land covers and uses on the map were cross-referenced with the *Guide to the Natural Communities of Florida*, 2010 Edition, Florida Natural Areas Inventory (FNAI). The database of the FNAI was accessed for Hillsborough County to review the listed animals, plants, and plant communities that could potentially occur within or in the vicinity of the subject property. The *Atlas of Florida Vascular Plants*, Institute for Systematic Botany, University of South Florida, was consulted for the proper plant species taxonomic nomenclature. The *UF Digital Collections* of George A. Smathers Libraries with the University of Florida was searched for historic aerial photographs of the land. The Florida Fish and Wildlife Conservation Commission (FWC) Water Bird Colony Locator and Bald Eagle Nest Locator were accessed for the occurrence of any documented wading bird rookeries or bald eagle nest sites within the surrounding area.

Field Survey

On April 12, 2017, Environmental Consulting & Technology, Inc. (ECT) conducted a field survey of the 199.04-acre subject property. The purpose of the survey was to identify existing upland and wetland habitats and their constituent species and search for the presence of any state and/or federally listed plant or animal species. The field survey was performed by an ECT ecologist by slowly traversing the more accessible areas of the property by vehicle and conducting pedestrian transects where vegetation or terrain made it necessary. It was warm, partly cloudy, and breezy during the survey. The following sections describe the vegetation and land use, wildlife, and listed species found at the subject property.

Results-Vegetation and Land Use

Land use and cover maps were prepared prior to the field inspection and, based on FLUCFCS Level III mapping, were modified to more accurately depict the conditions observed in the field. Special emphasis was placed upon searching for listed plants and animal species reported by the FNAI database for Hillsborough County. All plants and animals listed by the various agencies for the State of Florida and the U.S. Fish and Wildlife Service were sought based upon preferred habitat availability on the subject property. A description and quality assessment of each habitat type was recorded.

Figure 4 is a land use and vegetative cover map depicting the habitat types and land uses by FLUCFCS codes observed on the subject property. The use of the FLUCFCS 600 codes does not imply formal wetland jurisdictional lines. The delineations of land cover and use types were done by aerial photointerpretation, direct observation, and the use of other available data resources such as the NWI map and the Soil Survey of Hillsborough County, Florida (i.e., Figures 2 and3, respectively). Land use and cover types were mapped and classified into 6 FLUCFCS categories— 215-Field Crops (Hay) (189.27-acres), 260-other open lands, rural (1.79-acres), 425-temperate hardwoods (5.15-acres), 618-willow and elderberry (0.53-acre), 643-wet prairies (1.11-acres), and 814-access roads (1.19-acres).

The following is a brief description of each FLUCFCS plant community type or land use that occurs on the subject property. Dominant plant species are listed in the descriptions.

200 AGRICULTURE

215 Field Crops (FNAI: Agriculture) – Field crops generally refer to crops raised for grains or animal forage (grasses). The hayfields on the Cecil B. James property consist of two varieties of bermudagrass (*Cynodon dactylon* vars. Florakirk and Tifton 44) selected for horses and cattle. During the growing season, the fields are harvested about every 6 weeks and dried for baling. Approximately

95 percent of the subject property land use is hayfields. Very minor constituents of the hayfields include bahiagrass (*Paspalum notatum*), cutleaf evening primrose (*Oenothera lacinata*), Mexican clover (*Richardia brasiliensis*), dock (*Rumex fascicularis*), and pepperweed (*Lepidium virginicum*). Scattered live oaks (*Quercus virginiana*) are present in the hayfields.

260 Other Open Lands, Rural (FNAI: Agriculture) – This category generally refers to rural land with undetermined use. On the Cecil B. James property, this category is used for a small portion of land used for storing farm equipment, staging maintenance/harvesting, loading trucks, and other support activities (referred to as the compound). Vegetation in this area is generally similar to the hayfields.

400 UPLAND FORESTS

425 Temperate Hardwoods (FNAI: Mesic Hammock) – Temperate hardwoods is a general term referring to any species of broadleaf trees that shed their leaves on an annual basis. On the subject property, two areas have recruited a mix of broadleaf trees. The first area is a ring of trees surrounding a relic sinkhole; the second is near the center of the tract where trees became established in a remnant of citrus grove. Both areas contain a mix of native and exotic (non-native) species. Native trees include live oak, laurel oak (*Quercus laurifolia*), elm (*Ulmus americana*), black cherry (*Prunus serotina*), cabbage palm (*Sabal palmetto*), and red mulberry (*Morus rubra*). The primary non-native plant species is an invasive tree species, chinaberry (*Melia azedarach*), which is listed on the Florida Exotic Pest Plant Council invasive plant species list. A few loquat (*Eriobotrya japonica*) and other weedy trees were also observed.

600 WETLANDS

618 Willow and Elderberry (FNAI: Sinkhole) — A relic sinkhole on the property apparently holds water during seasonal rainfall. Stain lines indicate about eight feet of inundation. Historic aerial photographs show that in the 1930s and 1940s, the sinkhole looked more like a lake or pond in that no trees existed in or around it. Currently, the bottom of the sinkhole is concave and non-vegetated indicating extended periods of inundation which prevents the establishment of wetland plant species. Coastalplain willow (*Salix caroliniana*) and elderberry (*Sambucus nigra* subsp. *canadensis*) have established on the lower slopes as well as maiden fern (*Thelypteris kunthii*) and guineagrass (*Urochloa maxima*). Considerable vine cover and deadfall and some debris are present.

643 Wet Prairies (FNAI: Wet Prairie) — This herbaceous wetland type has predominately grassy vegetation and is a depression between topographic highs. The area is ditched to drain to the north and offsite. The plant community of this area is composed of bahiagrass, flatsedges (*Cyperus* spp.) manyflower marshpennywort (*Hydrocotyle umbellata*) and dotted smartweed (*Persicaria punctata*).

800 TRANSPORTATION, COMMUNICATIONS AND UTILITIES

814 Roads and Highways (FNAI: Road) — a main unpaved, access road is present onsite connecting Taylor Road to the compound area.

Results-Wildlife

The majority of the highly altered subject property consists of bermudagrass hayfields. It is evident from the review of historic aerial photographs that citrus was the main crop for decades. Prior to clearing in the 1940s, the land appears to have been scrub or sandhill. During the site survey, there was very little wildlife present, except for several cattle egrets (*Bubulcus ibis*) foraging in the pasture. Mounds of fresh soil indicated that pocket gophers (*Geomys pinetus*) were ubiquitous throughout. There were some passerines such as tree swallows (*Tachycineta bicolor*) and American crows (*Corvus brachyrhynchos*) also present. Two gopher tortoise (*Gopherus polyphemus*) burrows were present, but damaged by digging. The property caretaker stated that a coyote (*Canis latrans*) had dug out the two gopher tortoise burrows and had used them as dens. There were few signs of other herpetofauna or mammals observed. The above-referenced wildlife species as well as others in the area have become adapted to the altered condition of the subject property and regional wildlife populations should not be significantly affected by the proposed activities.

Results-Listed Species

No state or federally listed plant or animal species were observed on the subject property. Continual agricultural activities over the past six to seven decades have displaced the native habitats and discouraged wildlife usage of the land. The closest documented bald eagle nest site found on the FWC Eagle Nest Locator is located approximately 2.06 miles to the north-northeast of the subject property (HL013; last active in 1997; last surveyed 2013); the closest most recently used bald eagle nest site is 2.44 miles to the northeast (HL052, known to be active in 2014; last surveyed in 2013). No eagle nest sites were observed on or near to the subject property. The FWC Water Bird Colony Locator indicates that the closest water bird colony is approximately 1.5 miles to the northeast of the subject property (Id #611169; FID 348; last surveyed in the 70s; unknown). The closest active colonies are 8.5 miles to the west-southwest (Id #611308; FID 360; last surveyed in the 1990s) and seven miles to the southeast (Id # 615330; FID 585; last surveyed in the 1990s) The closest wood stork colony was recorded as being approximately 11 miles northwest of the subject property (i.e., Id #611310; last surveyed as active in the 90s; containing double-crested cormorants [*Phalacrocorax auritus*], wood storks [*Mycteria americana*], great egrets [*Ardea alba*], and brown pelicans [*Pelecanus occidentalis*]; 250 to 500 birds). No water bird colonies were observed on or in the immediate vicinity of the subject property.

The FNAI Species Tracking List identified 17 listed plants and 27 listed animals (one fish, 10 reptiles, 14 birds, and two mammals) as occurring within Hillsborough County, Florida. The potential for occurrence of the listed species on the subject property was determined by a habitat analysis, literature review, and ground surveys. Based upon an evaluation of habitat preference and distribution of species, out of the 44 listed plant and animal species recorded for Hillsborough County, Florida, four listed animal species (two reptiles and two birds) and two delisted, but still protected bird species, were identified as expected or possible to occur within or in proximity to the subject property (see Table 1). Based upon the detailed analysis and survey conducted, no adverse effects to federally or State listed threatened or endangered animal species are anticipated from the proposed action.

Summary

The subject property is in a highly altered condition with only marginal habitats to support wildlife. No listed plant or animal species have been identified on or in the immediate vicinity of the project site. Therefore, no adverse impacts are expected to local or regional populations of game species, species of special concern or commercial importance, or threatened or endangered species occurring or potentially occurring on or in the vicinity of the subject property. Less than one percent of the subject property is wetland and these areas are disturbed. Any project-related wetland impacts will require wetland permitting. There do not appear to be any major ecological issues that would result in denial of a wetland permit for construction, if the wetlands are to be developed or impacted.

TABLES

Table 1. Listed Wildlife Species Observed or Having Potential to Occur on the Cecil B. James Property

Species	Listed Status	Estimated Likelihood of Occurrence				
	State/Federal	Observed	Expected	Possible	Unlikely	Comments
Birds						
Florida Sandhill Crane *(Antigone* (*Grus) canadensis pratensis*)	ST/ U.S Migratory Bird Treaty Act		X			Hayfields offer forage, but sparse other resources nearby
Southeastern American Kestrel (*Falco sparverius paulus*)	ST		X			Open pastureland for hunting
Osprey (*Pandion haliaetus*)	Migratory Bird Treaty Act (16 U.S.C. 703-712) & Chapter 68A, F.A.C.		X			Ospreys are generally found near lakes and waterbodies in Florida
Bald eagle *(Haliaeetus leucocephalus)*	protected under 16 U.S.C. 668-668d		X			No large trees for nesting, but Lake Thonotosassa nearby for fishing.
Reptiles						
Eastern Indigo Snake (*Drymarchon couperi*)	FT			X		These snakes have large ranges and may be found in various uplands; GT commensal species
Gopher Tortoise (*Gopherus polyphemus*)	ST			X		Small area of upland soils, but habitat displaced by agriculture; 2 burrows destroyed by coyotes.

Wildlife: FE, FT - Federally listed as Endangered, Federally listed as Threatened, US Fish and Wildlife Service; **ST, SSC**- State listed as Threatened, State listed as Species of Special Concern.

Observed - animal or positive evidence of animal seen; **Expected** - Habitat present within animal's range, probable that animal would be observed; **Possible** - Habitat degraded, but animal may use on a limited basis; **Unlikely** - Habitat displaced, incidental use only by animal.

Table 2. Listed Plant Species Observed or Having Potential to Occur on the County Line Farms Property

Table 2. Listed Plant Species Observed or Having Potential to Occur on the Cecil B. James Property

Species	Listed Status	Estimated Likelihood of Occurrence				
	State/Federal	Observed	Expected	Possible	Unlikely	Comments
Plants						
Pine-woods Bluestem (*Andropogon arctatus*)	ST				X	Small area of xeric habitat, but impacted by cattle.
Sand Butterfly Pea *(Centrosema arenicola)*	SE			X		Habitat degraded by becoming overgrown; cattle present.
Florida Goldenaster (*Chrysopsis floridana*)	FE/SE			X		Habitat degraded by becoming overgrown; cattle present.
Tampa Vervain *(Glandularia tampensis)*	SE				X	Habitat degraded by becoming overgrown; cattle present.
Nodding Pinweed (*Lechea cernua*)	ST				X	Small area of xeric habitat, but impacted by cattle.
Giant Orchid (*Pteroglossaspis ecristata*)	ST				X	Infrequently, populations may persist in pastures.
Large-plumed Beaksedge (*Rhynchospora megaplumosa*)	SE				X	Small area of xeric habitat, but impacted by cattle.
Britton's Beargrass (*Nolina brittoniana*)	FE/SE				X	Small area of xeric habitat, but impacted by cattle.

Plants: SE, ST - State listed as Endangered or Threatened by the Florida Department of Agriculture Services, Division of Plant Industry; **FE, FT** - Federally listed as Endangered or Threatened

Observed - Positive ID plant seen; **Expected** - Habitat is appropriate for plant's range, probable that plant would be present; **Possible** - Habitat degraded, but plant may be found as a relict population; **Unlikely** - Habitat displaced, can no longer support life cycle of plant.

Printed on: 4/24/2017

P:\S2157_SLA 75, LLC\170265_Cecil James\6_Due Diligence\Tables 1_2Table 2

FIGURES

Q:\projects\Cecil_Property\170265\0200\Site_Location.mxd NAD 1983 StatePlane Florida West FIPS 0902 FeetTransverse Mercator jstebnisky 4/21/2017 2:13:04 PM

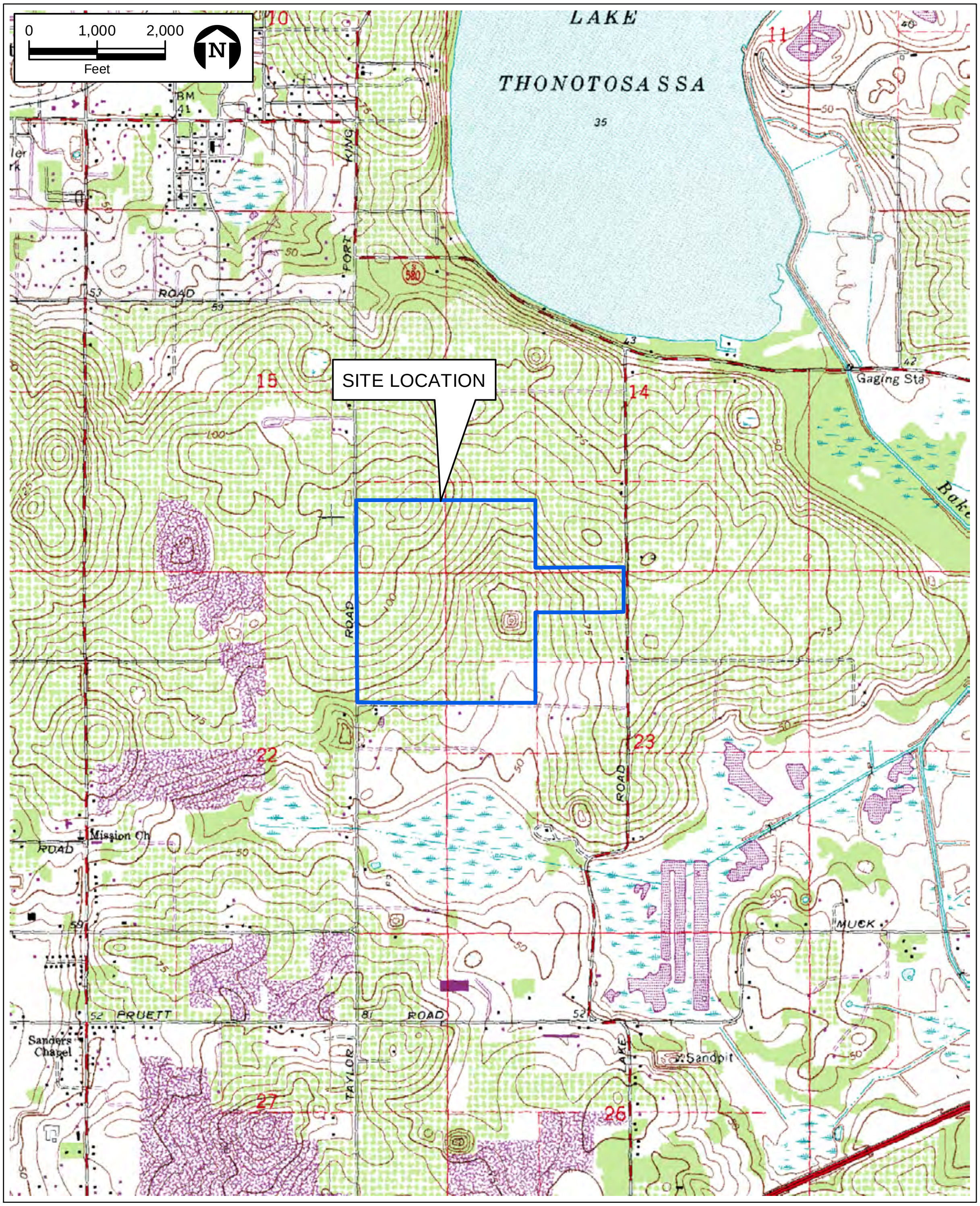
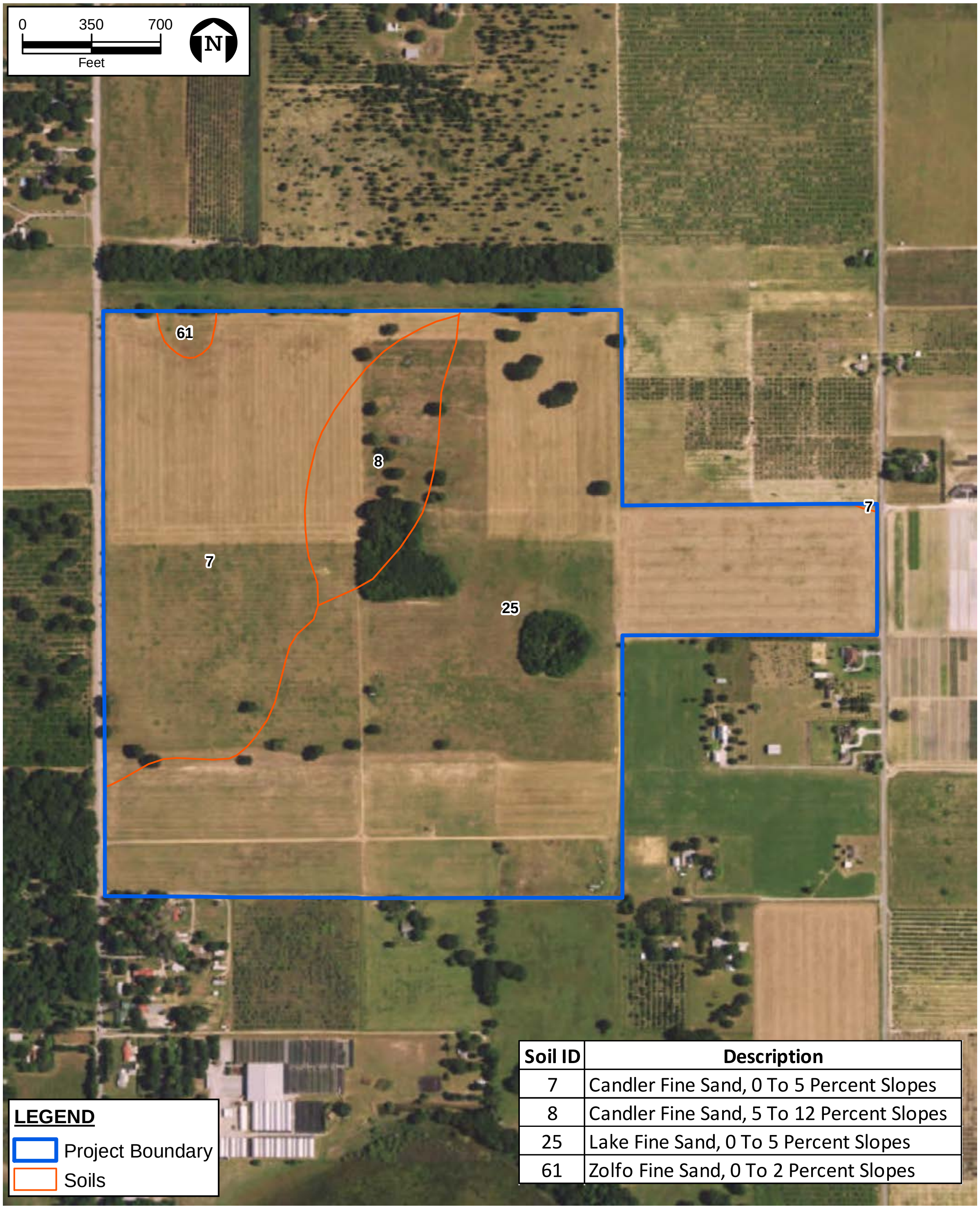


FIGURE 1.
SITE LOCATION MAP
CECIL B. JAMES PROPERTY
THONOTOSASSA, FLORIDA

Sources: Labins.org USGS Quad Map of Thonotosassa, FL, 1974; Hillsborough County PA, 2014; ECT, 2017.

ECT Environmental Consulting & Technology, Inc.

Q:\projects\Cecil_Property\170265\0200\Soils_map.mxd NAD 1983 StatePlane Florida West FIPS 0902 FeetTransverse Mercator jstebnisky 4/21/2017 4:05:13 PM



Soil ID	Description
7	Candler Fine Sand, 0 To 5 Percent Slopes
8	Candler Fine Sand, 5 To 12 Percent Slopes
25	Lake Fine Sand, 0 To 5 Percent Slopes
61	Zolfo Fine Sand, 0 To 2 Percent Slopes

FIGURE 2.
SOILS MAP
CECIL B. JAMES PROPERTY
THONOTOSASSA, FLORIDA

Sources: USDA FSA Aerial Photograph, 2015; NRCS, 2016; ECT, 2017.

ECT Environmental Consulting & Technology, Inc.

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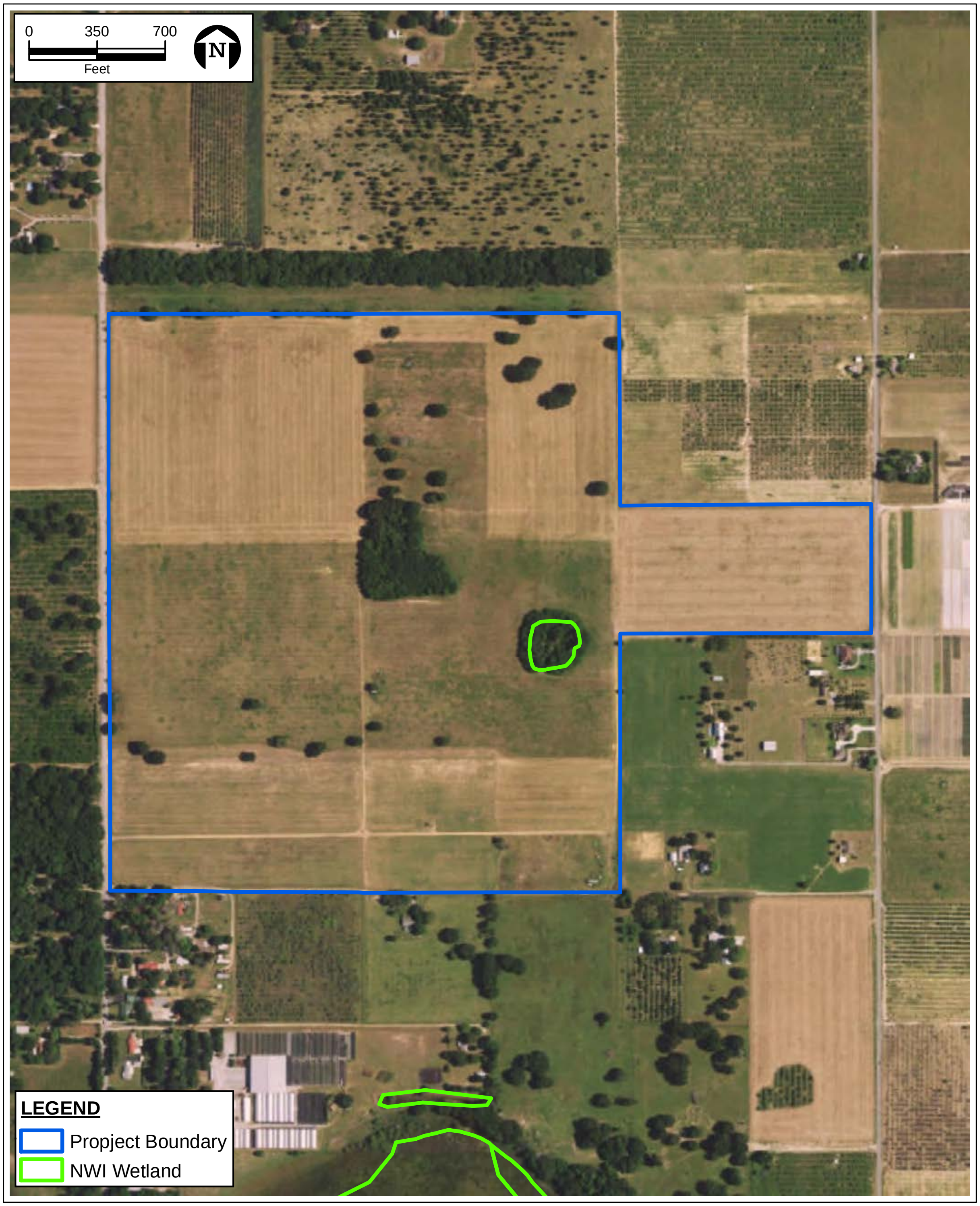

FIGURE 3.
NATIONAL WETLANDS INVENTORY MAP
CECIL B. JAMES PROPERTY
THONOTOSASSA, FLORIDA

Sources: USDA FSA Aerial Photograph, 2015; NWI, 2016; ECT, 2017.

ECT Environmental Consulting & Technology, Inc.

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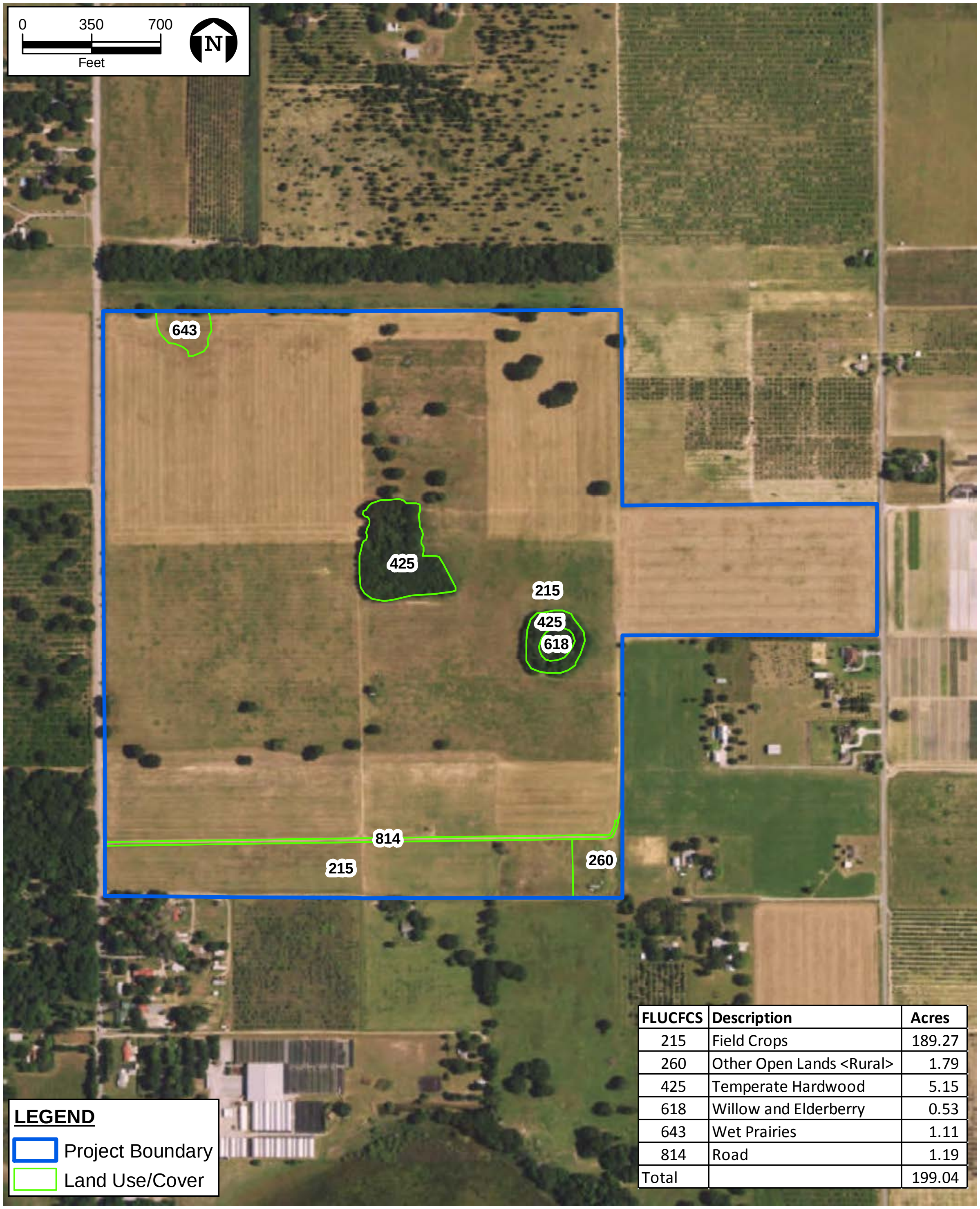


FLUCFCS	Description	Acres
215	Field Crops	189.27
260	Other Open Lands <Rural>	1.79
425	Temperate Hardwood	5.15
618	Willow and Elderberry	0.53
643	Wet Prairies	1.11
814	Road	1.19
Total		199.04

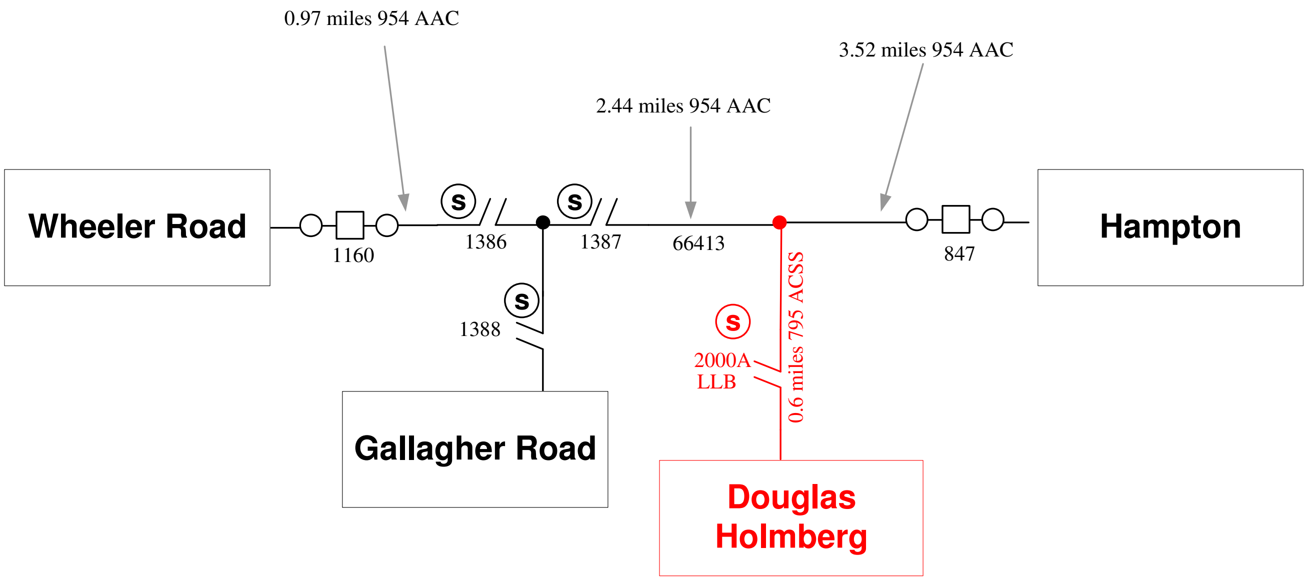
FIGURE 4.
LAND USE/COVER MAP
CECIL B. JAMES PROPERTY
THONOTOSASSA, FLORIDA

Sources: USDA FSA Aerial Photograph, 2015; ECT, 2017.

ECT Environmental Consulting & Technology, Inc.

TITLE: **Douglas Holmberg Solar Facility**	**2018**
DESCR: Tap circuit 66413 to connect to new Meter Station for Douglas Holmberg Solar Facility Install a 2000A LLB supervisory transmission line switch on Circuit 66413 north of new tap.	**IN SVC BY:** **Jun** **See Construction Schedule**
NOTES: Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels	N

Color Specifications:
Black: Existing Construction
Red: Proposed Construction



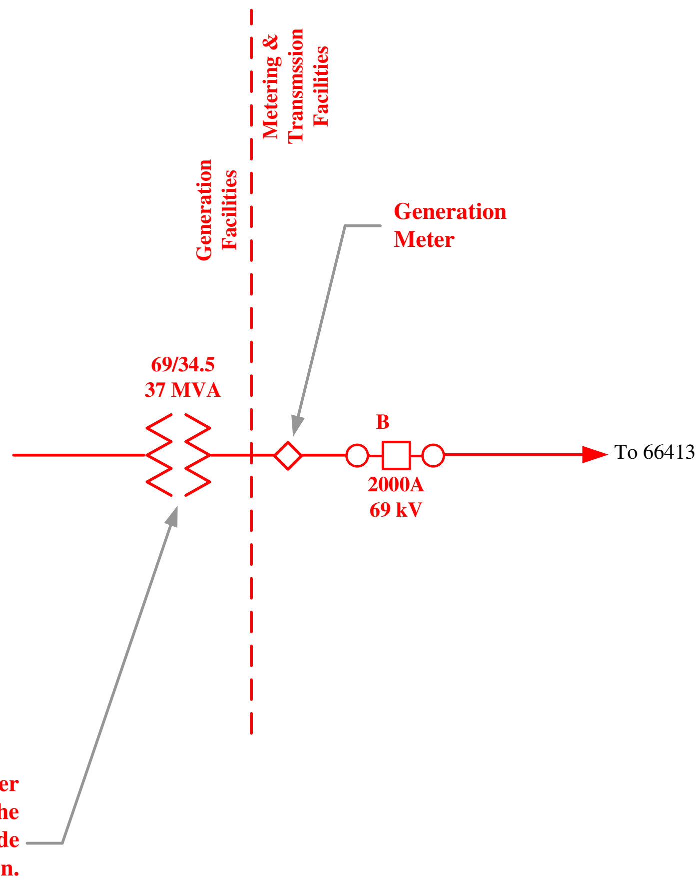
EDCP: PCA

IMPROVEMENT:		ESTIMATE #: **1964.000**	T
SUB #:	ISSUE DATE: **04/18/2017**	REVISION DATE:	
E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM			

TITLE: Douglas Holmberg Solar Facility	**2018**
DESCR: Metering station contains a 69/34.5 kV 37 MVA transformer. A 69 kV generation meter, CTs, PTs and 69 kV 2000A breaker will also be installed in station.	**IN SVC BY:** **Jun** **See Construction Schedule**
NOTES: Douglas Holmberg Solar Facility will be tapped off 69 kV circuit 66413 and is expected to have an output of 25MW	N

Color Specifications:
Black: Existing Construction
Red: Proposed Construction

Douglas Holmberg



EDCP: PCA

TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:	ESTIMATE #: **1964.000**	**S**
	SUB #: ISSUE DATE: **04/18/2017**	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM		

45

Holmberg
176± Acres on Sydney Washer Road
Aerial Photo Showing Topography

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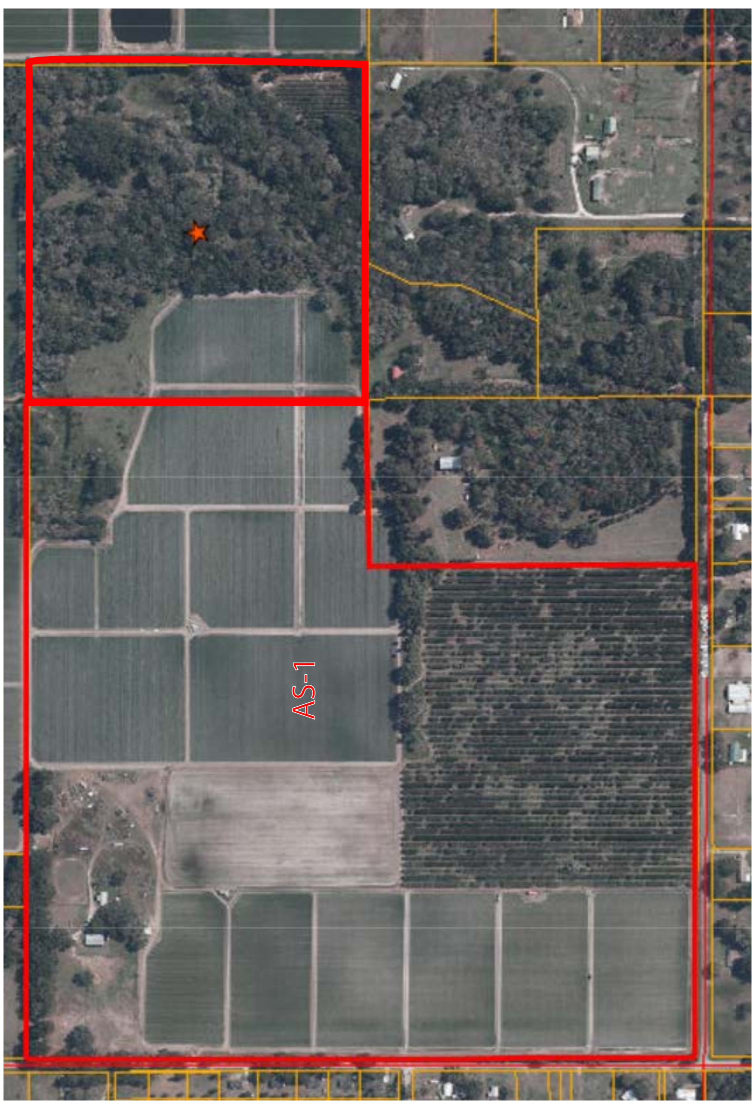
Holmberg
176± Acres on Sydney Washer Road
Existing Land Use - AS-1



Holmberg
176± Acres on Sydney Washer Road
Potential Wetlands Area

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INTERCONNECTION INFORMATION

Little Diehl:

Site is across the street from TEC's Gulf City substation

Construct 0.25 mile 69 kV line from site to substation

JayMar:

Polk-Aspen 2130kV (230401) line runs across property

Loop 230402 with a 3 position 230 kV ring buss at project site

Loop Farms:

Construct 3 miles 69kV line to intersect future Mines – Balm 69 kV substation

P2:

Construct 4 mile 69 kV line to tap into circuit 66658

Montesco:

Circuit 66603 runs across site

Loop/Tap 69 kV line at site

Cecil B James:

Circuit 66024 runs across site

Loop/Tap 69 kV line at site

Holmberg:

Construct 0.6 mile 69 kV line along road right of way and tap into circuit 66413

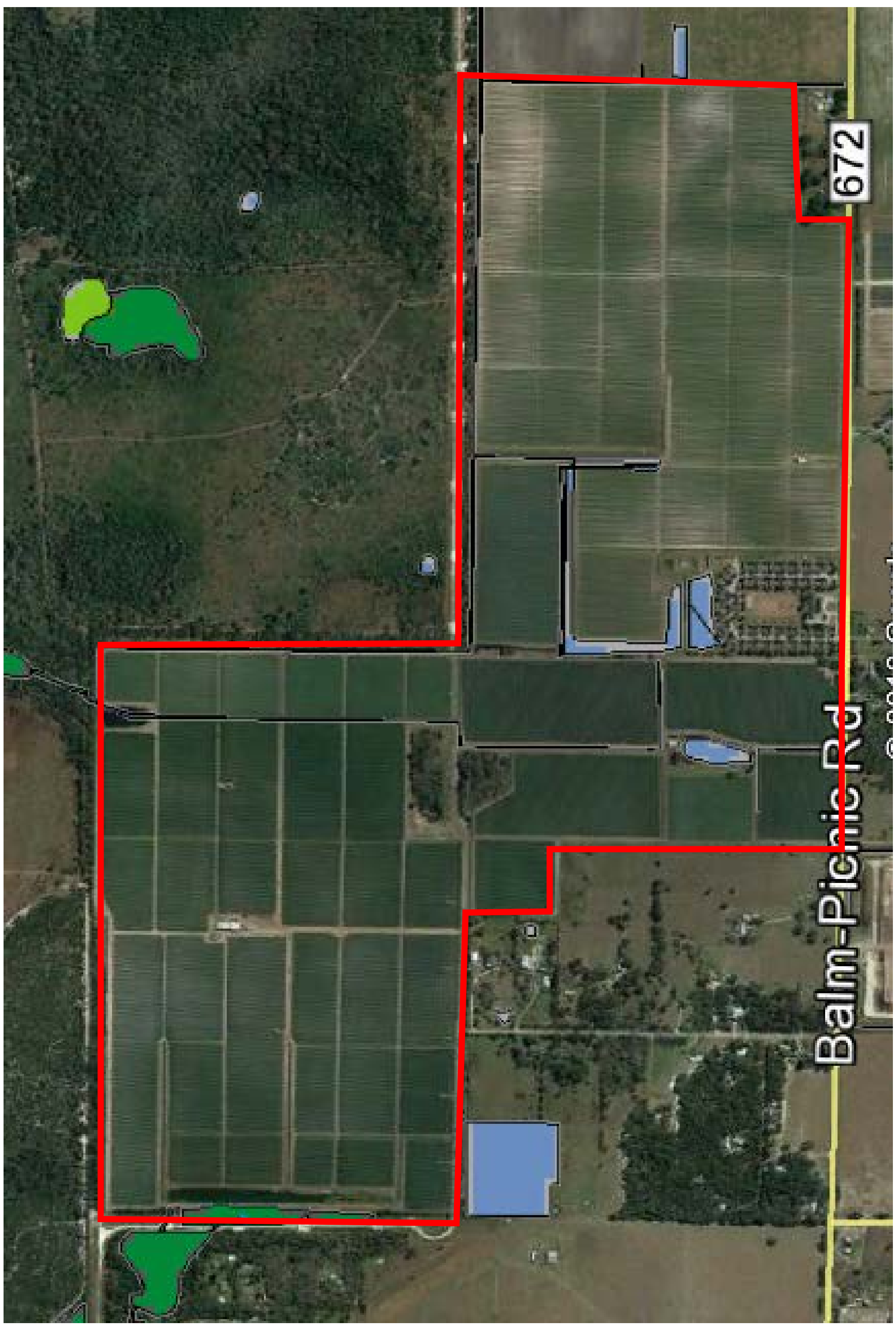
Jaymar Farms
554± Acres on Dupree Road
Aerial Photo Showing Topography

NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

Jaymar Farms
554± Acres on Dupree Road
Existing Land Use - AR

NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

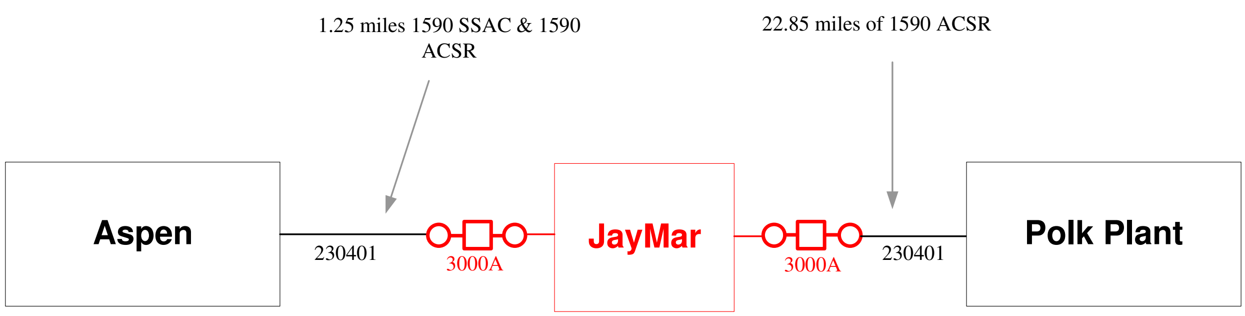
Jaymar Farms
554± Acres on Dupree Road
Potential Wetlands Area



NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

TITLE: **JayMar Solar Facility**	**2018**
DESCR: Loop 230401 into the JayMar Solar Site. A 4-position 230 kV ring-bus will be constructed at the project site to accommodate the interconnection. Any additional conductor used to loop the site in/out of 230401 shall not limit the ratings of 230401	**IN SVC BY:** **Jun** **See Construction Schedule**
NOTES: Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels	N

Color Specifications:
Black: Existing Construction
Red: Proposed Construction



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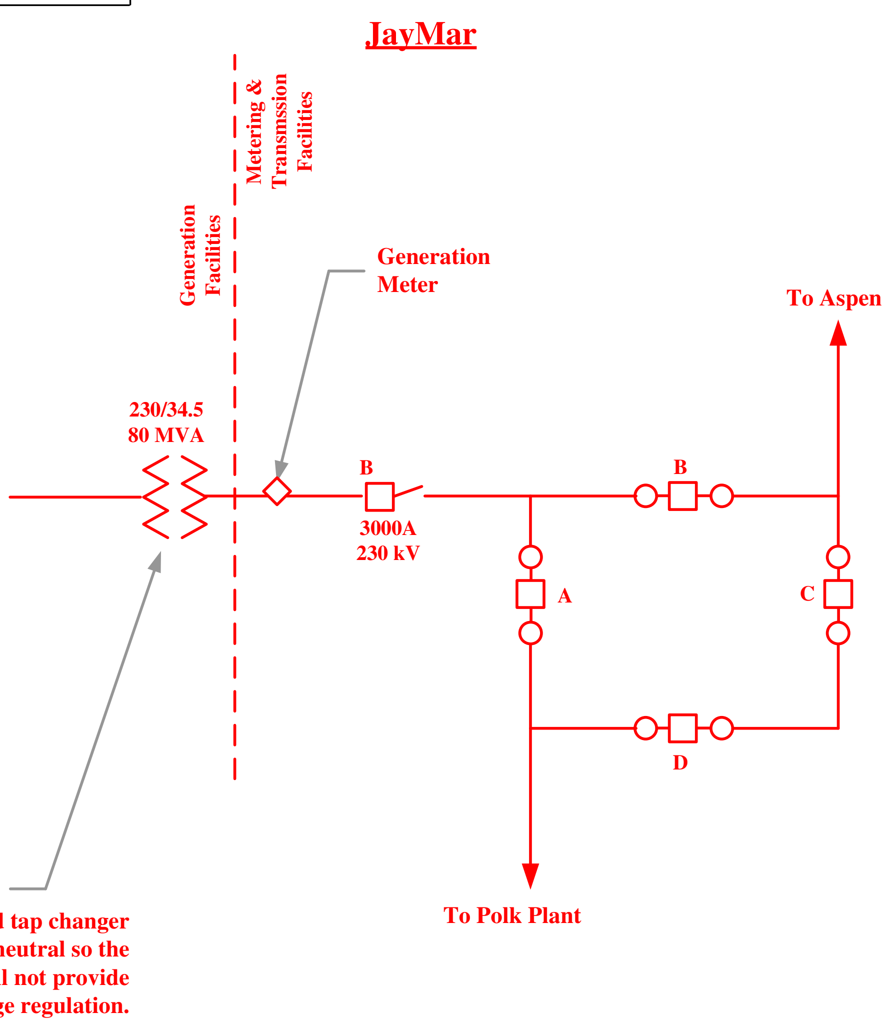
	SUB #: ISSUE DATE: **04/18/2017**	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM		

53

TITLE: JayMar Solar Facility	2018
DESCR: Metering station contains a 230/34.5 kV 80 MVA. A 230 kV generation meter, CTs, PTs and a 3000A, 230 kV circuit switcher and a 4-position ring-bus will be constructed. The breakers utilized shall be 3000A, 63kA with 3000A disconnects	IN SVC BY: Jun See Construction Schedule
NOTES: Aspen and Polk should not shall not share a common breaker to avoid a breaker failure taking both lines out of service.	N

Color Specifications:
Black: Existing Construction
Red: Proposed Construction



EDCP: PCA

TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:	ESTIMATE #: 1962.000	S
	SUB #: ISSUE DATE: 04/18/2017	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM		

54

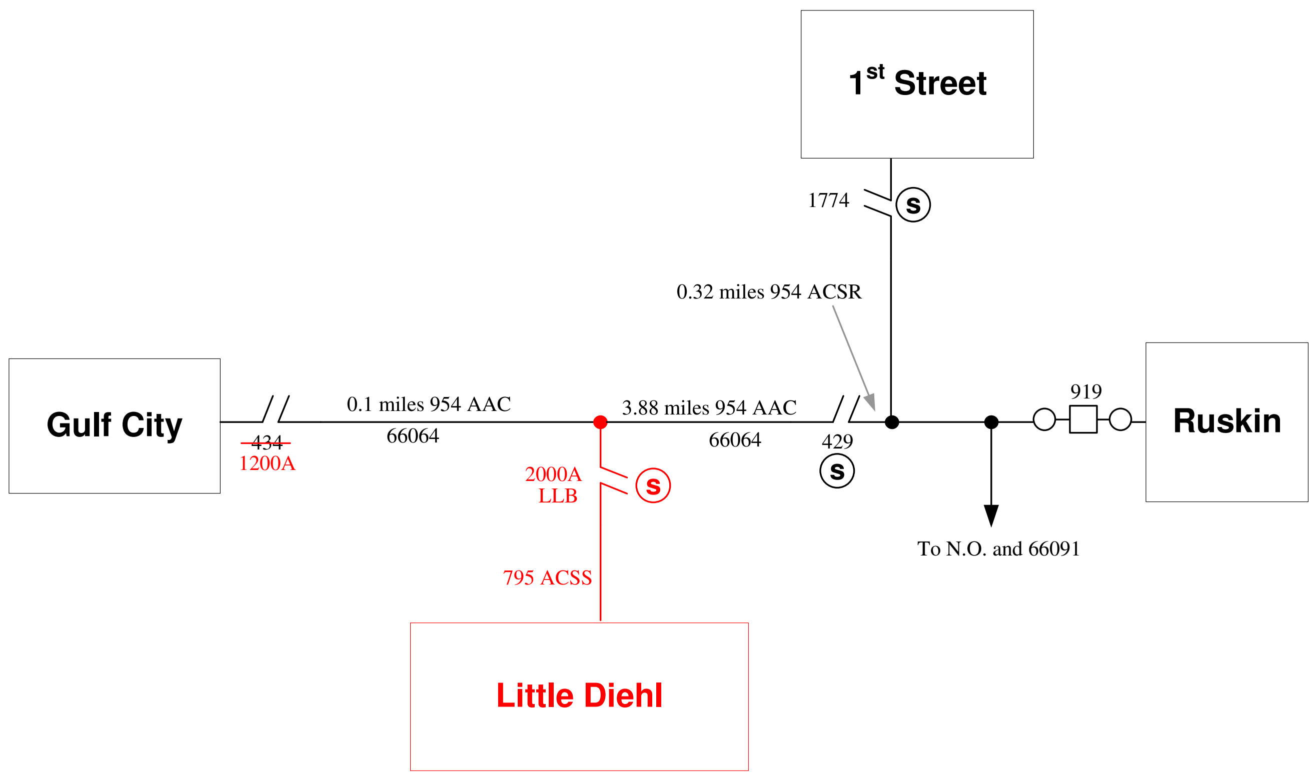
TITLE: **Little Diehl Solar Facility** | **2018**

DESCR: Tap circuit 66064 to connect to new Meter Station for Little Diehl Solar Facility
Install a 2000A LLB supervisory transmission line switch on Circuit 66064 north of new tap.

IN SVC BY: **Jun**
See Construction Schedule

NOTES: Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels

Color Specifications:
Black: Existing Construction
Red: Proposed Construction



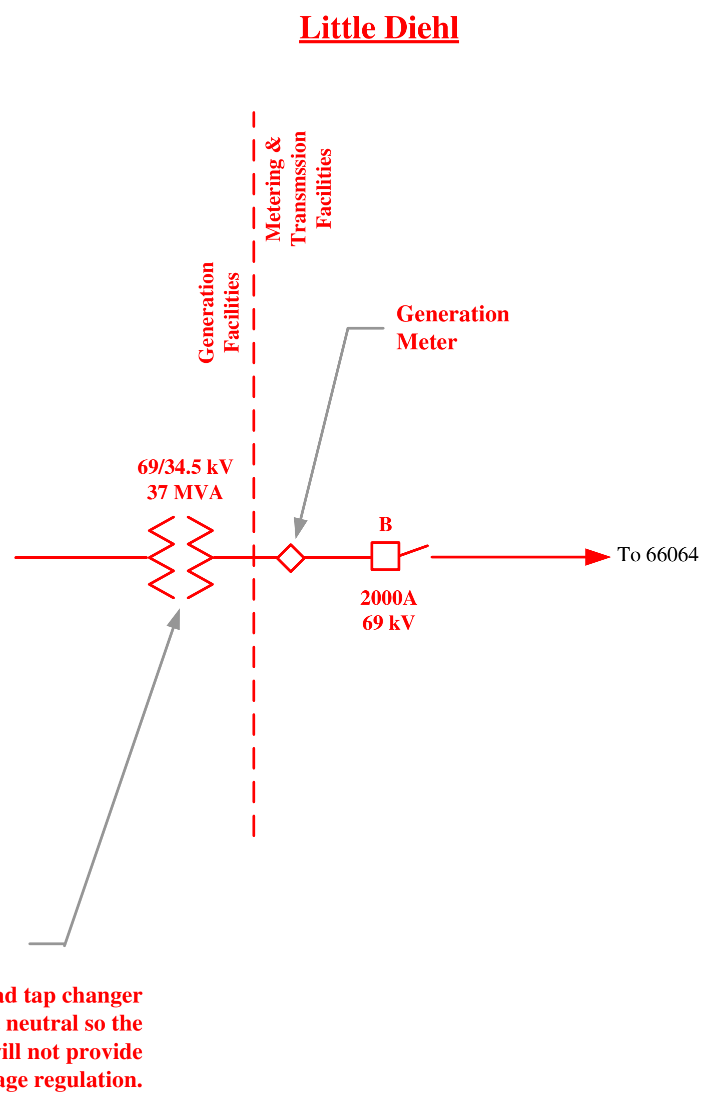
EDCP: SHA

TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:	ESTIMATE #: **1961.000**	**T**
	SUB #: ISSUE DATE: **04/18/2017**	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM		

55

TITLE: Little Diehl	2018
DESCR: Metering station contains a 69/34.5 kV 37 MVA transformer. A 69 kV generation meter, CTs, PTs and 69 kV 2000A circuit switcher will also be installed in station.	IN SVC BY: Jun See Construction Schedule
NOTES: Little Diehl Solar Facility will be tapped off 69 kV circuit 66064 and is expected to have an output of 21 MW	N

Color Specifications:
Black: Existing Construction
Red: Proposed Construction



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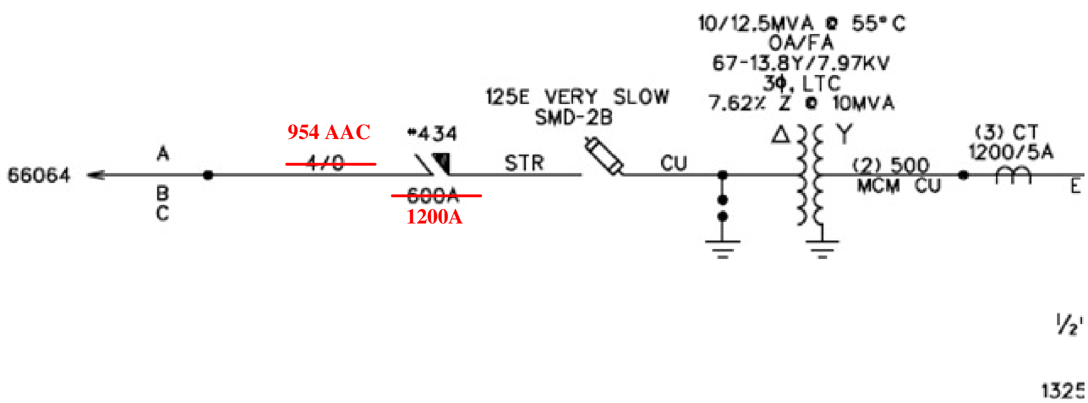
TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:		ESTIMATE #: 1961.000	S-1
	SUB #:	ISSUE DATE: 04/18/2017	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM			

TITLE: Little Diehl	2018
DESCR: Upgrade 4/0 string bus to 954 AAC and 600A switch # 434 to 1200A increasing the rating on First Street Tap – Gulf City to at least 1010A	IN SVC BY: Jun See Construction Schedule
NOTES: Little Diehl Solar Facility will be tapped off 69 kV circuit 66064 and is expected to have an output of 21 MW	

Color Specifications:
Black: Existing Construction
Red: Proposed Construction

Gulf City



EDCP: SHA

TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:		ESTIMATE #: 1961.000	S-2
	SUB #: 278D	ISSUE DATE: 04/18/2017	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM			

Frank Diehl
187± Acres on Old U.S. Highway 41
Aerial Photo Showing Topography

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Frank Diehl
187± Acres on Old U.S. Highway 41
Existing Land Use - AR

Frank Diehl
187± Acres on Old U.S. Highway 41
Potential Wetlands Area

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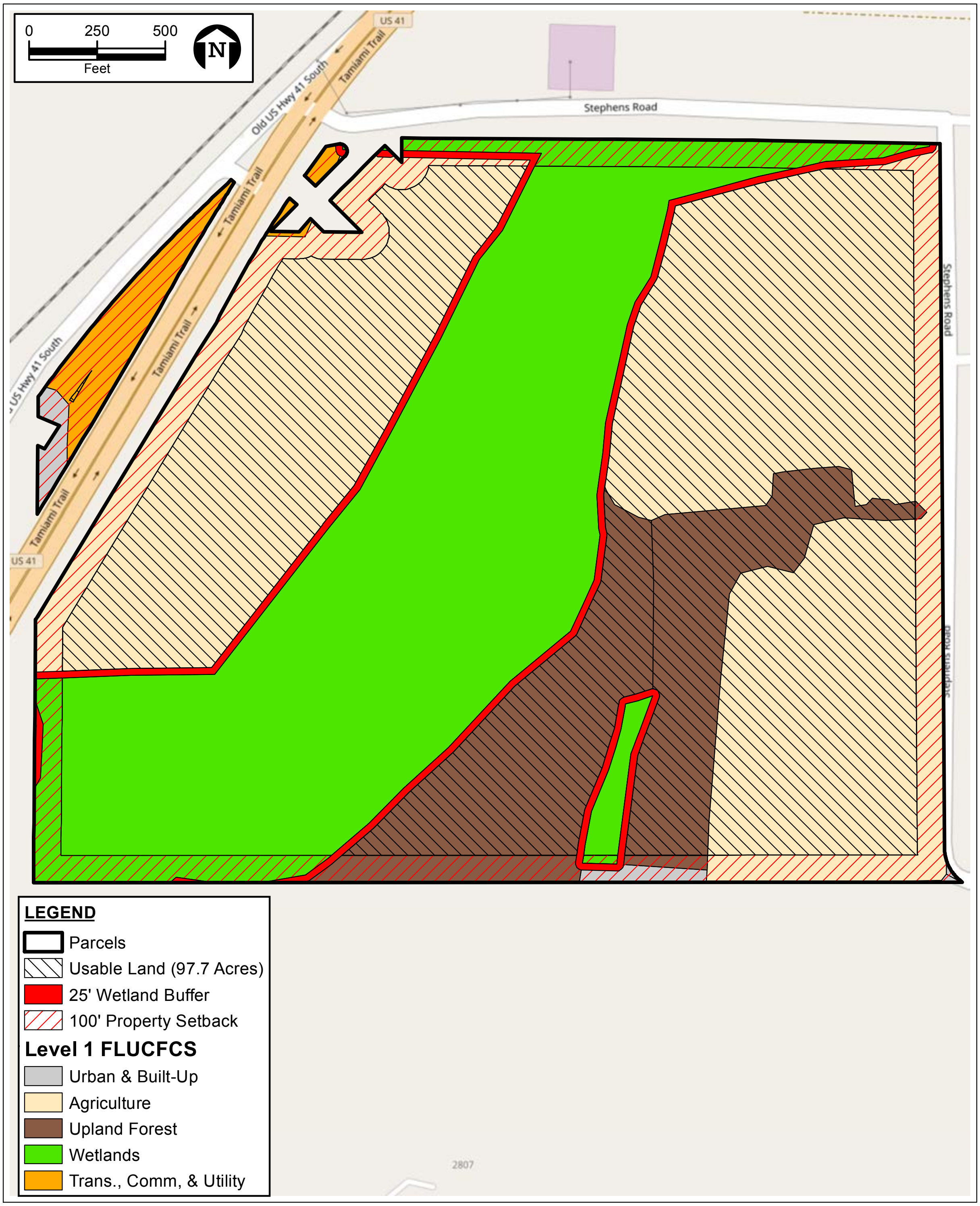
CONSTRAINT MAP WITH AERIAL
PARCEL NEAR SUN CITY
FLORIDA

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-EI
STAFF'S FIRST DATA REQUEST
FILED: OCTOBER 16, 2017

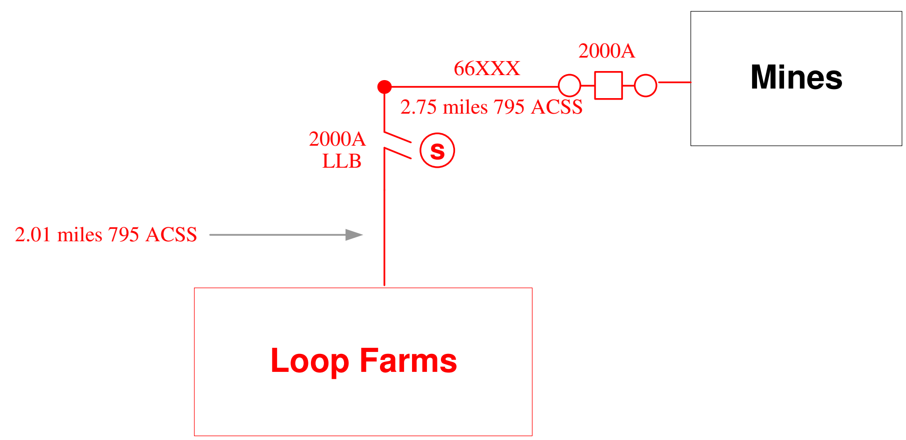
2/1/2017 3:35:24 PM



CONSTRAINT MAP
PARCEL NEAR SUN CITY
FLORIDA

TITLE: Loop Farms Solar Facility	**2018**
DESCR: Construct a new 69 kV circuit 66XXX from Mines substation ~ 2.75 miles west to the Loop Farms Tap. Install a 2000A LLB supervisory transmission line switch at the tap point and continue for another 2.01 miles to the Loop Farms Solar Facility.	**IN SVC BY:** **Jun** See Construction Schedule
NOTES: Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels	N

Color Specifications:
Black: Existing Construction
Red: Proposed Construction



EDCP: SHA

TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:	ESTIMATE #: **1963.000**	**T**
	SUB #: ISSUE DATE: **04/18/2017**	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM		

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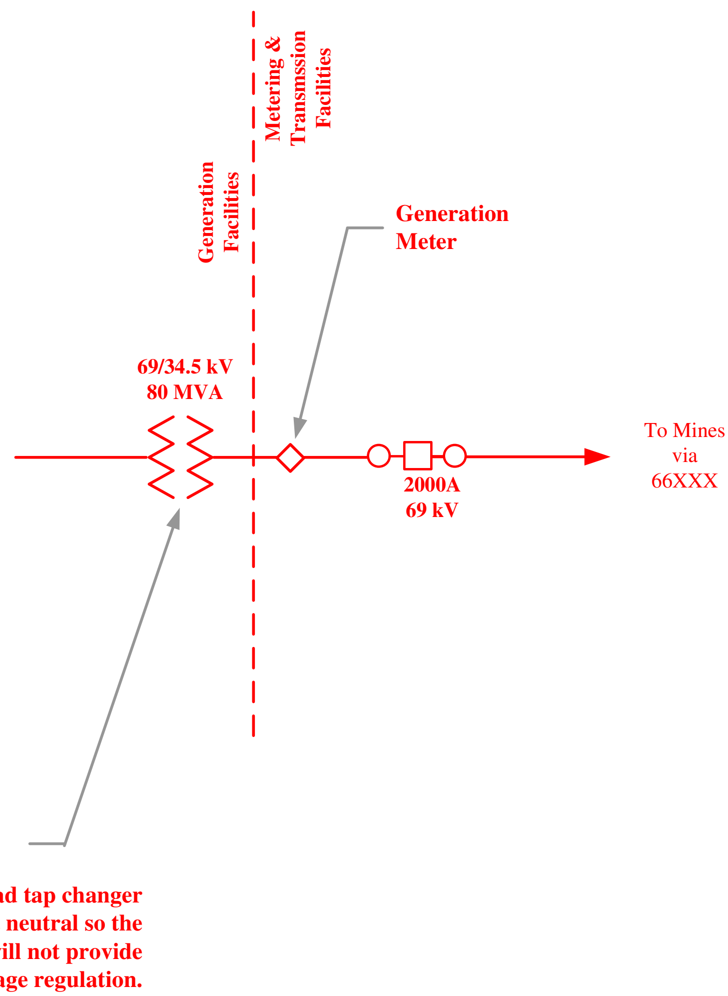
TAMPA ELECTRIC COMPANY
DOCKET NO. 20170210-EI
DOCKET NO. 20160160-EI
STAFF'S FIRST DATA REQUEST
FILED: OCTOBER 16, 2017

TITLE: **Loop Farms Solar Facility**	**2018**
DESCR: Metering station contains a 69/34.5 kV 80 MVA transformer. A 69 kV generation meter, CTs, PTs and 69 kV 2000A kV breaker will also be installed at the station.	**IN SVC BY:** **Jun** **See Construction Schedule**
NOTES: Loop Farms Solar Facility will have an expected output of 61 MW	N

Color Specifications:
Black: Existing Construction
Red: Proposed Construction

Loop Farms



EDCP: SHA

TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:	ESTIMATE #: **1963.000**	**S-1**
	SUB #: ISSUE DATE: **04/18/2017**	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM		

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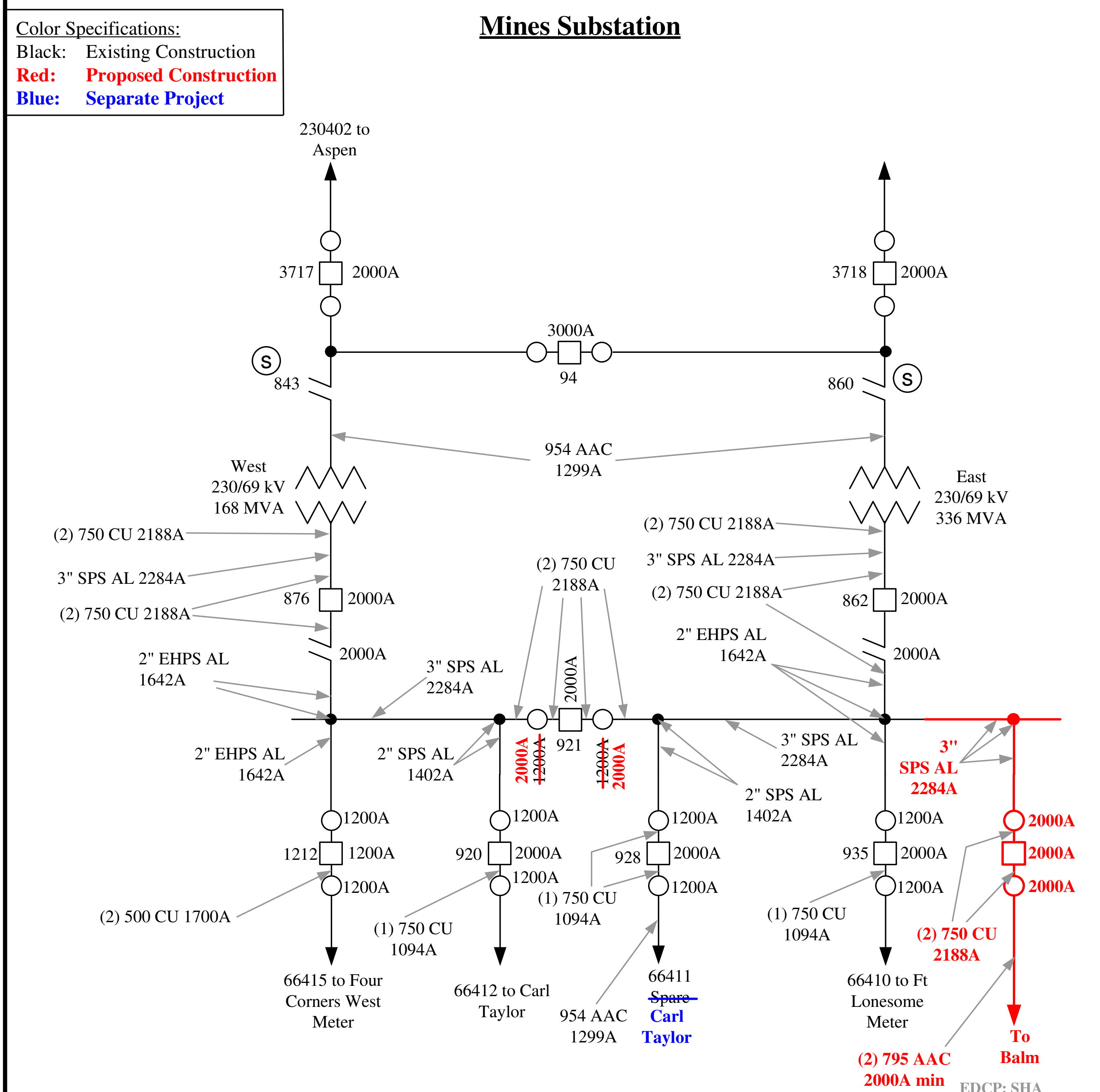
TITLE: **Loop Farms Solar Facility – Mines Substation**	**2018**
DESCR: Add a 69 kV, 40kA, 2000A breaker with 2000A disconnects and extend the 69 kV East Bus using 3" SPS AL to accommodate a new circuit to the Loop Farms Solar facility. Upgrade the 1200A disconnects on the 69 kV tie-breaker to 2000A. Install bundled 750 CU for the breaker leads and bundled 795 AAC to connect to the 69 kV circuit	**IN SVC BY:** **Jun** **See Construction Schedule**
NOTES: Loop Farms will be radially served out of Mines Substation until the ED project to complete the 69 kV path from the Loop Farms tap to the future Balm substation is in-service.	N



TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:		ESTIMATE #: **1963.000**	**S-2**
	SUB #: **266T**	ISSUE DATE: **04/18/2017**	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM			

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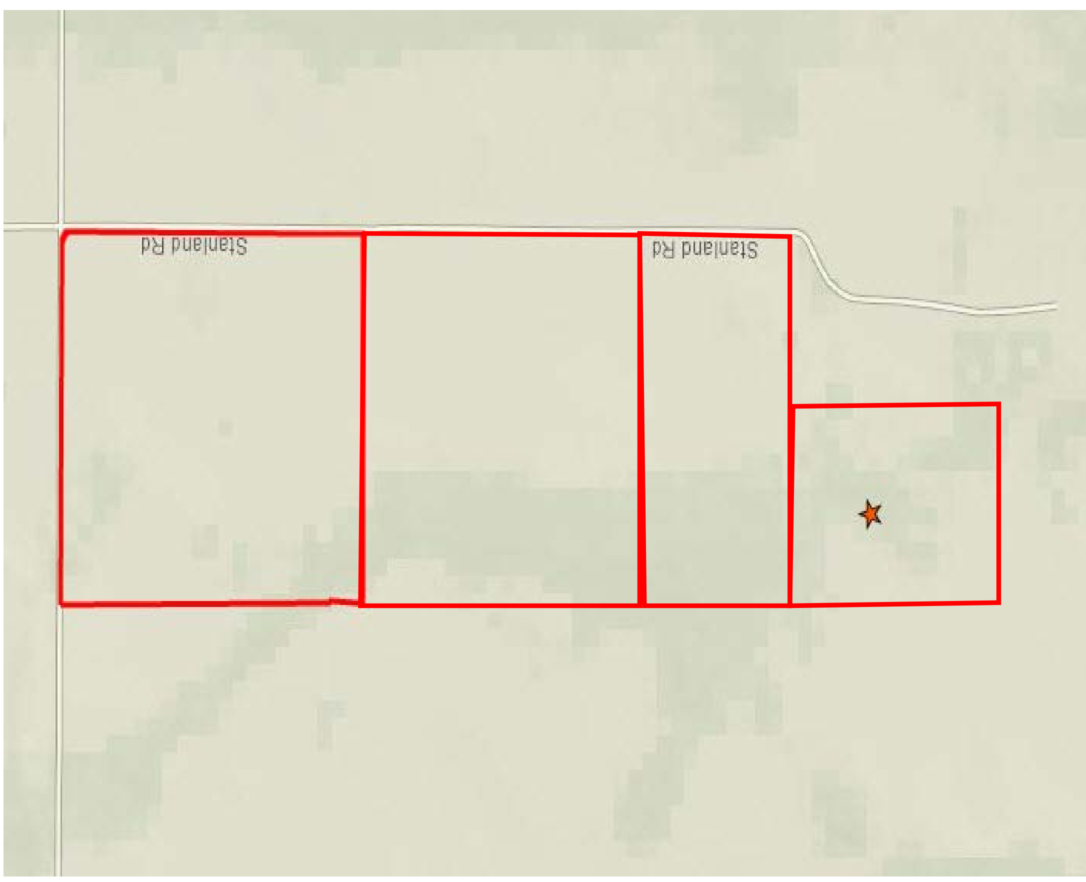
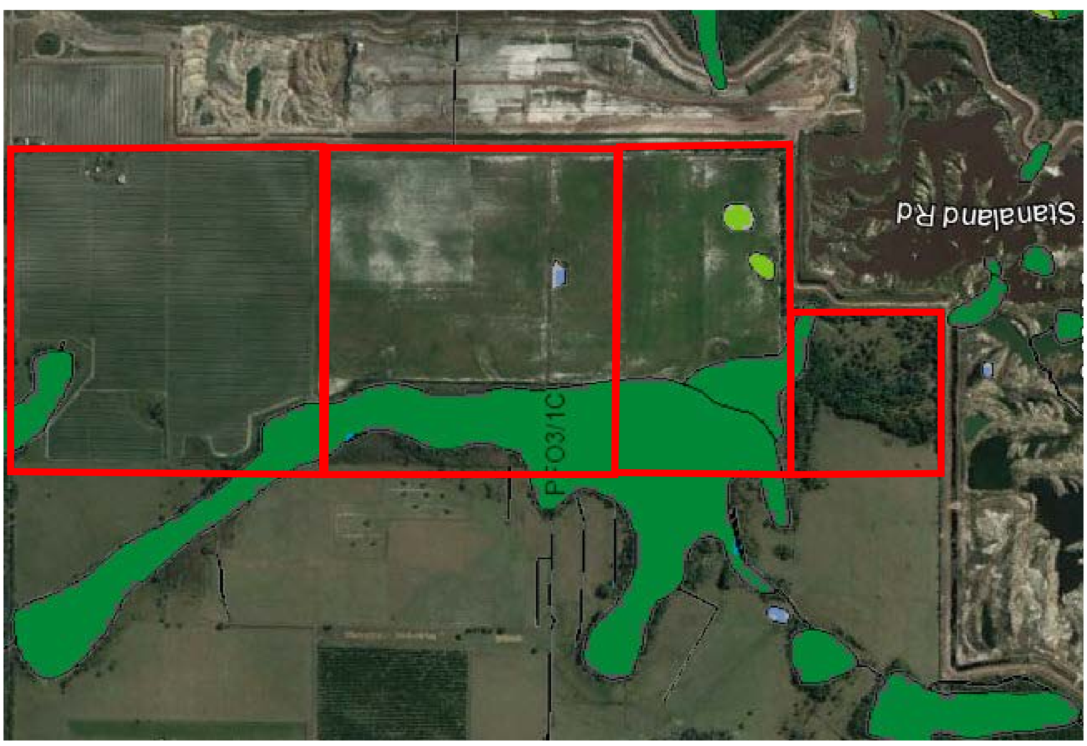
Loop Farms LLC
447± Acres on Stanaland Road
Aerial Photo Showing Topography

NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

Loop Farms LLC
447± Acres on Stanaland Road
Existing Land Use - AM

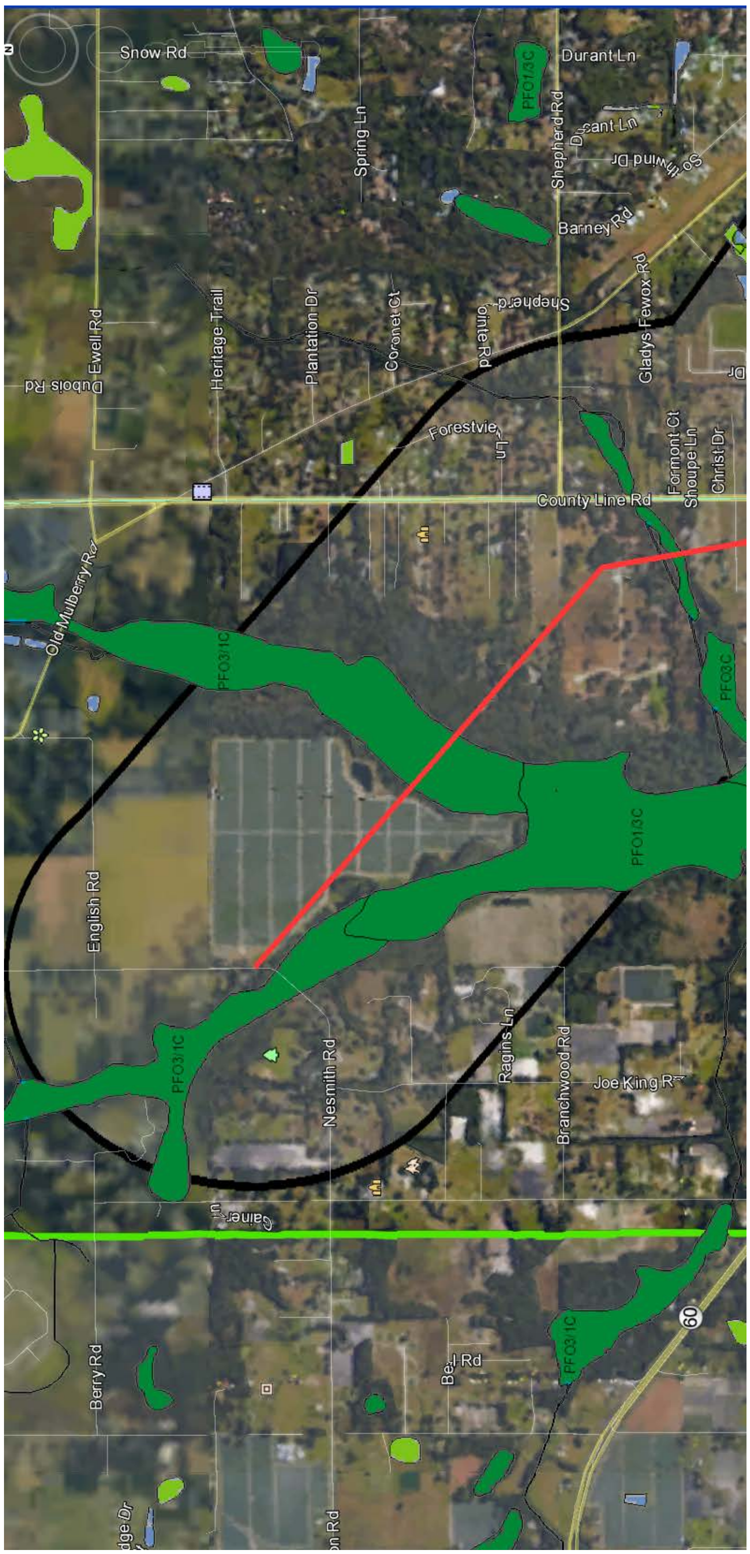


Loop Farms LLC
447± Acres on Stanaland Road
Potential Wetlands Area



NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

4808 Nesmith Rd.
Approx. 273 acres combined
(243 acres for Montesco and approx. 30 owned by Penny L Fuller)



Potential Wet Areas

NOTE: This document contains Critical Energy Infrastructure Information (CEII). Duplication or distribution of this document without the written consent of TECO Energy is strictly prohibited.

4808 Nesmith Rd.
Approx. 273 acres combined
(243 acres for Montesco and approx. 30 owned by Penny L Fuller)

Current Land Use - AS-0.4 | Agricultural SF Estate-1ut per 2.5 ac

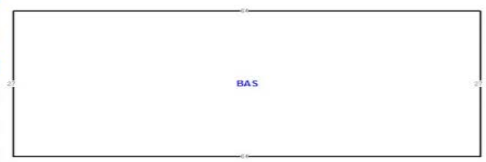
Building Information

Building 1

Type	02 | MANUFACTURED HOME (AYB > 1976)
Year Built	1992

Building 1 Construction Details

Element	Code	Construction Detail
Class	D	Wood Frame
Exterior Wall	13	Alum/Vinyl Siding
Roof Structure	3	Gable or Hip
Roof Cover	1	Minimum
Interior Walls	5	Drywall
Interior Flooring	8	Carpet
Heat/AC	2	Central
Condition	3	Average
Stories	1.0	
Bedrooms	3.0	
Bathrooms	2.0	
Units	1.0	



Building 1 subarea

Area Type	Gross Area	Heated Area	Depreciated Value
BAS	1,728	1,728	$28,873
Totals	**1,728**	**1,728**	**$28,873**

Extra Features

OB/XF Code	Description	Building	Year On Roll	Length	Width	Units	Value
0595	FIREPLACE	1	2002	0	0	1.00	$1,775
0470	OPEN SHED	0	2013	0	0	400.00	$4,914
0470	OPEN SHED	0	2013	0	0	400.00	$4,914
0470	OPEN SHED	0	2013	0	0	600.00	$7,371

Land Information - Total Acreage: 243.06

Use Code	Description	Zone	Front	Depth	Land Type	Total Land Units	Land Value
5110	STRAWBERRIES	AS-0.4	0.0	0.0	AC | ACREAGE	139.25	$375,975
6630	SPECIALTY GROVE	AS-0.4	0.0	0.0	AC | ACREAGE	22.00	$26,400
9600	GB LOWLANDS	AS-0.4	0.0	0.0	AC | ACREAGE	78.75	$3,938

Legal Description

S 1/2 OF NW 1/4 AND SW 1/4

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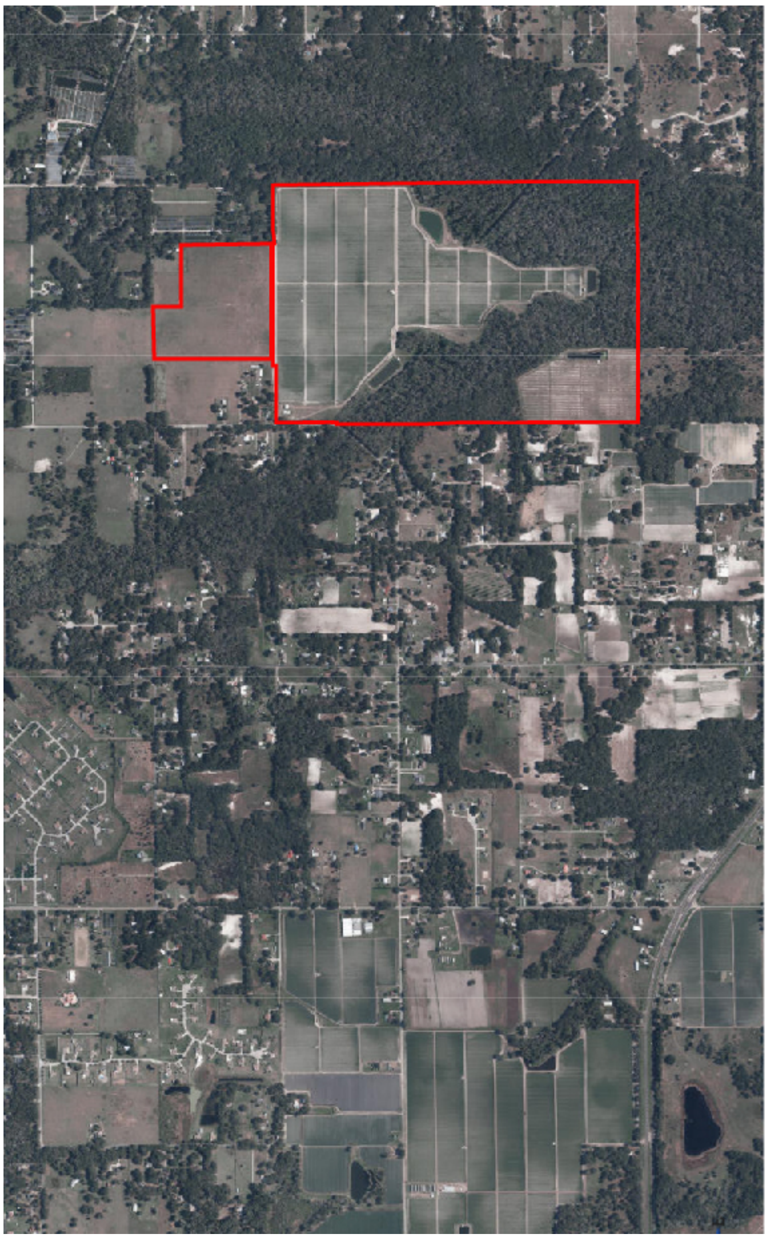
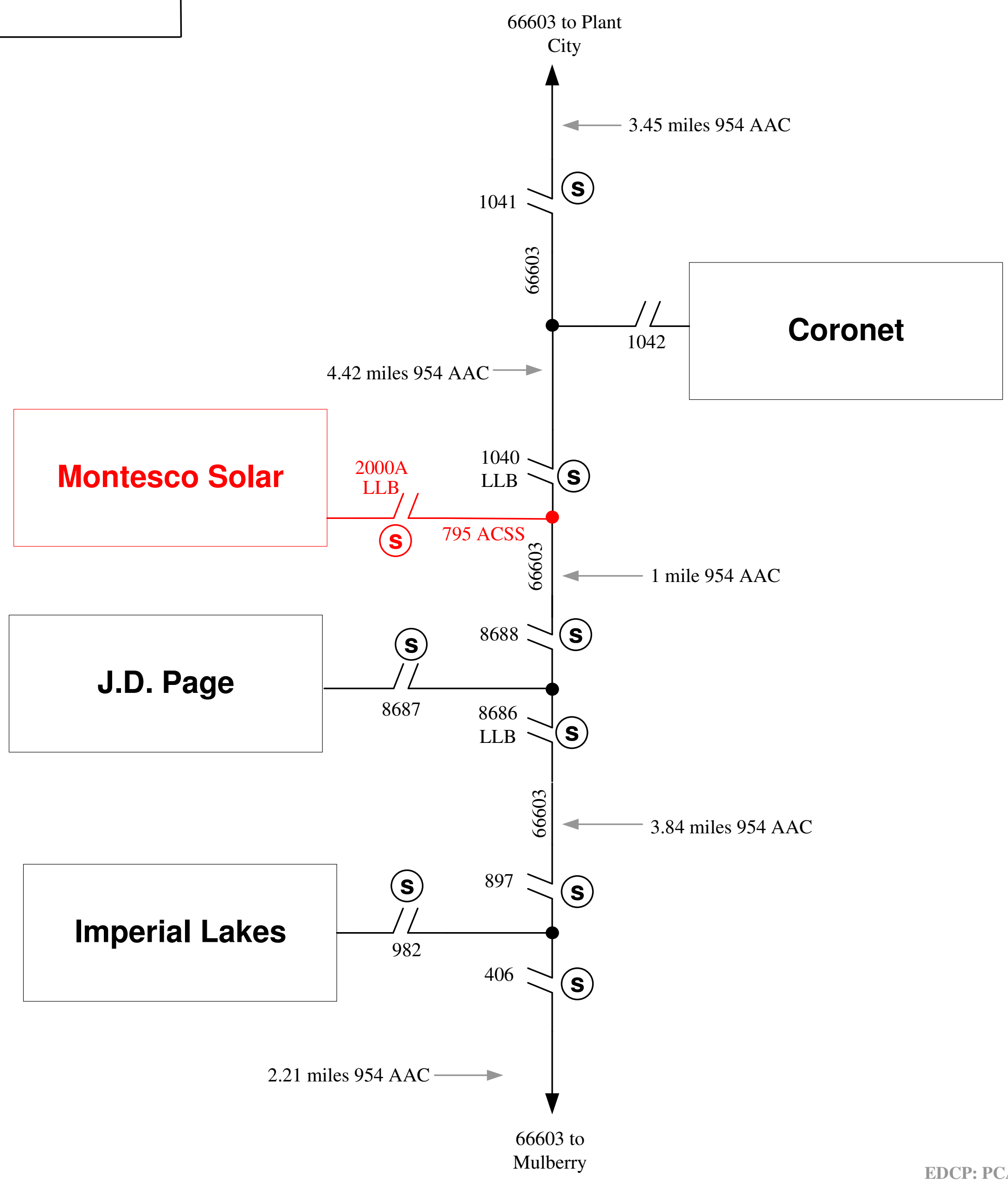
4808 Nesmith Rd.
Approx. 273 acres combined
(243 acres for Montesco and approx. 30 owned by Penny L Fuller)



Combined Montesco and Penny Fuller Properties

TITLE: Montesco Solar Facility	**2018**
DESCR: Tap circuit 66603 to connect to new Meter Station for Montesco Solar Facility Install a 2000A LLB supervisory transmission line switch on Circuit 66603 north of new tap.	**IN SVC BY:** **Jun** **See Construction Schedule**
NOTES: Coordinate tap conductor and transmission line switch mounting locations with PV system installer to avoid shading of PV panels	N

Color Specifications:
Black: Existing Construction
Red: Proposed Construction



EDCP: PCA

TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:		ESTIMATE #: **1959.000**	T
	SUB #:	ISSUE DATE: **04/18/2017**	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM			

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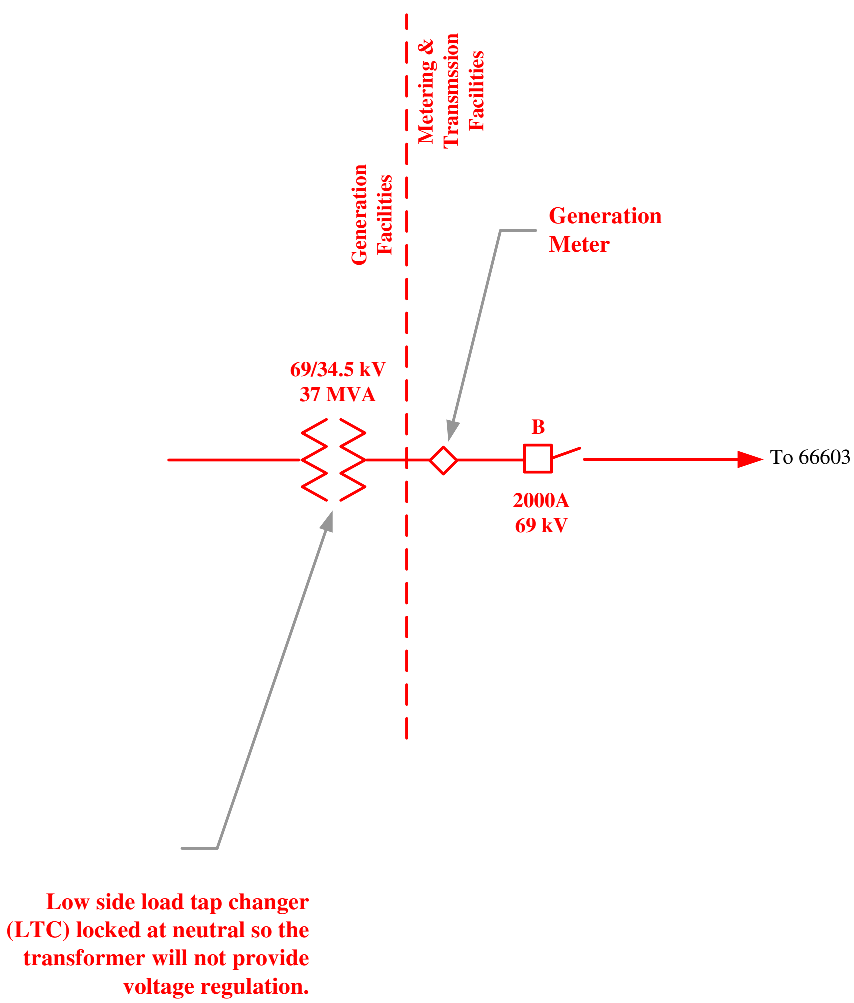
TITLE: Montesco	2018
DESCR: Metering station contains a 69/34.5 kV 37 MVA. A 69 kV generation meter, CTs, PTs and 69 kV 2000A circuit switcher will also be installed in station.	IN SVC BY: Jun See Construction Schedule
NOTES: Montesco Solar Facility will be tapped off 69 kV circuit 66603 and is expected to have an output of 22 MW with the potential to increase in the future.	N

Color Specifications:
Black: Existing Construction
Red: Proposed Construction

Montesco



EDCP: PCA

TECO TAMPA ELECTRIC AN EMERA COMPANY	IMPROVEMENT:		ESTIMATE #: 1959.000	S
	SUB #:	ISSUE DATE: 04/18/2017	REVISION DATE:	
	E.D. SYSTEM PLANNING CONSTRUCTION PROGRAM			

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Tampa Electric Company

2017 Solar Project Opportunity
Request for Information (RFI) No. 17-001

RFI Issued:
April 12, 2017

Responses Due:
April 21, 2017 (5:00 p.m. EST)

Tampa Electric Company (Tampa Electric) seeks information from firms qualified and experienced in the development, operation and delivery of utility scale solar projects.

Tampa Electric is primarily interested in utility-scale applications of 10 MW_{AC} to 74.5 MW_{AC} and is also interested in the opportunity that these projects are capable of deploying future battery energy storage. Prospective projects should be constructed on sites that can interconnect directly to Tampa Electric's transmission system, have a minimum operating life of 30 years, and are constructed with tier 1 equipment and in-market warranties. Upon commercial operation, ownership and operation of a project would be transferred to Tampa Electric.

Tampa Electric seeks specific responses to the questions set forth in Exhibit A.

Tampa Electric plans to use the responses to this RFI to help Tampa Electric identify and select one or more full-service developers who can help Tampa Electric reach its solar generation objectives.

Please note that Tampa Electric is undertaking this RFI process based on Tampa Electric's current plans and schedule for projects, all of which are subject to change. By inviting your firm to participate in this RFI process, Tampa Electric is not committing itself to any specific course of action or undertaking. This RFI process may be suspended, modified or terminated by Tampa Electric at any time at its sole discretion.

CONFIDENTIAL INFORMATION

This document, together with any related or supporting documents and information provided in connection hereunder, may contain confidential and proprietary information, and shall be considered Confidential Information of Tampa Electric. The reproduction of this RFI or any components thereof by electronic, photographic, xerographic, or other means is authorized solely for the purpose of preparing a response by the intended Respondent. Respondent shall not disclose to anyone, other than its employees, officers, and other authorized parties directly connected to responding to this document, any information concerning or found within this RFI to any third parties.

Unless otherwise agreed by Tampa Electric in writing, responses to this RFI can and may be used by Tampa Electric for any purpose whatsoever including, and not limited to, a future Request For Proposal (RFP). Tampa Electric will not be obligated to protect or treat as confidential any responses provided by a Respondent unless mutually agreed by Tampa Electric and Respondent in a non-disclosure agreement executed by the duly authorized representatives of each party.

No news release, public announcement, or any other reference to this RFI or any project hereunder pertaining to Tampa Electric shall be made without express written consent from Tampa Electric.

RFI SCHEDULE:

The tentative schedule for review is as follows:

RFI issued to interested parties: **April 12, 2017**

RFI responses submitted no later than 5 p.m. eastern standard time (EST), **April 21, 2017**

RFI evaluation completed and shortlist of Respondents notified **April 28, 2017**

Tampa Electric reserves the right to modify this schedule or to close this RFI at any time in its sole discretion.

RFI SUBMITTAL PROCESS

Respondents must submit their response(s) electronically by the aforementioned deadline to jlriendeau@tecoenergy.com**.** All submittals should be titled "2017 Solar Project Opportunity: [insert company name]."

DISCLAIMERS

Tampa Electric reserves the right, without qualification and in its sole discretion to: (i) select or reject any or all proposals, offers, or responses; (ii) waive any formality, technicality, requirement, or irregularity in any proposals received; (iii) discuss with any Respondent the details of any response submitted by a Respondent in order to fully evaluate the response; (iv) negotiate the terms of any proposal with any Respondent without seeking new or amended proposals from any other party; (v) decline to enter into any agreement with any Respondent for any reason or no reason at all; and (vi) close or terminate this RFI in whole or in part at any time.

All costs incurred by a Respondent in connection with the preparation and submission of a response, proposal and/or any subsequent negotiations in connection with this RFI shall be borne solely by the Respondent. Tampa Electric will not reimburse Respondents for their expenses under any circumstances, regardless of whether the RFI process proceeds to a successful conclusion or is abandoned by Tampa Electric in its sole discretion.

ABOUT TAMPA ELECTRIC

Tampa Electric Company is a regulated electric utility serving over 725,000 customers in the greater Tampa Bay area. Tampa Electric is a subsidiary of Emera Inc., a geographically diverse energy and services company headquartered in Halifax, Nova Scotia, Canada. The company invests in electricity generation, transmission and distribution, as well as gas transmission and utility energy services with a strategic focus on transformation from high carbon to low carbon energy sources. Emera has investments throughout North America and in four Caribbean countries.

EXHIBIT A

FULL SERVICE DEVELOPMENT, REQUEST FOR INFORMATION

I. Please list and describe the services your company provides that are self-performed including, but not limited to: land procurement, environmental assessment and permitting, engineering and design, electrical, project financing, regulatory support, engineering construction and procurement. Please limit this description to in-house capabilities, not services that the Respondent would contract. ***Limit response to three (3) pages.***

II. Please provide a description of any self-performed operation, monitoring and maintenance (O&M) services your company offers along with the corresponding pricing. Detail the number and size of the solar stations that you currently provide O&M services for. ***Limit response to two (2) pages.***

III. Please describe your company's ability to post performance bonds or other forms of project security.

IV. Please provide the last three (3) years of your company's audited financials.

V. Please list North American PV solar projects 10 MW_{AC} and greater that your company provided full development services and constructed or provided construction management during the last two (2) years. Specifically list the services performed. ***Limit response to two (2) pages.***

VI. Please provide solar development and construction experience in Florida. ***Limit response to two (2) pages.***

VII. Please describe your company's approach and ability for managing four (4) simultaneous utility-scale projects that are located within a 30-mile radius. Include your company's project development and construction philosophy. Assume each project is 50 MW_{AC}. Provide an overall project schedule that includes site evaluation, development, engineering, permitting, procurement and construction. ***Limit response to four (4) pages.***

VIII. Is your company willing to develop and construct a project on land owned by Tampa Electric?

IX. Does your company own or have the right to develop any sites within the Tampa Electric service area that could produce $10MW_{AC}$ or greater of photovoltaic (PV) solar energy, and that could be transferred to Tampa Electric upon commercial operation?

A. Please describe the property, including its location and size, and how the property is controlled and if any due diligence has been performed.

B. Solar Project General Description

1. Please provide a site boundary aerial map identifying the exact geographic location of the proposed facility, if known, or a general area under consideration for development.

2. Please provide the following information about the project:

a) Nameplate capacity (MW_{DC}/MW_{AC})
b) Contract price ($/$kW_{AC}$)
c) Energy price ($/MWh)
d) Expected annual gross generation (MWh)
e) Expected annual capacity factor (%)
f) Fixed and expected variable operation and maintenance ($/MW)
g) Expected system degradation (%/yr)

Note: Respondent proposed projects should include complete energy modeling results including 8760 hourly energy projections with their submissions; PV_{SYST} is the preferred model but alternative models are acceptable. Model assumptions and inputs should be included with the energy results.

3. Please provide a detailed description of the solar project:

   a) Proposed panel technology model and type
   b) Project interconnection point and voltage (kV)
   c) Identification of major equipment suppliers and description of manufacturers' and vendors' warranties, if known.
   d) Details regarding the design/service life of the project.
   e) Anticipated project construction time and anticipated construction milestone schedule
   f) Examples of similar systems in existence elsewhere in the world

4. Please describe the proposed project team and project financing structure:

   a) Team members
   b) Team members' experience with similar projects
   c) Team members' experience in FRCC, SERC, OR NERC
   d) Potential financing through construction

5. Please describe the proposed network and control scheme:

   a) SCADA system and communications equipment

6. Please describe any environmental, safety, and health issues related to the project:

   a) Safety concerns related to the project (if any)
   b) Physical dimensions of major equipment
   c) Land area required
   d) Relevant geographic restrictions or requirements
   e) Noise, visual or any negative community impact generated by equipment
   f) Water consumption

7. Please provide the all-in-cost up to the designated point of delivery (including land and step up transformer). The project cost should be presented in terms of an all-in-cost ($/kW$_{AC}$) and the levelized cost of energy produced (LCOE) based upon a 30-year life.

8. Please provide a project schedule, including permitting, with the shortest duration in which the project can be completed.

9. Please provide a conceptual summary outlining the following commercial terms:

   a) Proposed legal structure for construction and transfer of project (e.g., build, own and transfer).
   b) Equipment warranties
   c) Performance guarantees for output and availability

6. Has TECO acquired any land or land rights associated with the various SoBRA Tranches? If yes, please provide details of the acquisition(s) and associated documentation.

A. Yes. Tampa Electric employed a screening and due diligence process to select its solar sites. Each project site was evaluated and selected after considering environmental assessments, size of the project sites, proximity to Tampa Electric transmission facilities, cost of land, and suitability of the sites for solar PV construction.

Tampa Electric has purchased land for the two projects in tranche one and one site in tranche two. The sites that have been purchased for tranche one are Payne Creek Solar and Balm Solar. Grange Hall Solar, a tranche two project, has also been purchased.

The remaining sites planned for tranches two through four are under contract and controlled by Tampa Electric. Tampa Electric plans to purchase the remaining sites for tranche two by the end of 2017. Tranche three and four projects will be purchased in 2018.

The ten sites planned for Tampa Electric's 600 MW of PV solar projects total more than 4,500 acres and are located throughout Tampa Electric's service area.

7. Does TECO believe that joint ownership is feasible for any of the various SoBRA Tranches?

A. Possibly; however, multi-party ownership introduces complexity and additional costs in establishing ownership provisions and overseeing operational controls. Additionally, it could result in an adverse impact on cost-effectiveness and the company’s ability to control its committed cost cap.

8. Has TECO explored any joint ownership options for acquiring Solar PV capacity? If yes, please explain in detail.

A. Yes, Tampa Electric has been contacted by numerous solar PV developers over the last several years. In these meetings, multiple options have been discussed including joint ownership. During those discussions the developers were asked but have not offered a binding letter of intent or other commitment that meets the cost effectiveness and timing of 2018-2021 for Tampa Electric's proposed ten projects totaling 600 MW.

9. In Paragraph 6(c) of the proposed Settlement Agreement, it states “A SoBRA Tranche may consist of a single project or include multiple individual solar projects, which may be located throughout the Company’s retail service territory.” Is this language intended to limit the Company to only pursuing options that are located within its retail service territory? If so, why?

A. No. However, any solar projects built outside the company’s service area would be subject to incremental transmission or wheeling charges that would likely make them less cost-effective than those built within the company’s service area. Paragraph 6(c) is a Negotiated Term and is intended to emphasize that the SoBRA projects would be constructed for the benefit of the company’s retail customers.

10. Please provide a breakdown of estimated operating costs associated with the various SoBRA Tranches to be included in base rate revenue requirements.

A. Tampa Electric estimates operating costs to be $7/kw-yr and that they will be escalated annually by 2.5% during the Term. This includes operations and monitoring, performance engineering, maintenance, warranty administration, spare parts inventory and vegetation management.

11. Refer to Paragraph 6(d), which addresses the debt rate utilized to calculate the revenue requirements associated with the SoBRA projects.

a. Please explain exactly what the Company defines as "prospective long-term debt issuances."

b. Does this reflect a projected cost rate or an actual cost rate?

c. Please explain how the incremental cost rate for long-term debt will be calculated.

A. a. Paragraph 6(d) is a Negotiated Term intended to specify that the company will use the cost rate for long term debt that is issued to fund the solar projects to calculate the revenue requirement associated with a SoBRA. This is different from the cost rate of the company's embedded overall long-term debt as reported on its surveillance reports. By using the incremental rate, the first-year revenue requirement will reflect the additional cost of the solar project.

b. The company intends to use actual cost rates that reflect the company's most recent issuances of long term debt for purposes of calculating the revenue requirement for the solar projects.

c. See answer to b, above.

12. Refer to Paragraph 6(l) on page 18, which addresses the investment tax credits on a normalized basis associated with the SoBRA projects.

a. Please explain how the investment tax credits will be adjusted on a normalized basis.

b. What cost rate will be used for the investment tax credits?

c. What capital components (common equity, long-term debt, and short-term debt) will be included in the calculation of the cost rate for the investment tax credits?

A. a. The Agreement also allows the company to take advantage of the existing 30% solar investment tax credit for the benefit of customers while the credit remains in effect. Paragraph 6(l) is a Negotiated Term intended to ensure that the capital structure will be “adjusted” to include the investment tax credits consistent with tax normalization rules. The amount of the investment tax credits included in the capital structure will not be adjusted.

b. Consistent with tax normalization rules, the investment tax credits will be assigned a weighted cost rate based on the incremental equity and debt components that would have otherwise been used to fund the solar project.

c. See answer to b, above.

13. Please provide a resource plan that includes the solar projects and one without the solar projects for the term of the settlement. For each unit identified, please provide all features of the unit including but not limited to: MW, installed cost/MW, Fuel Type and Unit Type.

A. The solar projects planned for recovery under the SoBRA mechanism are a continuation of Tampa Electric's long-standing commitment to clean energy. The company's strategy to reduce its carbon footprint started in 1999 with the repowering of the former Gannon Station to natural gas-fired Bayside Power Station, and most recently included the expansion of the Polk Power Station's combined cycle generation. This strategy will reduce the company's exposure to financial and other risks associated with burning carbon-based fuels, and because the fuel cost of solar generation is zero, will provide an important measure of price stability to customers.

Using the SoBRA mechanism, the company plans to install over 6 million solar panels into various projects in its service territory. These projects and the SoBRA mechanism will allow the company to transition power generation to less carbon intensity while keeping prices for electricity affordable for its customers. When the projects are complete, about 6 percent of Tampa Electric's energy will come from the sun.

The requested resource plans are summarized in the tables below.

2017 TYSP No Solar

Year	Portfolio Additions	MW W in / Sum	Installed Cost / MW	Fuel Type	Unit Type
2018	-	-	-	-	-
2019	-	-	-	-	-
2020	-	-	-	-	-
2021	(1) GE 7FA.05	2 20 / 204	700,040	Gas	Combustion Turbine
2022	-	-	-	-	-

600 M W of Solar

Year	Portfolio Additions	MW W in / Sum	Installed Cost / MW	Fuel Type	Unit Type
2018	Solar Phase 1	0 / 150	1,396,000	Solar	PV
2019	Solar Phase 2	0 / 250	1,443,000	Solar	PV
2020	Solar Phase 3	0 / 150	1,437,000	Solar	PV
2021	Solar Phase 4	0 / 50	1,477,000	Solar	PV
2022	-	-	-	-	-

14. Please refer to Paragraph 6(b). Please provide an estimate of both the Incremental Annualized SoBRA Revenue Requirements and Cumulative Annualized SoBRA Revenue Requirements when using a $1,475kWac cost cap assuming full capacity buildout and 2% variance.

A. See table below.

Year	Earliest Rate Change And In-Service Date	Maximum Incremental SoBRA MW	Maximum Incremental Annualized SoBRA Revenue Requirements (millions)	Maximum Cumulative SoBRA MW	Maximum Cumulative Annualized SoBRA Revenue Requirements (millions)
2018	September 1	150	$28.3*	150	$28.3
2019	January 1	250	$47.2	400	$75.4
2020	January 1	150	$28.6	550	$104.0
2021	January 1	50	$9.8	600	$113.9

Note:
**The annual revenue requirement is approximately $28.3 million, however, since the first 150 MW phase is scheduled to come online September 1, 2018, the revenue requirements collected would be four months of the annual revenue requirements, or $9.4 million.*

15. Please refer to Paragraph 6(c).

a. Please explain whether TECO could buy an existing in-service solar farm and meet the terms of the settlement.

b. If so, please explain if this existing in-service solar farm would be subject to the $1,500kWac cost cap.

c. If not, would additional construction on an existing in-service solar farm satisfy the terms of the settlement and would that site then be subject to the $1,500kWac cost cap?

A. a. Paragraph 6(c) is a Negotiated Term. It contains this language: "Tampa Electric will construct and bring into full commercial operation, the full Maximum Incremental SoBRA MW for each year's Tranche by the dates shown in the table above." Based on this language, and as discussed in its answer to data request No. 6, above, the company has made plans to construct 600 MW of solar as set forth in the table. Additionally, the company is not aware of any large scale solar farms in existence within its retail service area.

b. N/A

c. The company is not aware of any existing non-company owned solar farms within its retail service area. If a site was available and land could be used to build company-owned solar, the newly constructed solar would be subject to the $1,500 / kWac cost cap.

16. Please refer to Paragraph 6(m).

a. Please provide the estimated rate impact annually of the solar projects for a 1000/kwh-mo residential customer using the $1,500 kWac cost cap.

b. Please provide the same rate impact when using a $1,475 kWac cost.

A. a. See table below.

Tampa Electric Residential Bill Comparison
SoBRA Settlement Impacts at $1500/kW
1,000 kWh Monthly Bill

Annual Change	Jan-Aug '18	Sep-Dec '18	2019	2020	2021
Base Energy Charge	-	2.13	2.97	1.80	0.62
Fuel Cost Recovery	(0.23)	-	(1.62)	(0.69)	(0.23)
Gross Receipts Tax	(0.01)	0.06	0.03	0.03	0.01
Total	$(0.24)	$2.19	$1.38	$1.14	$0.40

Cumulative Change	Jan-Aug '18	Sep-Dec '18	2019	2020	2021
Base Energy Charge	-	2.13	5.10	6.90	7.52
Fuel Cost Recovery	(0.23)	(0.23)	(1.85)	(2.54)	(2.77)
Gross Receipts Tax	(0.01)	0.05	0.08	0.11	0.12
Total	$(0.24)	$1.95	$3.33	$4.47	$4.87

Note:
**Compared to 2017 Approved Rates. Impacts of SoBRA Settlement Changes Only.*

b. See table below.

Tampa Electric Residential Bill Comparison
SoBRA Settlement Impacts at $1475/kW
1,000 kWh Monthly Bill

Annual Change	Jan-Aug '18	Sep-Dec '18	2019	2020	2021
Base Energy Charge	-	2.09	2.93	1.77	0.61
Fuel Cost Recovery	(0.23)	-	(1.62)	(0.69)	(0.23)
Gross Receipts Tax	(0.01)	0.06	0.03	0.03	0.01
Total	$(0.24)	$2.15	$1.34	$1.11	$0.39

Cumulative Change	Jan-Aug '18	Sep-Dec '18	2019	2020	2021
Base Energy Charge	-	2.09	5.02	6.79	7.40
Fuel Cost Recovery	(0.23)	(0.23)	(1.85)	(2.54)	(2.77)
Gross Receipts Tax	(0.01)	0.05	0.08	0.11	0.12
Total	$(0.24)	$1.91	$3.25	$4.36	$4.75
Note: **Compared to 2017 Approved Rates. Impacts of SoBRA Settlement Changes Only.*					

17. For all planned solar generation, please detail the depreciation life and actual life of each individual unit if available.

A. The average service life applied to the SoBRA generation assets is 30 years consistent with FPSC Order No. PSC-2015-0573-PAA-EI.

18. Please refer to Paragraph 6(j).

a. If TECO does not construct the Maximum Incremental SoBRA MW in one year of the settlement term, can the construction be completed in another year and cost recovery still be available for TECO? For example, if TECO were to not construct any approved solar tranches in 2020, could TECO construct the 2020 unused capacity in 2021 and still recover cost? Please explain.

b. If so, would these costs be limited to the Maximum Incremental Annualized SoBRA Revenue Requirements, the Maximum Cumulative Annualized SoBRA Revenue Requirements mentioned in Paragraph 6(b), or both.

A. a. Yes. Paragraph 6(j) is a Negotiated Term intended to specify that if the company does not construct the available 150 MW of SoBRA generation in 2020 per the example provided it would be able to carryover the 150 MW into 2021. However, the company will not be able to secure cost recovery via the SoBRA mechanism for more than 600 MW.

b. Yes. Paragraph 6(b) is a Negotiated Term intended to specify the maximum annualized and cumulative revenue requirement amounts available under the SoBRA mechanism.

19. Please refer to Paragraph 6(c).

a. Please explain the relationship between a 2% variance in revenue requirements and a 5 MW variance for 2019 SoBRA Tranche.

b. Please explain if the 2% and 5 MW variance only applies to 2018 and 2019 SoBRA Tranches.

c. Please explain if the 2% variance applies to the $1,500kWac cost cap as well.

A. a. Paragraph 6(c) is a Negotiated Term intended to specify that the two percent variance only applies to the 250 MW for the 2019 SoBRA tranche. This means, for example, that the company could construct 255 MW of solar projects in 2019 to accommodate efficient planning and construction of its planned solar projects. It is expected that a two percent increase in MW would translate to a two percent increase in revenue requirements.

b. The two percent variance only applies to the 2019 SoBRA tranche.

c. The two percent variance does not apply to the $1,500 / KWac cost cap.

20. Referring to Paragraph 6(i)(i) of the settlement, please explain the basis for only allocating 40 percent of the revenue requirement to the lighting class.

A. As with all the other elements of the 2017 Agreement, Paragraph 6(i)(i) is a Negotiated Term. The 40 percent is not a calculated amount, but rather, was settled on to reflect that the fuel benefit of the solar tranches will be included in the calculation of lighting fuel rates and reflects a negotiation position that 40% is a reasonable allocation of the revenue requirements of the solar.

21. Referring to Paragraph 6(i)(ii) of the settlement, please discuss the impact on low- vs high-load factor demand customers resulting from the proposed SOBRA increases to demand charges.

A. The attached chart in MFR Schedule A2 format shows a typical bill for Tampa Electric's GSD customers at 600 MW of SOBRA buildout. The impact of SOBRA is two-fold: the increased base revenue requirement is recovered from the demand charge and the reduced fuel cost is recovered through the fuel energy charge. As can be seen in column 18, for a demand billed customer the impact is lower at higher load factors.

SOBRA
12CP and 1/13 With 40% Allocation to Lighting
All Demand

SCHEDULE A-2 — FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS

FLORIDA PUBLIC SERVICE COMMISSION — EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of data shown:
XX Projected Test year Ended 12/31/2017

COMPANY: TAMPA ELECTRIC COMPANY

GSD - GENERAL SERVICE DEMAND

Line No.	(1) TYPICAL KW (RATE SCHEDULE GSD)	(2) TYPICAL KWH	(3) BASE RATE (Bill Under Present Rates)	(4) FUEL CHARGE	(5) ECCR CHARGE	(6) CAPACITY CHARGE	(7) ECRC CHARGE	(8) GRT CHARGE	(9) TOTAL	(10) BASE RATE (Bill Under Proposed Rates)	(11) FUEL CHARGE	(12) ECCR CHARGE	(13) CAPACITY CHARGE	(14) ECRC CHARGE	(15) GRT CHARGE	(16) TOTAL	(17) INCREASE DOLLARS (16)-(9)	(18) INCREASE PERCENT (17)/(9)	(19) COSTS IN CENTS/KWH PRESENT (9)/(2)*100	(20) COSTS IN CENTS/KWH PROPOSED (16)/(2)*100
1	75	10,950	$ 762.51	$ 323.68	$ 19.71	$ 6.90	$ 42.27	$ 29.62	$ 1,184.68	$ 856.57	$ 293.35	$ 20.59	$ 6.90	$ 42.27	$ 31.27	$ 1,250.95	$ 66.26	5.6%	10.82	11.42
2	75	19,163	$ 1,138.10	$ 566.44	$ 57.75	$ 20.25	$ 73.97	$ 47.60	$ 1,904.11	$ 1,300.85	$ 513.36	$ 60.75	$ 20.25	$ 73.97	$ 50.49	$ 2,019.67	$ 115.56	6.1%	9.94	10.54
3	75	32,850	$ 1,378.18	$ 971.05	$ 57.75	$ 20.25	$ 126.80	$ 65.49	$ 2,619.51	$ 1,540.93	$ 880.05	$ 60.75	$ 20.25	$ 126.80	$ 67.40	$ 2,696.19	$ 76.67	2.9%	7.97	8.21
4	75	49,275	$ 1,620.78	$ 1,448.81	$ 57.75	$ 20.25	$ 190.20	$ 85.58	$ 3,423.37	$ 1,781.70	$ 1,313.30	$ 60.75	$ 20.25	$ 190.20	$ 86.31	$ 3,452.52	$ 29.15	0.9%	6.95	7.01
5																				
6	500	73,000	$ 4,895.04	$ 2,157.88	$ 131.40	$ 45.99	$ 281.78	$ 192.62	$ 7,704.71	$ 5,522.11	$ 1,955.67	$ 137.24	$ 45.99	$ 281.78	$ 203.66	$ 8,146.45	$ 441.74	5.7%	10.55	11.16
7	500	127,750	$ 7,398.98	$ 3,776.29	$ 385.00	$ 135.00	$ 493.12	$ 312.52	$ 12,500.90	$ 8,483.98	$ 3,422.42	$ 405.00	$ 135.00	$ 493.12	$ 331.78	$ 13,271.29	$ 770.39	6.2%	9.79	10.39
8	500	219,000	$ 8,999.50	$ 6,473.64	$ 385.00	$ 135.00	$ 845.34	$ 431.76	$ 17,270.24	$ 10,084.50	$ 5,867.01	$ 405.00	$ 135.00	$ 845.34	$ 444.53	$ 17,781.38	$ 511.15	3.0%	7.89	8.12
9	500	328,500	$ 10,616.81	$ 9,658.72	$ 385.00	$ 135.00	$ 1,268.01	$ 565.73	$ 22,629.27	$ 11,689.66	$ 8,755.35	$ 405.00	$ 135.00	$ 1,268.01	$ 570.59	$ 22,823.61	$ 194.33	0.9%	6.89	6.95
10																				
11	2000	292,000	$ 19,480.44	$ 8,631.52	$ 525.60	$ 183.96	$ 1,127.12	$ 767.91	$ 30,716.55	$ 21,988.72	$ 7,822.68	$ 548.96	$ 183.96	$ 1,127.12	$ 812.09	$ 32,483.53	$ 1,766.97	5.8%	10.52	11.12
12	2000	511,000	$ 29,496.18	$ 15,105.16	$ 1,540.00	$ 540.00	$ 1,972.46	$ 1,247.53	$ 49,901.33	$ 33,836.18	$ 13,689.69	$ 1,620.00	$ 540.00	$ 1,972.46	$ 1,324.57	$ 52,982.90	$ 3,081.57	6.2%	9.77	10.37
13	2000	876,000	$ 35,898.28	$ 25,894.56	$ 1,540.00	$ 540.00	$ 3,381.36	$ 1,724.46	$ 68,978.66	$ 40,238.28	$ 23,468.04	$ 1,620.00	$ 540.00	$ 3,381.36	$ 1,775.58	$ 71,023.26	$ 2,044.59	3.0%	7.87	8.11
14	2000	1,314,000	$ 42,367.52	$ 38,634.89	$ 1,540.00	$ 540.00	$ 5,072.04	$ 2,260.37	$ 90,414.81	$ 46,658.92	$ 35,021.39	$ 1,620.00	$ 540.00	$ 5,072.04	$ 2,279.80	$ 91,192.15	$ 777.33	0.9%	6.88	6.94
15																				
16																				

Line		PRESENT GSD	PRESENT GSDT		PRESENT GSD OPT.		PROPOSED GSD	PROPOSED GSDT		PROPOSED GSD OPT.	
17											
18											
19	CUSTOMER CHARGE	33.24	33.24	$/Bill	33.24	$/Bill	33.24	33.24		33.24	$/Bill
20	DEMAND CHARGE	10.25	-	$/KW	-	$/KW	12.42	-	$/KW	-	$/KW
21	BILLING	-	3.46	$/KW	-	$/KW	-	4.19	$/KW	-	$/KW
22	PEAK	-	6.79	$/KW	-	$/KW	-	8.22	$/KW	-	$/KW
23	ENERGY CHARGE	1.754	-	¢/KWH	6.660	¢/KWH	1.754	-	¢/KWH	7.519	¢/KWH
24	ON-PEAK	-	3.211	¢/KWH	-	¢/KWH	-	3.211	¢/KWH	-	¢/KWH
25	OFF-PEAK	-	1.159	¢/KWH	-	¢/KWH	-	1.159	¢/KWH	-	¢/KWH
26	FUEL CHARGE	2.956	-	¢/KWH	2.956	¢/KWH	2.679	-	¢/KWH	2.679	¢/KWH
27	ON-PEAK		3.166	¢/KWH	-	¢/KWH		2.870	¢/KWH	-	¢/KWH
28	OFF-PEAK		2.865	¢/KWH	-	¢/KWH		2.597	¢/KWH	-	¢/KWH
29	CONSERVATION CHARGE	0.77	0.77	$/KW	0.180	¢/KWH	0.81	0.81	$/KW	0.188	¢/KWH
30	CAPACITY CHARGE	0.27	0.27	$/KW	0.063	¢/KWH	0.27	0.27	$/KW	0.063	¢/KWH
31	ENVIRONMENTAL CHARGE	0.386	0.386	¢/KWH	0.386	¢/KWH	0.386	0.386	¢/KWH	0.386	¢/KWH
32											

33 Notes:
34 A. The kWh for each kW group is based on 20, 35, 60, and 90% load factors (LF).
35 B. Charges at 20% LF are based on the GSD Option rate; 35% and 60% LF charges are based on the standard rate; and 90% LF charges are based on the TOD rate.
36 C. All calculations assume meter and service at secondary voltage.
37 D. TOD energy charges assume 25/75 on/off-peak % for 90% LF. Peak demand to billing demand ratios are assumed to be 99% at 90% LF.
38 E. Cost recovery clause factors are the current 2017 factors.
39

Supporting Schedules: E-13c, E-14 Supplement — Recap Schedules:

22. Please refer to Paragraph 8(b).

a. Please provide all the information and company's plan, known at this stage, regarding the expected retirements of the coal-fired generating assets or other assets of the magnitude that would ordinarily or otherwise require a capital recovery schedule.

b. When does the company expect to begin the retirement of its AMR meters, and how many years does TECO expect it will require to complete the AMR- to- AMI meter replacement?

c. What is the expected unrecovered net investment amount, in dollars, associated with the AMR meter retirement each year during the term of the 2017 Amended and Restated Stipulation and Settlement Agreement?

d. What will be the estimated percentage of the total investment booked to depreciation Account 37000 – Meters that is expected to be affected by the AMR to AMI meter replacement each year for the period of 2017 - 2021?

e. In reference to Rule 25-6.0436(7)(a), F.A.C., and the following excerpt of the Commission's previous order regarding the timely establishment of capital recovery schedules cited below[1], please explain how the approach of deferring the establishment of the capital recovery schedules described in Paragraph 8(b) would benefit TECO's customers.

> Ratepayers should pay their fair share of costs associated with plant which they are receiving service. Unrecovered amounts associated with non-existent plan do not benefit ratepayers. […] recovery of the identified unrecovered costs associated with planned near-term retirements over a period that matches the remaining period the related assets will provide service ensures intergenerational equity.

[1] Order No. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket Nos. 080677-EI and 090130-EI, *In re: Petition for increase in rates by Florida Power & Light Company, and 2009 depreciation and dismantlement study by Florida Power & Light Company*, pages 21-23.

A. a. The company has four coal-fired generating assets located at Big Bend Station and one IGCC generating unit at its Polk Power station. The existing retirement dates of the Big Bend coal units are 2035 for Unit 1, 2038 for Unit 2, 2041 for Unit 3, and 2049 for Unit 4. The company has been evaluating the remaining life cycle costs of its coal-fired units compared to other options, but has not completed its analysis. A firm decision on when, or if, early retirement of any of those units would take place has not been made.

b. The company anticipates beginning retirement of its AMR meters in December of 2018. Additionally, the company expects to complete the removal of AMR and replacement to AMI meters in two years.

c. The net book value of the AMR meters is expected to be approximately $39 million at the time of removal commencement. The annual depreciation expense expected over the settlement term is approximately $5 million per year.

d. Please see attached.

Please note that the asset balances for September 2017 are based on the actual plant records and can be uniquely identified by retirement units. The breakout by type for depreciation expense, reserve and net book value are based on an allocation since the depreciation and reserve amounts for group depreciated assets are not maintained below the depreciation group level.

The AMI Pilot Program for Meters began in 2016, therefore the 2017 reserve balance will include the ending reserve amount from December 2016 in addition to the 2017 depreciation expense.

The 2018 – 2021 plant amounts for AMI are based on estimates at this point in time and are subject to change.

e. Paragraph 8(b) is a Negotiated Term intended to specify that AMR and coal-fired generation assets, if retired, would remain in plant in service and rate base and would continue to be depreciated at their present depreciation rates as if there were no early retirements until the next depreciation study filed in advance of the next rate case.

Absent the Commission's approval of the 2017 Agreement, or in the absence of a settlement agreement, the company would seek an accelerated depreciation schedule when the assets were retired and removed from rate base. The accelerated depreciation would result in an increase to depreciation expense, which could contribute to a need for a base rate increase. Pursuant to the 2017 Agreement, the company agrees not to seek rate relief to be effective during the Term, which would include the incremental depreciation amounts in accelerated recovery schedules, which would benefit customers.

Plant Balance

	Sep 2017	Dec 2017	2018	2019	2020	2021
37000						
Other	13,138,130	13,138,130	13,138,130	13,138,130	13,138,130	13,138,130
AMR	69,655,204	69,655,204	69,655,204	69,655,204	69,655,204	69,655,204
AMI	1,361,336	11,485,215	16,428,002	97,494,002	182,281,002	187,081,002
Total	**84,154,670**	**94,278,549**	**99,221,335**	**180,287,335**	**265,074,335**	**269,874,335**
%AMR Assets	83%	74%	70%	39%	26%	26%
%AMI Assets	2%	12%	17%	54%	69%	69%

Annual Depr Expense

	Sep 2017	Dec 2017	2018	2019	2020	2021	Depr Rate
37000							
Other	709,810	236,486	945,945	945,945	945,945	945,945	**7.20%**
AMR	3,763,244	1,253,794	5,015,175	5,015,175	5,015,175	5,015,175	**7.20%**
AMI	50,413	206,734	1,182,816	7,019,568	13,124,232	13,469,832	**7.20%**
Total	**4,523,467**	**1,697,014**	**7,143,936**	**12,980,688**	**19,085,352**	**19,430,952**	

Reserve Balance

	Sep 2017	Dec 2017	2018	2019	2020	2021
37000						
Other	5,698,630	5,935,117	6,881,062	7,827,007	8,772,953	9,718,898
AMR	26,180,991	27,434,784	32,449,959	37,465,134	42,480,308	47,495,483
AMI	58,693	265,427	1,448,243	8,467,811	21,592,043	35,061,876
Total	**31,938,314**	**33,635,328**	**40,779,264**	**53,759,952**	**72,845,304**	**92,276,257**

Net Book Value

	Sep 2017	Dec 2017	2018	2019	2020	2021
37000						
Other	7,439,499	7,203,013	6,257,068	5,311,122	4,365,177	3,419,232
AMR	43,474,214	42,220,420	37,205,245	32,190,070	27,174,896	22,159,721
AMI	1,302,643	11,219,788	14,979,759	89,026,190	160,688,958	152,019,126
Total	**52,216,356**	**60,643,221**	**58,442,071**	**126,527,383**	**192,229,031**	**177,598,079**

23. Please refer to Paragraph 8(c) of the 2017 Amended and Restated Stipulation and Settlement Agreement. In consideration of Rule 25-6.0436(4)(d), F.A.C., what is meant by the phrase "[t]he depreciation and dismantlement study period shall match the test year in the company's MFRs…?"

A. Paragraph 8(c) is a Negotiated Term intended to ensure that the company submits a depreciation and dismantlement study that reflects rates corresponding with the timing of its test year MFRs. Under this approach, the depreciation expense reflected in the test year would be consistent with a full year's amount of depreciation based on the rates in the depreciation and dismantlement study.

24. Refer to Paragraph 11(a), which states that Tampa Electric will not enter into new financial natural gas hedging contracts through December 31, 2022.

a. Please identify the volume of natural gas for delivery in 2018 that will be purchased under previously-executed hedging contracts.

b. Please identify the volume of natural gas for delivery in 2019 that will be purchased under previously-executed hedging contracts.

c. Please identify the volume of natural gas for delivery in 2020 that will be purchased under previously-executed hedging contracts.

d. Please identify the month and year when all previously-executed hedging contracts will be fulfilled.

e. Please explain why the end-date of the 2017 Settlement (12/31/21) is different than the end-date of Paragraph 11(a), which is 12/31/22.

A. a. 5,880,000 MMbtus have been hedged for 2018.

b. No hedges have been put in place for 2019.

c. No hedges have been put in place for 2020.

d. November 2018

e. Paragraph 11(a) is a Negotiated Term. The parties agreed in the negotiation process to extend the moratorium on hedging one year longer than the Term of the 2017 Agreement.

25. Refer to Paragraph 11(c), addressing sales from solar assets.

a. Please define the term “separated sales,” providing examples.

b. Please define the term “stratified sales,” providing examples.

c. Describe how the sales addressed in Paragraph 11(c) are currently recorded in the Company’s books and records. As appropriate, identify the specific monthly schedules that are used for this purpose.

d. Assuming the Company’s Petition is approved, describe the changes, if any, in how the sales addressed in Paragraph 11(c) would be recorded in the Company’s books and records during the Term.

e. Hypothetically, if the Company made a “separated/stratified sale” for 100,000 kWh of energy, will the Company’s books and records indicate the generating asset(s) and/or fuel type used to produce the kWh for that sale? Please explain your response.

f. Upon the expiration of the Term, is it the Company’s intent to begin making “separated/stratified sales from energy generated by solar assets being recovered through a SoBRA?” Please explain your response.

A. a. Separated sales are firm wholesale sales greater than one year in duration that commit production capacity of the selling utility to a wholesale purchaser. The production plant assets and operating expenses associated with the sale are separated or removed from the retail jurisdictional cost responsibility. An example would be a firm power sale agreement for 50 MW with a two-year duration.

b. Stratified sales are sales made under the company’s Cost-Based Power Sales Tariff. Charges are based on costs for the units expected to serve the sale’s load. An example would be a 50 MW sale of peaking power. Terms of the sale would be specific to serving the sale from peaking units.

c. The costs associated with serving a separated sale are identified and separated from the retail (FPSC) jurisdiction and assigned to the wholesale (FERC) jurisdiction. Because Tampa Electric serves in only one state, all costs are assigned to either the FPSC or FERC jurisdictions. Retail cost responsibility is adjusted by 1) a reduction in the cost of service retail revenue requirements at the time of the utility's next base rate case; 2) continued monthly surveillance reporting, which, in the event a utility is over-earning, generates additional funds subject to Commission jurisdiction; or 3) through credits in the retail fuel and purchased power cost recovery clause equal to the selling utility's system average fuel costs.

d. Under Paragraph 11(c), separated/stratified sales are not allowed to be made from the energy generated by any solar assets being recovered through a SoBRA during the Term. This does not cause changes in how other sales are recorded in the company's books and records. In addition, the company does not currently have any separated sales.

e. Yes. In the hypothetical scenario described, the costs of a separated sale would be directly assigned to the wholesale jurisdiction for cost recovery purposes. The company would maintain records of the generating assets and/or fuel type expected to serve the sale, and the costs and revenues associated with the wholesale jurisdictional transaction would be excluded from the retail jurisdication in its books and records.

f. No. The company has no current intent to make separated or stratified sales upon the expiration of the term, unless circumstances change where these would be in the best interest of the general body of customers.

26. Refer to Paragraph 11(d), which addresses crediting the fuel clause when certain sales are made.

a. Please define the term "non-separated wholesale energy sales," providing examples.

b. Describe how the sales addressed in Paragraph 11(d) are currently recorded in the Company's books and records. As appropriate, identify the specific monthly schedules that are used for this purpose.

c. Assuming the Company's Petition is approved, describe the changes, if any, in how the sales addressed in Paragraph 11(d) would be recorded in the Company's books and records during the Term.

A. a. Non-separated wholesale energy sales are wholesale sales less than one year in duration. They are not separated because they are considered to be sporadic or non-recurring energy sales that do not require a long-term capacity commitment by the selling utility. The term of the sale may be hourly, blocks of hours, daily, weekly, monthly, or seasonal. These sales are typically recallable by the selling utility if it needs to serve its native load, and non-separated sales are not assigned cost responsibility through the jurisdictional cost of service study or monthly FPSC surveillance separation process. Since retail customers are responsible for the costs to make the sale, the margins of the sales are returned to customers through the fuel clause, subject to any applicable sharing specified by Order No. PSC-2000-1744-PAA-EI, and any transmission revenues or separately identifiable capacity revenues associated with the sales are credited to the capacity clause.

b. See the company's response to subpart 26a, above. The company reports non-separated, non-emergency sales to the FPSC each month on its Fuel Schedule A6. The company reports transmission and capacity revenues of sales on the monthly Fuel Schedule A12.

c. The sales would be recorded in the company's books and records during the Term of the agreement in the same manner they currently are. The only difference would be the different thresholds applicable to sharing under the proposed optimization mechanism, if approved as part of the Settlement agreement, instead of the current non-separated sales incentive approved by Order No. PSC-2000-1744-PAA-EI. The company would continue to follow the current practice of crediting the fuel clause with an amount equal to the company's incremental cost of generating or purchasing the amount of energy sold during the hours it was sold, as required by Order No. PSC-2001-2371-FOF-EI.

27. Please refer to Paragraphs 10 and 11(e). Please explain if solar renewable energy credits are sold would the profits from this sale be accounted for in the $4.5MM/year to $8.0MM/year range determined by the Asset Optimization/Incentive Mechanism program.

A. No. Any sales of solar renewable energy credits would not be considered as part of the Asset Optimization/Incentive Mechanism.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Carlos Aldazabal who deposed and said that he is Managing Director, Regulatory Affairs Tampa Electric Company. He prepared or assisted with Tampa Electric Company's response to Staff's First Request for Data Requests (Nos. 11–12, 17-19, and 22-27) to the best of his information and belief.

Dated at Tampa, Florida this 16 day of October, 2017.

Carlos Aldazabal
____

Sworn to and subscribed before me this 16th day of October, 2017.

Paula K. Brown
____

My Commission expires Notary Public State of Florida Paula K Brown My Commission GG 032689 Expires 12/04/2020

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared William R. Ashburn who deposed and said that he is Director, Pricing and Financial Analysis, Tampa Electric Company. He prepared or assisted with Tampa Electric Company's response to Staff's First Request for Data Requests (Nos. 1-4, 16 and 20-21) to the best of his information and belief.

Dated at Tampa, Florida this 16th day of October, 2017.

William Ashburn

Sworn to and subscribed before me this 16th day of October, 2017.

Paula K. Brown

My Commission expires Notary Public State of Florida Paula K Brown My Commission GG 032689 Expires 12/04/2020

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared R. James Rocha who deposed and said that he is Director, Generation Asset Strategy, Tampa Electric Company. He prepared or assisted with Tampa Electric Company's response to Staff's First Request for Data Requests (Nos. 10 and 13-14) to the best of his information and belief.

Dated at Tampa, Florida this 16th day of October, 2017.

R James Rocha
____

Sworn to and subscribed before me this 16th day of October, 2017.

Paula K. Brown
____

Notary Public State of Florida
Paula K Brown
My Commission GG 032689
Expires 12/04/2020

My Commission expires ____________________________

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Mark D. Ward who deposed and said that he is Director, Renewable Energy, Tampa Electric Company. He prepared or assisted with Tampa Electric Company's response to Staff's First Request for Data Requests (Nos. 5-9, and 15) to the best of his information and belief.

Dated at Tampa, Florida this 16th day of October, 2017.

Mark D. Ward
____

Sworn to and subscribed before me this 16th day of October, 2017.

Paula K. Brown
____

Notary Public State of Florida
Paula K Brown
My Commission GG 032689
Expires 12/04/2020

My Commission expires ___________________

4

TECO's responses to Staff's Second Data Requests (Nos. 28-37)

Additional file "(BS 13) Staff 2nd DR No. 35.xlsx" provided separately.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170210-EI   EXHIBIT: 4
PARTY: STAFF– (DIRECT)
DESCRIPTION: TECO's responses to Staff's Second Data Requests (Nos. 28-37)Additional file "(BS 13) Staff

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October 24, 2017

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Petition by Tampa Electric Company for a limited proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement, Docket No. 20170210-EI; Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism, Docket No. 20160160-EI

Dear Ms. Stauffer:

Attached are Tampa Electric Company's responses to Staff's Second Data Requests (Nos. 28-37), propounded and served by electronic mail on October 19, 2017.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

cc:	Bill McNulty	(w/attachment)
	J. R. Kelly/Charles Rehwinkel	(w/attachment)
	Jon C. Moyle, Jr.	(w/attachment)
	Robert Scheffel Wright	(w/attachment)
	Thomas Jernigan	(w/attachment)
	Mark Sundback	(w/attachment)
	Kenneth L. Wiseman	(w/attachment)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Tampa Electric Company for a Limited Proceeding to Approve 2017 Amended and Restated Stipulation and Settlement Agreement	**))))**	**DOCKET NO. 20170210-EI**

and

Petition by Tampa Electric Company for Approval of Energy Transaction Optimization Mechanism	**)))**	**DOCKET NO. 20160160-EI** **FILED: OCTOBER 24, 2017**

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SECOND DATA REQUEST (NOS. 28-37)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files its Answers to Data Request (Nos. 28-37) propounded and served on October 19, 2017 by the Florida Public Service Commission Staff.

28. IM Risk. Does the incentive mechanism expose TECO ratepayers to any risks beyond those that exist prior to the mechanism being put in place. If so, please also identify those risks and what safeguards will be put in place to mitigate such risks.

A. No. The incentive mechanism is designed to incent the company to maximize its utilization of existing assets for the benefit of customers. The company will only optimize the utilization of its assets if it is confident that it will not adversely impact its retail customers. The company will utilize safeguards that include review of transactions by middle and back office personnel as well as the risk management function to ensure that customers are protected.

29. IM Gains/Losses. For each activity the company included in the incentive mechanism, including each asset optimization activity, please describe how gains and losses are to be calculated and allocated between the ratepayers and shareholders.

A. For all new asset optimization transactions proposed for the optimization mechanism, the benefit will be calculated as the incremental revenue minus the incremental cost. Examples are provided in the following tables. The gains and losses on non-separated wholesale sales and short-term wholesale purchases will continue to be calculated and reported on Schedules A6 and A9 as they are currently. The net amount of the gains and any losses would be allocated entirely for the benefit of customers up to the $4.5 million threshold in the Settlement and then shared based on the agreed upon percentages.

Gas Storage Capacity Transaction

Description: Temporarily unused gas storage capacity is released to a counterparty for their use during a specified time period.

Example: TEC releases 10,000 mmBtu per day of storage capacity over the Thanskgiving long weekend.

Benefit			
Released Quantity		10,000	mmBtu per day
Rate	$	0.100	$/mmBtu per day
Number of Days		5	
Avoided Storage Reservation Cost	**$**	**5,000**	
Incremental Cost		0	
Gain	**$**	**5,000**	

City Gate Sale

Description: Sale of natural gas delivered to the customer's designated receipt point.

Example: Tampa Electric sells 10,000 MMBtu of gas to a neighboring utility at its FGT Interconnect.

Sell to Neighboring Utility on FGT		
Benefit		
Quantity		10,000
Posted City Gate Index Price	$	2.80
Incremental Revenue	**$**	**28,000**
Cost		
Quantity		10,000
Fuel		256
Total Quantity of Purchased Gas		10,256
FGT Zone 3 Index Price	$	2.45
FGT Usage Rate	$	0.04
Cost of Commodity	$	24,500
Cost of Fuel	$	628
Pipeline Usage	$	400
Incremental Cost	**$**	**25,528**
Gain	**$**	**2,472**

Production Area Gas Sales

Description: Buy natural gas commodity from one counterparty and re-sell it to another counterparty in the production area.

Example: Tampa Electric has FGT interstate pipeline capacity that is not needed to meet retail customer generation over a weekend. Tampa Electric buys commodity at one receipt point and re-sells that commodity at another receipt point.

Benefit			
Sell Gas in Zone 2		10,000	MMBtu
Sale Price	$	2.45	per MMBtu
Incremental Revenue	**$**	**24,500**	
Cost			
Buy Gas in Zone 1		10,000	MMBtu
Purchase Price	$	2.40	per MMBtu
Incremental Cost	**$**	**24,000**	
Gain	**$**	**500**	

Asset Management Agreement ("AMA") - Capacity Release

Description: Release interstate pipeline capacity to a third party under under an AMA arrangement in exchange for a fee.

Example: Tampa Electric releases 10,000 MMBtu of FGT interstate pipeline capacity to a third party under an Asset Management Agreement for a month in exchange for a Premium of $0.03 per MMBtu. Tampa Electric can recall the capacity when it is needed for retail load.

Benefit			
Quantity		10,000	MMBtu per Day
Rate	$	0.03	$/MMBtu per Day
Number of Days		31	
Incremental Revenue	**$**	**9,300**	
Incremental Cost	**$**	**-**	
Gain	**$**	**9,300**	

30. IM Gains/Losses. How will losses, if any, be treated under the incentive mechanism? Include in your response a discussion on whether ratepayers or shareholders would be responsible for recovery of losses.

A. Tampa Electric will execute transactions that have a projected positive benefit. This is applicable to all activities and sub-activities currently contemplated or that may arise in the future under the optimization mechanism.

The company does not expect to incur losses as a result of the optimization mechanism transactions. The results of each transaction included in the proposed optimization mechanism would be accumulated for a total, net annual benefit. The company has no incentive to, and will not, intentionally enter into transactions expected to result in a loss so the transaction can be bundled with a gain transaction. In the rare event of an unavoidable loss, it is expected that the loss would be outweighed by the cumulative benefits of other transactions. The net annual benefit inclusive of losses will be shared between customers and the company per the approved thresholds and sharing percentages.

31. IM Gains/Losses. For incentive mechanism activities that may involve transactions that must be reduced, curtailed, or eliminated in order to meet its retail customer needs, how does TECO intend to shield customers from losses on such transactions?

A. Tampa Electric will not make any asset optimization mechanism transactions until after the company's retail customers' needs have been satisfied. As is its current practice, Tampa Electric will perform sensitivity analyses before the transaction occurred to understand potential customer impacts that could occur in the event of supply disruption or greater than forecast peaks. In the rare event that circumstances change customers' needs to the point that the transaction needs to be cancelled, Tampa Electric will cancel the non-firm power sale or recall the interstate pipeline capacity. These types of transactions will be executed as either non-firm or recallable so that customers are protected.

32. IM Review Period. Please explain if the incentive mechanism is intended to survive the Term of the Settlement Agreement. If so, when will it expire and when will the Commission have an opportunity to review the incentive mechanism.

A. The incentive mechanism is a four-year pilot program effective during the term of the Settlement Agreement, from January 1, 2018 through December 31, 2021. The incentive mechanism pilot program can be extended with Commission approval. The Commission will be provided annual reports of the incentive mechanism results during the term of the Settlement Agreement and can review the incentive mechanism near the end of the term, prior to any request to extend the program.

33. SoBRA. Please refer to Paragraphs 6(b), 6(c), and 6(j). Reconcile the difference between the annual Maximum Incremental SoBRA capacity and revenue requirements outlined in 6(b) and the allowance for delayed in-service dates of projects in 6(c) and unused capacity in 6(j). As part of your response, explain whether projects would be eligible for recovery under these provisions if they exceed the maximum incremental annual capacity or revenue requirement values due to a delay in in-service date or unused capacity in a later year.

A. The SoBRA provisions in 6(b), 6(c) and 6(j) are intended to set maximum levels of solar capacity and associated revenue requirements that can be built in a period. However, if the in-service date of a particular project(s) is delayed and not in service as of the cutoff date for a particular period, the company could build that project in a future period provided the total capacity built up to that point did not exceed the maximum cumulative SoBRA MW reflected on the chart in 6(b). Similarly, the maximum cumulative annualized SoBRA revenue requirements could not be exceeded due to a delay in in-service date or reduced solar capacity built in a prior period. However, the company must petition for approval for cost recovery via a SoBRA during the Term of the 2017 Settlement Agreement and any project included in a SoBRA Tranche must be fully operational and providing service no later than December 31, 2022.

34. SoBRA. Please refer to Paragraph 6(c). Please explain the relationship between a 2% variance in revenue requirements and a 5MW variance for 2019 SoBRA Tranche.

a. Please explain if the 2% variance and 5 MW variance only applies to 2018 and 2019 SoBRA Tranches.

b. Please explain if the 2% variance applies to the $1,500kWac cost cap as well.

A. a. Paragraph 6(c) is a Negotiated Term intended to specify that the two percent variance only applies to the 250 MW for the 2019 SoBRA tranche. This means, for example, that the company could construct 255 MW of solar projects in 2019 to accommodate efficient planning and construction of its planned solar projects. It is expected that a two percent increase in MW would translate to a two percent increase in revenue requirements. The two percent variance (or 5 MW) only applies to the 2019 SoBRA tranche.

b. The two percent variance does not apply to the $1,500 / kWac cost cap.

35. IM Historic Data. Please provide, in an electronic (PDF or Excel if available) format, TECO's final year-to-date Fuel Savings Schedules A6 and A9 for the years 2007 through 2017 (as available).

A. The requested information is provided in the Excel file "BS 13 Staff 2nd DR No 35.xlsx."

36. Government Impositions. Please refer to the Settlement, Pages 7-8, Paragraph 4. In part, paragraph 4 states that the Company will not seek recovery in a cost recovery clause for "costs of any type or category that have historically or traditionally been recovered in base rates, unless such costs are: (i) the direct and unavoidable result of new government impositions or requirements . . .." Is the Company aware of any new "government impositions or requirements" that are under development at this time and are likely to be considered during the term of this Agreement? If so, please provide a detailed response, citing the applicable cost recovery clause(s) that could be impacted.

A. The company is not aware of any new government impositions or requirements that are under development at this time and are likely to be considered during the term of this Agreement.

37. Depreciation Rates. TECO's Petition for Approval of Depreciation Rates for Various Accounts in Docket No. 20170198-EI is currently scheduled to be voted upon by the Commission on November 7, 2017. Please confirm that the depreciation rates resulting from the Commission's vote in Docket No. 20170198-EI, extending through the Term of the Settlement, is acceptable to the Parties of the Settlement, the language of Paragraph 8(a) of the Settlement notwithstanding.

A. Commission Staff has clarified that this question is intended to refer to Docket No. 20170182-EI. The company currently has a Petition for Approval of Depreciation Rates for Various Accounts in Docket No. 20170182-EI scheduled to be voted upon by the Commission on November 7, 2017. The company is seeking to continue applying the referenced depreciation rates in the filing to the accounts provided in the filing on an interim basis until such time as depreciation rates are examined in detail in the company's next depreciation study. As noted in the filing, the company has been applying those depreciation rates since 2011. The company has confirmed with the Consumer Parties to the Settlement that the depreciation rates resulting from the Commission's vote in Docket No. 20170182-EI extending through the Term of the Settlement is acceptable, notwithstanding the language of Paragraph 8(a) of the Settlement Agreement.

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Carlos Aldazabal who deposed and said that he is Managing Director, Regulatory Affairs Tampa Electric Company. He prepared or assisted with Tampa Electric Company's response to Staff's Second Request for Data Requests (Nos. 28-37) to the best of his information and belief.

Dated at Tampa, Florida this 24th day of October 2017.

Carlos Aldazabal

Sworn to and subscribed before me this 24th day of October 2017.

Paula K. Brown

Notary Public State of Florida
Paula K Brown
My Commission GG 032689
Expires 12/04/2020

My Commission expires ____________________