Docket No. 20170183-EI
Comprehensive Exhibit List for Entry into Hearing Record
October 25, 2017

EXH #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
STAFF– (DIRECT)					
2			DEF's Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement and Exhibits *[Bates No. 00001-00182]*		stipulated
3			DEF's Response to Staff's First Set of Data Requests, No. 3A *[Bates No. 00183-00192]*		stipulated
4			DEF's Response to Staff's Second Data Request, Nos. 6, 7, 8 *[Bates No. 00193-00203]*		stipulated
5			DEF's Response to Staff's Third Data, No. Request 9 *[Bates No. 00204-00218]*		stipulated

6			DEF's Response to Staff's Fourth Data Request, Nos. 10-15 *[Bates No. 00219-00226]*		stipulated
7			DEF's Response to Staff's Fifth Data Request, No. 16 *[Bates No. 00227-00232]*		stipulated
8			DEF's Response to Staff's Sixth Set of Data Request, Nos. 17-29, 31-42, 45, 46, 48-52 *[Bates No. 00233-00263]*		stipulated
9			DEF's Response to Staff's Seventh Data Request, Nos. 54-56 *[Bates No. 00264-00272]*		stipulated
10			DEF's Response to Staff's Eighth's Data Request, Nos. 57-60 *[Bates No. 00273-00278]*		stipulated
11			DEF's Response to Staff's Ninth Data Request, Nos. 61, 63-67 *[Bates No. 00279-00285]*		stipulated
12			DEF'S Response to Staff's Tenth Data Request, No. 68-72 *[Bates No. 00286-00294]*		stipulated

2

DEF's Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement and Exhibits

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170183-EI EXHIBIT: 2
PARTY: STAFF– (DIRECT)
DESCRIPTION: DEF's Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Se...

DUKE ENERGY
FLORIDA

Dianne M. Triplett
ASSOCIATE GENERAL COUNSEL

August 29, 2017

VIA ELECTRONIC FILING

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

Re: In re: Duke Energy Florida, LLC's Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement, Including Certain Rate Adjustments; Docket No. ________________

Docket Numbers 20170001, 20170002, 20170009 and 2015171

Dear Ms. Stauffer:

Attached for filing on behalf of Duke Energy Florida, LLC ("DEF") is DEF's Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement, Including Certain Rate Adjustments with attached Second Revised and Restated Stipulation and Settlement Agreement and exhibits.

Thank you for your assistance in this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Sincerely,

/s/ Dianne M. Triplett

Dianne M. Triplett
Associate General Counsel

DMT/db
Attachment

cc: Certificate of Service

299 First Avenue North (33701) ▪ Post Office Box 14042 (33733) ▪ St. Petersburg, Florida
Phone: 727.820.4692 ▪ Fax: 727.820.5041 ▪ Email: dianne.triplett@duke-energy.com

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause	Docket No. 20170009-EI
In re: Examination of the outage and replacement fuel/power costs associated with the CR3 steam generator replacement project, by Progress Energy Florida, Inc.	Docket No. 100437-EI (closed)
In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 20170001-EI
In re: Petition of Duke Energy Florida, Inc., for issuance of a nuclear asset recovery financing order	Docket No. 20150171-EI
In re: Energy Conservation Cost Recovery Clause	Docket No. 20170002-EG
In re: Petition of Duke Energy Florida, LLC, for limited proceeding to approve 2017 Second Revised and Restated Settlement Agreement, including certain Rate Adjustments	Docket No. ______________ Filed: August 29, 2017

DUKE ENERGY FLORIDA, LLC'S PETITION FOR LIMITED PROCEEDING TO APPROVE 2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT, INCLUDING CERTAIN RATE ADJUSTMENTS

Duke Energy Florida, LLC ("DEF" or the "Company"), pursuant to Sections 366.076, 120.57(2), and 366.06(3), Florida Statutes ("F.S."), and Rule 28-106.301, F.A.C., respectfully petitions the Florida Public Service Commission ("PSC" or the "Commission") for a limited proceeding to approve the 2017 Second Revised and Restated Settlement Agreement attached as an exhibit to this Petition and incorporated and made a part of this Petition.

BACKGROUND

The 2017 Second Revised and Restated Settlement Agreement, with noted exceptions, replaces and supplants the 2013 Revised and Restated Stipulation and Settlement Agreement (the "2013 Settlement Agreement"), approved by the Commission in Order No. PSC-13-0598-FOF-EI, in the limited proceeding docket, Docket No. 130208-EI.[1] The Commission also approved three stipulations to amend the 2013 Settlement Agreement, *see* Order Nos: PSC-15-0465-S-EI, issued on October 14, 2015 in Docket Nos. 150148-EI and 150171-EI; PSC-16-0138- FOF-EI, issued on April 5, 2016 in Docket No. 150171-EI; and PSC-16-0425-PAA-EI, issued on October 3, 2016 in Docket No. 160151-EI. The 2017 Second Revised and Restated Settlement Agreement is between DEF, the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), White Springs Agriculture Chemicals, Inc. d/b/a PCS Phosphate ("White Springs"), and the Southern Alliance for Clean Energy ("SACE") (hereinafter collectively the "Parties").

Approval of the 2017 Second Revised and Restated Settlement Agreement in this limited proceeding under Section 366.076, F.S., is appropriate because, by way of example, it determines, in a comprehensive manner, all remaining issues regarding the Levy Nuclear Project ("LNP"). It resolves the uncertainties related to those issues that may adversely affect DEF's customers, in particular by providing that effective as of May 2015 there will never be any additional LNP-related costs recovered from DEF's retail customers. This 2017 Second Revised and Restated Settlement Agreement also addresses numerous base rate, infrastructure and clean energy matters that all Parties support as timely, appropriate and reasonable. Ultimately, this 2017 Second

[1] The Commission amended this order to correct a scrivener's error in Order No. PSC-13-0598A-FOF-EI. All remaining terms and conditions of Order No. PSC-13-0598-FOF-EI were reaffirmed and remain in full force and effect.

Revised and Restated Settlement Agreement between DEF and the Parties who represent customers' interests before the Commission is a fair, reasonable, and comprehensive resolution of matters that is in the best interests of DEF and its customers, and that is therefore in the public interest.

The exhibits to this Petition include the 2017 Second Revised and Restated Settlement Agreement and other supporting exhibits, all of which are integral parts of the 2017 Second Revised and Restated Settlement Agreement. The Parties have agreed to the terms and conditions of the 2017 Second Revised and Restated Settlement Agreement as a comprehensive and interdependent package, such that disapproval of any portion of the 2017 Second Revised and Restated Settlement Agreement would negate the effectiveness of the 2017 Second Revised and Restated Settlement Agreement. Accordingly, for all the reasons in this Petition, DEF requests and moves the Commission to grant this Petition and approve the 2017 Second Revised and Restated Settlement Agreement in its entirety.

I. Preliminary Information.

1. The Petitioner's name and address are:

Duke Energy Florida, LLC
299 1st Avenue North
St. Petersburg, Florida 33701

2. Any pleading, motion, notice, order, or other document required to be served upon DEF or filed by any party to this proceeding should be served upon the following individuals:

Dianne Triplett
dianne.triplett@duke-energy.com
Duke Energy Florida, LLC
299 1st Avenue North
St. Petersburg, Florida 33701
(727) 820-4692 / (727) 820-5519 (fax)

Matthew R. Bernier
matthew.bernier@duke-energy.com
Duke Energy Florida, LLC
106 E. College Ave., Ste. 800
Tallahassee, Florida 32301
(850) 521-1428 / (850) 521-1437 (fax)

3. DEF, the Petitioner, is an investor-owned electric utility, regulated by the Commission pursuant to Chapter 366, F.S., and is a wholly owned subsidiary of Duke Energy Corporation. The Company's principal place of business is located at 299 1st Avenue North, St. Petersburg, Florida 33701.

4. DEF serves more than 1.8 million retail customers in Florida. Its service area comprises approximately 20,000 square miles, encompassing the densely populated areas of Pinellas and western Pasco Counties and the greater Orlando area in Orange, Osceola, and Seminole Counties. DEF supplies electricity at retail to approximately 350 communities and at wholesale to Florida municipalities, utilities, and power agencies in the State of 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 Second Revised and Restated Settlement Agreement between the Parties.

6. Among other things, the 2017 Second Revised and Restated Settlement Agreement settles all remaining issues between the Parties in the Nuclear Cost Recovery Clause ("NCRC") docket pertaining to the LNP. It also streamlines and continues the complete and final exit of DEF from the NCRC proceeding process by the end of 2019, with DEF participating in its

last NCRC hearing in 2018. The 2017 Second Revised and Restated Settlement Agreement further presents a base rate plan that would establish rates through the end of the year 2021. The detailed terms are set forth in more detail in the 2017 Second Revised and Restated Settlement Agreement attached as an exhibit to and incorporated in the Petition. Additionally, inasmuch as the parties have engaged in extensive informal – but highly detailed – discovery and a general exchange of information over a period of more than six months, the revenue increases contained in the 2017 Second Revised and Restated Settlement Agreement, coupled with the base rate freeze and solar generation transformation, represent both a short-term and longer-term moderation of future rate impacts that would otherwise likely occur as a result of conventional base rate proceedings in and after 2018.

7. DEF believes, and represents the Parties believe, that the 2017 Second Revised and Restated Settlement Agreement in its totality is fair, just, and reasonable and that it is in the public interest. The 2017 Second Revised and Restated Settlement Agreement provides the Company, the Parties, and the Company's customers represented by the numerous Parties, a comprehensive resolution of all remaining LNP issues and additional matters as described in the 2017 Second Revised and Restated Settlement Agreement. As a result, the 2017 Second Revised and Restated Settlement Agreement fairly and reasonably balances the various positions of the Parties on the issues resolved by the 2017 Second Revised and Restated Settlement Agreement and serves the best interests of the customers they represent and the public interest in general. Approval of the 2017 Second Revised and Restated Settlement Agreement promotes administrative efficiency and avoids the time and expense associated with litigating the settled issues in the various existing and continuing Commission dockets and is further consistent with the Commission's long-standing

practice of encouraging parties to settle contested proceedings whenever possible.[2] DEF, therefore, requests and moves the Commission to grant this Petition and approve the 2017 Second Revised and Restated Settlement Agreement in its entirety.

8. Section 366.076(1), F.S., provides that the Commission may conduct a limited proceeding to consider and act upon any issue within its jurisdiction, including any issue which, once resolved, requires a public utility to adjust its rates. Approval of the 2017 Second Revised and Restated Settlement Agreement through a limited proceeding under Section 366.076, F.S., provides the Commission and the Parties a single proceeding in which all issues related to the LNP will be resolved. Concurrently with the filing of this Petition, DEF is filing, in the NCRC, a Motion to Defer or Continue the LNP portion of the NCRC Hearing, currently scheduled to begin on October 25, 2017, to allow the Commission time to consider the 2017 Second Revised and Restated Settlement Agreement. Because the 2017 Second Revised and Restated Settlement Agreement resolves all issues that would be decided in that NCRC hearing, if the Commission approves this 2017 Second Revised and Restated Settlement Agreement, continuance of the LNP portion of the NCRC hearing will allow the Commission to cancel it as moot under those

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[2] 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 for 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).

circumstances. Implementation of the Company's proposed base rate adjustments set forth in the 2017 Second Revised and Restated Settlement Agreement will become effective consistent with the terms of the 2017 Second Revised and Restated Settlement Agreement, pursuant to the Commission's Order granting the Petition and approval of the 2017 Second Revised and Restated Settlement Agreement in its entirety. Accordingly, DEF requests and moves the Commission to grant the Petition and approve the 2017 Second Revised and Restated Settlement Agreement.

III. Statement of No Disputed Issue of Material Fact.

9. DEF believes, and represents the other Parties believe, that there are no disputed issues of material fact that must be resolved in order for the Commission to grant the Petition and approve the 2017 Second Revised and Restated Settlement Agreement.

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

10. The ultimate facts that entitle DEF to the relief requested herein, i.e. the Commission granting the Petition and approving the 2017 Second Revised and Restated Settlement Agreement, are that the 2017 Second Revised and Restated Settlement Agreement represents a fair and reasonable resolution of all remaining issues related to the LNP, that the rates resulting from approval of the Petition and the 2017 Second Revised and Restated Settlement Agreement will be fair, just, and reasonable, and that the 2017 Second Revised and Restated Settlement Agreement is in the public interest. DEF is entitled to the relief requested pursuant to Chapter 366, F.S., and Chapter 120, F.S.

V. Effective Date, Notice, and Final Hearing.

11. DEF requests that the Commission provide public notice of this Petition for the approval of the 2017 Second Revised and Restated Settlement Agreement in this and the other

dockets affected by the 2017 Second Revised and Restated Settlement Agreement, and set the Petition approval of the 2017 Second Revised and Restated Settlement Agreement for final hearing. DEF asks that the Commission's consideration of the proposed 2017 Second Revised and Restated Settlement Agreement be decided by a bench vote at the conclusion of the requested final hearing. DEF has conferred with the other Parties to the 2017 Second Revised and Restated Settlement Agreement, and represents that those Parties support this approach.

12. The Parties to the 2017 Second Revised and Restated Settlement Agreement include OPC, who represents all customers, the organizations that represent the major customer groups served by the Company, and an environmental protection organization, and thus, the interests of all customers and customer classes are fairly represented by the signatories to the 2017 Second Revised and Restated Settlement Agreement. DEF, therefore, requests that the Commission proceed expeditiously to issue the public notice of the hearing on this Petition for approval of the 2017 Second Revised and Restated Settlement Agreement and to 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 Second Revised and Restated Settlement Agreement, it is the Parties' intent that the tariff sheets reflected in Exhibits 3 and 4 of the 2017 Second Revised and Restated Settlement Agreement become effective January 1, 2018. Accordingly, the Parties respectfully request that the final hearing be set no later than December 1, 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 DEF 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), F.S. Accordingly, if the Commission does not set a final hearing

such that the 2017 Second Revised and Restated Settlement Agreement will be approved before the first billing cycle of January 2018, DEF respectfully requests that the Commission authorize the implementation of DEF's tariff sheet changes, effective with the first billing cycle of January 2018, subject to refund, pending the outcome of the final hearing. DEF is authorized to represent that the Parties to the 2017 Second Revised and Restated Settlement Agreement affirmatively agree that in this event that the Commission should either vote to approve the attached tariffs or allow them to go into effect by operation of law with revenues held subject to refund as provided for pursuant to Section 366.06, F.S.

VI. Conclusion.

14. For all the reasons provided in this Petition, and the supporting 2017 Second Revised and Restated Settlement Agreement, complete with amended tariff sheets and other exhibits to the 2017 Second Revised and Restated Settlement Agreement filed with this Petition, DEF respectfully requests that the Commission promptly schedule the consideration of the 2017 Second Revised and Restated Settlement Agreement for final hearing, grant this Petition, and approve the 2017 Second Revised and Restated Settlement Agreement pursuant to Section 366.076(1), F.S.

Respectfully submitted this 29th day of August, 2017

s/ Dianne M. Triplett
Dianne M. Triplett
Associate General Counsel
DUKE ENERGY FLORIDA, LLC
Post Office Box 14042
St. Petersburg, FL 33733-4042
(727) 820-4692
dianne.triplett@duke-energy.com

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 29th day of August, 2017.

/s/ Dianne M. Triplett
Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Kelly Corbari Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us kcorbari@psc.state.fl.us ltan@psc.state.fl.us rgervasi@psc.state.fl.us scuello@psc.state.fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com kevin.donaldson@fpl.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com Russell A. Badders / Steven R. Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591 rab@beggslane.com srg@beggslane.com

George Cavros 120 E. Oakland Park Blvd, Suite 105 Fort Lauderdale, FL 33334 george@cavros-law.com Mike Cassel, Director Regulatory Affairs Florida Public Utilities Company 1750 S 14th Street, Suite 200 Fernandina Beach, FL 32034 mcassel@fpuc.com Rhonda J. Alexander Regulatory and Pricing Manager Gulf Power Company One Energy Place Pensacola, FL 32520-0780 rjalexad@southernco.com Jeffrey A. Stone, General Counsel Gulf Power Company One Energy Place Pensacola, FL 32520-0780 jastone@southernco.com Joseph Fichera Saber Partners, LLC 44 Wall Street New York, NY 10005 jfichera@saberpartners.com	Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com Ms. Paula K. Brown Manager, Regulatory Coordination Tampa Electric Company P.O. Box 111 Tampa, FL 33601 regdept@tecoenergy.com John T. Butler / Maria Jose Moncada Florida Power & Light Company 700 Universe Boulevard (LAW/JB) Juno Beach, FL 33408-0420 john.butler@fpl.com maria.moncada@fpl.com Kenneth Hoffman, Vice President Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Dean E. Criddle Orrick, Herrington & Sutcliffe 405 Howard Street, #11 San Francisco, CA 94105 dcriddle@orrick.com

2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT

Contents

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause	Docket No. 20170009-EI
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In re: Energy Conservation Cost Recovery Clause	Docket No. 20170002-EG
In re: Petition of Duke Energy Florida, LLC, for limited proceeding to approve Second Revised and Restated Settlement Agreement, including certain Rate Adjustments	Docket No. ______________ Submitted for filing: August 29, 2017

2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT

WHEREAS, Duke Energy Florida, LLC ("DEF" or the "Company"), the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), and White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate ("White Springs"), (collectively referenced as the "Original Parties"), previously resolved certain issues in a Stipulation and Settlement Agreement, dated January 20, 2012 (the "2012 Settlement Agreement"), that was approved by the Florida Public Service Commission ("FPSC" or the "Commission") in

Order No. PSC-12-0104- FOF-EI[1], issued on March 8, 2012 in Docket No. 120022-EI, as amended by Order No. PSC-12-0104A-FOF-EI; and

WHEREAS, the Original Parties resolved additional issues in that certain Revised and Restated Stipulation and Settlement Agreement (the "2013 Settlement Agreement"), dated July 31, 2013, that was approved by the Commission in Order No. PSC-13-0598- FOF-EI, issued on November 12, 2013 in Docket No. 130208-EI; and

WHEREAS, on August 6, 2015, the Original Parties entered into a stipulation in Docket No. 150009-EI, in which the Original Parties agreed that DEF would make its final true-up filing of all known Levy Nuclear Project ("LNP") costs in the 2017 nuclear cost recovery clause ("NCRC") hearing cycle; and

WHEREAS, the Original Parties entered into three stipulations to amend the 2013 Settlement Agreement, which were approved by the Commission in Order Nos: PSC-15-0465-S-EI, issued on October 14, 2015 in Docket Nos. 150148-EI and 150171-EI; PSC-16-0138- FOF-EI, issued on April 5, 2016 in Docket No. 150171-EI; and PSC-16-0425-PAA-EI, issued on October 3, 2016 in Docket No. 160151-EI; and

WHEREAS, on December 22, 2016, DEF received a judgment in the litigation against Westinghouse Electric Company ("WEC") regarding termination costs associated with the cancellation of the Engineering, Procurement, and Construction ("EPC") contract associated with the LNP, in which the trial court ordered DEF to pay a $30 million termination fee (plus approximately $4 million in prejudgment interest), denied DEF's claim for the return of $54 million previously paid to WEC for goods not

[1] The Parties note that historic (i.e. pre-2017) docket and order references were originally cited using a six digit format rather than the new eight digit format, and if reference is made herein using the six digit format, the intent of the Parties is that the effect of orders in this 2017 Second Revised and Restated Settlement Agreement remains as originally issued, regardless of the revised numbering format.

received, and denied the remainder of WEC's claim for approximately $482 million in additional termination costs. (*Duke Energy Florida, Inc. v. Westinghouse Electric Company*, in the United States District Court for the Western District of North Carolina, Charlotte Division, Civil Action No. 3:14-CV-00141-MOC-DSC); and

WHEREAS, WEC appealed that order on January 20, 2017, DEF cross-appealed on February 1, 2017, and the appellate cases were combined and at this time remain pending in the United States Court of Appeals for the Fourth Circuit (Case No. 17-1151 and 17-1087); and

WHEREAS, DEF petitioned for cost recovery of certain known costs, amounting to $81,901,218 (retail), as identified in the May 1, 2017 pre-filed testimony of Christopher M. Fallon and Thomas G. Foster, related to the LNP in Docket No. 20170009-EI, and sought to reserve the right to seek future recovery of additional LNP costs related to the pending WEC appellate case; and

WHEREAS, DEF has not yet submitted any claim for cost recovery in Docket 20170009-EI for its future litigation costs, nor the above-referenced $34 million (system) and $482 million (system), plus interest, related to the WEC appeal but has expressed an intent to do so if and to the extent such costs become known and measureable and an obligation of DEF; and

WHEREAS, the Original Parties and the Southern Alliance for Clean Energy ("SACE") (collectively referred to as the "Parties") agreed that in light of those decisions and actions that it is in the public interest to attempt to resolve all remaining LNP-related issues in Docket No. 20170009-EI, as well as additional matters described herein; and

WHEREAS, the Parties have reached an agreement regarding the matters set forth in this 2017 Second Revised and Restated Stipulation and Settlement Agreement ("2017 Second Revised and Restated Settlement Agreement"), dated August 29, 2017; and

WHEREAS, unless the context clearly indicates otherwise, the term Party or Parties means a signatory to this 2017 Second Revised and Restated Settlement Agreement, and Intervenor Parties mean collectively OPC, FIPUG, FRF, and White Springs; and

WHEREAS, agreement on the matters and issues in this 2017 Second Revised and Restated Settlement Agreement will promote administrative efficiency and avoids the time, expense, and uncertainty associated with addressing the issues in the above-referenced Commission dockets and other matters; and

WHEREAS, the Parties further recognize and agree that this 2017 Second Revised and Restated Settlement Agreement fully and finally determines, in a comprehensive manner, the issues related to the circumstances surrounding the LNP as described herein, and, as it impacts customers, resolves uncertainties related to these issues; and

WHEREAS, nothing in this 2017 Second Revised and Restated Settlement Agreement is an admission of liability, imprudence, or fault; and

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

NOW, THEREFORE, in consideration of the foregoing and the mutual covenants contained herein, and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties hereby agree and stipulate as follows:

1. This 2017 Second Revised and Restated Settlement Agreement incorporates the surviving terms and conditions of the 2013 Settlement Agreement and its Exhibits and, as a result, this 2017 Second Revised and Restated Settlement Agreement replaces and supplants the 2013 Settlement Agreement. Terms and conditions of the 2013 Settlement Agreement that are not expressly included in this 2017 Second Revised and Restated Settlement Agreement are extinguished and are of no further effect, except where the survival of a provision is a precedent for: (i) the determination by the Commission of the CR3 nuclear asset recovery costs (as defined in Section 366.95 (1)(k), F.S.) in Docket No. 150171-EI; (ii) DEF's right to recover (on behalf of Duke Energy Florida Project Finance, LLC) the nuclear asset recovery charges (as defined in Section 366.95(1)(j), F.S.) in Docket No. 150171-EI; or (iii) the validity and issuance of nuclear asset recovery bonds pursuant to Section 366.95, F.S., and Order No. PSC-15-0537-FOF-EI and except where such survival is otherwise expressly stated or necessarily implied herein to give force and effect to the intent of the parties in this 2017 Second Revised and Restated Settlement Agreement.

2. The provisions of this 2017 Second Revised and Restated Settlement Agreement will become effective upon Commission approval (the "Effective Date"), and continue through the last billing cycle for December 2021 (the "Term"), unless otherwise specified or provided for in this 2017 Second Revised and Restated Settlement Agreement. The Parties intend for the tariff sheets attached to this 2017 Second Revised and Restated Settlement Agreement to be effective on January 1, 2018, unless otherwise indicated in Paragraphs 29 and 30.

3. The Parties reserve all rights, unless such rights are expressly waived or released, under the terms of this 2017 Second Revised and Restated Settlement Agreement. However, no right reserved in the 2013 Settlement Agreement is waived or extinguished by virtue of this 2017 Second Revised and Restated Settlement Agreement replacing or supplanting the 2013 Settlement Agreement, unless such waiver is express on its face in this 2017 Second Revised and Restated Settlement Agreement. No waiver or release is given orally or by implication, and the only waivers and releases agreed to by any Party to this 2017 Second Revised and Restated Settlement Agreement are those that are expressly stated herein. The failure to specifically set forth a reservation of right(s) clause or an affirmative reservation of right(s) contained in this 2017 Second Revised and Restated Settlement Agreement in another portion of this 2017 Second Revised and Restated Settlement Agreement is not, and shall not, be interpreted as a waiver of any right(s) otherwise reserved by the Original Parties.

<u>CR3:</u>

4. It is the intent of the Original Parties and the Original Parties stipulate that this 2017 Second Revised and Restated Settlement Agreement resolves all

remaining issues that were included in Docket No. 100437-EI (i.e., pertaining to the 2009 CR3 outage, subsequent repair attempts, and retirement) on the terms and conditions set forth herein and in Order Nos. PSC-12-0104-FOF-EI and PSC-13-0598- FOF-EI, including the amendments approved in Order Nos. PSC-15-0465-S-EI, PSC-16-0138- FOF-EI, and PSC-16-0425-PAA-EI. The Intervenor Parties have fully and forever waived, released, discharged, and otherwise extinguished any and all of their rights, claims, and interests of whatever kind or nature, whether now known or unknown, to challenge the reasonableness or prudence of any DEF action, including inaction, or decision, of any kind, type, or nature, both prior to and subsequent to the Implementation Date of the 2012 Settlement Agreement, arising out of, or related or in any way connected to, directly or indirectly, any and all of the issues in Docket No. 100437-EI. Absent evidence of fraud, intentional misrepresentation, or intentional misconduct by DEF, the Intervenor Parties cannot and will not challenge in any Commission or judicial proceeding the prudence of DEF's actions in connection with the issues from Docket No. 100437-EI.

5. a. Pursuant to the 2012 Settlement Agreement, as restated in the 2013 Settlement Agreement, DEF placed CR3 in extended cold shutdown effective January 1, 2011, at which time depreciation and other accruals were suspended and/or reversed until the unit was retired on February 5, 2013. DEF removed CR3 from rate base, and the revenue requirements for CR3 were excluded from the rates established in the 2013 Settlement Agreement effective the first billing cycle for January 2013. Consistent with the terms of the 2013 Settlement Agreement, DEF implemented deferral accounting through the creation of a regulatory asset to address the capital cost amounts and revenue requirements associated with all CR3-related

costs, which was referred to as the "CR3 Regulatory Asset." As determined in Docket Nos. 150148-EI and 150171-EI, the Commission approved the amount of the CR3 Regulatory Asset to be recovered from customers and authorized the issuance of low-cost nuclear asset recovery bonds through securitization. Nothing in this 2017 Second Revised and Restated Settlement Agreement is intended to or does affect the Commission's Orders in these two dockets, or the applicability of Section 366.95, F.S.

(1). The projected dry cask storage ("DCS") facility costs. DEF shall be entitled to petition the Commission for approval of the reasonable and prudent projected DCS facility (also known as the Independent Spent Fuel Storage Installation or ISFSI) capital costs. The Parties are not precluded from fully participating in such a proceeding and do not waive any rights related to such participation or determination. DEF shall be entitled to petition for inclusion of the projected total (retail jurisdictional) value of the reasonable and prudent DCS facility capital costs in the Capacity Cost Recovery ("CCR") Clause using the pretax rate of return of 8.12%, pursuant to Exhibit 10 of the 2013 Settlement Agreement, subject to the amortization deferral approved in Order No. PSC-15-0027-PAA-EI, which costs shall be allocated to rate classes annually using a uniform percentage of the DCS costs to be recovered divided by the total forecasted retail base rate demand and energy revenues. The actual amounts recovered through the CCR Clause shall be subject to the Commission's standard clause true-up, review, audit, and approval processes; the Parties are not precluded from fully participating in such proceedings, for example and without limitation, to challenge the reasonableness and prudence of DEF's claimed DCS facility capital costs, and the Parties do not waive any rights related to such participation or determination. The Parties expressly agree that any proceeding to recover such costs associated with this Paragraph of this 2017 Second Revised and Restated Settlement Agreement shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings. DEF shall credit the CCR Clause with the retail portion of all applicable Department of Energy ("DOE") awards when they are received, and shall amortize the adjusted final DCS facility capital cost balance over the recovery period set forth in Subparagraph 5.c. and 5.d., unless another recovery period is agreed to by all the Original Parties.

b. Matters regarding rate recovery of the CR3 Regulatory Asset were decided by the Commission in Order No. PSC-13-0598-FOF-EI (which approved the 2013 Settlement Agreement), Order No. PSC-15-0465-S-EI (establishing the final amount of the CR3 Regulatory Asset), Order No. PSC-2015-0537-FOF-EI (the Financing Order for the CR3 securitized asset) and Order No. PSC-16-0138-FOF-EI (authorizing $38,108,444 of the CR3 Regulatory Asset to be recovered through the CCR Clause). The Intervenor Parties have fully and forever waived, released, discharged and otherwise extinguished any and all of their rights to contest DEF's right to recover a return of and return on the deferred and accumulated CR3 investments, regulatory assets/liabilities, and carrying costs in the rate increase for the CR3 Regulatory Asset referenced above in Subparagraph 5.a. of this 2017 Second Revised and Restated Settlement Agreement. The Intervenor Parties acknowledge that they have expressly waived, released, and have not retained the right to challenge the inclusion of, and the recovery of, the components of the CR3 Regulatory Asset that were at issue in Docket No. 100437-EI.

c. The Original Parties recognize that the CR3 nuclear asset-recovery costs (as defined in Section 366.95(1)(k), F.S.) are being recovered through the issuance of nuclear asset-recovery bonds (as defined in Section 366.95(1)(i), F.S.) and the recovery of nuclear asset recovery charges (as defined in Section 366.95(1)(j), F.S.), all as approved by the Commission in Docket No. 150171-EI. The Intervenor Parties acknowledge that they have fully and forever waived, released, discharged, and otherwise extinguished any and all of their rights to contest DEF's right to recover on behalf of Duke Energy Florida Project Finance, LLC, the nuclear asset-recovery costs and finance costs that are being recovered pursuant to the Commission's Order in Docket 150171-EI. Accordingly, the nuclear asset-recovery charge (as defined in Section 366.95(1)(j), F.S.) shall remain in effect until the nuclear asset-recovery bonds have been paid in full and the Commission-approved financing costs (as defined in Section 366.95(1)(e), F.S.) have been recovered in full, but in no event for a period longer than the close of the last billing cycle for the 276th month from inception of the nuclear asset-recovery charge, with the understanding that: (i) the nuclear asset-recovery bonds have been structured in a manner such that the scheduled final maturity date for the last maturing tranche of the nuclear asset-recovery bonds is as close as is reasonably possible to the close of the last billing cycle for the 240th month from inception of imposition of the nuclear asset-recovery charge; and (ii) any portion of the recovery period beyond the scheduled final maturity date for the last tranche of the nuclear asset-recovery bonds shall be strictly limited to the purpose of recovery of charges pursuant to the true-up mechanism permitted under any Financing Order that may be issued by the Commission and any adjustments approved by the Commission (in accordance with Section 366.95(2)(c)4, F.S.).

d. The Original Parties continue to intend that retail rate recovery for the nuclear asset recovery charge shall continue for a recovery period consistent with the last sentence in Subparagraph 5c, including a scheduled final maturity date for the last maturing tranche of the nuclear asset-recovery bonds as close as is reasonably possible to the close of the last billing cycle for the 240th month from inception of imposition of the nuclear asset-recovery charge.

e. DEF shall continue to exclude the following amounts related to CR3 from all earnings surveillance reports: (1) revenues associated with the recovery of the CR3 Regulatory Asset including the components referenced in Paragraph 9 and the amount of the excluded portion of the asset referenced in the first sentence of Paragraph 32; (2) rate base and Operating and Maintenance ("O&M") expense amounts (including, but not limited to, all amounts that have been deferred to or recorded in regulatory assets and liabilities); and (3) cost of capital accounts with specific adjustments for items including, but not limited to, deferred income taxes, with all other CR3-related items removed from capital structure on a pro-rata basis. All costs that are being recovered as part of the nuclear asset-recovery bonds shall be excluded from the earnings surveillance reports.

<u>Fuel Adjustment Clause:</u>

6. On June 13, 2017, in Order No. PSC-2017-0219-PCO-EI, the Commission denied DEF's Petition for a Mid-Course Correction to its fuel factor and deferred the matters raised in that petition to the hearing scheduled for October 25, 2017 in Docket No. 20170001-EI. The Parties agree that DEF shall recover the 2017 Actual/Estimated True-up under-recovery of fuel and purchased power costs that is finally determined by

the Commission, and which is proposed in DEF's August 24, 2017 petition in Docket No. 20170001-EI to be $195,503,774, over a two year period that begins January 1, 2018, i.e. fifty (50) percent in 2018 and fifty (50) percent in 2019. DEF shall continue to be entitled to recover its prudently incurred fuel and purchased power costs through the Fuel Clause without regard to the unavailability of CR3 for any reason for the period beginning October 1, 2009. Thus, for the period beginning October 1, 2009, the unavailability of CR3 for any reason shall not be the basis for any disallowance of fuel or purchased power costs, and the Intervenor Parties have waived their rights to challenge DEF's recovery of such costs, except that the Intervenor Parties have reserved their rights to raise issues regarding the prudence and reasonableness of DEF's fuel acquisition and power purchases, and other fuel prudence issues unrelated to the unavailability of CR3 for any reason.

Nuclear Decommissioning Trust:

7. If DEF determines that additional funds are necessary in order to fund the CR3 Nuclear Decommissioning Trust in support of decommissioning CR3, DEF shall be allowed to petition to collect those additional funds through a surcharge in base rates. This surcharge will be the lesser of the Commission-approved annual contribution amount or $8 million. The $8 million limitation shall expire with the last billing cycle for December 2021. After the last billing cycle for December 2021, DEF shall be authorized to recover the actual Commission-approved annual contribution to the Nuclear Decommissioning Trust through a base rate surcharge, subject to the applicability of Subparagraph 12.a. and Exhibit 6, and that surcharge shall expire following the conclusion of DEF's next base rate case. If the Commission approves an annual contribution to the Nuclear Decommissioning Trust in excess of $8 million prior

to the last billing cycle for December 2021, this incremental amount of the annual contribution in excess of what has been authorized for recovery in the base rate surcharge shall be deferred with carrying costs based on the Commission-approved allowance for funds used during construction ("AFUDC"), and recovered (including carrying costs) through the CCR Clause over a 4 year period beginning with the first billing cycle for January 2022, unless otherwise agreed to by the Original Parties. The Intervenor Parties reserve their rights to challenge the prudence of any additional CR3 decommissioning costs (funding accrual) in appropriate proceedings before the Commission. The Original Parties expressly agree that any proceeding to recover costs associated with decommissioning CR3 under this Paragraph shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings

<u>Crystal River 1 & 2 ("CRS") Retirement:</u>

8. If DEF retires Crystal River coal units 1 & 2 ("Crystal River South" or "CRS"), as a compliance measure to meet Mercury and Air Toxics Standards ("MATS"), the Best Available Retrofit Technology ("BART"), and/or the National Ambient Air Quality Standards ("NAAQS"), DEF shall be permitted to continue the annual depreciation expense and depreciation rate associated with CRS based on the last Commission-approved depreciation study, which assumed a 2020 CRS retirement date. DEF shall be permitted to recover in 2021, unless a different time for recovery is agreed to by the Original Parties, any remaining CRS net book value existing as of December 31, 2020 through the CCR Clause.

CR3 Extended Power Uprate Project ("EPU" or "Uprate"):

9. As set forth in the 2013 Settlement Agreement, DEF has been recovering all CR3 EPU revenue requirements through the NCRC consistent with the provisions of Section 366.93(6), F.S., and Commission Rule 25-6.0423(6), Florida Administrative Code ("F.A.C."), in accord with the seven (7) year amortization recovery period established as 2013-2019 (the estimated unrecovered investment balance is $86,682,782 not including carrying costs as of December 31, 2017 subject to the addition of applicable carrying costs and other recoverable costs as set out in the statute and rule above). Any final true-up of these costs will occur through the CCR Clause after December 31, 2019 for any under or over-recovery. The Intervenor Parties have fully and forever waived, released, discharged, and otherwise extinguished any and all of their rights, claims, and interests of whatever kind or nature, whether now known or unknown, to challenge the prudence of DEF's CR3 EPU investment and activities, except that the Intervenor Parties do not waive their rights to participate in the NCRC or other appropriate docket(s) for purposes of verification that DEF has fulfilled its obligation to minimize future costs of the abandoned Uprate Project. DEF shall in accord with its obligation to do so, minimize the costs of the CR3 EPU Regulatory Asset (as illustrated in Thomas G. Foster's Exhibit TGF-4, filed by DEF on May 1, 2017 in Docket No. 20170009-EI), and use reasonable and prudent efforts to curtail avoidable future costs or to sell or otherwise salvage assets that would have otherwise been included in the CR3 EPU Regulatory Asset. The Original Parties agree that CR3 EPU assets that were placed in-service and closed to electric plant in-service FERC 101, which amount equals $35,894,547 as of December 31, 2015 and includes carrying charges through December 31, 2015,

have not been, nor shall be, included in, or recovered or further trued up as part of the CR3 Regulatory Asset but instead shall continue to be recovered in an amount estimated to be $38,108,444 as of December 31, 2016 (subject to true-up), through the CCR Clause over the years 2017 and 2018 at a carrying cost rate of 3 percent, pursuant to Order No. PSC-16-0138-FOF-EI; and CR3 EPU assets never closed to electric plant in-service FERC 101 of $86,682,782, identified in the first sentence of this Paragraph, shall continue to be recovered, along with applicable carrying costs, as a part of the CR3 EPU Regulatory Asset as set forth in this Paragraph. DEF has discontinued and will forever cease active efforts to market CR3-related assets that are not in use, not usable or not otherwise encumbered, and shall only undertake to sell or salvage assets if clearly cost-effective sales or salvage opportunities are presented. If CR3 EPU assets are sold or salvaged, or costs are incurred that were not included in the 2017 Petition for rate recovery filed in Docket 20170009-EI by DEF, which are newly incurred after the Effective Date, then the retail portion of the sale or salvage proceeds and any newly incurred costs shall be recovered or returned, with carrying costs (debit or credit as applicable) at the rate prescribed in Section 366.93(6), F.S., and Rule 25-6.0423(6), F.A.C., through the CCR Clause.

Levy Nuclear Project ("LNP"):

10. By no later than January 1, 2019, DEF shall remove the Levy Land from rate base and earnings surveillance report results. Levy Land is defined as the land reflected in DEF's 2016 FERC Form 1, page 214, lines 6 and 8, specifically the Lybasse parcel (1,845 acres) in the amount of $27,667,950 (system) and the Rayonier/Lybasse parcel (3,105 and 94 acres, respectively) in the amount of $66,404,373 (system), for a total of $94,072,323 (system). Upon this initial removal

of the Levy Land from rate base, DEF shall write off its actual post-2013 costs, in the amount of $36,621,816.70 (system) as estimated on July 31, 2017, related to the LNP Combined Operating License ("COL"), including AFUDC. DEF agrees not to seek future recovery from retail customers of any of the LNP's COL- related costs, including carrying charges. DEF retains the right to maintain ownership of the Levy Land and to file a petition with the Commission in conjunction with its next general base rate case, or any other relevant proceeding during the Term of this 2017 Second Revised and Restated Settlement Agreement pursuant to Paragraph 15, for potential re-inclusion of any portion of such land into rate base, subject to approval by the Commission in DEF's next base rate proceeding or other relevant proceeding contemplated under this 2017 Second Revised and Restated Settlement Agreement. Parties reserve the right to object to inclusion of such land costs in rate base or rates. If DEF sells the Levy Land, DEF's shareholders will be permitted to retain any gain or loss on sale. Any Levy Land restored to rate base by Commission approval shall be thereafter subject to the Commission's policy on gains or losses on sales.

11. In the 2013 Settlement, the Original Parties supported DEF terminating the LNP EPC contract with WEC, because DEF was unable to obtain the LNP COL from the NRC by January 1, 2014. Consistent with the 2013 Settlement, DEF exercised the provisions of Section 366.93(6), F.S., and elected not to complete the construction of the LNP. DEF terminated the EPC contract in January 2014. After termination, litigation with WEC ensued as to the amount of termination costs owed by DEF to WEC. Consistent with the terms of this 2017 Second Revised and Restated Settlement Agreement, DEF will write off all remaining but yet unrecovered LNP costs, whether incurred as of the Effective Date or later, including the

$81,901,218 (retail), as identified in the May 1, 2017 pre-filed testimony of Christopher M. Fallon and Thomas G. Foster (which includes historical litigation costs), at issue in Docket No. 20170009-EI, the $34 million (system) termination fee ordered by the trial court to be paid to WEC, WEC's pending appellate claims for additional cost recovery, and additional future litigation costs, through any and all appeals, for which DEF has not yet sought recovery in Docket 20170009-EI. To the extent DEF agrees to, or is obligated to pay or incur, any additional LNP-related costs of any type or nature whatsoever arising from any claim, legal action, regulatory or other proceedings before any governmental authority, transaction, or any other event whatsoever, including but not limited to any and all litigation costs, damages, regulatory costs, interest, fines, penalties, costs paid pursuant to any agreement or arbitration award, or additional termination costs ordered by the court in connection with the WEC appeal of the order issued in Civil Action No.: 3:14-cv-00141 (appellate case No. 17-1087, consolidated with 17-1151), or in any other litigation, arbitration, regulatory, or any other proceedings, whether currently pending or future, involving any party or entity whatsoever, DEF is forever barred from recovering said costs from retail customers. For clarity, it is the intent of all the Parties that, as a matter of rights between and among the Parties and as a matter of law pursuant to FPSC approval of this 2017 Second Revised and Restated Settlement Agreement, after the Effective Date or December 31, 2017, whichever is sooner, there will never be any LNP-related costs of any type or nature whatsoever recovered from DEF's retail ratepayers.

<u>Base Rate Adjustments:</u>

12.

a. DEF's base rate revenue requirements will change in 2018 pursuant to

Paragraph 14. In addition, there will be an adjustment of base rates among customer rate classes to implement the changes in the delivery voltage credit referenced in Paragraph 21 and to implement the change referenced in Paragraph 24. The tariff sheets reflecting these and other relevant changes necessary to implement this 2017 Second Revised and Restated Settlement Agreement are attached as Exhibits 3 and 4 (clean and legislative, respectively). The Parties agree that all the tariffs in Exhibits 3 and 4 will have an effective date of January 1, 2018.

b. Effective with the first billing cycle for January 2019, DEF will be allowed a multi-year increase to its base rates as reflected in the chart below:

	Total Increase	**Uniform % Increase Method (1)**	**Uniform % increase Method (2)**
2019	$67 million	$50 million	$17 million
2020	$67 million	$50 million	$17 million
2021	$67 million	$50 million	$17 million

Uniform % increase method (1): Amount to be recovered through a uniform percent increase to the customer, demand and energy base rate charges for all retail customer classes, but, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted.
Uniform % Increase Method (2): Amount to be recovered through a uniform percent increase to customer charges for all retail rate classes except the interruptible and curtailable rate classes.

c. If the applicable federal or state income tax rate for DEF changes before any of the increases provided for in Paragraph 7, 12, 14, 15, 21, 24, or 37, DEF 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 6 (i.e. lines 1-14). Any base rate adjustments or changes that are implemented before the effective date of the Federal Corporate Income Tax Change will be adjusted as part of the overall method outlined in Paragraph 16 and Exhibit 6. The illustration of the methodology to be utilized for income tax changes described in this Paragraph 12 is shown in Exhibit 6. The Parties expressly agree that any proceeding to implement the base rate revenue increases associated with this Paragraph of the 2017 Second Revised and Restated Settlement Agreement shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings.

d. Except for the base rate increases provided for in Paragraphs 7, 12, 14, 15, 21, 24, and 37, the Company shall freeze its base rates through the last billing cycle for December 2021. As a part of this base rate freeze 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 traditionally or historically have been or would be recovered in base rates, unless such deferral and subsequent recovery is expressly authorized herein or otherwise agreed to by the Parties.

13. DEF shall have an authorized return on equity of 10.5% with a range of reasonableness of +/-100 basis points for the purpose of addressing earnings levels, earnings surveillance and cost recovery clauses. The applicable annual AFUDC rate will be 7.44%, as provided for in the 2013 Settlement, through year-end 2018 and then will be updated periodically consistent with Commission practice going forward.

14. a. Consistent with the 2013 Settlement, DEF was authorized to petition the Commission for a need determination for additional generation, not to exceed 1800 MW, to be placed in service in 2018. DEF filed such a petition for construction of its Citrus County Combined Cycle Units, and the Commission granted that

determination of need in Order No. PSC-14-0557-FOF-EI. If DEF constructs and places in service the Citrus County Combined Cycle Units in 2018, DEF's base rates shall be increased by the annualized base revenue requirement for the first 12 months of operation (the "Annualized Base Revenue Requirement"). The Annualized Base Revenue Requirement shall reflect the costs pursuant to which the need determination was granted by the Commission. This base rate increase shall be referred to as the 2018 Generation Base Rate Adjustment ("GBRA"). The Intervenor Parties retain all rights to challenge DEF's actions made or taken pursuant to Subparagraphs 14.a., 14.b., and 14.e., including, but not limited to, the right to challenge the need for, or prudence of any costs associated with, the construction of any additional generation placed in service in 2018 as well as the initial 2018 GBRA factor and any subsequent revisions to it pursuant to Rule 25.22.082(15), F.A.C., but have waived the right to argue that this 2017 Second Revised and Restated Settlement Agreement prevents DEF from seeking recovery for the costs described in this Paragraph that the Commission determines to be reasonable and prudent.

b. The initial 2018 GBRA factor shall be established by the application of a uniform percentage increase to the demand and energy charges reflected in the Company's base rate schedules existing at the time of the increase, but, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted. The uniform percentage increase shall be calculated using the billing determinants included in the Company's most recent projection clause filing unless otherwise agreed to by the Original Parties, with the understanding that the Intervenor Parties retain the right to challenge the accuracy and validity of the billing determinants. DEF shall begin applying the 2018 GBRA to meter readings made on and after the commercial in-service date(s) of the 2018 Citrus County Combined Cycle Units.

c. The 2018 GBRA Annualized Base Revenue Requirement shall be calculated using a 10.5% ROE and DEF's projected 13-month average capital structure for the first 12 months of operation, including all specific adjustments consistent with DEF's then most recently filed December earnings surveillance report, and adjusted to include an Accumulated Deferred Income Tax ("ADIT") proration adjustment consistent with 26 C.F.R. Section 1.167(l)-1(h)(6). DEF will calculate and submit the 2018 GBRA rates for Commission approval using the billing determinants from the most recent projection clause filings.

d. In the event that the actual capital expenditures are less than the projected costs used to develop the initial 2018 GBRA factor, the lower figure shall be the new basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised 2018 GBRA factor shall be computed using the same data and methodology incorporated in the initial 2018 GBRA factor, with the exception that the actual capital expenditures shall be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. This credit shall be the difference between the cumulative base revenues since the implementation of the initial 2018 GBRA factor and the cumulative base revenues that would have resulted if the revised 2018 GBRA factor had been in-place during the same time period and shall be credited to customers through the CCR Clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, F.A.C. On a going-forward basis, base rates shall be adjusted to reflect the revised 2018 GBRA factor.

e. In the event that the actual capital expenditures are higher than the projection on which the Annualized Base Revenue Requirement was based, DEF at its option may initiate a limited proceeding pursuant to Section 366.076, F.S., limited to the issue of whether DEF has met the requirements of Rule 25-22.082(15), F.A.C. If the Commission finds that DEF has met the requirements of Rule 25-22.082(15), F.A.C., then DEF shall increase the 2018 GBRA by the corresponding incremental revenue requirement due to such additional capital costs. However, DEF's election not to seek such an increase in the 2018 GBRA shall not preclude DEF from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. No Party is precluded from participating in any such limited proceeding. The Original Parties expressly agree that any proceeding to recover costs associated with this Subparagraph of the 2017 Second Revised and Restated Settlement Agreement shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings.

Solar Base Rate Adjustment:

15.

a. DEF projects that for purposes of the cost recovery set forth in this Paragraph, it will undertake construction of approximately 175 MW per calendar year of solar generation (for a maximum of 700 MW) reasonably projected to go into service during the Term of this 2017 Second Revised and Restated Settlement Agreement or within one year following expiration of the Term; provided, however, DEF will not implement a Commission-approved base rate adjustment as contemplated in this Paragraph at any time during 2018. Solar base rate adjustments may be authorized for solar projects for which DEF files for Commission approval pursuant to this Paragraph during the Term. For each solar project that is approved by the Commission for cost recovery pursuant to the process described in this Paragraph, DEF's base rates will be increased by the incremental annualized base revenue requirement (as defined in Subparagraph 15.e.) for the first 12 months of operation (the "Annualized Base Revenue Requirement"), but in no event before the facility is in service. The Commission's approval may occur before or after expiration of the Term. The projects constructed or acquired pursuant to this Paragraph must be scheduled and reasonably projected to be placed into service no later than one year following the expiration of the Term. DEF agrees that, during the Term of this 2017 Second Revised and Restated Settlement Agreement, it will not place any material solar projects into service that are not subject to the solar base rate adjustment process described in this Paragraph. During the Term of this 2017 Second Revised and Restated Settlement Agreement, the cost of the components, engineering and construction for any solar project constructed or acquired by DEF pursuant to this Paragraph shall be reasonable and cost effective and in no event shall the weighted average cost of all projects in any filing for Commission approval of the base rate adjustments as contemplated in this Paragraph exceed $1,650 per kilowatt alternating current ("kWac"). This cap is generally based on an assumption and current intent by DEF that a single axis tracking technology will be utilized as further described in this Paragraph. Additionally, this cap is intended as a protection for customers and is not intended to be a target or "build to" number; however, it is not intended to discourage DEF from engineering or designing projects in order to deliver the maximum efficiency and benefit to customers. DEF agrees that, for projects constructed or acquired by DEF, the following cost categories will be included in the $1,650 kWac cost cap, but that the cost cap is not limited to these categories of costs, and includes any and all construction costs attributable to the solar projects: Engineering, Procurement, and Construction ("EPC") costs, development costs including third party development fees, if any, permitting, land acquisition, taxes, and utility costs to support or complete development, transmission interconnection costs, Installation Labor and Equipment, Electrical Balance of System, Structural Balance of System, Inverters, and Modules. To the extent that the cost(s) of any of DEF's solar projects materially exceed total project cost(s) reflected in another Florida utility's similar solar base rate adjustment filing made after February 28, 2017, DEF agrees to demonstrate the reasonableness of said difference(s), including a departure, if any, from the current intent to utilize single axis tracking technology, provided that DEF's explanation is subject to public availability of information about the other utility's project costs. It is DEF's current intent, but not a guarantee, to utilize single axis tracking technology, whenever possible and cost effective, in its solar projects subject to this Paragraph. This intent, however, may exclude certain projects originating from third parties. In implementing potential solar projects, DEF will utilize a reasonable competitive solicitation process(es) to select its contractors and to procure equipment and materials, and DEF will also consider buying out existing potential projects in any stage of development, as long as those projects meet DEF's reasonable standards, the cost cap, and the cost differential requirements of this Paragraph. Affiliate companies to DEF will not be allowed to participate as potential contractors in this competitive solicitation process. DEF 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.

b. For solar generation projects subject to the Florida Electrical Power Plant Siting Act (i.e., 75 MW or greater), DEF will file a petition for need determination pursuant to Chapter 25-22, F.A.C. If approved pursuant to the procedures described in this Paragraph and Section 403.519, F.S., DEF will calculate and submit for Commission confirmation the base rate adjustment for each such solar project, consistent with Subparagraphs 15.e. and 15.f.

c. Solar generation projects not subject to the Florida Electrical Power Plant Siting Act (i.e., fewer than 75 MW), also will be subject to approval by the Commission as follows: (i) DEF will file a request for approval of the solar generation project in a separate docket; and (ii) the issues for determination are limited to: the reasonableness and cost effectiveness of the solar generation projects (i.e., will the projects lower the projected system cumulative present value revenue requirement "CPVRR" as compared to such CPVRR without the solar projects); the amount of revenue requirements; and whether, when considering all relevant factors, DEF needs the solar project(s). Any Party may challenge the reasonableness of DEF's actual or projected solar project costs. If approved, DEF will calculate and submit for Commission confirmation the base rate adjustment for each such solar project, consistent with Subparagraphs 15.e. and 15.f.

d. The maximum cumulative amount(s) of solar projects (in MW) for which DEF may recover through the base rate adjustment provided for in this Paragraph in any year covered by this 2017 Second Revised and Restated

Settlement Agreement are as follows: 2019: 350 MW; 2020: 525 MW; 2021: 700 MW; 2022: 700 MW.

e. Each base rate adjustment allowed by or implemented pursuant to this Paragraph is to be reflected on DEF's customer bills by increasing customer demand and energy base rate charges by an equal percentage contemporaneously; however, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted. The calculation of the percentage change in rates will be based on the ratio of (i) the forecasted jurisdictional Annualized Base Revenue Requirement for the solar project(s) covered by any single base rate increase to (ii) the forecasted retail base revenues from the sales of electricity during the first twelve months of operation. The forecasted retail base revenues from the sales of electricity during the first twelve months of operation will be based upon DEF's billing determinants for the first 12 months following such project's commercial in-service date, where such sales forecast is that used in DEF's then-most-current CCR Clause filings with the Commission, including, to the extent necessary, 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 such solar project's operation. DEF shall be authorized to begin applying the base rate charges for each adjustment authorized by this Paragraph to meter readings beginning with the first billing cycle on or after the commercial in-service date of that solar generation project.

f. Each base rate adjustment created by this Paragraph will be calculated using a 10.5% ROE and DEF's projected 13-month average capital structure for the first 12 months of operation, including all specific adjustments consistent with DEF's most recently filed December earnings surveillance report, and excluding the treatment of common equity and rate base (working capital) allowed in Paragraph 18 of the 2013 Settlement Agreement, and adjusted to include an ADIT proration adjustment consistent with 26 C.F.R. Section 1.167(l)-1(h)(6) and adjusted to reflect the inclusion of investment tax credits on a normalized basis.

g. In the event that the actual capital expenditures are less than the approved projected costs, included in the petition for cost recovery and used to develop the initial base rate adjustment, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised base rate adjustment will be computed using the same data and methodology incorporated in the initial base rate adjustment, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. On a going-forward basis, base rates will be adjusted to reflect the revised base rate adjustment. The difference between the cumulative base revenues since the implementation of the initial base rate adjustment and the cumulative base revenues that would have resulted if the revised base rate adjustment had been in-place during the same time period will be credited to customers through the CCR Clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, F.A.C.

h. Subject to the maximum cost of $1,650 per kWac set forth in Subparagraph 15(a), in the event that actual capital costs for solar generation projects in any filing are higher than the projection on which the Annualized Base Revenue Requirement was based, DEF at its option may initiate a limited proceeding per Section 366.076, F.S., limited to the issue of whether DEF has met the requirements of Rule 25-22.082(15), F.A.C. Nothing in this 2017 Second Revised and Restated Settlement Agreement shall prohibit a Party from participating in any such limited proceeding for the purpose of challenging whether DEF has met the requirements of Rule 25-22.082(15), F.A.C., or otherwise acted in accordance with this 2017 Second Revised and Restated Settlement Agreement. If the Commission finds that DEF has met the requirements of Rule 25-22.082(15), F.A.C., then DEF shall increase the base rate adjustment at issue by the corresponding incremental revenue requirement due to such additional capital costs, provided, consistent with Subparagraph 15(a) above, DEF is prohibited from recovering through this or any other mechanism or proceeding any costs greater than $1,650 per kWac (calculated as the weighted average cost of the projects submitted in the particular filing at issue) under any circumstances. However, DEF's election not to seek such an increase in base rates shall not preclude DEF from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Nothing in this 2017 Second Revised and Restated Settlement Agreement shall preclude any Party to this 2017 Second Revised and Restated Settlement Agreement or any other lawful party from participating, consistent with the full rights of an intervenor, in any such limited proceeding.

Federal Corporate Income Tax Changes:

16.

a. Federal or state corporate income tax changes ("Tax Reform") can take many forms, including changes to tax rates, changes to deductibility of certain costs, and changes to the timing of deductibility of certain costs. Therefore the impact of Tax Reform could impact the effective tax rate recognized by DEF 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, specified the method and period for 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.

b. If Tax Reform is enacted before DEF's next general base rate proceeding, DEF will quantify the impact of Tax Reform on its Florida Jurisdictional base revenue requirement as projected in DEF's forecasted earnings surveillance report for the calendar year that includes the period in which Tax Reform is effective. DEF will also adjust base rate adjustments 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, except that each year throughout the term of this 2017 Second Revised and Restated Settlement Agreement 40% of such impacts, up to $50 million pre-tax, would be recorded as an acceleration of depreciation expense associated with Crystal River Units 4 and 5, thereby reducing the FPSC-adjusted net operating income impact of Tax Reform by up to the after-tax impact of this accelerated depreciation. All remaining base rate impacts of Tax Reform will be flowed back to 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. This one-time adjustment shall be accomplished through a uniform percentage decrease to customer, demand and energy base rate charges, excluding delivery voltage credits, 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 CCR Clause on the same basis as used in any base rate adjustment. An illustration is included as Exhibit 6. If Tax Reform results in an increase in base revenue requirements, DEF 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 of this 2017 Second Revised and Restated Settlement Agreement. In this situation, DEF 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 DEF's next base rate proceeding or in a limited scope proceeding before the Commission no sooner than the expiration of this 2017 Second Revised and Restated Settlement Agreement.

c. 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 is a rebuttable presumption that the following flow-back period(s) will apply: (1) if the cumulative regulatory liability is less than $200 million, the flow-back period will be five years; or (2) if the cumulative regulatory liability is greater than $200 million, the flow-back period will be ten years. DEF 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 DEF'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 (referred to as the "50 Percent Period"). The relevant factors to support DEF's demonstration include, but are not limited to, the impact the flow-back period would have on DEF's cash flow and credit metrics or the optimal capitalization of DEF's jurisdictional operations in Florida. If DEF 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 Revised and Restated Settlement 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), the Commission shall be authorized to permit a longer flow-back period.

17. Electric Vehicle Charging Station Pilot Program:

a. Size and Scope

i. DEF is authorized to purchase, install, own, and support Electric Vehicle Service Equipment (EVSE) at DEF's customers' locations.

ii. DEF may incur up to $8 million plus reasonable operating and maintenance expense, with a minimum deployment of 530 EVSE, with the minimum numbers distributed as set forth in the attached Exhibit 7, in relation to this EVSE program. In the event that DEF is unable to find willing host sites for a given segment, program expenditures may be shifted to other segments identified in Subparagraph 17.b., or new segments proposed by DEF, as approved in advance by the Commission.

iii. The EVSE program will be a pilot program ("Pilot") for five (5) years.

iv. For purposes of this 2017 Second Revised and Restated Settlement Agreement, Level 2 refers to EVSE technology which delivers AC power at 208 or 240 volt, and DC Fast Charging refers to EVSE technology which delivers DC power at 44kW and above.

b. Targeted market segments and EVSE technologies

i. DEF must strategically deploy EVSE as set forth in Exhibit 7 subject to the exception provided for in Subparagraph 17.a.ii. above.

ii. At least ten (10) percent of the charging stations shall be installed in low income communities, as that term is defined in Section 288.9913(3), F.S.

c. **Electricity pricing:** Where EV drivers make purchases directly from DEF when using the EVSE, said drivers will pay the appropriate Commission-approved rates/prices for energy use at the EVSE. Total prices paid by EV drivers may include nominal administrative or processing fees.

d. Accessibility & interoperability

i. Level 2 EVSE shall be network ready and able to communicate with a network management system (NMS) and use Open Charge Point Protocol (OCPP 1.6 or later).

ii. EVSE vendors must provide a certified OpenADR 2.0b Virtual End Node (VEN or Client) that can interface with an OpenADR 2.0b server to interpret signals and manage charging.

iii. DEF shall conduct a Request For Proposal process in selecting EVSE hardware and network solution providers for each segment contained in the Pilot to create a competitive process open to all EVSE vendors.

e. **Consumer education:** DEF shall establish dedicated program funding for market education and outreach, to be capped at five (5) percent of $8 million.

f. Data collection and reporting

i. For the full term of the Pilot, DEF shall collect comprehensive data related to the Pilot, including but not limited to charging station deployment by market segment (e.g., multi-family, workplace, public, etc.) and technology type (e.g., Level 2 or Direct Current Fast Charger); installation cost by segment and technology type; segment-level data regarding load growth, the potential for demand response, load profiles, electricity prices paid by EV drivers, and EV charging equipment providers.

ii. DEF shall report to the Commission and Parties on an annual basis in a report which includes, but is not limited to, the data points and metrics detailed in Subparagraph 17.f.i. above.

iii. DEF shall either initiate a separate proceeding for approval of a permanent electric vehicle charging station offering within 4 years of the Effective Date or shall make a filing with the Commission to explain why a permanent offering is not warranted.

iv. DEF shall coordinate with transit agencies to expand awareness of Zero Emission Buses.

g. Regulatory treatment and procedure

i. DEF shall be authorized to defer the recovery of its EVSE program capital costs and operating expenses (full revenue requirements) to a regulatory asset that will earn DEF's AFUDC rate. Revenues generated through the EVSE shall offset the amount of the costs to be deferred to the regulatory asset. At the time DEF makes the filing described above in Subparagraph 17.f.iii. above, but in no event sooner than the expiration of the Term, DEF will be authorized to recover the amount of the regulatory asset over a four year period through a uniform percent increase to the customer, demand and energy base rate charges, but, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted.

ii. The EVSE shall be subject to a depreciation rate of 20 percent.

iii. The Parties agree that the Commission retains the ability to make a determination about the appropriate regulatory treatment for the permanent EV offering, if DEF files it, at such time as DEF initiates the separate proceeding, and there shall be no presumption of correctness in that separate proceeding regarding how this 2017 Second Revised and Restated Settlement Agreement permits the treatment of costs for purposes of the Pilot.

<u>Economic Development and Economic Re-Development Tariffs:</u>

18. DEF shall make permanent the pilot Economic Development and Economic Re-Development Tariffs that were initially approved by the Commission in the 2013 Settlement Agreement, and approved for another three year period in Order No. PSC-16-0423-TRF-EI (consummating Order No. PSC-16-0497-CO-EI). The

permanent tariffs are part of Exhibits 3 and 4.

Other Matters:

19. DEF shall be authorized, at its discretion, to accelerate in full or in part the amortization of the regulatory assets for FAS 109 Deferred Tax Benefits Previously Flowed Through, Unamortized Loss on Reacquired Debt, 2009 Pension Regulatory Asset, and Interest on Income Tax Deficiency over the Term of this 2017 Second Revised and Restated Settlement Agreement. DEF will be authorized to continue making a specific adjustment to its common equity balance and rate base working capital balance for the purposes of calculation of rate base and the capitalization ratios used for surveillance reporting pursuant to Rule 25-6.1352, F.A.C., and pass-through clauses, prior to and including the December 2018 surveillance report. DEF shall be allowed to make this adjustment for purposes of setting the rates for the GBRA increase referenced in Paragraph 14 but it shall not be used for purposes of calculating the base rate adjustments pursuant to Paragraphs 7, 12, 15, 21, 24, or 37, or any Tax Reform adjustments applicable to prospective rate adjustments made pursuant to Paragraphs 7, 12, 15, 21, 24, or 37. For clarity the last time this adjustment will be made is December 2018. The calculation of this adjustment will be based on the methodology employed by Standard and Poor's Ratings Service ("S&P") in its determination of imputed off balance sheet obligations related to future capacity payments to qualifying facilities and other entities under long-term purchase power agreements. The amount of the adjustment to common equity and rate base will fluctuate over time with changes in the amount of future purchase power obligations. The Original Parties agree that the common equity and rate base adjustments set forth in this Paragraph are unique to the specific

circumstances of DEF, as it relates to this 2017 Second Revised and Restated Settlement Agreement, and the treatment of DEF's common equity and rate base in this Paragraph shall not constitute binding Commission precedent or create a presumption of correctness as to the adjustment for future ratemaking in any future proceeding involving DEF or any other utility. Moreover, this adjustment and the Original Parties' agreement to such adjustment in this unique proceeding shall be without prejudice to any party advocating a different position in future proceedings not involving this 2017 Second Revised and Restated Settlement Agreement. The methodology employed by S&P shall not be taken into account for purposes of calculating interim rates or determining whether DEF can seek a base rate adjustment pursuant to Paragraph 37 of this 2017 Second Revised and Restated Settlement Agreement.

20. All other cost of service and rate design issues will be determined in accordance with Exhibit 1 to this 2017 Second Revised and Restated Settlement Agreement. The level of the credits specified in Exhibit 1 will not change during the Term. DEF agrees that the level of clause-recoverable credits, including IS, CS, and GSLM-2, will not change after the expiration of the Term absent a Commission order in a general base rate proceeding or a Demand Side Management goals and plan approval proceeding. As it has done since the first billing cycle for January 2014, DEF shall continue billing the Retail CCR Clause for demand rate classes on a kilo-watt ("kW") basis rather than the previously-used kilo-watt-hour ("kWh") method.

21. Effective with the first billing cycle after this 2017 Second Revised and Restated Settlement Agreement becomes effective, DEF shall increase the monthly delivery voltage credits for distribution primary delivery level customers from

$0.41/KW to $1.19/KW and for transmission delivery level customers from $1.55/KW to $5.95/KW. The cost of the increased delivery voltage credits shall be recovered from all DEF retail customers through a uniform percent increase to the other base rate charges, including customer, demand, and energy charges. This uniform percentage increase was calculated using the billing determinants included as Exhibit 2 to this 2017 Second Revised and Restated Settlement Agreement for the projected year of 2018. The delivery voltage credits shall not be further changed during the Term of this 2017 Second Revised and Restated Settlement Agreement; specifically, the delivery voltage credits shall not change when calculating the effects of any change in rates provided for in this 2017 Second Revised and Restated Settlement Agreement, including the changes provided for in Paragraphs 7, 12, 14, 15, 16, 24, and 37. To the extent Tax Reform results in a reduction to the base rate revenue requirements after the Effective Date, DEF shall consider the then-current statutory federal corporate income tax rate in the determination of the delivery voltage credit proposed in the next base rate proceeding.

22. DEF will enter into no new financial natural gas hedging contracts effective January 1, 2018, throughout the Term. DEF shall be allowed to recover the costs associated with the financial hedges it has already executed prior to the Effective Date, through the normal course of Docket No. 20170001-EI and subsequent fuel clause proceedings. DEF further agrees that, during the Term of this 2017 Second Revised and Restated Settlement Agreement, it will not seek to recover costs from customers related to investments in oil and/or natural gas exploration and/or production, including but not limited to investments in fracking.

23. DEF will be allowed to defer all O&M costs incurred in the development

and implementation of the new Customer Information System ("CIS") to a regulatory asset that will not accrue an AFUDC carrying cost. DEF will amortize the regulatory asset over fifteen (15) years beginning in 2023. The Parties will not be precluded from challenging the reasonableness and prudence of such costs in the next base rate proceeding.

24. DEF will be allowed to transfer the net book value ("NBV") of all Mobile Meter Reading ("MMR") assets and the commercial Silver Springs Network ("SSN") meters to a regulatory asset and amortize these investments, starting with the Effective Date, at the current level of depreciation until fully recovered. The new Advanced Metering Infrastructure ("AMI") assets will be permitted a depreciable life of fifteen (15) years. Upon completion of AMI meter deployment, DEF will introduce a residential Time of Use rate. In addition, effective with the first billing cycle for January 2018, DEF will be allowed to move the commercial SSN meters from recovery in the Energy Conservation Cost Recovery Clause to recovery through base rates through a uniform percent increase to the demand and energy charges for all rate classes except the IS and CS rate classes, but, consistent with Paragraph 21, the delivery voltage credits and IS/CS/GSLM-2 credits shall not be adjusted. This uniform percentage increase shall be calculated using the billing determinants included as Exhibit 2 to this 2017 Second Revised and Restated Settlement Agreement for the projected year of 2018.

25. Regarding the University of Florida ("UF"), if UF expresses an intent to exercise or exercises its option to require DEF to retire the UF Cogeneration Plant, DEF will be allowed to continue the current level of depreciation expense on the UF Plant until it files its next base rate proceeding and will then be allowed to recover the

remaining NBV of the UF Plant over a five (5) year period as part of its base rate filing.

26. In the event that DEF is required to implement settlement accounting for Pension Benefits Expense, DEF will be permitted to defer, to a regulatory asset, the impact associated with the Generally Accepted Accounting Principles ("GAAP") required recognition of the unrealized losses and amortize that regulatory asset over a period to be determined in the next base rate proceeding.

27. DEF may implement a 50 MW battery storage pilot program ("Battery Storage Pilot") designed to enhance service for retail customers, or to enhance operations of existing or planned solar facilities. The Parties to this 2017 Second Revised and Restated Settlement Agreement will work cooperatively regarding the location of the battery storage projects; however, DEF shall ultimately be responsible for determining the projects and locations that provide the most benefits at the time of installation. The cost to install battery storage projects pursuant to this Paragraph shall be reasonable and, on average, shall not exceed $2,300 per kWac. The Parties to this 2017 Second Revised and Restated Settlement Agreement agree that the Battery Storage Pilot implementation in accordance with this 2017 Second Revised and Restated Settlement Agreement (and not in violation of any law) is a prudent investment to make and provides benefits for customers. DEF may request cost recovery for the Battery Storage Pilot in its next general base rate case, and the Parties to this 2017 Second Revised and Restated Settlement Agreement agree not to contest the prudence of the decision to make the investment that complies with this 2017 Second Revised and Restated Settlement Agreement. This 2017 Second Revised and Restated Settlement Agreement does not affect the right of Parties to

challenge the reasonableness of the costs incurred for the Battery Storage Pilot.

28. DEF shall include a capacity value for solar facilities in its Ten Year Site Plan to be filed April 1, 2018. DEF agrees to consider input from SACE or any other Party in the design of the data to be collected and will share the information with SACE and any other Party requesting it prior to filing its Ten Year Site Plan.

29. DEF will be allowed to offer a Shared Solar Tariff to its customers, attached as part of Exhibit 5, which shall be approved upon approval of this 2017 Second Revised and Restated Settlement Agreement, and will become effective after the completion of programming. The tariff sheet will be filed by the Company and may be administratively approved by Commission Staff at that time. A Party's execution or approval of this 2017 Second Revised and Restated Settlement Agreement does not necessarily signify an endorsement of the Shared Solar tariff, program design, or rates.

30. DEF will be allowed to offer a FixedBill program to its residential customers, as reflected in the attached FixedBill tariff, attached as part of Exhibit 5. DEF will determine the amount of FixedBill revenues for surveillance and other regulatory purposes by multiplying the actual energy used by FixedBill participants by the otherwise applicable tariff rates. This calculated amount will be reflected in base rates and recovery clauses on a monthly basis as though these were the revenues charged to customers for their usage. The difference between the calculated amount and what customers are actually billed under FixedBill will be treated as a below the line revenue or expense, along with any costs to implement and maintain the program. This proposed regulatory treatment will hold non-participants harmless as they will not subsidize or be subsidized by the FixedBill program. The attached

FixedBill tariff shall become effective on March 1, 2018.

31. The Parties agree that DEF shall be deemed to have satisfied the requirement that periodic servicing and administration fees in excess of DEF's incremental cost of performing those functions be included in DEF's cost of service, as required by Ordering Paragraph 80 of Order No. PSC-15-0537-FOF-EI in Docket Nos. 150148-EI and 150171-EI.

32. The cost of removal regulatory asset (excluding the $107.469 million related to CR3) will be recovered commencing on the earlier of the Company's next filed base rate proceeding or upon the completion and approval by this Commission of the Company's next depreciation study. Any recovery period of this regulatory asset shall be no longer than the average remaining service life of the assets, approved in the Company's most recent depreciation study. DEF shall file a Depreciation Study, Fossil Dismantlement Study, Storm Reserve Study, and Nuclear Decommissioning Study (collectively the "Studies") on or before March 31, 2022, or accompanying the next base rate case, whichever occurs first. In any event, DEF shall file the Studies at least 90 days before the filing of its MFRs and testimony in connection with its next base rate case, such that all issues arising from such studies can be litigated by the Parties in the next base rate case. For clarity, the Parties agree that this Paragraph revises the reference that DEF will file a new depreciation study and dismantlement study including the Osprey Plant by March 31, 2019, included in the Commission's Order No. PSC-16-0521-TRF-EI, issued November 21, 2016 in Docket No. 160178-E, such that DEF will file these studies, and include the Osprey Plant, no later than March 31, 2022.

33. During the Term of this 2017 Second Revised and Restated Settlement

Agreement DEF commits to collect data on the economic and operational benefits and costs, to the extent such benefits and costs can be reasonably identified, from the use of demand-side solar on its system to support overall rate design, which may, during the Term of this 2017 Second Revised and Restated Settlement Agreement, entail the installation of meters on the demand-side solar generation at no cost to the customer. DEF agrees to consider input from SACE or any other Party in the design of the data to be collected, and will share the information with SACE and any other Party requesting it prior to any filing that involves changes in rate design. DEF commits, during the Term of this 2017 Second Revised and Restated Settlement Agreement, to not introduce any new tariffs that impact rates on customers that use demand-side solar, or any other tariff related to distributed energy resources, absent a cost of service study approved by the Commission or a directive by the Commission. No Parties are precluded from taking a position on such a filing or proceeding.

34. DEF may not petition for an increase in base rates and charges that would take effect prior to the first billing cycle for January 2022, except for the increases in base rates and charges provided for or allowed by the terms of this 2017 Second Revised and Restated Settlement Agreement, including, without limitation, the recovery of nuclear asset-recovery charges that are being recovered on behalf of Duke Energy Florida Project Finance, LLC, pursuant to Commission Docket No. 150171-EI. In addition, the Parties agree that the base rate increases or charges that, pursuant to the terms of this 2017 Second Revised and Restated Settlement Agreement extend beyond the last billing cycle for December 2021 and survive the expiration of the Term or termination of this 2017 Second Revised and Restated

Settlement Agreement, specifically include, without limitation, (A) the recovery of the nuclear asset-recovery charge until the nuclear asset-recovery bonds have been paid in full and the Commission-approved financing costs have been recovered in full, and for such a period consistent with the proviso in Subparagraph 5.c. of this 2017 Second Revised and Restated Settlement Agreement; (B) the potential recovery of additional funds to fund the CR3 Nuclear Decommissioning Trust pursuant to Paragraph 7 of this 2017 Second Revised and Restated Settlement Agreement; (C) the potential recovery of the CRS net book value pursuant to Paragraph 8 of this 2017 Second Revised and Restated Settlement Agreement; (D) the recovery of solar facilities brought into service beyond the Term, as provided for in Subparagraph 15.a. of this 2017 Second Revised and Restated Settlement Agreement; (E) the recovery of the DCS facility capital costs through the Capacity Cost Recovery Clause, as reflected in Subparagraph 5.a.1. of this 2017 Second Revised and Restated Settlement Agreement; (F) the potential recovery of the UF NBV pursuant to Paragraph 25 of this 2017 Second Revised and Restated Settlement Agreement; (G) the recovery of the deferred CIS O&M pursuant to Paragraph 23 of this 2017 Second Revised and Restated Settlement Agreement; and (H) the recovery of EVSE pursuant to Paragraph 17 of this 2017 Second Revised and Restated Settlement Agreement. Notwithstanding the rate relief mechanism described in Paragraph 37, DEF is prohibited from seeking or implementing an interim rate increase pursuant to Section 366.071, F.S., until the expiration of the Term of this 2017 Second Revised and Restated Settlement Agreement. The Parties likewise will neither seek nor support any reduction in DEF's base rates and charges, including limited, interim, or any other rate decreases, that would take effect prior to the first billing cycle for January 2022, except for any reduction requested by DEF or as otherwise provided for in this 2017 Second Revised and Restated Settlement Agreement. Unless expressly prohibited under this 2017 Second Revised and Restated Settlement Agreement, the Commission shall not be precluded, in the Company's next base rate proceeding, from reviewing any aspect of DEF's financial condition since its last rate case (2013).

35. Notwithstanding the expiration of the Term of this 2017 Second Revised and Restated Settlement Agreement, DEF's base rate and non-DSM credit levels applied to customer bills, including the effects of the base rate adjustments as implemented pursuant to this 2017 Second Revised and Restated Settlement Agreement (i.e., uniform percent increase for all rate classes applied to base rate revenues and charges), shall continue in effect until next reset by the Commission in a general base rate proceeding.

36. No Party to this 2017 Second Revised and Restated Settlement Agreement will request, support, or seek to impose a change to any provision in this 2017 Second Revised and Restated Settlement Agreement. This 2017 Second Revised and Restated Settlement Agreement, and the attached exhibits and schedules, represent the entire and complete agreement between the Parties. The Parties consider each provision to be integral to their respective support for the 2017 Second Revised and Restated Settlement Agreement in its entirety, and no provision may be changed or altered without the consent of each signatory Party in a written document duly executed by all Parties to this 2017 Second Revised and Restated Settlement Agreement. To the extent a dispute arises among the Parties about the provisions, interpretation, or application of this 2017 Second Revised and Restated Settlement 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. Florida law will govern all terms, conditions, and provisions of this 2017 Second Revised and Restated Settlement Agreement, including, but not limited to, any disputes arising from this 2017 Second Revised and Restated Settlement Agreement.

37. If DEF's retail base rate earnings fall below a 9.5% ROE as reported on a Commission adjusted or pro-forma basis on a DEF monthly earnings surveillance report during the Term of this 2017 Second Revised and Restated Settlement Agreement, DEF may petition the Commission to amend its base rates during the Term of this 2017 Second Revised and Restated Settlement Agreement. Such request by the Company shall be limited to an increase that would achieve a 10.5% ROE. No Party waives its right to participate in such a proceeding, and such participation will only be limited by the terms of this 2017 Second Revised and Restated Settlement Agreement. If DEF's retail base rate earnings exceed an 11.5% ROE as reported on a Commission adjusted or pro-forma basis on a DEF monthly earnings surveillance report during the Term of the 2017 Second Revised and Restated Settlement Agreement, any Intervenor Party shall be entitled to petition the Commission for a review of DEF's base rates and charges. The Parties to this 2017 Second Revised and Restated Settlement Agreement are not precluded from participating in any such proceedings. This Paragraph shall not be construed to bar or limit DEF from any recovery of costs otherwise contemplated by this 2017 Second Revised and Restated Settlement Agreement, and all other provisions of this 2017 Second Revised and Restated Settlement Agreement shall remain in force and effect.

38. Nothing shall preclude the Company from requesting the Commission to

approve the recovery of the following types of costs:

a. Costs that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or

b. It is the intent of the Parties that, in conjunction with the provisions of Subparagraph 12.d., DEF shall not seek to recover, nor shall DEF 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 and traditionally been recovered in base rates, unless such costs are: (i) the direct and unavoidable result of new governmental impositions or requirements; (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 DEF's operations; or (iii) costs that would otherwise be recoverable through base rates that the Florida Legislature has expressly authorized as clause recoverable by public utilities, as that term is defined in Section 366.02(2), F.S.

c. With respect to storm damage costs caused by a tropical system named by the National Hurricane Center or its successor, nothing in this 2017 Second Revised and Restated Settlement Agreement shall preclude DEF from petitioning the Commission to seek recovery of costs associated with any storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings. The Parties agree that recovery from customers for storm damage costs will begin, subject to Commission approval on an interim basis, sixty (60) days following the filing of a cost recovery petition with the Commission, and subject to true-up pursuant to further proceedings before the Commission, and will be based on a

12-month recovery period. All storm-related costs shall be calculated and disposed of pursuant to Commission Rule 25-6.0143, F.A.C., and will be limited to costs resulting from a tropical system named by the National Hurricane Center or its successor, an estimate of incremental costs above the level of storm reserve prior to the storm event, and replenishment of the storm reserve to the level as of the Implementation Date of the 2012 Settlement Agreement (as the term "Implementation Date" is defined in the 2012 Settlement Agreement) or approximately $132 million (retail). The Parties to this 2017 Second Revised and Restated Settlement Agreement are not precluded from participating in any such proceedings. 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 the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings.

39. The provisions of this 2017 Second Revised and Restated Settlement Agreement are contingent on approval of this 2017 Second Revised and Restated Settlement Agreement in its entirety by the Commission. The Parties further agree that this 2017 Second Revised and Restated Settlement Agreement is in the public interest, and that they will support this 2017 Second Revised and Restated Settlement Agreement and will not request or support any order, relief, outcome, or result in express conflict with the terms of this 2017 Second Revised and Restated Settlement Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this 2017 Second Revised and Restated Settlement Agreement or the subject matter hereof. No Party will assert in any proceeding before the Commission that this 2017 Second

Revised and Restated Settlement Agreement or any of the terms in the 2017 Second Revised and Restated Settlement Agreement shall have any precedential value. The Parties' agreement to the terms in the 2017 Second Revised and Restated Settlement Agreement shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving the 2017 Second Revised and Restated Settlement Agreement. The Parties further expressly agree that no individual provision, by itself, necessarily represents a position of any Party in a future proceeding nor shall any Party represent in any future forum that another Party endorses a specific provision of this 2017 Second Revised and Restated Settlement Agreement because of that Party's signature herein. It is the intent of the Parties to this 2017 Second Revised and Restated Settlement Agreement that the Commission's approval of all the terms and provisions of this 2017 Second Revised and Restated Settlement 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 Second Revised and Restated Settlement Agreement endorses a specific provision, in isolation, of this 2017 Second Revised and Restated Settlement Agreement because of that Party's signature herein.

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

41. This 2017 Second Revised and Restated Settlement Agreement dated as of August 29, 2017 may be executed in counterpart originals, and a facsimile or PDF email of an original signature shall be deemed an original.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this 2017 Second Revised and Restated Settlement Agreement by their signatures below.

[Remainder of page left intentionally blank]

Duke Energy Florida, LLC

By________________________

Harry Sideris
299 1st Ave N
St. Petersburg, Florida 33701

Office of Public Counsel

By______________________________

J.R. Kelly, Esquire
Charles Rehwinkel, Esquire
111 W. Madison St., Room 812
Tallahassee, Florida 32399

Florida Industrial Power Users Group

By ____________________ Aug. 28, 2017

Jon C. Moyle, Jr., Esquire
Moyle Law Firm, PA
118 North Gadsden Street
Tallahassee, FL 32301

White Springs Agricultural Chemicals, Inc.

By James W. Brew

8/25/2017

James W. Brew, Esquire
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson Street, NW
Eighth Floor, West Tower
Washington, DC 20007

Florida Retail Federation

By Robert Scheffel Wright

Robert Scheffel Wright, Esq.
Gardner Law Firm
1300 Thomaswood Drive
Tallahassee, FL 32308

Southern Alliance for Clean Energy

By______________________________

George Cavros, Esquire
Attorney for SACE
120 E. Oakland Park Blvd.,
Suite 105
Fort Lauderdale, FL 33334

Exhibit Number	Description
Exhibit 1	Cost of Service and Rate Design Issues
Exhibit 2	2018 Billing Determinants and Calculation of Uniform Percent Increase
Exhibit 3	Revised Tariff Sheets in Clean Copy Format
Exhibit 4	Revised Tariff Sheets in Legislative Format
Exhibit 5	Original Tariff Sheets in Clean Copy and Legislative Format
Exhibit 6	Methodology of Income Tax Change (illustrative)
Exhibit 7	EVSE Chart

Cost of Service and Rate Design Issues

1) Effective with the first billing cycle for January 2018, monthly interruptible and curtailable credits shall be as follows:

IS-1	6.71	per KW of billing demand
IST-1	6.71	per KW of on-peak demand
CS-1	5.03	per KW of billing demand
CST-1	5.03	per KW of on-peak demand
IS-2, IST-2	11.70	per KW of load factor adjusted demand
CS-2, CST-2	8.77	per KW of load factor adjusted demand
CS-3, CS7-3	8.77	per KW of fixed curtailable demand

SS-2 —the greater of:

$1.170 per KW times the Specified Standby Capacity, or the sum of the daily maximum 30 minute KW demand of actual standby use occurring during on-peak periods times $0.557 per KW times the appropriate monthly factor.

SS-3 —the greater of:

$0.877 per KW times the Specified Standby Capacity, or the sum of the daily maximum 30 minute KW demand of actual standby use occurring during on-peak periods times $0.418 per KW times the appropriate monthly factor.

2) Until such time as the Commission sets new base rates in a general rate case proceeding, for all rate making purposes including base rates, monthly actual and annual forecasted earnings surveillance reporting and all cost recovery clause including storm surcharges (if applicable) the demand related retail jurisdictional separation factors will be as follows:

Production Base	92.885%
Production Intermediate	72.703%
Production Peaking	95.924%
Production Solar	96.905%
Transmission	70.203%
Distribution Primary	99.561%

3) Effective with the 1st billing cycle for January 2018, the capacity component of the GSLM-2 Monthly Credit Amount for the Standby Generation load management program shall be as follows:

$4.84 X C + $0.50 x kwh monthly

The capacity component of the Monthly Credit Amount is that defined to be multiplied by "C" in the GSLM-2 tariff where "C"' initially represents the customer's standby generation capacity.

4) The Company will maintain the production capacity cost allocation method of 12CP and 13th AD unless such allocation is changed in the Company's next general rate case.

5) In addition to the provisions of this 2017 Second Revised and Restated Settlement Agreement allowing for or permitting changes in base rates, credits, or charges, subject to Commission approval, DEF may seek Commission authorization to implement any new or revised tariff provision(s) or rate schedule(s) provided that such tariff request does not increase any existing base rate component of a tariff or rate schedule during the term of this 2017 Second Revised and Restated Stipulation and Settlement Agreement unless the application of such new or revised tariff or rate schedule is optional to DEF's customers. Additionally, DEF may seek approval to implement new or revised tariff provisions or rate schedules if any such provision or rate schedule is (a) required in order to implement a legislative requirement for which compliance is mandatory during the Term of this 2017 Second Revised and Restated Settlement Agreement or (b) required to implement a Commission order of statewide applicability, and such order expressly provides (i) that compliance is necessary to protect the integrity of the bulk power supply grid or the safety of persons and property, and (ii) that compliance is mandatory during the Term of this 2017 Second Revised and Restated Settlement Agreement.

2018 billing determinants and calculation of uniform percent increase.

DUKE ENERGY FLORIDA
Detailed Unit Charges and Billed Revenue by Rate Schedule
Proposed Increases: January 2018

Line	Rate Schedule	Type of Charge	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			UNITS	RATES					BASE REVENUE ($000s)				
					0.655%	0.170%	7.500%			Delivery			
					Del. Volt. Cr.	SSN Meters	IS/CS/	Total		Voltage	SSN	Total	
			2018	Current	Proposed	Proposed	GSLM2 Cr.	Proposed	Current	Credit	Meters	Increase /	Proposed
Line	Rate Schedule	Type of Charge	Units	Rates	Increase	Increase	Increase	Rates	Revenue	Revenue	Revenue	(Decrease)	Revenue
					(B) x % incr.	(B) x % incr.	(B) x % incr.	Sum(B:E)	(A) x (B)	(A) x (C)	(A) x (D)	(H) + (I)	(G) + (J)
1	**RS-1,**	Customer Charge - $ per Line of Billing											
2	**RST-1,**	Standard	19,005,748	8.76	0.06	-		8.82	166,490	1,090	-	1,090	167,580
3	**RSS-1,**	Seasonal (RSS-1)	216,653	4.58	0.03	-		4.61	992	6	-	6	999
4	**RSL-1, 2**	Time of Use											
5		Single Phase	194	16.19	0.11	-		16.30	3	0	-	0	3
6		Customer CIAC Paid	156	8.76	0.06	-		8.82	1	0	-	0	1
7													
8		TOU Metering CIAC - $ One Time Charge		90.00	-	-		90.00	-	-	-	-	-
9													
10		Energy Charge - cents per KWH											
11		Standard											
12		0 - 1,000 KWH	14,248,311	5.171	0.034	0.009		5.214	736,780	4,822	1,264	6,086	742,866
13		Over 1,000 KWH	5,749,357	6.587	0.043	0.011		6.641	378,710	2,479	650	3,128	381,838
14		Time of Use - On Peak	142	15.969	0.105	0.027		16.101	23	0	0	0	23
15		Time of Use - Off Peak	413	0.887	0.006	0.002		0.894	4	0	0	0	4
16													
17	**TOTAL RS**								1,283,004	8,397	1,914	10,311	1,293,315
18													
19	**GS-1,**	Customer Charge - $ per Line of Billing											
20	**GST-1**	Standard											
21		Unmetered	5,132	6.54	0.04	-		6.58	34	0	-	0	34
22		Secondary	1,544,930	11.59	0.08	-		11.67	17,906	117	-	117	18,023
23		Primary	461	146.56	0.96	-		147.52	68	0	-	0	68
24		Transmission	-	722.90	4.73	-		727.63	-	-	-	-	-
25		Time of Use											
26		Single & Three Phase	10,714	19.01	0.12	-		19.13	204	1	-	1	205
27		Customer CIAC Paid	24	11.59	0.08	-		11.67	0	0	-	0	0
28		Primary	68	153.99	1.01	-		155.00	11	0	-	0	11
29		Transmission	12	730.32	4.78	-		735.10	9	0	-	0	9
30		TOU Metering CIAC - $ One Time Charge		132.00	-	-		132.00	-	-	-	-	-
31													
32		Energy Charge - cents per KWH											
33		Standard	1,838,035	5.617	0.037	0.010		5.663	103,242	676	177	853	104,095
34		Time of Use - On Peak	24,205	15.942	0.104	0.027		16.074	3,859	25	7	32	3,891
35		Time of Use - Off Peak	76,250	0.864	0.006	0.001		0.871	659	4	1	5	664
36													
37		Premium Distribution Charge - cents per KWH		0.767	0.005	0.001		0.773	-	-	-	-	-
38													
39		Meter Voltage Adjustment - % of Demand & Energy Charges											
40		Primary	(1,135,372)	1.0%				1.0%	(11)	(0)	(0)	(0)	(11)
41		Transmission	(53,463)	2.0%				2.0%	(1)	(0)	(0)	(0)	(1)
42													
43	**TOTAL GS-1**								125,978	825	185	1,009	126,987

DUKE ENERGY FLORIDA
Detailed Unit Charges and Billed Revenue by Rate Schedule
Proposed Increases: January 2018

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			UNITS	RATES					BASE REVENUE ($000s)				
					0.655% Del. Volt. Cr.	0.170% SSN Meters	7.500% IS/CS/ GSLM2 Cr.			Delivery Voltage	SSN		
Line	Rate Schedule	Type of Charge	2018 Units	Current Rates	Proposed Increase (B) x % incr.	Proposed Increase (B) x % incr.	Increase (B) x % incr.	Total Proposed Rates Sum(B:E)	Current Revenue (A) x (B)	Credit Revenue (A) x (C)	Meters Revenue (A) x (D)	Total Increase / (Decrease) (H) + (I)	Proposed Revenue (G) + (J)
44													
45	**GS-2**	Customer Charge - $ per Line of Billing											
46		Standard											
47		Unmetered	11,500	6.54	0.04	-		6.58	75	0	-	0	76
48		Metered	156,466	11.59	0.08	-		11.67	1,813	12	-	12	1,825
49													
50		Energy Charge - cents per KWH											
51		Standard	173,218	2.129	0.014	0.004		2.147	3,688	24	6	30	3,718
52													
53		Premium Distribution Charge - cents per KWH		0.155	0.001	0.000		0.156	-	-	-	-	-
54													
55	**TOTAL GS-2**								5,576	36	6	43	5,619
56													
57	**GSD-1,**	Customer Charge - $ per Line of Billing											
58	**GSDT-1**	Standard											
59		Secondary	443,320	11.59	0.08	-		11.67	5,138	34	-	34	5,172
60		Primary	1,043	146.56	0.96	-		147.52	153	1	-	1	154
61		Transmission		722.90	4.73	-		727.63	-	-	-	-	-
62		Time of Use											
63		Secondary	153,106	19.01	0.12	-		19.13	2,911	19	-	19	2,930
64		Secondary - Customer CIAC paid	132	11.59	0.08	-		11.67	2	0	-	0	2
65		Primary	2,695	153.99	1.01	-		155.00	415	3	-	3	418
66		Primary - Customer CIAC paid	48	146.56	0.96	-		147.52	7	0	-	0	7
67		Transmission	6	730.32	4.78	-		735.10	5	0	-	0	5
68		Transmission Customer CIAC paid		722.90	4.73	-		727.63	-	-	-	-	-
69													
70		Demand Charge - $ per KW											
71		Standard	13,518,654	5.26	0.03	0.01		5.30	71,108	465	122	587	71,696
72		Time of Use											
73		Base	21,577,606	1.29	0.01	0.00		1.30	27,835	182	48	230	28,065
74		On Peak	20,762,649	3.91	0.03	0.01		3.94	81,182	531	139	671	81,853
75		Delivery Voltage Credits - $ per KW								-	-	-	-
76		Primary	(4,496,129)	0.41	0.78	-		1.19	(1,843)	(3,507)	-	(3,507)	(5,350)
77		Transmission	(7,449)	1.55	4.40	-		5.95	(12)	(33)	-	(33)	(44)
78		Premium Distribution Charge - $ per KW	445,155	1.13	0.01	0.00		1.14	503	3	1	4	507
79													
80		Energy Charge - cents per KWH											
81		Standard	4,138,023	2.346	0.015	0.004		2.365	97,078	635	167	802	97,880
82		Time of Use - On Peak	2,770,631	5.106	0.033	0.009		5.148	141,468	926	243	1,169	142,637
83		Time of Use - Off Peak	7,149,975	0.856	0.006	0.001		0.863	61,204	401	105	506	61,709
84													
85		Meter Voltage Adjustment - % of Demand & Energy Charges											
86		Primary	(65,192,813)	1.0%				1.0%	(652)	31	(1)	30	(622)
87		Transmission	-	2.0%				2.0%	-	-	-	-	-
88													
89		Power Factor - $ per KVar	(698,631)	0.30	-	-		0.30	(210)	-	-	-	(210)
90													
91	**TOTAL GSD**								486,292	(308)	823	515	486,806

DUKE ENERGY FLORIDA
Detailed Unit Charges and Billed Revenue by Rate Schedule
Proposed Increases: January 2018

Line	Rate Schedule	Type of Charge	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			UNITS	RATES					BASE REVENUE ($000s)				
			2018 Units	Current Rates	0.655% Del. Volt. Cr. Proposed Increase (B) x % incr.	0.170% SSN Meters Proposed Increase (B) x % incr.	7.500% IS/CS/ GSLM2 Cr. Increase (B) x % incr.	Total Proposed Rates Sum(B:E)	Current Revenue (A) x (B)	Delivery Voltage Credit Revenue (A) x (C)	SSN Meters Revenue (A) x (D)	Total Increase / (Decrease) (H) + (I)	Proposed Revenue (G) + (J)
92													
93	**CS-1,**	Customer Charge - $ per Line of Billing											
94	**CS-2,**	Secondary	-	75.96	0.50	-		76.46	-	-	-	-	-
95	**CS-3,**	Primary	37	210.93	1.38	-		212.31	8	0	-	0	8
96	**CST-1,2,3**	Transmission	-	787.26	5.15	-		792.41	-	-	-	-	-
97													
98		Demand Charge - $ per KW											
99		Standard	-	8.45	0.06	-		8.51	-	-	-	-	-
100		Time of Use											
101		Base	294,392	1.25	0.01	-		1.26	368	2	-	2	370
102		On Peak	250,209	7.13	0.05	-		7.18	1,784	12	-	12	1,796
103													
104		Curtailable Demand Credit											
105		CS-1, CST-1 - $ per KW of Curtail. Demand (CST=on peak)		4.68			0.35	5.03	n/a	n/a	n/a	n/a	n/a
106		CS-2, CST-2 - $ per KW LF adjusted Demand		8.16			0.61	8.77	n/a	n/a	n/a	n/a	n/a
107		CS-3, CST-3 - $ per KW of Contract Demand		8.16			0.61	8.77	n/a	n/a	n/a	n/a	n/a
108													
109		Delivery Voltage Credits - $ per KW											
110		Primary	(294,392)	0.41	0.78	-		1.19	(121)	(230)	-	(230)	(350)
111		Transmission	-	1.55	4.40	-		5.95	-	-	-	-	-
112													
113		Premium Distribution Charge - $ per KW		1.13	0.01	-		1.14	-	-	-	-	-
114													
115		Energy Charge - cents per KWH											
116		Standard	-	1.544	0.010	-		1.554	-	-	-	-	-
117		Time of Use - On Peak	17,327	2.833	0.019	-		2.852	491	3	-	3	494
118		Time of Use - Off Peak	53,822	0.851	0.006	-		0.857	458	3	-	3	461
119													
120		Meter Voltage Adjustment - % of Demand & Energy Charges											
121		Primary	(2,980,188)	1.0%				1.0%	(30)	2	-	2	(28)
122		Transmission	-	2.0%				2.0%	-	-	-	-	-
123													
124		Power Factor - $ per KVar	(2,225)	0.30	-	-		0.30	(1)	-	-	-	(1)
125													
126	**TOTAL CS**								2,958	(207)	-	(207)	2,750

20170183-EI Staff Hearing Exhibits 00078

DUKE ENERGY FLORIDA
Detailed Unit Charges and Billed Revenue by Rate Schedule
Proposed Increases: January 2018

Line	Rate Schedule	Type of Charge	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			UNITS	RATES					BASE REVENUE ($000s)				
			2018 Units	Current Rates	0.655% Del. Volt. Cr. Proposed Increase (B) x % incr.	0.170% SSN Meters Proposed Increase (B) x % incr.	7.500% IS/CS/ GSLM2 Cr. Increase (B) x % incr.	Total Proposed Rates Sum(B:E)	Current Revenue (A) x (B)	Delivery Voltage Credit Revenue (A) x (C)	SSN Meters Revenue (A) x (D)	Total Increase / (Decrease) (H) + (I)	Proposed Revenue (G) + (J)
127													
128	**IS-1,**	Customer Charge - $ per Line of Billing											
129	**IS-2,**	Secondary	381	278.95	1.83	-		280.78	106	1	-	1	107
130	**IST-1,**	Primary	1,034	413.94	2.71	-		416.65	428	3	-	3	431
131	**IST-2**	Transmission	71	990.26	6.48	-		996.74	70	0	-	0	71
132													
133		Demand Charge - $ per KW											
134		Standard	567,793	7.15	0.05	-		7.20	4,060	27	-	27	4,086
135		Time of Use											
136		Base	4,212,784	1.13	0.01	-		1.14	4,760	31	-	31	4,792
137		On Peak	4,019,057	6.26	0.04	-		6.30	25,159	165	-	165	25,324
138		Interruptible Demand Credit											
139		IS-1, IST-1 - $ per KW of Billing Demand (IST= on peak)		6.24			0.47	6.71	n/a	n/a	n/a	n/a	n/a
140		IS-2, IST-2 - $ per KW LF Adjusted Demand		10.88			0.82	11.70	n/a	n/a	n/a	n/a	n/a
141		Delivery Voltage Credits - $ per KW											
142		Primary	(3,070,541)	0.41	0.78	-		1.19	(1,259)	(2,395)	-	(2,395)	(3,654)
143		Transmission	(1,481,869)	1.55	4.40	-		5.95	(2,297)	(6,520)	-	(6,520)	(8,817)
144		Premium Distribution Charge - $ per KW		1.13	0.01	-		1.14		-	-	-	-
145													
146		Energy Charge - cents per KWH											
147		Standard	164,338	1.034	0.007	-		1.041	1,699	11	-	11	1,710
148		Time of Use - On Peak	450,647	1.449	0.009	-		1.458	6,530	43	-	43	6,573
149		Time of Use - Off Peak	1,278,542	0.845	0.006	-		0.851	10,804	71	-	71	10,874
150													
151		Meter Voltage Adjustment - % of Demand & Energy Charges											
152		Primary	(40,245,172)	1.0%				1.0%	(402)	58	-	58	(344)
153		Transmission	(6,755,571)	2.0%				2.0%	(135)	55	-	55	(80)
154													
155		Power Factor - $ per KVar	(98,482)	0.30	-	-		0.30	(30)	-	-	-	(30)
156													
157	**TOTAL IS**								49,494	(8,451)	-	(8,451)	41,043
158													
159	**LS-1**	Customer Charge - $ per Line of Billing											
160		Standard											
161		Unmetered	750,056	1.19	0.01	-		1.20	893	6	-	6	898
162		Metered	12,568	3.42	0.02	-		3.44	43	0	-	0	43
163													
164		Energy and Demand Charge - cents per KWH											
165		Standard	378,883	2.216	0.015	0.004		2.234	8,396	55	14	69	8,465
166													
167	**TOTAL LS**								9,332	61	14	75	9,407

DUKE ENERGY FLORIDA
Detailed Unit Charges and Billed Revenue by Rate Schedule
Proposed Increases: January 2018

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			UNITS	RATES					BASE REVENUE ($000s)				
Line	Rate Schedule	Type of Charge	2018 Units	Current Rates	0.655% Del. Volt. Cr. Proposed Increase (B) x % incr.	0.170% SSN Meters Proposed Increase (B) x % incr.	7.500% IS/CS/ GSLM2 Cr. Increase (B) x % incr.	Total Proposed Rates Sum(B:E)	Current Revenue (A) x (B)	Delivery Voltage Credit Revenue (A) x (C)	SSN Meters Revenue (A) x (D)	Total Increase / (Decrease) (H) + (I)	Proposed Revenue (G) + (J)
168													
169	**SS-1**	Customer Charge - $ per Line of Billing											
170		Secondary		100.71	0.66	-		101.37	-	-	-	-	-
171		Primary	50	235.69	1.54	-		237.23	12	0	-	0	12
172		Transmission	10	812.02	5.31	-		817.33	8	0	-	0	8
173		Customer Owned	72	81.21	0.53	-		81.74	6	0	-	0	6
174													
175		Energy Charge - cents per KWH	49,065	1.021	0.007	0.002		1.029	501	3	1	4	505
176													
177		Distribution Charge - $ per KW											
178		Applicable to Specified SB Capacity	111,036	2.07	0.01	0.00		2.09	230	2	0	2	232
179													
180		Generation and Transmission Capacity Charge											
181		Greater of : - $ per KW											
182		Monthly Reservation Charge											
183		Applicable to Specified SB Capacity	252,768	1.153	0.008	0.002		1.163	291	2	0	2	294
184		Peak Day Utilized SB Power Charge of:	1,880,750	0.549	0.004	0.001		0.554	1,033	7	2	9	1,041
185													
186		Delivery Voltage Credits - $ per KW											
187		Primary	(111,036)	0.37	0.82	-		1.19	(41)	(91)	-	(91)	(132)
188		Transmission		n/a	n/a	n/a		n/a	n/a	n/a	n/a	n/a	n/a
189		Premium Distribution Charge - $ per KW		1.05	0.01	0.00		1.06		-	-	-	-
190													
191		Meter Voltage Adjustment - % of Demand & Energy Charges											
192		Primary	(1,517,717)	1.0%				1.0%	(15)	(0)	(0)	(0)	(15)
193		Transmission	(537,059)	2.0%				2.0%	(11)	(0)	(0)	(0)	(11)
194													
195	**TOTAL SS-1**								2,013	(78)	3	(74)	1,939

DUKE ENERGY FLORIDA
Detailed Unit Charges and Billed Revenue by Rate Schedule
Proposed Increases: January 2018

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			UNITS	RATES					BASE REVENUE ($000s)				
					0.655%	0.170%	7.500%			Delivery			
					Del. Volt. Cr.	SSN Meters	IS/CS/	Total		Voltage	SSN	Total	
	Rate		2018	Current	Proposed	Proposed	GSLM2 Cr.	Proposed	Current	Credit	Meters	Increase /	Proposed
Line	Schedule	Type of Charge	Units	Rates	Increase	Increase	Increase	Rates	Revenue	Revenue	Revenue	(Decrease)	Revenue
					(B) x % incr.	(B) x % incr.	(B) x % incr.	Sum(B:E)	(A) x (B)	(A) x (C)	(A) x (D)	(H) + (I)	(G) + (J)
196													
197	**SS-2**	Customer Charge - $ per Line of Billing											
198		Secondary		303.71	1.99	-		305.70		-	-	-	-
199		Primary	26	438.68	2.87	-		441.55	11	0	-	0	11
200		Transmission	(0)	1,015.02	6.64	-		1,021.66	(0)	(0)	-	(0)	(0)
201		Customer Owned	7	284.20	1.86	-		286.06	2	0	-	0	2
202													
203		Energy Charge - cents per KWH	106,187	1.009	0.007	-		1.016	1,071	7	-	7	1,078
204													
205		Distribution Charge - $ per KW											
206		Applicable to Specified SB Capacity	114,000	2.07	0.01	-		2.08	236	2	-	2	238
207													
208		Generation and Transmission Capacity Charge											
209		Greater of : - $ per KW											
210		Monthly Reservation Charge											
211		Applicable to Specified SB Capacity	55,696	1.153	0.008	-		1.161	64	0	-	0	65
212		Peak Day Utilized SB Power Charge of:	3,869,671	0.549	0.004	-		0.553	2,124	14	-	14	2,138
213													
214		Interruptible Capacity Credit - $ per KW											
215		Monthly Reservation Credit		1.088			0.082	1.170	-	-	-	-	-
216		Daily Demand Credit		0.518			0.039	0.557	-	-	-	-	-
217													
218		Delivery Voltage Credits - $ per KW											
219		Primary	(114,000)	0.37	0.82	-		1.19	(42)	(93)	-	(93)	(136)
220		Transmission		n/a	n/a	n/a		n/a		-	-	-	-
221		Premium Distribution Charge - $ per KW		1.05	0.01	-		1.06		-	-	-	-
222													
223		Meter Voltage Adjustment - % of Demand & Energy Charges											
224		Primary	(2,359,024)	1.0%				1.0%	(24)	(0)	-	(0)	(24)
225		Transmission	(1,137,051)	2.0%				2.0%	(23)	(0)	-	(0)	(23)
226													
227	**TOTAL SS-2**								3,421	(71)	-	(71)	3,350

DUKE ENERGY FLORIDA
Detailed Unit Charges and Billed Revenue by Rate Schedule
Proposed Increases: January 2018

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			UNITS	RATES					BASE REVENUE ($000s)				
Line	Rate Schedule	Type of Charge	2018 Units	Current Rates	0.655% Del. Volt. Cr. Proposed Increase (B) x % incr.	0.170% SSN Meters Proposed Increase (B) x % incr.	7.500% IS/CS/ GSLM2 Cr. Increase (B) x % incr.	Total Proposed Rates Sum(B:E)	Current Revenue (A) x (B)	Delivery Voltage Credit Revenue (A) x (C)	SSN Meters Revenue (A) x (D)	Total Increase / (Decrease) (H) + (I)	Proposed Revenue (G) + (J)
228													
229	**SS-3**	Customer Charge - $ per Line of Billing											
230		Secondary		100.71	0.66	-		101.37	-	-	-	-	-
231		Primary	13	235.69	1.54	-		237.23	3	0	-	0	3
232		Transmission	-	812.02	5.31	-		817.33	-	-	-	-	-
233		Customer Owned	-	81.21	0.53	-		81.74	-	-	-	-	-
234													
235		Energy Charge - cents per KWH	55,813	1.013	0.007	-		1.020	565	4	-	4	569
236													
237		Distribution Charge - $ per KW											
238		Applicable to Specified SB Capacity	266,652	2.07	0.01	-		2.08	552	4	-	4	556
239													
240		Generation and Transmission Capacity Charge											
241		Greater of : - $ per KW											
242		Monthly Reservation Charge											
243		Applicable to Specified SB Capacity	133,326	1.153	0.008	-		1.161	154	1	-	1	155
244		Peak Day Utilized SB Power Charge of:	1,614,827	0.549	0.004	-		0.553	887	6	-	6	892
245													
246		Curtailable Capacity Credit - $ per KW											
247		Monthly Reservation Credit		0.816			0.061	0.877					
248		Daily Demand Credit		0.389			0.029	0.418					
249													
250		Delivery Voltage Credits - $ per KW											
251		Primary	(266,652)	0.37	0.82	-		1.19	(99)	(219)	-	(219)	(317)
252		Transmission		n/a	n/a	n/a		n/a		-	-	-	-
253		Premium Distribution Charge - $ per KW		1.05	0.01	-		1.06		-	-	-	-
254													
255		Meter Voltage Adjustment - % of Demand & Energy Charges											
256		Primary	(2,157,619)	1.0%				1.0%	(22)	(0)	-	(0)	(22)
257		Transmission	-	2.0%				2.0%	-	-	-	-	-
258													
259	**TOTAL SS-3**								2,041	(205)	-	(205)	1,836
260													
261	**GSLM-2**	Capacity Credit		4.50			0.34	4.84					
262													
263	**TOTAL**								1,970,108	(0)	2,946	2,945	1,973,053

Revised Tariff Sheets in Clean Copy Format

Thirty-Second Revised Sheet No. 6.120
Thirty-Fourth Revised Sheet No. 6.130
Twentieth Revised Sheet No. 6.135
Twenty-Sixth Revised Sheet No. 6.140
Thirty-Third Revised Sheet No. 6.150
Twenty-Ninth Revised Sheet No. 6.160
Thirty-Second Revised Sheet No. 6.165
Twenty-Ninth Revised Sheet No. 6.170
Twenty-Third Revised Sheet No. 6.171
Thirtieth Revised Sheet No. 6.180
Twenty-Third Revised Sheet No. 6.181
Tenth Revised Sheet No. 6.225
Thirty-Fourth Revised Sheet No. 6.230
Twenty-Eighth Revised Sheet No. 6.231
Nineteenth Revised Sheet No. 6.235
Fourteenth Revised Sheet No. 6.236
Sixteenth Revised Sheet No. 6.2390
Thirty-Third Revised Sheet No. 6.240
Twenty-Sixth Revised Sheet No. 6.241
Eighteenth Revised Sheet No. 6.245
Fourteenth Revised Sheet No. 6.246
Sixteenth Revised Sheet No. 6.2490
Twelfth Revised Sheet No. 6.2491
Thirty-Fourth Revised Sheet No. 6.250
Twentieth Revised Sheet No. 6.255
Thirty-Fourth Revised Sheet No. 6.260
Twenty-Seventh Revised Sheet No. 6.261
Nineteenth Revised Sheet No. 6.265
Thirteenth Revised Sheet No. 6.266
Thirtieth Revised Sheet No. 6.280
Twenty-Seventh Revised Sheet No. 6.281
Sixth Revised Sheet No. 6.2811
Twenty-Second Revised Sheet No. 6.312
Twenty-First Revised Sheet No. 6.313
Twenty-Sixth Revised Sheet No. 6.317
Twentieth Revised Sheet No. 6.318
Twenty-Second Revised Sheet No. 6.322
Eighth Revised Sheet No. 6.350
Second Revised Sheet No. 6.380
First Revised Sheet No. 6.381
Third Revised Sheet No. 6.385
First Revised Sheet No. 6.386

RATE SCHEDULE RS-1
RESIDENTIAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To residential customers in a single dwelling house, a mobile home, or individually metered single apartment unit or other unit having housekeeping facilities, occupied by one family or household as a residence. The premises of such single dwelling may include an additional apartment with separate housekeeping facilities, as well as a garage and other separate structures where they are occupied or used solely by the members or servants of such family or household. Also, for energy used in commonly-owned facilities in condominium and cooperative apartment buildings subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owner's benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery is separately metered and billed.
4. A responsible legal entity is established as the customer to whom the Company can render its bill(s) for said service.

Character of Service:

Continuous service, alternating current, 60 cycles per second, single-phase or three-phase, at the Company's standard available distribution voltage. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$ 8.82
Demand and Energy Charges:	
Non-Fuel Energy Charges:	
First 1,000 kWh	5.214¢ per kWh
All additional kWh	6.641¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

(Continued on Page No. 2)

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT

Availability:

Available only within the range of the Company's Load Management System.
Available to customers whose premises have active load management devices installed prior to June 30, 2007.
Available to customers whose premises have load management devices installed after June 30, 2007 that have and are willing to submit to load control of, at a minimum, central electric cooling and heating systems.

Applicable:

To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh (based on the most recent 12 months, or, where not available, a projection for 12 months), and utilizing any of the following electrical equipment:

1. Water Heater
2. Central Electric Heating System
3. Central Electric Cooling System
4. Swimming Pool Pump

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

For new service requests after June 30, 2007 customers with a central electric heating system that is a heat pump will be installed on Interruption Schedule S. All other new service requests will be installed on Interruption Schedule B. Interruption Schedule C shall be at the option of the customer.

For new service requests after April 1, 1995, and before June 30, 2007, customers who select the swimming pool pump schedule must also select at least one other schedule.

An installation of an alternative thermal storage heating system under Special Provision No. 7 of this rate schedule is not available after April 1, 1995.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge: $ 8.82

Energy and Demand Charges:

Non-Fuel Energy Charges:

First 1,000 kWh	5.214¢ per kWh
All additional kWh	6.641¢ per kWh

Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor: See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Monthly Credit Amounts:[1,2]

Interruptible Equipment	Interruption Schedule A	B	C	D	S
Water Heater	-	-	$3.50	-	-
Central Heating System[3]	$2.00	$8.00	-	-	$8.00
Central Heating System w/Thermal Storage[3]	-	-	-	$8.00	-
Central Cooling System[4]	$1.00	$5.00	-	-	$5.00
Swimming Pool Pump	-	-	$2.50	-	-

(Continued on Page No. 2)

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY

Availability:

Available only within the range of the Company's Load Management System.

Applicable:

To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh for the months of November through March (based on the most recent billings, where not available, a projection for those months) and utilizing **both** electric water heater and central electric heating systems.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$ 8.82
Energy and Demand Charges:	
Non-Fuel Energy Charges:	
First 1,000 kWh	5.214¢ per kWh
All additional kWh	6.641¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Credit Amount:[1]

Interruptible Equipment	Monthly Credit[2]
Water Heater and Central Heating System	$11.50

Notes: (1) Load management credit shall not exceed 40% of the Non-Fuel Energy Charge associated with kWh billed in excess of 600 kWh/month.

(2) For billing months of November through March only.

Appliance Interruption Schedule:

Heating — Equipment interruptions to achieve an effective equipment duty cycle of approximately 45% during control periods within the Company's designated Peak Periods. Heat pump back-up strip may be interrupted continuously, not to exceed 300 minutes, during the Company's designated Peak. When the heat pump back-up strip is being interrupted, the heat pump will not be interrupted.

Water Heater — Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE RST-1
RESIDENTIAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 02/10/10)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of residential customers otherwise eligible for service under Rate Schedule RS-1, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Continuous service, alternating current, 60 cycle, single phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations Governing Electric Service."

Rate Per Month:

Customer Charge: $ 16.30

Energy and Demand Charges:

Non-Fuel Energy Charges:	16.101¢ per On-Peak kWh 0.894¢ per Off-Peak kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy used during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Rating Periods:

(a) **On-Peak Periods** - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March, Monday through Friday *: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October, Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(b) **Off-Peak Periods** - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

(Continued on Page No. 2)

RATE SCHEDULE GS-1
GENERAL SERVICE – NON-DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes for which no other rate schedule is specifically applicable.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase or three-phase, at the Company's standard distribution voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Unmetered Account:	$ 6.58
Secondary Metering Voltage:	$ 11.67
Primary Metering Voltage:	$ 147.52
Transmission Metering Voltage:	$ 727.63

Energy and Demand Charges:

Non-Fuel Energy Charge:	5.663¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Non-Fuel Energy Charge included in the Rate per Month section of this rate schedule shall be increased by 0.773¢ per kWh for the cost of reserving capacity in the alternate distribution circuit.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above standard distribution secondary, the applicable following reduction factor shall apply to the Non-Fuel Energy Charge hereunder:

Metering Voltage	**Reduction Factor**
Distribution Primary	1.0%
Transmission	2.0%

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

(Continued on Page No. 2)

RATE SCHEDULE GST-1
GENERAL SERVICE – NON-DEMAND
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of non-residential customers otherwise eligible for service under Rate Schedule GS-1, provided that all of the electric load requirements on the Customer's premises are metered through one point of delivery.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase or three-phase, at the Company's standard distribution voltage available.

Limitation of Service:

Standby or Resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate per Month:

Customer Charge:

Secondary Metering Voltage:	$ 19.13
Primary Metering Voltage:	$ 155.00
Transmission Metering Voltage:	$ 735.10

Energy and Demand Charge:

Non-Fuel Energy Charge:	16.074¢ per On-Peak kWh 0.871¢ per Off-Peak kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Non-Fuel Charges included in the Rate per Month section of this rate schedule shall be increased by 0.773¢ per kWh for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

(a) **On-Peak Periods** - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March, Monday through Friday *:	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
(2) For the calendar months of April through October, Monday through Friday*:	12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE GS-2
GENERAL SERVICE – NON-DEMAND
100% LOAD FACTOR USAGE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, with fixed wattage loads operating continuously throughout the billing period (such as traffic signals, cable TV amplifiers and gas transmission substations).

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase or three-phase, at the Company's standard distribution voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate per Month:

Customer Charge:

Unmetered Account:	$ 6.58
Metered Account:	$ 11.67

Energy and Demand Charges:

Non-Fuel Energy Charge:	2.147¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Non-Fuel Energy Charge included in the Rate per Month section of this rate schedule shall be increased by 0.156¢ per kWh for the cost of reserving capacity in the alternate distribution circuit.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

(Continued on Page No. 2)

RATE SCHEDULE GSD-1
GENERAL SERVICE - DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes for which no other rate schedule is specifically applicable with a measured annual kWh consumption of 24,000 kWh or greater per year.

Character of Service:

Continuous service, alternating current, 60 cycle, singe-phase or three-phase, at the Company's standard distribution voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 11.67
Primary Metering Voltage:	$ 147.52
Transmission Metering Voltage:	$ 727.63

Demand Charge: $ 5.30 per kW of Billing Demand

Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106

Energy Charge:

Non-Fuel Energy Charge:	2.365¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

Determination of Billing Demand:

The billing demand shall be the maximum 30-minute kW demand established during the current billing period.

(Continued on Page No. 2)

RATE SCHEDULE GSD-1
GENERAL SERVICE - DEMAND
(Continued from Page No. 1)

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credits:

For Distribution Primary Delivery Voltage:	$1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95 per kW of Billing Demand

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the applicable following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with measured demands of 1,000 kW or more for three (3) or more months out of the twelve (12) consecutive months ending with the current billing period, bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on the bill at Company-designated locations.

Term of Service:

Service under this rate shall be for a minimum initial term of twelve (12) months from commencement of service and shall continue thereafter until receipt of notice by the Company from the customer to disconnect, or upon disconnect by the Company under Florida Public Service Commission or Company Rules.

Customers taking service under another Company rate schedule who elect to transfer to this rate must remain on this rate for a minimum term of twelve (12) months.

(Continued on Page No. 3)

RATE SCHEDULE GSDT-1
GENERAL SERVICE - DEMAND
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of the customer, otherwise eligible for service under Rate Schedule GSD-1, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase or three-phase, at the Company's standard distribution voltage available.

Limitation of Service:

Standby or Resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate per Month:

Customer Charge:

Secondary Metering Voltage:	$ 19.13
Primary Metering Voltage:	$ 155.00
Transmission Metering Voltage:	$ 735.10

Demand Charges:

Base Demand Charge:	$ 1.30 per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 3.94 per kW of On-Peak Demand

Energy Charges:

Non-Fuel Energy Charge:	5.148¢ per On-Peak kWh 0.863¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

RATE SCHEDULE GSDT-1
GENERAL SERVICE DEMAND
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

Rating Periods:

(a) **On-Peak Periods** - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March,
Monday through Friday *: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October,
Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(b) **Off-Peak Periods -** The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate schedule at a delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credits:

For Distribution Primary Delivery Voltage:	$1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95 per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the applicable following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with metered demands of 1,000 kW or more for three (3) or more months out of the twelve (12) consecutive months ending with the current billing period, bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds numerically .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

(Continued on Page No. 3)

RATE SCHEDULE GSLM-2
GENERAL SERVICE LOAD MANAGEMENT – STANDBY GENERATION

Availability:

Available only within the range of the Company's radio switch communications capability.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1 who have standby generation that will allow facility demand reduction at the request of the Company. The customer's Standby Generation Capacity calculation must be at least 50 kW in order to remain eligible for the rate. Customers cannot be on this rate schedule and also the General Service Load Management (GSLM-1) rate schedule. Not applicable to Net Metering customers. Customers cannot use the standby generation for peak shaving. Available only to those customers whose standby generation equipment is compliant with all applicable federal, state, and local codes and rules.

Limitation of Service:

Operation of the customer's equipment will occur at the Company's request. Requests by the Company for the customer to reduce facility demand by operation of their standby generation can occur at any time. Power to the facility from the Company will normally remain as back up power for the standby generation. The Customer will be given fifteen (15) minutes to initiate the demand reduction before the capacity calculation (see Definitions) is impacted.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1 or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

GSLM-2 MONTHLY CREDIT AMOUNT
STANDBY GENERATION

Credit	Cumulative Fiscal Year Hours
\$4.84 x ***C*** + \$0.50 x kWh monthly	All CRH

Immediately upon going on the rate, the customer's Capacity (***C***) is set to a value equivalent to the load the customer's standby generator carries during testing observed by the Customer and a Company representative. The ***C*** will remain at that value until the equipment is requested to run by the Company. The ***C*** for that month and subsequent months will be a calculated value based upon the following formula:

$$C = \frac{\text{kWh annual}}{[\text{CAH} - (\text{\# of Requests} \times \frac{1}{4}\text{ hour})]}$$

Definitions:

kWh annual = Actual measured kWh generated by the standby generator during the previous twelve (12) months during Company control periods (rolling total).

CAH = Cumulative hours requested by the Company for the standby generation to operate for the previous twelve (12) months (rolling total).

CRH = Cumulative standby generator running hours during request periods of the Company for the current fiscal year (the fiscal year begins on the month the customer goes on the GSLM-2 rate).

# of Requests = The cumulative number of times the Company has requested the standby generation to be operated for the previous twelve (12) months (rolling total).

kWh monthly = Actual measured kWh generated by the standby generator for the current month during Company control periods.

(Continued on Page No. 2)

RATE SCHEDULE CS-1
CURTAILABLE GENERAL SERVICE
(Closed to New Customers as of 04/16/96)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes where the customer agrees during a period of requested curtailment to curtail as a minimum the greater of: (a) 25 kW or (b) 25% of their average monthly billing demand (based on the most recent twelve (12) months or, where not available, a projection for twelve (12) months).

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Curtailable service under this rate schedule is not subject to curtailment during any time period for economic reasons. Curtailable service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to curtailable loads except under the conditions set forth in Special Provision No. 6 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 76.46
Primary Metering Voltage:	$ 212.31
Transmission Metering Voltage:	$ 792.41

Demand Charge:	$ 8.51 per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Curtailable Demand Credit:	$ 5.03 per kW of Curtailable Demand

Energy Charge:

Non-Fuel Energy Charge:	1.554¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

RATE SCHEDULE CS-1
CURTAILABLE GENERAL SERVICE
(Closed to New Customers as of 04/16/96)
(Continued from Page No. 1)

Determination of Billing Demand:

The billing demand shall be the maximum 30-minute kW demand established during the current billing period.

Determination of Curtailable Demand:

The Curtailable Demand shall be the difference, if any, between the current Billing Demand and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of this rate. In no event shall the Curtailable Demand be less than zero.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$ 5.95 per kW of Billing Demand

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with measured demands of 1,000 kW or more for three (3) or more months out of the twelve (12) consecutive months ending with the current billing period, bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Term of Service:

Service under this rate schedule shall be for a minimum initial term of two (2) years from the commencement of service and shall continue thereafter until terminated by either party by written notice sixty (60) days prior to termination.

(Continued on Page No. 3)

RATE SCHEDULE CS-2
CURTAILABLE GENERAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes where the billing demand is 500 kW or more, and where the customer agrees to curtail 25% of their average monthly billing demand (based on the most recent twelve (12) months or, where not available, a projection for twelve (12) months).

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Curtailable service under this rate schedule is not subject to curtailment during any time period for economic reasons. Curtailable service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to curtailable loads except under the conditions set forth in Special Provision No. 6 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 76.46
Primary Metering Voltage:	$ 212.31
Transmission Metering Voltage:	$ 792.41

Demand Charge:	$ 8.51 per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Curtailable Demand Credit:	$ 8.77 per kW of Load Factor Adjusted Demand

Energy Charge:

Non-Fuel Energy Charge:	1.554¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

RATE SCHEDULE CS-2
CURTAILABLE GENERAL SERVICE
(Continued from Page No. 1)

Determination of Billing Demand:

The billing demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 500 kW.

Determination of Load Factor Adjusted Demand:

The Load Factor Adjusted Demand shall be the difference, if any, between the maximum 30-minute kW demand established during the current billing period and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of this rate, multiplied by the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand, multiplied by the number of hours in the billing period). In no event shall the Curtailable Demand be less than zero.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95 per kW of Billing Demand

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

Bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Demand Charge for the current billing period. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Term of Service:

Service under this rate shall be for a minimum initial term of two (2) years from the commencement of service, and shall continue thereafter until terminated by either party by written notice sixty (60) days prior to termination.

(Continued on Page No. 3)

RATE SCHEDULE CS-3
CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes where the billing demand is 2,000 kW or more (based on most recent twelve (12) months or, where not available, projected billing demand for twelve (12) months), and where the customer agrees to curtail its demand by a fixed contractual amount of not less than 2,000 kW upon request of the Company in accordance with the provisions of this rate schedule.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. Service under this rate schedule is not subject to curtailment for economic reasons. The Company will not make off-system purchases during such curtailment periods to maintain service hereunder except as set forth in Special Provision No. 6 below.

Service under this rate is subject to the "General Rules and Regulations Governing Electric Service" contained in Section IV of the Company's currently effective and filed retail tariff.

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 76.46
Primary Metering Voltage:	$ 212.31
Transmission Metering Voltage:	$ 792.41

Demand Charge: $ 8.51 per kW of Billing Demand

Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*: See Sheet No. 6.105 and 6.106

Curtailable Demand Credit: $ 8.77 per kW of Fixed Curtailable Demand

Energy Charge:

Non-Fuel Energy Charge: 1.554¢ per kW

Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor: See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where the customer receives Premium Distribution Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer, including, all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

Determination of Billing Demand:

The billing demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 2,000 kW.

Delivery Voltage Credit:

When a customer takes service under this rate schedule at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95 per kW of Billing Demand

(Continued on Page No. 2)

RATE SCHEDULE CST-1
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 04/16/96)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of customers otherwise eligible for service under Rate Schedule CS-1, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Curtailable Service under this rate schedule is not subject to curtailment during any time period for economic reasons. Curtailable Service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to curtailable loads except under the conditions set forth in Special Provision No. 6 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate per Month:

Customer Charge:

Secondary Metering Voltage:	$ 76.46
Primary Metering Voltage:	$ 212.31
Transmission Metering Voltage:	$ 792.41

Demand Charges:

Base Demand Charge:	$ 1.26 per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 7.18 per kW of On-Peak Demand

Curtailable Demand Credit:	$ 5.03 per kW of Curtailable Demand

Energy Charge:

Non-Fuel Energy Charge:	2.852¢ per On-Peak kWh 0.857¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

RATE SCHEDULE CST-1
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 04/16/96)
(Continued from Page No. 1)

Rating Periods:

(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March,
Monday through Friday *: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October,
Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(b) Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Determination of Curtailable Demand:

The Curtailable Demand shall be the difference, if any, between the current On-Peak Demand and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of this rate. In no event shall the Curtailable Demand be less than zero.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95 per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

Bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106

(Continued on Page No. 3)

RATE SCHEDULE CST-2
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of customers otherwise eligible for service under Rate Schedule CS-2, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Curtailable service under this rate schedule is not subject to curtailment during any time period for economic reasons. Curtailable service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to curtailable loads except under the conditions set forth in Special Provision No. 6 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 76.46
Primary Metering Voltage:	$ 212.31
Transmission Metering Voltage:	$ 792.41

Demand Charges:

Base Demand Charge:	$ 1.26 per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 7.18 per kW of On-Peak Demand

Curtailable Demand Credit:	$ 8.77 per kW of Load Factor Adjusted Demand

Energy Charge:

Non-Fuel Energy Charge:	2.852¢ per On-Peak kWh 0.857¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

ISSUED BY: Javier J. Portuondo, Managing Director Rates & Regulatory Strategy – FL

EFFECTIVE: January 1, 2018

RATE SCHEDULE CST-2
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

Rating Periods:

(a) **On-Peak Periods** - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March,
Monday through Friday *: 6:00 a.m. to 10:00 a.m. and
6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October,
Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(b) **Off-Peak Periods** - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 500 kW.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Determination of Load Factor Adjusted Demand:

The Load Factor Adjusted Demand shall be the difference, if any, between the maximum 30-minute kW demand established during the current billing period and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of this rate, multiplied by the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand, multiplied by the number of hours in the billing period). In no event shall the Curtailable Demand be less than zero.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95 per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	**Reduction Factor**
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

Bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106

(Continued on Page No. 3)

RATE SCHEDULE CST-3
CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer otherwise eligible for service under Rate Schedule CS-3, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments, or b) supply emergency interchange service to another utility for its firm load obligations only. Service under this rate schedule is not subject to curtailment for economic reasons. The Company will not make off-system purchases during such curtailment periods to maintain service hereunder except as set forth in Special Provision No. 6 below.

Service under this rate is subject to the "General Rules and Regulations Governing Electric Service" contained in Section IV of the Company's currently effective and filed retail tariff.

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 76.46
Primary Metering Voltage:	$ 212.31
Transmission Metering Voltage:	$ 792.41

Demand Charges:

Base Demand Charge:	$ 1.26 per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 7.18 per kW of On-Peak Demand
Curtailable Demand Credit:	$ 8.77 per kW of Fixed Curtailable Demand

Energy Charge:

Non-Fuel Energy Charge:	2.852¢ per On-Peak kWh 0.857¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where the customer receives Premium Distribution Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including, all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

For the calendar months of November through March, Monday through Friday*:	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
For the calendar months of April through October, Monday through Friday*:	12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas. In the event the holiday occurs on a Saturday or Sunday, the following Monday shall be excluded from the On-Peak Periods.

Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

(Continued on Page No. 2)

RATE SCHEDULE CST-3
CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

Determination of Billing Demand:

The Base Demand for billing purposes shall be the maximum 30-minute kW demand established during the current billing period, but not less than **2,000** kW.

The On-Peak Demand for billing purposes shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate schedule at a delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$ 1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$ 5.95 per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit, and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor Adjustment:

Bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Demand Charge for the current billing period. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Term of Service:

Service under this rate schedule shall be for a minimum initial term of two (2) years from the commencement of service, and shall continue thereafter until terminated by either party by written notice sixty (60) days prior to termination.

Special Provisions:

1. As used in this rate schedule, the term "period of requested curtailment" shall mean a period for which the Company has requested curtailment and for which energy purchased from sources outside the Company's system, pursuant to Special Provision No. 6, is not available. If such energy can be purchased, the terms of Special Provision No. 6 will apply and a period of requested curtailment will not be deemed to exist while such energy remains available.

(Continued on Page No. 3)

RATE SCHEDULE IS-1
INTERRUPTIBLE GENERAL SERVICE
(Closed to New Customers as of 04/16/96)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes where service may be interrupted by the Company.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is not subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 280.78
Primary Metering Voltage:	$ 416.65
Transmission Metering Voltage:	$ 996.74

Demand Charge:	$ 7.20 per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Interruptible Demand Credit:	$ 6.71 per kW of Billing Demand

Energy Charge:

Non-Fuel Energy Charge:	1.041¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

Determination of Billing Demand:

The Billing Demand shall be the maximum 30-minute kW demand established during the billing period.

Delivery Voltage Credit:

When a customer takes service under this rate schedule at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95 per kW of Billing Demand

(Continued on Page No. 2)

RATE SCHEDULE IS-2
INTERRUPTIBLE GENERAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicability:

Applicable to customers, other than residential, for light and power purposes where the billing demand is 500 kW or more, and where service may be interrupted by the Company. For customer accounts established under this rate schedule after June 3, 2003, service is limited to premises at which an interruption of electric service will primarily affect only the customer, its employees, agents, lessees, tenants or business guests, and will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. Examples of premises at which service under this rate schedule may not be provided, unless adequate on-site backup generation is available, include, but are not limited to: retail businesses, offices, and governmental facilities open to members of the general public, stores, hotels, motels, convention centers, theme parks, schools, hospitals and health care facilities, designated public shelters, detention and correctional facilities, police and fire stations, and other similar facilities.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is <u>not</u> subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency Interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 280.78
Primary Metering Voltage:	$ 416.65
Transmission Metering Voltage:	$ 996.74
Demand Charge:	$ 7.20 per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Interruptible Demand Credit:	$ 11.70 per kW of Load Factor Adjusted Demand
Energy Charge:	
Non-Fuel Energy Charge:	1.041¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

Determination of Billing Demand:

The Billing Demand shall be the maximum 30-minute kW demand established during the billing period, but not less than 500 kW.

Determination of Load Factor Adjusted Demand:

The Load Factor Adjusted Demand shall be the product of the maximum 30-minute kW demand established during the current billing period and the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand times the number of hours in the billing period).

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95 per kW of Billing Demand

(Continued on Page No. 2)

RATE SCHEDULE IST-1
INTERRUPTIBLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 04/16/96)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of customers otherwise eligible for service under Rate Schedule IS-1, provided that the total electric load requirements at each point of delivery are measured through one meter.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is not subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 280.78
Primary Metering Voltage:	$ 416.65
Transmission Metering Voltage:	$ 996.74

Demand Charge:

Base Demand Charge:	$ 1.14 per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 6.30 per kW of On-Peak Demand
Interruptible Demand Credit:	$ 6.71 per kW of On-Peak Demand

Energy Charge:

Non-Fuel Energy Charge:	1.458¢ per On-Peak kWh 0.851¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy used during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March, Monday through Friday*:	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
(2) For the calendar months of April through October, Monday through Friday*:	12:00 Noon to 9:00 p.m.

(Continued on Page No. 2)

RATE SCHEDULE IST-1
INTERRUPTIBLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 04/16/96)
(Continued from Page No. 1)

Rating Periods: (Continued)

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Period.

(b) **Off-Peak Periods -** The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Base Demand charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95 per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, Interruptible Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with measured demands of 1,000 kW or more for three (3) or more months out of the twelve (12) consecutive months ending with the current billing period, bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds numerically, .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

(Continued on Page No. 3)

RATE SCHEDULE IST-2
INTERRUPTIBLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicability:

At the option of the customer, applicable to customers otherwise eligible for service under Rate Schedule IS-2, where the billing demand is 500 kW or more, provided that the total electric requirements at each point of delivery are measured through one meter. For customer accounts established under this rate schedule after June 3, 2003, service is limited to premises at which an interruption of electric service will primarily affect only the customer, its employees, agents, lessees, tenants, or business guests, and will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. Examples of premises at which service under this rate schedule may not be provided, unless adequate on-site backup generation is available, include, but are not limited to: retail businesses, offices, and governmental facilities open to members of the general public, stores, hotels, motels, convention centers, theme parks, schools, hospitals and health care facilities, designated public shelters, detention and correctional facilities, police and fire stations, and other similar facilities.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is <u>not</u> subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments, or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 280.78
Primary Metering Voltage:	$ 416.65
Transmission Metering Voltage:	$ 996.74

Demand Charge:

Base Demand Charge:	$ 1.14 per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 6.30 per kW of On-Peak Demand
Interruptible Demand Credit:	$ 11.70 per kW of Load Factor Adjusted Demand

Energy Charge:

Non-Fuel Energy Charge:	1.458¢ per On-Peak kWh 0.851¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy used during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit. In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14 per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March, Monday through Friday*: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October, Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

Continued on Page No. 2)

RATE SCHEDULE IST-2
INTERRUPTIBLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

Rating Periods: (Continued)

(b) Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 500 kW.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Determination of Load Factor Adjusted Demand:

The Load Factor Adjusted Demand shall be the product of the maximum 30-minute kW demand established during the current billing period and the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand times the number of hours in the billing period).

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Base Demand charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19 per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95 per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges, Interruptible Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with measured demands of 1,000 kW or more for three (3) or more months out of the twelve (12) consecutive months ending with the current billing period, bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds numerically, .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Demand Charge for the current billing period. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

(Continued on Page No. 3)

RATE SCHEDULE LS-1
LIGHTING SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer for the sole purpose of lighting roadways or other outdoor land use areas; served from either Company or customer owned fixtures of the type available under this rate schedule. Service hereunder is provided for the sole and exclusive benefit of the customer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose any obligation on the Company to any such third party.

Character of Service:

Continuous dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating current, 60 cycle, single phase, at the Company's standard voltage available.

Limitation of Service:

Availability of certain fixture or pole types at a location may be restricted due to accessibility.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations Governing Electric Service."

Rate Per Month:

Customer Charge:

Unmetered:	$ 1.20 per line of billing
Metered:	$ 3.44 per line of billing

Energy and Demand Charge:

Non-Fuel Energy Charge:	2.234¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Per Unit Charges:

I. **Fixtures:**

BILLING TYPE	DESCRIPTION	LAMP SIZE [2] INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	CHARGES PER UNIT FIXTURE	MAINTENANCE	NON-FUEL ENERGY [3]
	Incandescent: [1]						
110	Roadway	1,000	105	32	$1.03	$4.07	$0.71
115	Roadway	2,500	205	66	1.61	3.67	1.47
170	Post Top	2,500	205	72	20.39	3.67	1.61
	Mercury Vapor: [1]						
205	Open Bottom	4,000	100	44	$2.55	$1.80	$0.98
210	Roadway	4,000	100	44	2.95	1.80	0.98
215	Post Top	4,000	100	44	3.47	1.80	0.98
220	Roadway	8,000	175	71	3.34	1.77	1.59
225	Open Bottom	8,000	175	71	2.50	1.77	1.59
235	Roadway	21,000	400	158	4.04	1.81	3.53
240	Roadway	62,000	1,000	386	5.29	1.78	8.62
245	Flood	21,000	400	158	5.29	1.81	3.53
250	Flood	62,000	1,000	386	6.20	1.78	8.62

(Continued on Page No. 2)

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 1)

I. Fixtures: (Continued)

BILLING TYPE	DESCRIPTION	LAMP SIZE [2] INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	CHARGES PER UNIT FIXTURE	MAINTENANCE	NON-FUEL ENERGY [3]
	Sodium Vapor:						
300	HPS Deco Rdwy White	50,000	400	168	$14.73	$1.61	$3.75
301	Sandpiper HPS Deco Roadway	27,500	250	104	13.81	1.72	2.32
302	Sandpiper HPS Deco Rdwy Blk	9,500	100	42	14.73	1.58	0.94
305	Open Bottom [1]	4,000	50	21	2.54	2.04	0.47
310	Roadway [1]	4,000	50	21	3.12	2.04	0.47
313	Open Bottom [1]	6,500	70	29	4.19	2.05	0.65
314	Hometown II	9,500	100	42	4.08	1.72	0.94
315	Post Top - Colonial/Contemp [1]	4,000	50	21	5.04	2.04	0.47
316	Colonial Post Top [1]	4,000	50	34	4.05	2.04	0.76
318	Post Top [1]	9,500	100	42	2.50	1.72	0.94
320	Roadway-Overhead Only	9,500	100	42	3.64	1.72	0.94
321	Deco Post Top - Monticello	9,500	100	49	12.17	1.72	1.09
322	Deco Post Top - Flagler	9,500	100	49	16.48	1.72	1.09
323	Roadway-Turtle OH Only	9,500	100	42	4.32	1.72	0.94
325	Roadway-Overhead Only	16,000	150	65	3.78	1.75	1.45
326	Deco Post Top – Sanibel	9,500	100	49	18.16	1.72	1.09
330	Roadway-Overhead Only	22,000	200	87	3.64	1.83	1.94
335	Roadway-Overhead Only	27,500	250	104	4.16	1.72	2.32
336	Roadway-Bridge [1]	27,500	250	104	6.74	1.72	2.32
337	Roadway-DOT [1]	27,500	250	104	5.87	1.72	2.32
338	Deco Roadway–Maitland	27,500	250	104	9.62	1.72	2.32
340	Roadway-Overhead Only	50,000	400	169	5.03	1.76	3.78
341	HPS Flood-City of Sebring only [1]	16,000	150	65	4.06	1.75	1.45
342	Roadway-Turnpike [1]	50,000	400	168	8.95	1.76	3.75
343	Roadway-Turnpike [1]	27,500	250	108	9.12	1.72	2.41
345	Flood-Overhead Only	27,500	250	103	5.21	1.72	2.30
347	Clermont	9,500	100	49	20.65	1.72	1.09
348	Clermont	27,500	250	104	22.65	1.72	2.32
350	Flood-Overhead Only	50,000	400	170	5.19	1.76	3.80
351	Underground Roadway	9,500	100	42	6.22	1.72	0.94
352	Underground Roadway	16,000	150	65	7.58	1.75	1.45
354	Underground Roadway	27,500	250	108	8.10	1.72	2.41
356	Underground Roadway	50,000	400	168	8.69	1.76	3.75
357	Underground Flood	27,500	250	108	9.36	1.72	2.41
358	Underground Flood [1]	50,000	400	168	9.49	1.76	3.75
359	Underground Turtle Roadway	9,500	100	42	6.09	1.72	0.94
360	Deco Roadway Rectangular [1]	9,500	100	47	12.53	1.72	1.05
365	Deco Roadway Rectangular	27,500	250	108	11.89	1.72	2.41
366	Deco Roadway Rectangular	50,000	400	168	12.00	1.76	3.75
370	Deco Roadway Round [1]	27,500	250	108	15.41	1.72	2.41
375	Deco Roadway Round [1]	50,000	400	168	15.42	1.76	3.75
380	Deco Post Top – Ocala	9,500	100	49	8.78	1.72	1.09
381	Deco Post Top [1]	9,500	100	49	4.05	1.72	1.09
383	Deco Post Top-Biscayne	9,500	100	49	14.17	1.72	1.09
385	Deco Post Top – Sebring	9,500	100	49	6.75	1.72	1.09
393	Deco Post Top [1]	4,000	50	21	8.72	2.04	0.47
394	Deco Post Top [1]	9,500	100	49	18.16	1.72	1.09

(Continued on Page No. 3)

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 2)

I. Fixtures: (Continued)

BILLING TYPE	DESCRIPTION	LAMP SIZE [2] INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	CHARGES PER UNIT FIXTURE	MAINTENANCE	NON-FUEL ENERGY [3]
	Metal Halide:						
307	Deco Post Top-MH Sanibel P	11,600	150	65	$16.85	$2.68	$1.45
308	Clermont Tear Drop P	11,600	150	65	19.91	2.68	1.45
309	MH Deco Rectangular P	36,000	320	126	13.07	2.74	2.81
311	MH Deco Cube P	36,000	320	126	15.98	2.74	2.81
312	MH Flood P	36,000	320	126	10.55	2.74	2.81
319	MH Post Top Biscayne P	11,600	150	65	15.24	2.68	1.45
327	Deco Post Top-MH Sanibel [1]	12,000	175	74	18.39	2.72	1.65
349	Clermont Tear Drop [1]	12,000	175	74	21.73	2.72	1.65
371	MH Deco Rectangular [1]	38,000	400	159	14.26	2.84	3.55
372	MH Deco Circular [1]	38,000	400	159	16.70	2.84	3.55
373	MH Deco Rectangular [1, 5]	110,000	1,000	378	15.30	2.96	8.44
386	MH Flood [1, 5]	110,000	1,000	378	13.17	2.96	8.44
389	MH Flood-Sportslighter [1, 5]	110,000	1,000	378	13.01	2.96	8.44
390	MH Deco Cube [1]	38,000	400	159	17.44	2.84	3.55
396	Deco PT MH Sanibel Dual [5]	24,000	350	148	33.73	5.43	3.31
397	MH Post Top-Biscayne [1]	12,000	175	74	14.98	2.72	1.65
398	MH Deco Cube [1, 5]	110,000	1,000	378	20.34	2.96	8.44
399	MH Flood	38,000	400	159	11.51	2.84	3.55
	Light Emitting Diode (LED):						
106	Underground Sanibel	5,500	70	25	$20.80	$1.39	$0.56
107	Underground Traditional Open	3,908	49	17	13.57	1.39	0.38
108	Underground Traditional w/Lens	3,230	49	17	13.57	1.39	0.38
109	Underground Acorn	4,332	70	25	20.16	1.39	0.56
111	Underground Mini Bell	2,889	50	18	17.88	1.39	0.40
133	ATBO Roadway	4,521	48	17	6.22	1.39	0.38
134	Underground ATBO Roadway	4,521	48	17	7.71	1.39	0.38
136	Roadway	9,233	108	38	7.05	1.39	0.85
137	Underground Roadway	9,233	108	38	8.55	1.39	0.85
138, 176	Roadway	18,642	216	76	11.61	1.39	1.70
139	Underground Roadway	18,642	216	76	13.11	1.39	1.70
141, 177	Roadway	24,191	284	99	14.08	1.39	2.21
142, 162	Underground Roadway	24,191	284	99	15.58	1.39	2.21
147, 174	Roadway	12,642	150	53	9.74	1.39	1.18
148	Underground Roadway	12,642	150	53	11.24	1.39	1.18
151	ATBS Roadway	4,500	49	17	5.07	1.39	0.38
167	Underground Mitchell	5,186	50	18	21.44	1.39	0.40
168	Underground Mitchell w/Top Hat	4,336	50	18	21.44	1.39	0.40
361	Roadway [1]	6,000	95	33	16.93	2.43	0.74
362	Roadway [1]	9,600	157	55	20.07	2.43	1.23
363	Shoebox Type 3 [1]	20,664	309	108	41.08	2.84	2.41
364	Shoebox Type 4 [1]	14,421	206	72	32.59	2.84	1.61
367	Shoebox Type 5 [1]	14,421	206	72	31.65	2.84	1.61
369	Underground Biscayne	6,500	80	28	18.60	1.39	0.63

(Continued on Page No. 4)

RATE SCHEDULE SS-1
FIRM STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. Initially, the customer and the Company shall mutually agree upon a maximum amount of standby capacity in kW to be supplied by the Company. This shall be termed for billing purposes as the "Specified Standby Capacity".
2. Where a bona fide change in the customer's standby capacity requirement occurs, the Company and the customer shall establish a new Specified Standby Capacity.
3. The Specified Standby Capacity for the current billing period shall be the greater of: (1) the mutually agreed upon Specified Standby Capacity, (2) the maximum 30-minute kW standby power requirement established in the current billing month, or (3) the maximum 30-minute kW standby power requirement established in any of the twenty-three (23) preceding billing months.

Rate Per Month:

1. Customer Charge:

Secondary Metering Voltage:	$ 101.37
Primary Metering Voltage:	$ 237.23
Transmission Metering Voltage:	$ 817.33

Note: Where the Customer has paid the costs of metering equipment pursuant to a Cogeneration Agreement, the Customer Charge shall be $81.74.

2. Supplemental Service Charges:

All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. Standby Service Charges:

A. Distribution Capacity:

$2.09 per kW times the Specified Standby Capacity.

Note: No charge is applicable to a customer who has provided all the facilities for interconnection to the Company's transmission system.

B. Generation & Transmission Capacity:

The charge shall be the greater of:
1. $1.163 per kW times the Specified Standby Capacity or
2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-Peak Periods times $0.554/kW times the appropriate following monthly factor:

Billing Month	Factor
March, April, May, October	0.80
June, September, November, December	1.00
January, February, July, August	1.20

Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*: See Sheet No. 6.105 and 6.106

C. Energy Charges

Non-Fuel Energy Charge: 1.029¢ per kWh

Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor: See Sheet No. 6.105 and 6.106

(Continued on Page No. 4)

RATE SCHEDULE SS-1
FIRM STANDBY SERVICE
(Continued from Page No. 3)

Rate Per Month: (Continued)

3. **Standby Service Charges: (Continued)**

D. **Delivery Voltage Credit:**

When a customer takes service under this rate at a distribution primary delivery voltage, the Distribution Capacity Charge hereunder will be reduced by 1.19¢ per kW.

E. **Metering Voltage Adjustment:**

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Distribution Capacity Charge, Generation & Transmission Capacity Charge, Non-Fuel Energy Charge, and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

F. **Fuel Cost Recovery Factor:**

Time of Use Fuel Charges of applicable metering voltage provided on Tariff Sheet No. 6.105.

G.	**Asset Securitization Charge Factor:**	See Sheet No. 6.105
H.	**Gross Receipts Tax Factor:**	See Sheet No. 6.106
I.	**Right-of-Way Utilization Fee:**	See Sheet No. 6.106
J.	**Municipal Tax:**	See Sheet No. 6.106
K.	**Sales Tax:**	See Sheet No. 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 3 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition the Distribution Capacity Charge included in the Rate per Month section of this rate schedule shall be increased by $1.06 per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

1. **On-Peak Periods -** The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

A.	For the calendar months of November through March, Monday through Friday*:	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
B.	For the calendar months of April through October, Monday through Friday*:	12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

2. **Off-Peak Periods -** The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth above.

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Capacity Charges for Standby Service. Where Special Equipment to service the customer is required, the Company may require a specified minimum charge.

(Continued on Page No. 5)

RATE SCHEDULE SS-2
INTERRUPTIBLE STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. Initially, the customer and the Company shall mutually agree upon a maximum amount of standby capacity in kW to be supplied by the Company. This shall be termed for billing purposes as the "Specified Standby Capacity".
2. Where a bona fide change in the customer's standby capacity requirement occurs, the Company and the customer shall establish a new Specified Standby Capacity.
3. The Specified Standby Capacity for the current billing period shall be the greater of: (1) the mutually agreed upon Specified Standby Capacity, (2) the maximum 30-minute kW standby power requirement established in the current billing month, or (3) the maximum 30-minute kW standby power requirement established in any of the twenty-three (23) preceding billing months.

Rate Per Month:

1. **Customer Charge:**

Secondary Metering Voltage:	$ 305.70
Primary Metering Voltage:	$ 441.55
Transmission Metering Voltage:	$ 1,021.66

Note: Where the customer has paid the costs of metering equipment pursuant to a Cogeneration Agreement, the Customer Charge shall be $286.06.

2. **Supplemental Service Charges:**
All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. **Standby Service Charges:**

A. **Distribution Capacity:**
$2.08 per kW times the Specified Standby Capacity.
Note: No charge is applicable to a Customer who has provided all the facilities for interconnection to the Company's transmission system.

B. **Generation & Transmission Capacity:**
The charge shall be the greater of:
1. $1.161 per kW times the Specified Standby Capacity or
2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-Peak Periods times $0.553 kW times the appropriate following monthly factor:

Billing Month	Factor
March, April, May, October	0.80
June, September, November, December	1.00
January, February, July, August	1.20

Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*: See Sheet No. 6.105 and 6.106

C. **Interruptible Capacity Credit:**
The credit shall be the greater of:
1. $1.17 per kW times the Specified Standby Capacity, or
2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-peak periods times $0.557/kW times the appropriate Billing Month Factor shown in part 3.B. above.

D. **Energy Charges:**
Non-Fuel Energy Charge: 1.016¢ per kWh

Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor: See Sheet No. 6.105 and 6.106

E. **Delivery Voltage Credit:**
When a customer takes service under this rate at a distribution primary delivery voltage, the Distribution Capacity Charge hereunder will be reduced by 1.19¢ per kW.

(Continued on Page No. 4)

RATE SCHEDULE SS-2
INTERRUPTIBLE STANDBY SERVICE
(Continued from Page No. 3)

Rate Per Month: (Continued)

3. Standby Service Charges: (Continued)

F. Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Distribution Capacity Charge, Generation & Transmission Capacity Charge, Interruptible Capacity Credit, Non-Fuel Energy Charge and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

G. Fuel Cost Recovery Factor:
Time of Use Fuel Charges of applicable metering voltage provided on Tariff Sheet No. 6.105.

H.	**Asset Securitization Charge Factor:**	See Sheet No. 6.105
I.	**Gross Receipts Tax Factor:**	See Sheet No. 6.106
J.	**Right-of-Way Utilization Fee:**	See Sheet No. 6.106
K.	**Municipal Tax:**	See Sheet No. 6.106
L.	**Sales Tax:**	See Sheet No. 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 4 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition the Distribution Capacity Charge included in the Rate per Month section of this rate schedule shall be increased by $1.05 per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

1. **On-Peak Periods -** The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

   A. For the calendar months of November through March,
   Monday through Friday*: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.

   B. For the calendar months of April through October,
   Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

2. **Off-Peak Periods -** The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth above.

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Capacity Charges for Standby Service. Where Special Equipment to service the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at company-designated locations.

Term of Service:

Service under this rate schedule shall be under the same terms as that specified in the otherwise applicable rate schedule.

Special Provisions:

1. When the customer increases the electrical load, which increase requires the Company to increase facilities installed for the specific use of the customer, a new Term of Service may be required under this rate at the option of the Company.
2. Customers taking service under another Company rate schedule who elect to transfer to this rate will be accepted by the Company on a first-come, first-served basis. Required interruptible equipment will be installed accordingly, subject to availability. Service under this rate schedule shall commence with the first full billing period following the date of equipment installation.

(Continued on Page No. 5)

RATE SCHEDULE SS-3
CURTAILALBE STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. Initially, the customer and the Company shall mutually agree upon a maximum amount of standby capacity in kW to be supplied by the Company. This shall be termed for billing purposes as the "Specified Standby Capacity".
2. Where a bona fide change in the customer's standby capacity requirement occurs, the Company and the customer shall establish a new Specified Standby Capacity.
3. The Specified Standby Capacity for the current billing period shall be the greater of: (1) the mutually agreed upon Specified Standby Capacity, (2) the maximum 30-minute kW standby power requirement established in the current billing month or (3) the maximum 30-minute kW standby power requirement established in any of the twenty-three (23) preceding billing months.

Rate Per Month:

1. **Customer Charge:**

Secondary Metering Voltage:	$ 101.37
Primary Metering Voltage:	$ 237.23
Transmission Metering Voltage:	$ 817.33

Note: Where the customer has paid the costs of metering equipment pursuant to a Cogeneration Agreement, the Customer Charge shall be $81.74.

2. **Supplemental Service Charges:**
All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. **Standby Service Charges:**

A. **Distribution Capacity:**
$2.08 per kW times the Specified Standby Capacity.
Note: No charge is applicable to a customer who has provided all the facilities for interconnection to the Company's transmission system.

B. **Generation & Transmission Capacity:**
The charge shall be the greater of:
1. $1.161 per kW times the Specified Standby Capacity or
2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-Peak Periods times $0.553/kW times the appropriate following monthly factor:

Billing Month	Factor
March, April, May, October	0.80
June, September, November, December	1.00
January, February, July, August	1.20

Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*: See Sheet No. 6.105 and 6.106

C. **Curtailable Capacity Credit:**
The credit shall be the greater of:
1. $0.877 per kW times the Specified Standby Capacity, or
2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-peak periods times $0.418/kW times the appropriate Billing Month Factor shown in part 3.B. above.

D. **Energy Charges:**

Non-Fuel Energy Charge:	1.020¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis listed in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

E. **Delivery Voltage Credit:**
When a customer takes service under this rate at a distribution primary delivery voltage, the Distribution Capacity Charge hereunder will be reduced by 1.19¢ per kW.

(Continued on Page No. 4)

RATE SCHEDULE RSS-1
RESIDENTIAL SEASONAL SERVICE RIDER

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To customers receiving residential service under Rate Schedule RS-1, RSL-1 or RSL-2 that meet the special provisions of this schedule.

Rate Per Month:

Other than as stated below, the otherwise applicable rate schedule for electric service will apply.

Standard Customer Charge	$ 8.82
Seasonal Customer Charge	$ 4.61

Seasonal Billing Periods:

The billing months of March through October.

Special Provisions:

1. To qualify for service under this rider, the customer's premise must be occupied each year during a portion of the billing months of November through February and must not be occupied at least three months during the billing months of March through October.
2. The maximum allowable consumption for a seasonal billing period is 210 kWh. However, if the seasonal billing period exceeds 30 days, the maximum allowable consumption is increased by seven (7) kWh per day.
3. If kWh usage during the seasonal billing period is less than or equal to the maximum allowable consumption for the billing period, the seasonal customer charge will apply. For non-seasonal billing months and those seasonal billing months that exceed the allowed maximum allowable consumption, the standard customer charge will apply.
4. All other provisions of the otherwise applicable rate schedule will apply to customers served under this schedule..

RATE SCHEDULE ED-1
ECONOMIC DEVELOPMENT RIDER

Availability:

Available throughout the entire territory served by the Company. Customers desiring to take service under this tariff must make a written request for service.

Applicable:

To any customer taking firm service, other than residential, for light and power purposes who meet the Qualifying Criteria set forth in this tariff. This tariff provides for an Economic Development Rate Reduction Factor as described herein for new load which is defined as load being established after the date of the original issue of this tariff sheet by a new business or the expansion of an existing business. This rider is not available for retention of existing load or for relocation of existing load within the Company's service territory. Relocating businesses that provide expansion of existing business may qualify for the expanded load only. This rider is not available for short-term, construction, temporary service, or renewal of a previously existing service. Customers must execute an Economic Development Service Agreement and such agreement must specify all qualifying criteria customer expects to meet for this rider to be applicable.

Qualifying Criteria:

a) The minimum qualifying new load must be at least 500 kW with a minimum load factor of 50% at a single point of delivery.
b) The new or expanding business must be a targeted industry as defined by the state of Florida's most current economic development policy.
c) The new or expanding business must also meet at least one of the following two requirements at the project location:
   1) The addition of 25 net new full time equivalent (FTE) jobs in the Company's Florida service area; or
   2) Capital investment of $500,000 or greater and a net increase in FTE jobs in the Company's Florida service area.
d) Customer must provide written documentation attesting that the availability of this rider is a significant factor in the Customer's location/expansion decision.

Limitation of Service:

Service under this tariff is limited to a total load served under both this tariff and the EDR-1 tariff of 300 megawatts or a total of 25 customer accounts served under both this tariff and the EDR-1 tariff. Standby or resale service not permitted hereunder. Service under this tariff is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service." Service under this tariff may not be combined with service under the EDR-1 tariff. Service under this tariff is available on a first come, first served basis.

Otherwise Applicable General Service Tariff:

Service under this rider shall be provided under any of the Company's currently available general service tariffs to be initially determined by mutual agreement of the Company and customer based on the usage characteristics provided by the customer for new load. All provisions, terms and conditions of the Otherwise Applicable General Service Tariff shall apply.

Rate Per Month:

All charges shall be those set forth in the Otherwise Applicable General Service Tariff adjusted by the Economic Development Rate Reduction Factor.

Economic Development Rate Reduction Factor:

The following rate reduction factors shall apply:

Year of Agreement	Reduction of Base Rate Demand and Energy Charges
Year 1	50%
Year 2	40%
Year 3	30%
Year 4	20%
Year 5	10%

(Continued on Page No. 2)

RATE SCHEDULE ED-1
ECONOMIC DEVELOPMENT RIDER
(Continued from Page No. 1)

Term of Service:

Service under this rider shall be for a term of five (5) years from the commencement of service of new load. Service under this rider will terminate at the end of the 5 year period.

Penalty for Non-Compliance with Qualifying Criteria or Term of Service:

If at any time during the term of the rider agreement the customer violates the terms and conditions of the rider or agreement, the Company may discontinue the discount provided for under this rider, and bill the customer based on the Otherwise Applicable General Service Tariff. If the customer terminates service prior to the end of the agreement period, or fails to meet the qualifying criteria agreed to for the term of the agreement, this will constitute a violation of the terms and conditions of the rider and agreement.

Should service under this rider be discontinued by the Company or the customer for said violation the customer shall be required to repay to the Company the amount of the cumulative discounts received under this rider with interest.

RATE SCHEDULE EDR-1
ECONOMIC RE-DEVELOPMENT RIDER

Availability:

Available throughout the entire territory served by the Company. Customers desiring to take service under this tariff must make a written request for service.

Applicable:

To any customer taking firm service, other than residential, for light and power purposes who meet the Qualifying Criteria set forth in this tariff. This tariff provides for an Economic Re-Development Rate Reduction Factor as described herein for new load which is defined as load being established after the date of the original issue of this tariff sheet by a new business or the expansion of an existing business. This rider is not available for retention of existing load or for relocation of existing load within the Company's service territory. Relocating businesses that provide expansion of existing business may qualify for the expanded load only. This rider is not available for short-term, construction, temporary service, or renewal of a previously existing service. Customers must execute an Economic Re-Development Service Agreement and such agreement must specify all qualifying criteria customer expects to meet for this rider to be applicable.

Qualifying Criteria:

a) New load must be at an existing Company premise location previously served by the Company which has been unoccupied or otherwise essentially dormant (evidenced by minimal to no electric usage) for a minimum period of 90 days.
b) Customer must not have a relationship with the previous occupant of the unoccupied premise location.
c) The minimum qualifying new load must be at least 350 kW with a minimum load factor of 50% at a single point of delivery.
d) The new or expanding business must be a targeted industry as defined by the state of Florida's most current economic development policy.
e) The new or expanding business must also meet at least one of the following two requirements at the project location:
    1) The addition of 15 net new full time equivalent (FTE) jobs in the Company's Florida service area; or
    2) Capital investment of $200,000 or greater and a net increase in FTE jobs in the Company's Florida service area.
f) Customer must provide written documentation attesting that the availability of this rider is a significant factor in the Customer's location/expansion decision.

Limitation of Service:

Service under this tariff is limited to a total load served under both this tariff and the ED-1 tariff of 300 megawatts or a total of 25 customer accounts served under both this tariff and the ED-1 tariff. Standby or resale service not permitted hereunder. Service under this tariff is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service." Service under this tariff may not be combined with service under the ED-1 tariff. Service under this tariff is available on a first come, first served basis.

Otherwise Applicable General Service Tariff:

Service under this rider shall be provided under any of the Company's currently available general service tariffs to be initially determined by mutual agreement of the Company and customer based on the usage characteristics provided by the customer for new load. All provisions, terms and conditions of the Otherwise Applicable General Service Tariff shall apply.

Rate Per Month:

All charges shall be those set forth in the Otherwise Applicable General Service Tariff adjusted by the Economic Re-Development Rate Reduction Factor.

Economic Re-Development Rate Reduction Factor:

The following rate reduction factors shall apply:

Year of Agreement	Reduction of Base Rate Demand and Energy Charge	Reduction of the Non-Fuel and non-ASC BA-1 Tariff Charges
Year 1	50%	50%
Year 2	35%	35%
Year 3	15%	15%
Year 4	0%	0%
Year 5	0%	0%

(Continued on Page No. 2)

RATE SCHEDULE EDR-1
ECONOMIC RE-DEVELOPMENT RIDER
(Continued from Page No. 1)

Term of Service:

Service under this rider shall be for a term of five (5) years from the commencement of service of new load. Service under this rider will terminate at the end of the 5 year period.

Penalty for Non-Compliance with Qualifying Criteria or Term of Service:

If at any time during the term of the rider agreement the customer violates the terms and conditions of the rider or agreement, the Company may discontinue the discount provided for under this rider, and bill the customer based on the Otherwise Applicable General Service Tariff. If the customer terminates service prior to the end of the agreement period, or fails to meet the qualifying criteria agreed to for the term of the agreement, this will constitute a violation of the terms and conditions of the rider and agreement.

Should service under this rider be discontinued by the Company or the customer for said violation the customer shall be required to repay to the Company the amount of the cumulative discounts received under this rider with interest. Repayments will be appropriately treated and apportioned by the Company in direct proportion to the base rate or clause revenues as discounts were achieved and repaid.

Other Charges:

Customers requiring installation of additional new facilities at an existing premise location may be subject to contribution in aid to construction, construction advances or equipment rental charges as may be applicable in accordance with the Company's Rules and Regulations.

Revised Tariff Sheets in Legislative Format

Thirty-Second Revised Sheet No. 6.120
Thirty-Fourth Revised Sheet No. 6.130
Twentieth Revised Sheet No. 6.135
Twenty-Sixth Revised Sheet No. 6.140
Thirty-Third Revised Sheet No. 6.150
Twenty-Ninth Revised Sheet No. 6.160
Thirty-Second Revised Sheet No. 6.165
Twenty-Ninth Revised Sheet No. 6.170
Twenty-Third Revised Sheet No. 6.171
Thirtieth Revised Sheet No. 6.180
Twenty-Third Revised Sheet No. 6.181
Tenth Revised Sheet No. 6.225
Thirty-Fourth Revised Sheet No. 6.230
Twenty-Eighth Revised Sheet No. 6.231
Nineteenth Revised Sheet No. 6.235
Fourteenth Revised Sheet No. 6.236
Sixteenth Revised Sheet No. 6.2390
Thirty-Third Revised Sheet No. 6.240
Twenty-Sixth Revised Sheet No. 6.241
Eighteenth Revised Sheet No. 6.245
Fourteenth Revised Sheet No. 6.246
Sixteenth Revised Sheet No. 6.2490
Twelfth Revised Sheet No. 6.2491
Thirty-Fourth Revised Sheet No. 6.250
Twentieth Revised Sheet No. 6.255
Thirty-Fourth Revised Sheet No. 6.260
Twenty-Seventh Revised Sheet No. 6.261
Nineteenth Revised Sheet No. 6.265
Thirteenth Revised Sheet No. 6.266
Thirtieth Revised Sheet No. 6.280
Twenty-Seventh Revised Sheet No. 6.281
Sixth Revised Sheet No. 6.2811
Twenty-Second Revised Sheet No. 6.312
Twenty-First Revised Sheet No. 6.313
Twenty-Sixth Revised Sheet No. 6.317
Twentieth Revised Sheet No. 6.318
Twenty-Second Revised Sheet No. 6.322
Eighth Revised Sheet No. 6.350
Second Revised Sheet No. 6.380
First Revised Sheet No. 6.381
Third Revised Sheet No. 6.385
First Revised Sheet No. 6.386

RATE SCHEDULE RS-1
RESIDENTIAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To residential customers in a single dwelling house, a mobile home, or individually metered single apartment unit or other unit having housekeeping facilities, occupied by one family or household as a residence. The premises of such single dwelling may include an additional apartment with separate housekeeping facilities, as well as a garage and other separate structures where they are occupied or used solely by the members or servants of such family or household. Also, for energy used in commonly-owned facilities in condominium and cooperative apartment buildings subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owner's benefit.

2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.

3. Each point of delivery is separately metered and billed.

4. A responsible legal entity is established as the customer to whom the Company can render its bill(s) for said service.

Character of Service:

Continuous service, alternating current, 60 cycles per second, single-phase or three-phase, at the Company's standard available distribution voltage. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$ 8.82~~76~~
Demand and Energy Charges:	
Non-Fuel Energy Charges:	
First 1,000 kWh	5.214~~171~~¢ per kWh
All additional kWh	6.641~~587~~¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

(Continued on Page No. 2)

ISSUED BY: Javier J. Portuondo, Managing Director Rates & Regulatory Strategy – FL

EFFECTIVE: ~~April 1, 2017~~January 1, 2018

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT

Availability:

Available only within the range of the Company's Load Management System.
Available to customers whose premises have active load management devices installed prior to June 30, 2007.
Available to customers whose premises have load management devices installed after June 30, 2007 that have and are willing to submit to load control of, at a minimum, central electric cooling and heating systems.

Applicable:

To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh (based on the most recent 12 months, or, where not available, a projection for 12 months), and utilizing any of the following electrical equipment:

1. Water Heater
2. Central Electric Heating System
3. Central Electric Cooling System
4. Swimming Pool Pump

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

For new service requests after June 30, 2007 customers with a central electric heating system that is a heat pump will be installed on Interruption Schedule S. All other new service requests will be installed on Interruption Schedule B. Interruption Schedule C shall be at the option of the customer.

For new service requests after April 1, 1995, and before June 30, 2007, customers who select the swimming pool pump schedule must also select at least one other schedule.

An installation of an alternative thermal storage heating system under Special Provision No. 7 of this rate schedule is not available after April 1, 1995.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$ 8.82~~76~~
Energy and Demand Charges:	
Non-Fuel Energy Charges:	
First 1,000 kWh	5.214~~171~~¢ per kWh
All additional kWh	6.641~~587~~¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Monthly Credit Amounts:[1,2]

Interruptible Equipment	Interruption Schedule				
	A	B	C	D	S
Water Heater	-	-	$3.50	-	-
Central Heating System[3]	$2.00	$8.00	-	-	$8.00
Central Heating System w/Thermal Storage[3]	-	-	-	$8.00	-
Central Cooling System[4]	$1.00	$5.00	-	-	$5.00
Swimming Pool Pump	-	-	$2.50	-	-

(Continued on Page No. 2)

ISSUED BY: Javier J. Portuondo, Managing Director Rates & Regulatory Strategy – FL

EFFECTIVE: January 1, 2018~~April 1, 2017~~

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY

Availability:

Available only within the range of the Company's Load Management System.

Applicable:

To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh for the months of November through March (based on the most recent billings, where not available, a projection for those months) and utilizing **both** electric water heater and central electric heating systems.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge: $ 8.82~~76~~

Energy and Demand Charges:

Non-Fuel Energy Charges:

First 1,000 kWh	5.214~~171~~¢ per kWh
All additional kWh	6.641~~587~~¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Credit Amount:[1]

Interruptible Equipment	Monthly Credit[2]
Water Heater and Central Heating System	$11.50

Notes: (1) Load management credit shall not exceed 40% of the Non-Fuel Energy Charge associated with kWh billed in excess of 600 kWh/month.

(2) For billing months of November through March only.

Appliance Interruption Schedule:

Heating — Equipment interruptions to achieve an effective equipment duty cycle of approximately 45% during control periods within the Company's designated Peak Periods. Heat pump back-up strip may be interrupted continuously, not to exceed 300 minutes, during the Company's designated Peak. When the heat pump back-up strip is being interrupted, the heat pump will not be interrupted.

Water Heater — Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE RST-1
RESIDENTIAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 02/10/10)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of residential customers otherwise eligible for service under Rate Schedule RS-1, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Continuous service, alternating current, 60 cycle, single phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations Governing Electric Service."

Rate Per Month:

Customer Charge: $ 16.30~~19~~

Energy and Demand Charges:

Non-Fuel Energy Charges: 16.101~~15.969~~¢ per On-Peak kWh
0.894~~887~~¢ per Off-Peak kWh

Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor: See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy used during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Rating Periods:

(a) **On-Peak Periods** - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March,
Monday through Friday *: 6:00 a.m. to 10:00 a.m. and
6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October,
Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(b) **Off-Peak Periods** - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

(Continued on Page No. 2)

RATE SCHEDULE GS-1
GENERAL SERVICE – NON-DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes for which no other rate schedule is specifically applicable.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase or three-phase, at the Company's standard distribution voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Unmetered Account:	$ 6.58~~54~~
Secondary Metering Voltage:	$ 11.67~~59~~
Primary Metering Voltage:	$ 147.52~~6.56~~
Transmission Metering Voltage:	$ 727.63~~2.90~~

Energy and Demand Charges:

Non-Fuel Energy Charge:	5.663~~617~~¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Non-Fuel Energy Charge included in the Rate per Month section of this rate schedule shall be increased by 0.773~~67~~¢ per kWh for the cost of reserving capacity in the alternate distribution circuit.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above standard distribution secondary, the applicable following reduction factor shall apply to the Non-Fuel Energy Charge hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

(Continued on Page No. 2)

RATE SCHEDULE GST-1
GENERAL SERVICE – NON-DEMAND
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of non-residential customers otherwise eligible for service under Rate Schedule GS-1, provided that all of the electric load requirements on the Customer's premises are metered through one point of delivery.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase or three-phase, at the Company's standard distribution voltage available.

Limitation of Service:

Standby or Resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate per Month:

Customer Charge:

Secondary Metering Voltage:	$ 19.13~~01~~
Primary Metering Voltage:	$ 155.00~~3.99~~
Transmission Metering Voltage:	$ 735.10~~0.32~~

Energy and Demand Charge:

Non-Fuel Energy Charge:	16.074~~15.942~~¢ per On-Peak kWh 0.871~~64~~¢ per Off-Peak kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Non-Fuel Charges included in the Rate per Month section of this rate schedule shall be increased by 0.773~~67~~¢ per kWh for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March, Monday through Friday *: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October, Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE GS-2
GENERAL SERVICE – NON-DEMAND
100% LOAD FACTOR USAGE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, with fixed wattage loads operating continuously throughout the billing period (such as traffic signals, cable TV amplifiers and gas transmission substations).

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase or three-phase, at the Company's standard distribution voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate per Month:

Customer Charge:

Unmetered Account:	$ 6.58~~4~~
Metered Account:	$ 11.67~~59~~

Energy and Demand Charges:

Non-Fuel Energy Charge:	2.147~~29~~¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments*, except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Non-Fuel Energy Charge included in the Rate per Month section of this rate schedule shall be increased by 0.156~~5~~¢ per kWh for the cost of reserving capacity in the alternate distribution circuit.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

(Continued on Page No. 2)

RATE SCHEDULE GSD-1
GENERAL SERVICE - DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes for which no other rate schedule is specifically applicable with a measured annual kWh consumption of 24,000 kWh or greater per year.

Character of Service:

Continuous service, alternating current, 60 cycle, singe-phase or three-phase, at the Company's standard distribution voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 11.67~~59~~
Primary Metering Voltage:	$ 147.52~~6.56~~
Transmission Metering Voltage:	$ 727.63~~2.90~~

Demand Charge: $ 5.30~~26~~ per kW of Billing Demand

Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106

Energy Charge:

Non-Fuel Energy Charge:	2.365~~46~~¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14~~3~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

Determination of Billing Demand:

The billing demand shall be the maximum 30-minute kW demand established during the current billing period.

(Continued on Page No. 2)

RATE SCHEDULE GSD-1
GENERAL SERVICE - DEMAND
(Continued from Page No. 1)

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credits:

For Distribution Primary Delivery Voltage:	$1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95~~1.55~~ per kW of Billing Demand

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the applicable following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with measured demands of 1,000 kW or more for three (3) or more months out of the twelve (12) consecutive months ending with the current billing period, bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on the bill at Company-designated locations.

Term of Service:

Service under this rate shall be for a minimum initial term of twelve (12) months from commencement of service and shall continue thereafter until receipt of notice by the Company from the customer to disconnect, or upon disconnect by the Company under Florida Public Service Commission or Company Rules.

Customers taking service under another Company rate schedule who elect to transfer to this rate must remain on this rate for a minimum term of twelve (12) months.

(Continued on Page No. 3)

DUKE ENERGY.

SECTION NO. VI
THIRTIETH~~TWENTY-NINTH~~ REVISED SHEET NO. 6.180
CANCELS TWENTY-NINTH~~EIGHTH~~ REVISED SHEET NO. 6.180

RATE SCHEDULE GSDT-1
GENERAL SERVICE - DEMAND
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of the customer, otherwise eligible for service under Rate Schedule GSD-1, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase or three-phase, at the Company's standard distribution voltage available.

Limitation of Service:

Standby or Resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate per Month:

Customer Charge:

Secondary Metering Voltage:	$ 19.13~~01~~
Primary Metering Voltage:	$ 155.00~~3.99~~
Transmission Metering Voltage:	$ 735.10~~0.32~~

Demand Charges:

Base Demand Charge:	$ 1.30~~29~~ per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 3.94~~1~~ per kW of On-Peak Demand

Energy Charges:

Non-Fuel Energy Charge:	5.148~~106~~¢ per On-Peak kWh 0.863~~56~~¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14~~3~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

ISSUED BY: Javier J. Portuondo, Managing Director Rates & Regulatory Strategy – FL

EFFECTIVE: ~~April 1, 2017~~January 1, 2018

RATE SCHEDULE GSDT-1
GENERAL SERVICE DEMAND
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

Rating Periods:

(a) **On-Peak Periods** - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March,
Monday through Friday *: 6:00 a.m. to 10:00 a.m. and
6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October,
Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(b) **Off-Peak Periods** - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate schedule at a delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credits:

For Distribution Primary Delivery Voltage:	$1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95~~1.55~~ per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the applicable following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with metered demands of 1,000 kW or more for three (3) or more months out of the twelve (12) consecutive months ending with the current billing period, bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds numerically .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

(Continued on Page No. 3)

RATE SCHEDULE GSLM-2
GENERAL SERVICE LOAD MANAGEMENT – STANDBY GENERATION

Availability:

Available only within the range of the Company's radio switch communications capability.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1 who have standby generation that will allow facility demand reduction at the request of the Company. The customer's Standby Generation Capacity calculation must be at least 50 kW in order to remain eligible for the rate. Customers cannot be on this rate schedule and also the General Service Load Management (GSLM-1) rate schedule. Not applicable to Net Metering customers. Customers cannot use the standby generation for peak shaving. Available only to those customers whose standby generation equipment is compliant with all applicable federal, state, and local codes and rules.

Limitation of Service:

Operation of the customer's equipment will occur at the Company's request. Requests by the Company for the customer to reduce facility demand by operation of their standby generation can occur at any time. Power to the facility from the Company will normally remain as back up power for the standby generation. The Customer will be given fifteen (15) minutes to initiate the demand reduction before the capacity calculation (see Definitions) is impacted.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1 or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

GSLM-2 MONTHLY CREDIT AMOUNT
STANDBY GENERATION

Credit	Cumulative Fiscal Year Hours
$4.84~~50~~ x ***C*** + $0.50 x kWh monthly	All CRH

Immediately upon going on the rate, the customer's Capacity (***C***) is set to a value equivalent to the load the customer's standby generator carries during testing observed by the Customer and a Company representative. The ***C*** will remain at that value until the equipment is requested to run by the Company. The ***C*** for that month and subsequent months will be a calculated value based upon the following formula:

$$C = \frac{\text{kWh annual}}{[\text{CAH} - (\#\text{ of Requests} \times \frac{1}{4}\text{ hour})]}$$

Definitions:

kWh annual = Actual measured kWh generated by the standby generator during the previous twelve (12) months during Company control periods (rolling total).

CAH = Cumulative hours requested by the Company for the standby generation to operate for the previous twelve (12) months (rolling total).

CRH = Cumulative standby generator running hours during request periods of the Company for the current fiscal year (the fiscal year begins on the month the customer goes on the GSLM-2 rate).

\# of Requests = The cumulative number of times the Company has requested the standby generation to be operated for the previous twelve (12) months (rolling total).

kWh monthly = Actual measured kWh generated by the standby generator for the current month during Company control periods.

(Continued on Page No. 2)

RATE SCHEDULE CS-1
CURTAILABLE GENERAL SERVICE
(Closed to New Customers as of 04/16/96)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes where the customer agrees during a period of requested curtailment to curtail as a minimum the greater of: (a) 25 kW or (b) 25% of their average monthly billing demand (based on the most recent twelve (12) months or, where not available, a projection for twelve (12) months).

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Curtailable service under this rate schedule is not subject to curtailment during any time period for economic reasons. Curtailable service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to curtailable loads except under the conditions set forth in Special Provision No. 6 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 76.46~~5.96~~
Primary Metering Voltage:	$ 212.31~~10.93~~
Transmission Metering Voltage:	$ 792.41~~87.26~~

Demand Charge:	$ 8.51~~45~~ per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Curtailable Demand Credit:	$ 5.03~~4.68~~ per kW of Curtailable Demand

Energy Charge:

Non-Fuel Energy Charge:	1.55444¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14~~3~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

RATE SCHEDULE CS-1
CURTAILABLE GENERAL SERVICE
(Closed to New Customers as of 04/16/96)
(Continued from Page No. 1)

Determination of Billing Demand:

The billing demand shall be the maximum 30-minute kW demand established during the current billing period.

Determination of Curtailable Demand:

The Curtailable Demand shall be the difference, if any, between the current Billing Demand and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of this rate. In no event shall the Curtailable Demand be less than zero.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$ 5.95~~1.55~~ per kW of Billing Demand

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with measured demands of 1,000 kW or more for three (3) or more months out of the twelve (12) consecutive months ending with the current billing period, bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Term of Service:

Service under this rate schedule shall be for a minimum initial term of two (2) years from the commencement of service and shall continue thereafter until terminated by either party by written notice sixty (60) days prior to termination.

(Continued on Page No. 3)

RATE SCHEDULE CS-2
CURTAILABLE GENERAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes where the billing demand is 500 kW or more, and where the customer agrees to curtail 25% of their average monthly billing demand (based on the most recent twelve (12) months or, where not available, a projection for twelve (12) months).

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Curtailable service under this rate schedule is not subject to curtailment during any time period for economic reasons. Curtailable service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to curtailable loads except under the conditions set forth in Special Provision No. 6 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 76.46~~75.96~~
Primary Metering Voltage:	$ 212.31~~210.93~~
Transmission Metering Voltage:	$ 792.41~~787.26~~
Demand Charge:	$ 8.51~~45~~ per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Curtailable Demand Credit:	$ 8.77~~16~~ per kW of Load Factor Adjusted Demand

Energy Charge:

Non-Fuel Energy Charge:	1.554~~44~~¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14~~3~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

RATE SCHEDULE CS-2
CURTAILABLE GENERAL SERVICE
(Continued from Page No. 1)

Determination of Billing Demand:

The billing demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 500 kW.

Determination of Load Factor Adjusted Demand:

The Load Factor Adjusted Demand shall be the difference, if any, between the maximum 30-minute kW demand established during the current billing period and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of this rate, multiplied by the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand, multiplied by the number of hours in the billing period). In no event shall the Curtailable Demand be less than zero.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95~~1.55~~ per kW of Billing Demand

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

Bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Demand Charge for the current billing period. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Term of Service:

Service under this rate shall be for a minimum initial term of two (2) years from the commencement of service, and shall continue thereafter until terminated by either party by written notice sixty (60) days prior to termination.

(Continued on Page No. 3)

RATE SCHEDULE CS-3
CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes where the billing demand is 2,000 kW or more (based on most recent twelve (12) months or, where not available, projected billing demand for twelve (12) months), and where the customer agrees to curtail its demand by a fixed contractual amount of not less than 2,000 kW upon request of the Company in accordance with the provisions of this rate schedule.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. Service under this rate schedule is not subject to curtailment for economic reasons. The Company will not make off-system purchases during such curtailment periods to maintain service hereunder except as set forth in Special Provision No. 6 below.

Service under this rate is subject to the "General Rules and Regulations Governing Electric Service" contained in Section IV of the Company's currently effective and filed retail tariff.

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 76.46~~75.96~~
Primary Metering Voltage:	$ 212.31~~210.93~~
Transmission Metering Voltage:	$ 792.41~~787.26~~
Demand Charge:	$ 8.51~~45~~ per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Curtailable Demand Credit:	$ 8.77~~16~~ per kW of Fixed Curtailable Demand
Energy Charge:	
Non-Fuel Energy Charge:	1.554~~44~~¢ per kW
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where the customer receives Premium Distribution Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer, including, all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14~~3~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

Determination of Billing Demand:

The billing demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 2,000 kW.

Delivery Voltage Credit:

When a customer takes service under this rate schedule at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95~~1.55~~ per kW of Billing Demand

(Continued on Page No. 2)

ISSUED BY: **Javier J. Portuondo, Managing Director Rates & Regulatory Strategy – FL**

EFFECTIVE: ~~April 1, 2017~~**January 1, 2018**

RATE SCHEDULE CST-1
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 04/16/96)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of customers otherwise eligible for service under Rate Schedule CS-1, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Curtailable Service under this rate schedule is not subject to curtailment during any time period for economic reasons. Curtailable Service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to curtailable loads except under the conditions set forth in Special Provision No. 6 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate per Month:

Customer Charge:

Secondary Metering Voltage:	$ 76.46~~75.96~~
Primary Metering Voltage:	$ 212.31~~210.93~~
Transmission Metering Voltage:	$ 792.41~~787.26~~

Demand Charges:

Base Demand Charge:	$ 1.26~~5~~ per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 7.18~~3~~ per kW of On-Peak Demand

Curtailable Demand Credit: $ 5.03~~4.68~~ per kW of Curtailable Demand

Energy Charge:

Non-Fuel Energy Charge:	2.85~~233~~¢ per On-Peak kWh 0.857~~1~~¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14~~3~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

RATE SCHEDULE CST-1
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 04/16/96)
(Continued from Page No. 1)

Rating Periods:

(a) **On-Peak Periods** - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March,
Monday through Friday *: 6:00 a.m. to 10:00 a.m. and
6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October,
Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(b) **Off-Peak Periods** - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Determination of Curtailable Demand:

The Curtailable Demand shall be the difference, if any, between the current On-Peak Demand and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of this rate. In no event shall the Curtailable Demand be less than zero.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95~~1.55~~ per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

Bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106

(Continued on Page No. 3)

RATE SCHEDULE CST-2
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of customers otherwise eligible for service under Rate Schedule CS-2, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Curtailable service under this rate schedule is not subject to curtailment during any time period for economic reasons. Curtailable service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to curtailable loads except under the conditions set forth in Special Provision No. 6 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 76.46~~75.96~~
Primary Metering Voltage:	$ 212.31~~210.93~~
Transmission Metering Voltage:	$ 792.41~~787.26~~

Demand Charges:

Base Demand Charge:	$ 1.26~~5~~ per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 7.18~~3~~ per kW of On-Peak Demand

Curtailable Demand Credit: $ 8.77~~16~~ per kW of Load Factor Adjusted Demand

Energy Charge:

Non-Fuel Energy Charge:	2.85~~233~~¢ per On-Peak kWh 0.857~~1~~¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14~~3~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

RATE SCHEDULE CST-2
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

Rating Periods:

(a) **On-Peak Periods** - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March,
Monday through Friday *: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October,
Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(b) **Off-Peak Periods** - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 500 kW.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Determination of Load Factor Adjusted Demand:

The Load Factor Adjusted Demand shall be the difference, if any, between the maximum 30-minute kW demand established during the current billing period and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of this rate, multiplied by the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand, multiplied by the number of hours in the billing period). In no event shall the Curtailable Demand be less than zero.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95~~1.55~~ per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

Bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106

(Continued on Page No. 3)

RATE SCHEDULE CST-3
CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer otherwise eligible for service under Rate Schedule CS-3, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments, or b) supply emergency interchange service to another utility for its firm load obligations only. Service under this rate schedule is not subject to curtailment for economic reasons. The Company will not make off-system purchases during such curtailment periods to maintain service hereunder except as set forth in Special Provision No. 6 below.

Service under this rate is subject to the "General Rules and Regulations Governing Electric Service" contained in Section IV of the Company's currently effective and filed retail tariff.

Rate Per Month:

Customer Charge:	
Secondary Metering Voltage:	$ 76.46~~75.96~~
Primary Metering Voltage:	$ 212.31~~210.93~~
Transmission Metering Voltage:	$ 792.41~~787.26~~
Demand Charges:	
Base Demand Charge:	$ 1.26~~5~~ per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 7.18~~3~~ per kW of On-Peak Demand
Curtailable Demand Credit:	$ 8.77~~16~~ per kW of Fixed Curtailable Demand
Energy Charge:	
Non-Fuel Energy Charge:	2.852~~33~~¢ per On-Peak kWh 0.857~~1~~¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where the customer receives Premium Distribution Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including, all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14~~3~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

For the calendar months of November through March, Monday through Friday*:	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
For the calendar months of April through October, Monday through Friday*:	12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas. In the event the holiday occurs on a Saturday or Sunday, the following Monday shall be excluded from the On-Peak Periods.

Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

(Continued on Page No. 2)

RATE SCHEDULE CST-3
CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

Determination of Billing Demand:

The Base Demand for billing purposes shall be the maximum 30-minute kW demand established during the current billing period, but not less than **2,000** kW.

The On-Peak Demand for billing purposes shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate schedule at a delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$ 1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$ 5.95~~1.55~~ per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit, and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor Adjustment:

Bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Demand Charge for the current billing period. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Term of Service:

Service under this rate schedule shall be for a minimum initial term of two (2) years from the commencement of service, and shall continue thereafter until terminated by either party by written notice sixty (60) days prior to termination.

Special Provisions:

1. As used in this rate schedule, the term "period of requested curtailment" shall mean a period for which the Company has requested curtailment and for which energy purchased from sources outside the Company's system, pursuant to Special Provision No. 6, is not available. If such energy can be purchased, the terms of Special Provision No. 6 will apply and a period of requested curtailment will not be deemed to exist while such energy remains available.

(Continued on Page No. 3)

RATE SCHEDULE IS-1
INTERRUPTIBLE GENERAL SERVICE
(Closed to New Customers as of 04/16/96)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes where service may be interrupted by the Company.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is not subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 280.78~~78.95~~
Primary Metering Voltage:	$ 416.65~~3.94~~
Transmission Metering Voltage:	$ 996.74~~0.26~~

Demand Charge:	$ 7.20~~15~~ per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Interruptible Demand Credit:	$ 6.71~~24~~ per kW of Billing Demand

Energy Charge:

Non-Fuel Energy Charge:	1.041~~34~~¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14~~3~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

Determination of Billing Demand:

The Billing Demand shall be the maximum 30-minute kW demand established during the billing period.

Delivery Voltage Credit:

When a customer takes service under this rate schedule at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95~~1.55~~ per kW of Billing Demand

(Continued on Page No. 2)

DUKE ENERGY.

SECTION NO. VI
TWENTIETH~~NINETEENTH~~ REVISED SHEET NO. 6.255
CANCELS NINETEENTH~~EIGHTEENTH~~ REVISED SHEET NO. 6.255

RATE SCHEDULE IS-2
INTERRUPTIBLE GENERAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicability:

Applicable to customers, other than residential, for light and power purposes where the billing demand is 500 kW or more, and where service may be interrupted by the Company. For customer accounts established under this rate schedule after June 3, 2003, service is limited to premises at which an interruption of electric service will primarily affect only the customer, its employees, agents, lessees, tenants or business guests, and will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. Examples of premises at which service under this rate schedule may not be provided, unless adequate on-site backup generation is available, include, but are not limited to: retail businesses, offices, and governmental facilities open to members of the general public, stores, hotels, motels, convention centers, theme parks, schools, hospitals and health care facilities, designated public shelters, detention and correctional facilities, police and fire stations, and other similar facilities.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is not subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency Interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 280.78~~78.95~~
Primary Metering Voltage:	$ 416.65~~3.94~~
Transmission Metering Voltage:	$ 996.74~~0.26~~
Demand Charge:	$ 7.20~~15~~ per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Interruptible Demand Credit:	$ 11.70~~0.88~~ per kW of Load Factor Adjusted Demand

Energy Charge:

Non-Fuel Energy Charge:	1.041~~34~~¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.13~~4~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

Determination of Billing Demand:

The Billing Demand shall be the maximum 30-minute kW demand established during the billing period, but not less than 500 kW.

Determination of Load Factor Adjusted Demand:

The Load Factor Adjusted Demand shall be the product of the maximum 30-minute kW demand established during the current billing period and the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand times the number of hours in the billing period).

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95~~1.55~~ per kW of Billing Demand

(Continued on Page No. 2)

ISSUED BY: Javier J. Portuondo, Managing Director Rates & Regulatory Strategy – FL

EFFECTIVE: ~~April 1, 2017~~January 1, 2018

RATE SCHEDULE IST-1
INTERRUPTIBLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 04/16/96)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of customers otherwise eligible for service under Rate Schedule IS-1, provided that the total electric load requirements at each point of delivery are measured through one meter.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is not subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 280.78~~78.95~~
Primary Metering Voltage:	$ 416.65~~3.94~~
Transmission Metering Voltage:	$ 996.74~~0.26~~

Demand Charge:

Base Demand Charge:	$ 1.14~~3~~ per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 6.30~~26~~ per kW of On-Peak Demand
Interruptible Demand Credit:	$ 6.71~~24~~ per kW of On-Peak Demand

Energy Charge:

Non-Fuel Energy Charge:	1.458~~49~~¢ per On-Peak kWh 0.851~~45~~¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy used during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14~~3~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March, Monday through Friday*:	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
(2) For the calendar months of April through October, Monday through Friday*:	12:00 Noon to 9:00 p.m.

(Continued on Page No. 2)

RATE SCHEDULE IST-1
INTERRUPTIBLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 04/16/96)
(Continued from Page No. 1)

Rating Periods: (Continued)

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Period.

(b) Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Base Demand charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95~~1.55~~ per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, Interruptible Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with measured demands of 1,000 kW or more for three (3) or more months out of the twelve (12) consecutive months ending with the current billing period, bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds numerically, .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

(Continued on Page No. 3)

RATE SCHEDULE IST-2
INTERRUPTIBLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicability:

At the option of the customer, applicable to customers otherwise eligible for service under Rate Schedule IS-2, where the billing demand is 500 kW or more, provided that the total electric requirements at each point of delivery are measured through one meter. For customer accounts established under this rate schedule after June 3, 2003, service is limited to premises at which an interruption of electric service will primarily affect only the customer, its employees, agents, lessees, tenants, or business guests, and will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. Examples of premises at which service under this rate schedule may not be provided, unless adequate on-site backup generation is available, include, but are not limited to: retail businesses, offices, and governmental facilities open to members of the general public, stores, hotels, motels, convention centers, theme parks, schools, hospitals and health care facilities, designated public shelters, detention and correctional facilities, police and fire stations, and other similar facilities.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is not subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments, or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 280.78~~278.95~~
Primary Metering Voltage:	$ 416.65~~413.94~~
Transmission Metering Voltage:	$ 996.74~~990.26~~

Demand Charge:

Base Demand Charge:	$ 1.14~~3~~ per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 6.30~~26~~ per kW of On-Peak Demand
Interruptible Demand Credit:	$ 11.70~~0.88~~ per kW of Load Factor Adjusted Demand

Energy Charge:

Non-Fuel Energy Charge:	1.458~~49~~¢ per On-Peak kWh 0.851~~45~~¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy used during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit. In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.14~~3~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March, Monday through Friday*: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October, Monday through Friday*: 12:00 Noon to 9:00 p.m.

Continued on Page No. 2)

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

Continued on Page No. 2)

RATE SCHEDULE IST-2
INTERRUPTIBLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

Rating Periods: (Continued)

(b) Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 500 kW.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Determination of Load Factor Adjusted Demand:

The Load Factor Adjusted Demand shall be the product of the maximum 30-minute kW demand established during the current billing period and the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand times the number of hours in the billing period).

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Base Demand charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.19~~0.41~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$5.95~~1.55~~ per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges, Interruptible Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with measured demands of 1,000 kW or more for three (3) or more months out of the twelve (12) consecutive months ending with the current billing period, bills computed under the above rate per month charges will be increased 30¢ for each KVAR by which the reactive demand exceeds numerically, .62 times the measured kW demand, and will be decreased 30¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Demand Charge for the current billing period. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

(Continued on Page No. 3)

RATE SCHEDULE LS-1
LIGHTING SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer for the sole purpose of lighting roadways or other outdoor land use areas; served from either Company or customer owned fixtures of the type available under this rate schedule. Service hereunder is provided for the sole and exclusive benefit of the customer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose any obligation on the Company to any such third party.

Character of Service:

Continuous dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating current, 60 cycle, single phase, at the Company's standard voltage available.

Limitation of Service:

Availability of certain fixture or pole types at a location may be restricted due to accessibility.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations Governing Electric Service."

Rate Per Month:

Customer Charge:

Unmetered:	$ 1.20~~19~~ per line of billing
Metered:	$ 3.44~~2~~ per line of billing

Energy and Demand Charge:

Non-Fuel Energy Charge:	2.234~~216~~¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Per Unit Charges:

I. Fixtures:

		LAMP SIZE [2]			CHARGES PER UNIT		
BILLING TYPE	DESCRIPTION	INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	FIXTURE	MAINTENANCE	NON-FUEL ENERGY [3]
	Incandescent: [1]						
110	Roadway	1,000	105	32	$1.03	$4.07	$0.71
115	Roadway	2,500	205	66	1.61	3.67	1.47~~6~~
170	Post Top	2,500	205	72	20.39	3.67	1.61~~0~~
	Mercury Vapor: [1]						
205	Open Bottom	4,000	100	44	$2.55	$1.80	$0.98
210	Roadway	4,000	100	44	2.95	1.80	0.98
215	Post Top	4,000	100	44	3.47	1.80	0.98
220	Roadway	8,000	175	71	3.34	1.77	1.59~~7~~
225	Open Bottom	8,000	175	71	2.50	1.77	1.59~~7~~
235	Roadway	21,000	400	158	4.04	1.81	3.53~~0~~
240	Roadway	62,000	1,000	386	5.29	1.78	8.62~~55~~
245	Flood	21,000	400	158	5.29	1.81	3.53~~0~~
250	Flood	62,000	1,000	386	6.20	1.78	8.62~~55~~

(Continued on Page No. 2)

DUKE ENERGY.

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 1)

I. Fixtures: (Continued)

		LAMP SIZE [2]			CHARGES PER UNIT		
BILLING TYPE	DESCRIPTION	INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	FIXTURE	MAINTENANCE	NON-FUEL ENERGY [3]
	Sodium Vapor:						
300	HPS Deco Rdwy White	50,000	400	168	$14.73	$1.61	$3.75~~2~~
301	Sandpiper HPS Deco Roadway	27,500	250	104	13.81	1.72	2.32~~0~~
302	Sandpiper HPS Deco Rdwy Blk	9,500	100	42	14.73	1.58	0.94~~3~~
305	Open Bottom [1]	4,000	50	21	2.54	2.04	0.47
310	Roadway [1]	4,000	50	21	3.12	2.04	0.47
313	Open Bottom [1]	6,500	70	29	4.19	2.05	0.65~~4~~
314	Hometown II	9,500	100	42	4.08	1.72	0.94~~3~~
315	Post Top - Colonial/Contemp [1]	4,000	50	21	5.04	2.04	0.47
316	Colonial Post Top [1]	4,000	50	34	4.05	2.04	0.76~~5~~
318	Post Top [1]	9,500	100	42	2.50	1.72	0.94~~3~~
320	Roadway-Overhead Only	9,500	100	42	3.64	1.72	0.94~~3~~
321	Deco Post Top - Monticello	9,500	100	49	12.17	1.72	1.09
322	Deco Post Top - Flagler	9,500	100	49	16.48	1.72	1.09
323	Roadway-Turtle OH Only	9,500	100	42	4.32	1.72	0.94~~3~~
325	Roadway-Overhead Only	16,000	150	65	3.78	1.75	1.45~~4~~
326	Deco Post Top – Sanibel	9,500	100	49	18.16	1.72	1.09
330	Roadway-Overhead Only	22,000	200	87	3.64	1.83	1.94~~3~~
335	Roadway-Overhead Only	27,500	250	104	4.16	1.72	2.32~~0~~
336	Roadway-Bridge [1]	27,500	250	104	6.74	1.72	2.32~~0~~
337	Roadway-DOT [1]	27,500	250	104	5.87	1.72	2.32~~0~~
338	Deco Roadway–Maitland	27,500	250	104	9.62	1.72	2.32~~0~~
340	Roadway-Overhead Only	50,000	400	169	5.03	1.76	3.78~~5~~
341	HPS Flood-City of Sebring only [1]	16,000	150	65	4.06	1.75	1.45~~4~~
342	Roadway-Turnpike [1]	50,000	400	168	8.95	1.76	3.75~~2~~
343	Roadway-Turnpike [1]	27,500	250	108	9.12	1.72	2.41~~39~~
345	Flood-Overhead Only	27,500	250	103	5.21	1.72	2.30~~28~~
347	Clermont	9,500	100	49	20.65	1.72	1.09
348	Clermont	27,500	250	104	22.65	1.72	2.32~~0~~
350	Flood-Overhead Only	50,000	400	170	5.19	1.76	3.80~~77~~
351	Underground Roadway	9,500	100	42	6.22	1.72	0.94~~3~~
352	Underground Roadway	16,000	150	65	7.58	1.75	1.45~~4~~
354	Underground Roadway	27,500	250	108	8.10	1.72	2.41~~39~~
356	Underground Roadway	50,000	400	168	8.69	1.76	3.75~~2~~
357	Underground Flood	27,500	250	108	9.36	1.72	2.41~~39~~
358	Underground Flood [1]	50,000	400	168	9.49	1.76	3.75~~2~~
359	Underground Turtle Roadway	9,500	100	42	6.09	1.72	0.94~~3~~
360	Deco Roadway Rectangular [1]	9,500	100	47	12.53	1.72	1.05~~4~~
365	Deco Roadway Rectangular	27,500	250	108	11.89	1.72	2.41~~39~~
366	Deco Roadway Rectangular	50,000	400	168	12.00	1.76	3.75~~2~~
370	Deco Roadway Round [1]	27,500	250	108	15.41	1.72	2.41~~39~~
375	Deco Roadway Round [1]	50,000	400	168	15.42	1.76	3.75~~2~~
380	Deco Post Top – Ocala	9,500	100	49	8.78	1.72	1.09
381	Deco Post Top [1]	9,500	100	49	4.05	1.72	1.09
383	Deco Post Top-Biscayne	9,500	100	49	14.17	1.72	1.09
385	Deco Post Top – Sebring	9,500	100	49	6.75	1.72	1.09
393	Deco Post Top [1]	4,000	50	21	8.72	2.04	0.47
394	Deco Post Top [1]	9,500	100	49	18.16	1.72	1.09

(Continued on Page No. 3)

ISSUED BY: Javier J. Portuondo, Managing Director Rates & Regulatory Strategy – FL

EFFECTIVE: ~~April 1, 2017~~January 1, 2018

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 2)

I. Fixtures: (Continued)

BILLING TYPE	DESCRIPTION	LAMP SIZE [2] INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	CHARGES PER UNIT FIXTURE	MAINTENANCE	NON-FUEL ENERGY [3]
	Metal Halide:						
307	Deco Post Top-MH Sanibel P	11,600	150	65	$16.85	$2.68	$1.45~~4~~
308	Clermont Tear Drop P	11,600	150	65	19.91	2.68	1.45~~4~~
309	MH Deco Rectangular P	36,000	320	126	13.07	2.74	2.81~~79~~
311	MH Deco Cube P	36,000	320	126	15.98	2.74	2.81~~79~~
312	MH Flood P	36,000	320	126	10.55	2.74	2.81~~79~~
319	MH Post Top Biscayne P	11,600	150	65	15.24	2.68	1.45~~4~~
327	Deco Post Top-MH Sanibel [1]	12,000	175	74	18.39	2.72	1.65~~4~~
349	Clermont Tear Drop [1]	12,000	175	74	21.73	2.72	1.65~~4~~
371	MH Deco Rectangular [1]	38,000	400	159	14.26	2.84	3.55~~2~~
372	MH Deco Circular [1]	38,000	400	159	16.70	2.84	3.55~~2~~
373	MH Deco Rectangular [1, 5]	110,000	1,000	378	15.30	2.96	8.44~~38~~
386	MH Flood [1, 5]	110,000	1,000	378	13.17	2.96	8.44~~38~~
389	MH Flood-Sportslighter [1, 5]	110,000	1,000	378	13.01	2.96	8.44~~38~~
390	MH Deco Cube [1]	38,000	400	159	17.44	2.84	3.55~~2~~
396	Deco PT MH Sanibel Dual [5]	24,000	350	148	33.73	5.43	3.31~~28~~
397	MH Post Top-Biscayne [1]	12,000	175	74	14.98	2.72	1.65~~4~~
398	MH Deco Cube [1, 5]	110,000	1,000	378	20.34	2.96	8.44~~38~~
399	MH Flood	38,000	400	159	11.51	2.84	3.55~~2~~
	Light Emitting Diode (LED):						
106	Underground Sanibel	5,500	70	25	$20.80	$1.39	$0.56~~5~~
107	Underground Traditional Open	3,908	49	17	13.57	1.39	0.38
108	Underground Traditional w/Lens	3,230	49	17	13.57	1.39	0.38
109	Underground Acorn	4,332	70	25	20.16	1.39	0.56~~5~~
111	Underground Mini Bell	2,889	50	18	17.88	1.39	0.40
133	ATBO Roadway	4,521	48	17	6.22	1.39	0.38
134	Underground ATBO Roadway	4,521	48	17	7.71	1.39	0.38
136	Roadway	9,233	108	38	7.05	1.39	0.85~~4~~
137	Underground Roadway	9,233	108	38	8.55	1.39	0.85~~4~~
138, 176	Roadway	18,642	216	76	11.61	1.39	1.70~~68~~
139	Underground Roadway	18,642	216	76	13.11	1.39	1.70~~68~~
141, 177	Roadway	24,191	284	99	14.08	1.39	2.21~~19~~
142, 162	Underground Roadway	24,191	284	99	15.58	1.39	2.21~~19~~
147, 174	Roadway	12,642	150	53	9.74	1.39	1.18~~7~~
148	Underground Roadway	12,642	150	53	11.24	1.39	1.18~~7~~
151	ATBS Roadway	4,500	49	17	5.07	1.39	0.38
167	Underground Mitchell	5,186	50	18	21.44	1.39	0.40
168	Underground Mitchell w/Top Hat	4,336	50	18	21.44	1.39	0.40
361	Roadway [1]	6,000	95	33	16.93	2.43	0.74~~3~~
362	Roadway [1]	9,600	157	55	20.07	2.43	1.23~~2~~
363	Shoebox Type 3 [1]	20,664	309	108	41.08	2.84	2.41~~39~~
364	Shoebox Type 4 [1]	14,421	206	72	32.59	2.84	1.61~~0~~
367	Shoebox Type 5 [1]	14,421	206	72	31.65	2.84	1.61~~0~~
369	Underground Biscayne	6,500	80	28	18.60	1.39	0.63~~2~~

(Continued on Page No. 4)

RATE SCHEDULE SS-1
FIRM STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. Initially, the customer and the Company shall mutually agree upon a maximum amount of standby capacity in kW to be supplied by the Company. This shall be termed for billing purposes as the "Specified Standby Capacity".

2. Where a bona fide change in the customer's standby capacity requirement occurs, the Company and the customer shall establish a new Specified Standby Capacity.

3. The Specified Standby Capacity for the current billing period shall be the greater of: (1) the mutually agreed upon Specified Standby Capacity, (2) the maximum 30-minute kW standby power requirement established in the current billing month, or (3) the maximum 30-minute kW standby power requirement established in any of the twenty-three (23) preceding billing months.

Rate Per Month:

1. Customer Charge:

Secondary Metering Voltage:	$ 101.37~~0.71~~
Primary Metering Voltage:	$ 237.23~~5.69~~
Transmission Metering Voltage:	$ 817.33~~2.02~~

Note: Where the Customer has paid the costs of metering equipment pursuant to a Cogeneration Agreement, the Customer Charge shall be $81.74~~21~~.

2. Supplemental Service Charges:

All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. Standby Service Charges:

A. Distribution Capacity:

$2.09~~7~~ per kW times the Specified Standby Capacity.

Note: No charge is applicable to a customer who has provided all the facilities for interconnection to the Company's transmission system.

B. Generation & Transmission Capacity:

The charge shall be the greater of:

1. $1.163~~53~~ per kW times the Specified Standby Capacity or

2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-Peak Periods times $0.554~~49~~/kW times the appropriate following monthly factor:

Billing Month	Factor
March, April, May, October	0.80
June, September, November, December	1.00
January, February, July, August	1.20

Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*: See Sheet No. 6.105 and 6.106

C. Energy Charges

Non-Fuel Energy Charge: 1.029~~1~~¢ per kWh

Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor: See Sheet No. 6.105 and 6.106

(Continued on Page No. 4)

RATE SCHEDULE SS-1
FIRM STANDBY SERVICE
(Continued from Page No. 3)

Rate Per Month: (Continued)

3. Standby Service Charges: (Continued)

D. Delivery Voltage Credit:

When a customer takes service under this rate at a distribution primary delivery voltage, the Distribution Capacity Charge hereunder will be reduced by 1.19~~37~~¢ per kW.

E. Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Distribution Capacity Charge, Generation & Transmission Capacity Charge, Non-Fuel Energy Charge, and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

F. Fuel Cost Recovery Factor:

Time of Use Fuel Charges of applicable metering voltage provided on Tariff Sheet No. 6.105.

G.	**Asset Securitization Charge Factor:**	See Sheet No. 6.105
H.	**Gross Receipts Tax Factor:**	See Sheet No. 6.106
I.	**Right-of-Way Utilization Fee:**	See Sheet No. 6.106
J.	**Municipal Tax:**	See Sheet No. 6.106
K.	**Sales Tax:**	See Sheet No. 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 3 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition the Distribution Capacity Charge included in the Rate per Month section of this rate schedule shall be increased by $1.06~~5~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

1. **On-Peak Periods -** The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

A.	For the calendar months of November through March, Monday through Friday*:	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
B.	For the calendar months of April through October, Monday through Friday*:	12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

2. **Off-Peak Periods -** The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth above.

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Capacity Charges for Standby Service. Where Special Equipment to service the customer is required, the Company may require a specified minimum charge.

(Continued on Page No. 5)

RATE SCHEDULE SS-2
INTERRUPTIBLE STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. Initially, the customer and the Company shall mutually agree upon a maximum amount of standby capacity in kW to be supplied by the Company. This shall be termed for billing purposes as the "Specified Standby Capacity".

2. Where a bona fide change in the customer's standby capacity requirement occurs, the Company and the customer shall establish a new Specified Standby Capacity.

3. The Specified Standby Capacity for the current billing period shall be the greater of: (1) the mutually agreed upon Specified Standby Capacity, (2) the maximum 30-minute kW standby power requirement established in the current billing month, or (3) the maximum 30-minute kW standby power requirement established in any of the twenty-three (23) preceding billing months.

Rate Per Month:

1. Customer Charge:

Secondary Metering Voltage:	$ 305.70~~3.71~~
Primary Metering Voltage:	$ 441.55~~38.68~~
Transmission Metering Voltage:	$ 1,021.66~~15.02~~

Note: Where the customer has paid the costs of metering equipment pursuant to a Cogeneration Agreement, the Customer Charge shall be $286.06~~4.20~~.

2. Supplemental Service Charges:
All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. Standby Service Charges:

A. Distribution Capacity:
$2.08~~7~~ per kW times the Specified Standby Capacity.
Note: No charge is applicable to a Customer who has provided all the facilities for interconnection to the Company's transmission system.

B. Generation & Transmission Capacity:
The charge shall be the greater of:
1. $1.161~~53~~ per kW times the Specified Standby Capacity or
2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-Peak Periods times $0.553~~49~~ kW times the appropriate following monthly factor:

Billing Month	Factor
March, April, May, October	0.80
June, September, November, December	1.00
January, February, July, August	1.20

Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*: See Sheet No. 6.105 and 6.106

C. Interruptible Capacity Credit:
The credit shall be the greater of:
1. $1.17~~088~~ per kW times the Specified Standby Capacity, or
2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-peak periods times $0.557~~18~~/kW times the appropriate Billing Month Factor shown in part 3.B. above.

D. Energy Charges:
Non-Fuel Energy Charge: 1.016~~09~~¢ per kWh

Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor: See Sheet No. 6.105 and 6.106

E. Delivery Voltage Credit:
When a customer takes service under this rate at a distribution primary delivery voltage, the Distribution Capacity Charge hereunder will be reduced by 1.19~~37~~¢ per kW.

(Continued on Page No. 4)

RATE SCHEDULE SS-2
INTERRUPTIBLE STANDBY SERVICE
(Continued from Page No. 3)

Rate Per Month: (Continued)

3. Standby Service Charges: (Continued)

F. Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Distribution Capacity Charge, Generation & Transmission Capacity Charge, Interruptible Capacity Credit, Non-Fuel Energy Charge and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

G. Fuel Cost Recovery Factor:
Time of Use Fuel Charges of applicable metering voltage provided on Tariff Sheet No. 6.105.

H.	**Asset Securitization Charge Factor:**	See Sheet No. 6.105
I.	**Gross Receipts Tax Factor:**	See Sheet No. 6.106
J.	**Right-of-Way Utilization Fee:**	See Sheet No. 6.106
K.	**Municipal Tax:**	See Sheet No. 6.106
L.	**Sales Tax:**	See Sheet No. 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 4 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition the Distribution Capacity Charge included in the Rate per Month section of this rate schedule shall be increased by $1.05 per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

1. On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

A. For the calendar months of November through March,
Monday through Friday*: 6:00 a.m. to 10:00 a.m. and
6:00 p.m. to 10:00 p.m.

B. For the calendar months of April through October,
Monday through Friday*: 12:00 Noon to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

2. Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth above.

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Capacity Charges for Standby Service. Where Special Equipment to service the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at company-designated locations.

Term of Service:

Service under this rate schedule shall be under the same terms as that specified in the otherwise applicable rate schedule.

Special Provisions:

1. When the customer increases the electrical load, which increase requires the Company to increase facilities installed for the specific use of the customer, a new Term of Service may be required under this rate at the option of the Company.
2. Customers taking service under another Company rate schedule who elect to transfer to this rate will be accepted by the Company on a first-come, first-served basis. Required interruptible equipment will be installed accordingly, subject to availability. Service under this rate schedule shall commence with the first full billing period following the date of equipment installation.

(Continued on Page No. 5)

RATE SCHEDULE SS-3
CURTAILALBE STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. Initially, the customer and the Company shall mutually agree upon a maximum amount of standby capacity in kW to be supplied by the Company. This shall be termed for billing purposes as the "Specified Standby Capacity".
2. Where a bona fide change in the customer's standby capacity requirement occurs, the Company and the customer shall establish a new Specified Standby Capacity.
3. The Specified Standby Capacity for the current billing period shall be the greater of: (1) the mutually agreed upon Specified Standby Capacity, (2) the maximum 30-minute kW standby power requirement established in the current billing month or (3) the maximum 30-minute kW standby power requirement established in any of the twenty-three (23) preceding billing months.

Rate Per Month:

1. Customer Charge:

Secondary Metering Voltage:	$ 101.37~~0.71~~
Primary Metering Voltage:	$ 237.23~~5.69~~
Transmission Metering Voltage:	$ 817.33~~2.02~~

Note: Where the customer has paid the costs of metering equipment pursuant to a Cogeneration Agreement, the Customer Charge shall be $81.74~~21~~.

2. Supplemental Service Charges:
All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. Standby Service Charges:

A. Distribution Capacity:
$2.08~~7~~ per kW times the Specified Standby Capacity.
Note: No charge is applicable to a customer who has provided all the facilities for interconnection to the Company's transmission system.

B. Generation & Transmission Capacity:
The charge shall be the greater of:
1. $1.161~~53~~ per kW times the Specified Standby Capacity or
2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-Peak Periods times $0.553~~49~~/kW times the appropriate following monthly factor:

Billing Month	Factor
March, April, May, October	0.80
June, September, November, December	1.00
January, February, July, August	1.20
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106

C. Curtailable Capacity Credit:
The credit shall be the greater of:
1. $0.877~~16~~ per kW times the Specified Standby Capacity, or
2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-peak periods times $0.418~~389~~/kW times the appropriate Billing Month Factor shown in part 3.B. above.

D. Energy Charges:

Non-Fuel Energy Charge:	1.020~~13~~¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis listed in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

E. Delivery Voltage Credit:
When a customer takes service under this rate at a distribution primary delivery voltage, the Distribution Capacity Charge hereunder will be reduced by 1.19~~37~~¢ per kW.

(Continued on Page No. 4)

RATE SCHEDULE RSS-1
RESIDENTIAL SEASONAL SERVICE RIDER

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To customers receiving residential service under Rate Schedule RS-1, RSL-1 or RSL-2 that meet the special provisions of this schedule.

Rate Per Month:

Other than as stated below, the otherwise applicable rate schedule for electric service will apply.

Standard Customer Charge	$ 8.82~~76~~
Seasonal Customer Charge	$ 4.61~~58~~

Seasonal Billing Periods:

The billing months of March through October.

Special Provisions:

1. To qualify for service under this rider, the customer's premise must be occupied each year during a portion of the billing months of November through February and must not be occupied at least three months during the billing months of March through October.
2. The maximum allowable consumption for a seasonal billing period is 210 kWh. However, if the seasonal billing period exceeds 30 days, the maximum allowable consumption is increased by seven (7) kWh per day.
3. If kWh usage during the seasonal billing period is less than or equal to the maximum allowable consumption for the billing period, the seasonal customer charge will apply. For non-seasonal billing months and those seasonal billing months that exceed the allowed maximum allowable consumption, the standard customer charge will apply.
4. All other provisions of the otherwise applicable rate schedule will apply to customers served under this schedule..

ISSUED BY: **Javier J. Portuondo, Managing Director Rates & Regulatory Strategy – FL**

EFFECTIVE: ~~April 29, 2013~~January 1, 2018

RATE SCHEDULE ED-1
ECONOMIC DEVELOPMENT RIDER
~~EXPERIMENTAL PILOT PROGRAM~~

Availability:

Available throughout the entire territory served by the Company. Customers desiring to take service under this tariff must make a written request for service. ~~Application for service under this tariff is available to qualifying customers until October 17, 2019.~~

Applicable:

To any customer taking firm service, other than residential, for light and power purposes who meet the Qualifying Criteria set forth in this tariff. This tariff provides for an Economic Development Rate Reduction Factor as described herein for new load which is defined as load being established after the date of the original issue of this tariff sheet by a new business or the expansion of an existing business. This rider is not available for retention of existing load or for relocation of existing load within the Company's service territory. Relocating businesses that provide expansion of existing business may qualify for the expanded load only. This rider is not available for short-term, construction, temporary service, or renewal of a previously existing service. Customers must execute an Economic Development Service Agreement and such agreement must specify all qualifying criteria customer expects to meet for this rider to be applicable.

Qualifying Criteria:

a) The minimum qualifying new load must be at least 500 kW with a minimum load factor of 50% at a single point of delivery.
b) The new or expanding business must be a targeted industry as defined by the state of Florida's most current economic development policy.
c) The new or expanding business must also meet at least one of the following two requirements at the project location:
   1) The addition of 25 net new full time equivalent (FTE) jobs in the Company's Florida service area; or
   2) Capital investment of $500,000 or greater and a net increase in FTE jobs in the Company's Florida service area.
d) Customer must provide written documentation attesting that the availability of this rider is a significant factor in the Customer's location/expansion decision.

Limitation of Service:

Service under this tariff is limited to a total load served under both this tariff and the EDR-1 tariff of 300 megawatts or a total of 25 customer accounts served under both this tariff and the EDR-1 tariff. Standby or resale service not permitted hereunder. Service under this tariff is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service." Service under this tariff may not be combined with service under the EDR-1 tariff. Service under this tariff is available on a first come, first served basis.

Otherwise Applicable General Service Tariff:

Service under this rider shall be provided under any of the Company's currently available general service tariffs to be initially determined by mutual agreement of the Company and customer based on the usage characteristics provided by the customer for new load. All provisions, terms and conditions of the Otherwise Applicable General Service Tariff shall apply.

Rate Per Month:

All charges shall be those set forth in the Otherwise Applicable General Service Tariff adjusted by the Economic Development Rate Reduction Factor.

Economic Development Rate Reduction Factor:

The following rate reduction factors shall apply:

Year of Agreement	Reduction of Base Rate Demand and Energy Charges
Year 1	50%
Year 2	40%
Year 3	30%
Year 4	20%
Year 5	10%

(Continued on Page No. 2)

ISSUED BY: Javier J. Portuondo, Managing Director, Rates & Regulatory Strategy - FL

EFFECTIVE: ~~September 13, 2016~~January 1, 2018

RATE SCHEDULE ED-1
ECONOMIC DEVELOPMENT RIDER
~~EXPERIMENTAL PILOT PROGRAM~~
(Continued from Page No. 1)

Term of Service:

Service under this rider shall be for a term of five (5) years from the commencement of service of new load. Service under this rider will terminate at the end of the 5 year period.

Penalty for Non-Compliance with Qualifying Criteria or Term of Service:

If at any time during the term of the rider agreement the customer violates the terms and conditions of the rider or agreement, the Company may discontinue the discount provided for under this rider, and bill the customer based on the Otherwise Applicable General Service Tariff. If the customer terminates service prior to the end of the agreement period, or fails to meet the qualifying criteria agreed to for the term of the agreement, this will constitute a violation of the terms and conditions of the rider and agreement.

Should service under this rider be discontinued by the Company or the customer for said violation the customer shall be required to repay to the Company the amount of the cumulative discounts received under this rider with interest.

RATE SCHEDULE EDR-1
ECONOMIC RE-DEVELOPMENT RIDER
~~**EXPERIMENTAL PILOT PROGRAM**~~

Availability:

Available throughout the entire territory served by the Company. Customers desiring to take service under this tariff must make a written request for service. ~~Application for service under this tariff is available to qualifying customers until October 17, 2019.~~

Applicable:

To any customer taking firm service, other than residential, for light and power purposes who meet the Qualifying Criteria set forth in this tariff. This tariff provides for an Economic Re-Development Rate Reduction Factor as described herein for new load which is defined as load being established after the date of the original issue of this tariff sheet by a new business or the expansion of an existing business. This rider is not available for retention of existing load or for relocation of existing load within the Company's service territory. Relocating businesses that provide expansion of existing business may qualify for the expanded load only. This rider is not available for short-term, construction, temporary service, or renewal of a previously existing service. Customers must execute an Economic Re-Development Service Agreement and such agreement must specify all qualifying criteria customer expects to meet for this rider to be applicable.

Qualifying Criteria:

a) New load must be at an existing Company premise location previously served by the Company which has been unoccupied or otherwise essentially dormant (evidenced by minimal to no electric usage) for a minimum period of 90 days.
b) Customer must not have a relationship with the previous occupant of the unoccupied premise location.
c) The minimum qualifying new load must be at least 350 kW with a minimum load factor of 50% at a single point of delivery.
d) The new or expanding business must be a targeted industry as defined by the state of Florida's most current economic development policy.
e) The new or expanding business must also meet at least one of the following two requirements at the project location:
    1) The addition of 15 net new full time equivalent (FTE) jobs in the Company's Florida service area; or
    2) Capital investment of $200,000 or greater and a net increase in FTE jobs in the Company's Florida service area.
f) Customer must provide written documentation attesting that the availability of this rider is a significant factor in the Customer's location/expansion decision.

Limitation of Service:

Service under this tariff is limited to a total load served under both this tariff and the ED-1 tariff of 300 megawatts or a total of 25 customer accounts served under both this tariff and the ED-1 tariff. Standby or resale service not permitted hereunder. Service under this tariff is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service." Service under this tariff may not be combined with service under the ED-1 tariff. Service under this tariff is available on a first come, first served basis.

Otherwise Applicable General Service Tariff:

Service under this rider shall be provided under any of the Company's currently available general service tariffs to be initially determined by mutual agreement of the Company and customer based on the usage characteristics provided by the customer for new load. All provisions, terms and conditions of the Otherwise Applicable General Service Tariff shall apply.

Rate Per Month:

All charges shall be those set forth in the Otherwise Applicable General Service Tariff adjusted by the Economic Re-Development Rate Reduction Factor.

Economic Re-Development Rate Reduction Factor:

The following rate reduction factors shall apply:

Year of Agreement	Reduction of Base Rate Demand and Energy Charge	Reduction of the Non-Fuel and non-ASC BA-1 Tariff Charges
Year 1	50%	50%
Year 2	35%	35%
Year 3	15%	15%
Year 4	0%	0%
Year 5	0%	0%

(Continued on Page No. 2)

RATE SCHEDULE EDR-1
ECONOMIC RE-DEVELOPMENT RIDER
~~**EXPERIMENTAL PILOT PROGRAM**~~
(Continued from Page No. 1)

Term of Service:

Service under this rider shall be for a term of five (5) years from the commencement of service of new load. Service under this rider will terminate at the end of the 5 year period.

Penalty for Non-Compliance with Qualifying Criteria or Term of Service:

If at any time during the term of the rider agreement the customer violates the terms and conditions of the rider or agreement, the Company may discontinue the discount provided for under this rider, and bill the customer based on the Otherwise Applicable General Service Tariff. If the customer terminates service prior to the end of the agreement period, or fails to meet the qualifying criteria agreed to for the term of the agreement, this will constitute a violation of the terms and conditions of the rider and agreement.

Should service under this rider be discontinued by the Company or the customer for said violation the customer shall be required to repay to the Company the amount of the cumulative discounts received under this rider with interest. Repayments will be appropriately treated and apportioned by the Company in direct proportion to the base rate or clause revenues as discounts were achieved and repaid.

Other Charges:

Customers requiring installation of additional new facilities at an existing premise location may be subject to contribution in aid to construction, construction advances or equipment rental charges as may be applicable in accordance with the Company's Rules and Regulations.

Original Tariff Sheets in Clean Copy and Legislative Format

Original Sheet No. 6.390
Original Sheet No. 6.391
Original Sheet No. 6.392
Original Sheet No. 6.395
Original Sheet No. 6.396

RATE SCHEDULE FB-1
Optional – FixedBill Program

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To customers taking service under the Company's Standard Residential Tariff Rate Schedules who have lived in their current residence for the previous 12 months, have had their electricity priced on the Company's Standard Residential Tariffs for the previous 12 months, have a load profile that can be modeled with reasonable predictability, and are current on their electric service bill. Within the last 12 months, the customer may not have:

1) Defaulted on a payment arrangement;
2) Entered into a multi-month payment arrangement;
3) Had a payment that was not honored by a financial institution; or
4) Been disconnected for non-payment of electric service.

Character of Service:

Electric energy supplied hereunder must meet the Character of Service and usage specifications consistent with service under the Company's Standard Residential Tariffs.

Limitation of Service:

Service under this rate schedule is not available to Net Metering customers or customers with multiple electric meters on one account. Customers may not participate in both *FixedBill* and Budget Billing.

***FixedBill* Amount:**

Subject to its Terms and Conditions, *FixedBill* offers customers a predetermined electric bill for 12 months and protects participating customers from unpredictable bills caused by weather related usage and changes in electric rates. The customer's Monthly *FixedBill* Amount will be calculated starting with at least 12 months of past Actual Usage data, applying weather normalization and any applicable Usage and Risk Adders, using the following formula:

[(Predicted Weather Normalized Monthly kWh Usage x (1+Usage Adder)) x (expected Non-Fuel Energy Charges including expected Cost Recovery Factors, expected Fuel Cost Recovery Factor and expected Asset Securitization Charge)] x (1+Risk Adder) – expected applicable credits + expected Customer Charge.

The Monthly FixedBill Amount will not include Applicable Taxes and other charges such as service charges, lighting and non-regulated products and services. Applicable Taxes and fees will be applied to the *FixedBill* Amount and included in the total amount due.

Definitions:

Applicable Removal Charges: Charges incurred when the customer discontinues *FixedBill* service before the 12 month Service Agreement period expires. The Company will calculate what the customer would have paid under the Standard Residential Tariff during the *FixedBill* Service Agreement period. If the customer has paid less than the Standard Residential Tariff, the customer will be charged the difference. If the customer paid more than the Standard Residential Tariff, the customer will not be credited the difference.

Applicable Taxes: See Rate Schedule BA-1, Sheet No.6.105

Asset Securitization Charge: See Rate Schedule BA-1, Sheet no. 6.106

Actual Energy Usage: The customer's actual energy usage for a designated time period.

Cost Recovery Factors: See Rate Schedule BA-1, Sheet no. 6.105 and 6.106

Non-Fuel Energy Charge: See Rate Schedule RS-1, Sheet no. 6.120

Fuel Cost Recovery Factor: See Rate Schedule BA-1, Sheet no. 6.105 and 6.106.

Load Management Credit Amounts: See Rate Schedule RSL-1, Sheet no. 6.130

(Continued on Page No. 2)

RATE SCHEDULE FB-1
Optional – FixedBill Program
(Continued from Page No. 1)

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Normal Weather: Weather at the 50th weather percentile based on the Company's historical seasonal heating degree-days and cooling degree-days.

Actual Weather: Weather experienced during a historical time period measured using actual heating degree-days and cooling degree-days.

Predicted Weather Normalized Monthly kWh Usage: The customer's predicted monthly usage (kWh) based on Normal Weather.

Predicted Weather Adjusted Total kWh Usage: The customer's predicted total usage (kWh) for the applicable time period based on Actual Weather.

Risk Adder: This adder is used to compensate the Company for the risk associated with weather-related consumption and non-weather related impacts. This adder will not exceed 6%.

Usage Adder: This adder is used to compensate the Company for the risk associated with increased usage by customers in their first year while on *FixedBill* not associated with weather. The initial usage adder will be 4% and capped at 6%. This adder will only be applied during the customer's first year on the *FixedBill* program.

Standard Residential Tariff: The Company's RS-1, RSL-1 and RSL-2 Rate Schedules, beginning Sheet Nos. 6.120, 6.130, and 6.135, respectively.

Terms and Conditions:

1. The customer will enter into a Service Agreement with the Company that will specify the Monthly *FixedBill* Amount that the customer will be required to pay.

2. The term of the Service Agreement will be for twelve (12) months. The Company will calculate a new Monthly *FixedBill* Amount for the following year, and notify the customer of the new contractual amount before the current 12-month *FixedBill* period expires. The customer will be automatically renewed at the new Monthly *FixedBill* Amount for the following year unless the customer notifies the Company of their intent to be removed from the *FixedBill* program.

3. Removal from the program:

A. Move from Current Residence.
If a participating customer moves from their current residence before the 12 month Service Agreement period expires, Applicable Removal Charges will apply.

B. Delinquent FixedBill Payments.
If a customer becomes delinquent in a *FixedBill* payment, the Company will follow standard procedures for Standard Residential Tariff customers. If the customer is disconnected for nonpayment, the customer will be removed from the *FixedBill* program and Applicable Removal Charges will apply.

C. Increased Actual Energy Usage Above Expected Usage (Excess Usage).
The Company reserves the right to terminate the customer's *FixedBill* program Service Agreement if the customer's total Actual Energy Usage in months three (3) through nine (9) of the contract year exceeds their Predicted Weather Adjusted Total kWh_Usage by at least 30% for at least three months. If the customer is removed from the *FixedBill* program due to excessive usage, Applicable Removal Charges will apply. The Company will notify the customer in advance if they are at risk of being removed from the program due to excessive usage.

D. Customer Voluntary Removal.
If a customer chooses to leave the *FixedBill* program prior to the end of the 12-month Service Agreement period, the customer will be removed from the *FixedBill* program and Applicable Removal Charges will apply. After the end of each Service Agreement period, eligible customers will automatically renew for the next *FixedBill* Service Agreement period unless the customer indicates their intention to return to the Standard Residential Tariff. If the Standard Residential Tariff election is made prior to the automatic renewal of the *FixedBill* Service Agreement, no Applicable Removal Charges will apply.

(Continued on Page No. 3)

RATE SCHEDULE FB-1
Optional – FixedBill Program
(Continued from Page No. 2)

E. Other Reason.
If the customer leaves or is removed from the *FixedBill* program before the end of the Service Agreement period for any other reason, Applicable Removal Charges will apply.

F. Emergency Conditions/Deceased Customers.
Company shall have the right to waive the Applicable Removal Charges if the circumstances giving rise to the application of such charges are directly related to a natural disaster or other similar conditions for which an emergency has been declared by a governmental body authorized to make such a declaration. Company shall also waive the Applicable Removal Charges if presented with evidence that the customer is deceased before the end of the 12-month Service Agreement period.

RATE SCHEDULE SOL-1
SHARED SOLAR RIDER
EXPERIMENTAL PILOT PROGRAM

Availability:

This Rider is available to all Customers throughout the entire service area served by the Company on a first come first served basis subject to subscription availability. Customers may subscribe to individual blocks, of 50 kWh per month, of output from solar photovoltaic (PV) facilities owned and operated by Duke Energy Florida. Multiple subscriptions may be purchased up to a maximum of 25 blocks per month for residential, 150 blocks for commercial and 2,000 blocks for industrial customers. Application for service under this tariff is available to qualifying customers throughout the 5 year pilot period. The Company reserves the right to close the program to new applicants at any time during the 5-year availability period.

Applicable:

This optional rider is offered in conjunction with the applicable rates, terms, and conditions under which the Customer takes service from the Company.

Rate: Monthly Subscription Fee per block: $7.75

Bill Credit:

Participating Customers will receive a monthly bill credit for each subscription purchased. The monthly bill credit will be based on DEF's annual projection of as-available energy purchases from renewable generating facilities during forecasted daylight solar production hours from typical DEF solar photovoltaic, (PV) facilities located in Florida and will be calculated and fixed for each upcoming calendar year.

Example Calculation for Maximum Monthly Bill Credit

Residential Customers: ($0.025/kWh)* x 50 kWH/block x 25 blocks = $31.25
Commercial Customers: ($0.025/kWh)* x 50 kWH/block x 150 blocks = $187.50
Industrial Customers: ($0.025/kWh) * x 50 kWH/block x 2,000 blocks = $2,500.00

* Estimated fixed solar annual average avoided energy price (subject to change annually)

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on the bill at Company-designated locations.

Term of Service:

The Monthly Subscription Fee will be fixed through the duration of the 5-year pilot program and each subscription will automatically renew each month, unless the Customer notifies the Company of their desire to cancel.

Special Provisions:

1. The location and power produced from the Solar facilities shall be controlled by Duke Energy and may not be specifically delivered to the Customer, but may displace power that would have been otherwise produced from DEF's generation resource portfolio.
2. Customers will continue to be billed for all of their electricity consumption at the applicable retail rate and will see the bill credits for solar facility production.
3. Customers may cancel, or modify their participation with 30-day written notice, without any charge.
4. Customers shall not be permitted to redirect Bill Credits or transfer the obligation to pay Subscription Fees to other Duke Energy customer accounts, nor will the Company assign Bill Credits or Subscription Fees to any party other than the original subscribing customer.
5. If the customer is delinquent on paying the Subscription Fee for at least 2 months, the Company reserves the right to terminate the customer's participation in the Shared Solar Program. Customers will not be subject to disconnection of retail energy service with non-payment of subscription fees.
6. In the event that the customer transfers their electric service to a different location within Duke Energy Florida's (DEF's) service area, the customer's subscription shall be transferred to the new service location.
7. If, for any reason, the customer moves to a location outside of DEF's service area and discontinues electric service with DEF, the customer shall be released from any obligation to pay DEF any subsequent Subscription Fees. The customer or the Company shall not be entitled to a refund for Subscription Fees but will receive corresponding Bill Credits which have already been billed.

(Continued on Page No. 2)

RATE SCHEDULE SOL-1
SHARED SOLAR RIDER
EXPERIMENTAL PILOT PROGRAM
(Continued From Page No. 1)

8. The Company shall not certify any environmental or renewable attributes in conjunction with the Shared Solar Program and will render the Customer's environmental or renewable attributes unavailable for future sale, trading or other use upon the Customer's payment of the Monthly Subscription Fee.

9. In the event that the Shared Solar Pilot Program is discontinued or modified by the Florida Public Service Commission, the Company reserves the right to discontinue service under this Rider. In such case, the customer shall be released from any obligation to pay DEF for Subscription Fees which have yet to be billed to the customer. The customer or the Company shall not be entitled to a refund for Subscription Fees but will receive corresponding Bill Credits which have already been billed.

10. Participation in this program does not convey to the customer any right, title or interest in or to any portion of the property comprising of any Duke Energy owned solar facilities or any solar facilities constructed pursuant to the Shared Solar Program.

RATE SCHEDULE FB-1
Optional – FixedBill Program

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To customers taking service under the Company's Standard Residential Tariff Rate Schedules who have lived in their current residence for the previous 12 months, have had their electricity priced on the Company's Standard Residential Tariffs for the previous 12 months, have a load profile that can be modeled with reasonable predictability, and are current on their electric service bill. Within the last 12 months, the customer may not have:
1) Defaulted on a payment arrangement;
2) Entered into a multi-month payment arrangement;
3) Had a payment that was not honored by a financial institution; or
4) Been disconnected for non-payment of electric service.

Character of Service:

Electric energy supplied hereunder must meet the Character of Service and usage specifications consistent with service under the Company's Standard Residential Tariffs.

Limitation of Service:

Service under this rate schedule is not available to Net Metering customers or customers with multiple electric meters on one account. Customers may not participate in both *FixedBill* and Budget Billing.

***FixedBill* Amount:**

Subject to its Terms and Conditions, *FixedBill* offers customers a predetermined electric bill for 12 months and protects participating customers from unpredictable bills caused by weather related usage and changes in electric rates. The customer's Monthly *FixedBill* Amount will be calculated starting with at least 12 months of past Actual Usage data, applying weather normalization and any applicable Usage and Risk Adders, using the following formula:

[(Predicted Weather Normalized Monthly kWh Usage x (1+Usage Adder)) x (expected Non-Fuel Energy Charges including expected Cost Recovery Factors, expected Fuel Cost Recovery Factor and expected Asset Securitization Charge)] x (1+Risk Adder) – expected applicable credits + expected Customer Charge.

The Monthly FixedBill Amount will not include Applicable Taxes and other charges such as service charges, lighting and non-regulated products and services. Applicable Taxes and fees will be applied to the *FixedBill* Amount and included in the total amount due.

Definitions:

Applicable Removal Charges: Charges incurred when the customer discontinues *FixedBill* service before the 12 month Service Agreement period expires. The Company will calculate what the customer would have paid under the Standard Residential Tariff during the *FixedBill* Service Agreement period. If the customer has paid less than the Standard Residential Tariff, the customer will be charged the difference. If the customer paid more than the Standard Residential Tariff, the customer will not be credited the difference.

Applicable Taxes: See Rate Schedule BA-1, Sheet No.6.105

Asset Securitization Charge: See Rate Schedule BA-1, Sheet no. 6.106

Actual Energy Usage: The customer's actual energy usage for a designated time period.

Cost Recovery Factors: See Rate Schedule BA-1, Sheet no. 6.105 and 6.106

Non-Fuel Energy Charge: See Rate Schedule RS-1, Sheet no. 6.120

Fuel Cost Recovery Factor: See Rate Schedule BA-1, Sheet no. 6.105 and 6.106.

Load Management Credit Amounts: See Rate Schedule RSL-1, Sheet no. 6.130

(Continued on Page No. 2)

RATE SCHEDULE FB-1
Optional – FixedBill Program
(Continued from Page No. 1)

Normal Weather: Weather at the 50th weather percentile based on the Company's historical seasonal heating degree-days and cooling degree-days.

Actual Weather: Weather experienced during a historical time period measured using actual heating degree-days and cooling degree-days.

Predicted Weather Normalized Monthly kWh Usage: The customer's predicted monthly usage (kWh) based on Normal Weather.

Predicted Weather Adjusted Total kWh Usage: The customer's predicted total usage (kWh) for the applicable time period based on Actual Weather.

Risk Adder: This adder is used to compensate the Company for the risk associated with weather-related consumption and non-weather related impacts. This adder will not exceed 6%.

Usage Adder: This adder is used to compensate the Company for the risk associated with increased usage by customers in their first year while on *FixedBill* not associated with weather. The initial usage adder will be 4% and capped at 6%. This adder will only be applied during the customer's first year on the *FixedBill* program.

Standard Residential Tariff: The Company's RS-1, RSL-1 and RSL-2 Rate Schedules, beginning Sheet Nos. 6.120, 6.130, and 6.135, respectively.

Terms and Conditions:

1. The customer will enter into a Service Agreement with the Company that will specify the Monthly *FixedBill* Amount that the customer will be required to pay.

2. The term of the Service Agreement will be for twelve (12) months. The Company will calculate a new Monthly *FixedBill* Amount for the following year, and notify the customer of the new contractual amount before the current 12-month *FixedBill* period expires. The customer will be automatically renewed at the new Monthly *FixedBill* Amount for the following year unless the customer notifies the Company of their intent to be removed from the *FixedBill* program.

3. Removal from the program:

   A. Move from Current Residence.
   If a participating customer moves from their current residence before the 12 month Service Agreement period expires, Applicable Removal Charges will apply.

   B. Delinquent FixedBill Payments.
   If a customer becomes delinquent in a *FixedBill* payment, the Company will follow standard procedures for Standard Residential Tariff customers. If the customer is disconnected for nonpayment, the customer will be removed from the *FixedBill* program and Applicable Removal Charges will apply.

   C. Increased Actual Energy Usage Above Expected Usage (Excess Usage).
   The Company reserves the right to terminate the customer's *FixedBill* program Service Agreement if the customer's total Actual Energy Usage in months three (3) through nine (9) of the contract year exceeds their Predicted Weather Adjusted Total kWh Usage by at least 30% for at least three months. If the customer is removed from the *FixedBill* program due to excessive usage, Applicable Removal Charges will apply. The Company will notify the customer in advance if they are at risk of being removed from the program due to excessive usage.

   D. Customer Voluntary Removal.
   If a customer chooses to leave the *FixedBill* program prior to the end of the 12-month Service Agreement period, the customer will be removed from the *FixedBill* program and Applicable Removal Charges will apply. After the end of each Service Agreement period, eligible customers will automatically renew for the next *FixedBill* Service Agreement period unless the customer indicates their intention to return to the Standard Residential Tariff. If the Standard Residential Tariff election is made prior to the automatic renewal of the *FixedBill* Service Agreement, no Applicable Removal Charges will apply.

(Continued on Page No. 3)

RATE SCHEDULE FB-1
Optional – FixedBill Program
(Continued from Page No. 2)

E. Other Reason.
If the customer leaves or is removed from the *FixedBill* program before the end of the Service Agreement period for any other reason, Applicable Removal Charges will apply.

F. Emergency Conditions/Deceased Customers.
Company shall have the right to waive the Applicable Removal Charges if the circumstances giving rise to the application of such charges are directly related to a natural disaster or other similar conditions for which an emergency has been declared by a governmental body authorized to make such a declaration. Company shall also waive the Applicable Removal Charges if presented with evidence that the customer is deceased before the end of the 12-month Service Agreement period.

RATE SCHEDULE SOL-1
SHARED SOLAR RIDER
EXPERIMENTAL PILOT PROGRAM

Availability:

This Rider is available to all Customers throughout the entire service area served by the Company on a first come first served basis subject to subscription availability. Customers may subscribe to individual blocks, of 50 kWh per month, of output from solar photovoltaic (PV) facilities owned and operated by Duke Energy Florida. Multiple subscriptions may be purchased up to a maximum of 25 blocks per month for residential, 150 blocks for commercial and 2,000 blocks for industrial customers. Application for service under this tariff is available to qualifying customers throughout the 5 year pilot period. The Company reserves the right to close the program to new applicants at any time during the 5-year availability period.

Applicable:

This optional rider is offered in conjunction with the applicable rates, terms, and conditions under which the Customer takes service from the Company.

Rate: Monthly Subscription Fee per block: $7.75

Bill Credit:

Participating Customers will receive a monthly bill credit for each subscription purchased. The monthly bill credit will be based on DEF's annual projection of as-available energy purchases from renewable generating facilities during forecasted daylight solar production hours from typical DEF solar photovoltaic, (PV) facilities located in Florida and will be calculated and fixed for each upcoming calendar year.

Example Calculation for Maximum Monthly Bill Credit

Residential Customers: ($0.025/kWh)* x 50 kWH/block x 25 blocks = $31.25
Commercial Customers: ($0.025/kWh)* x 50 kWH/block x 150 blocks = $187.50
Industrial Customers: ($0.025/kWh) * x 50 kWH/block x 2,000 blocks = $2,500.00

* Estimated fixed solar annual average avoided energy price (subject to change annually)

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on the bill at Company-designated locations.

Term of Service:

The Monthly Subscription Fee will be fixed through the duration of the 5-year pilot program and each subscription will automatically renew each month, unless the Customer notifies the Company of their desire to cancel.

Special Provisions:

1. The location and power produced from the Solar facilities shall be controlled by Duke Energy and may not be specifically delivered to the Customer, but may displace power that would have been otherwise produced from DEF's generation resource portfolio.
2. Customers will continue to be billed for all of their electricity consumption at the applicable retail rate and will see the bill credits for solar facility production.
3. Customers may cancel, or modify their participation with 30-day written notice, without any charge.
4. Customers shall not be permitted to redirect Bill Credits or transfer the obligation to pay Subscription Fees to other Duke Energy customer accounts, nor will the Company assign Bill Credits or Subscription Fees to any party other than the original subscribing customer.
5. If the customer is delinquent on paying the Subscription Fee for at least 2 months, the Company reserves the right to terminate the customer's participation in the Shared Solar Program. Customers will not be subject to disconnection of retail energy service with non-payment of subscription fees.
6. In the event that the customer transfers their electric service to a different location within Duke Energy Florida's (DEF's) service area, the customer's subscription shall be transferred to the new service location.
7. If, for any reason, the customer moves to a location outside of DEF's service area and discontinues electric service with DEF, the customer shall be released from any obligation to pay DEF any subsequent Subscription Fees. The customer or the Company shall not be entitled to a refund for Subscription Fees but will receive corresponding Bill Credits which have already been billed.

(Continued on Page No. 2)

RATE SCHEDULE SOL-1
SHARED SOLAR RIDER
EXPERIMENTAL PILOT PROGRAM
(Continued From Page No. 1)

8. The Company shall not certify any environmental or renewable attributes in conjunction with the Shared Solar Program and will render the Customer's environmental or renewable attributes unavailable for future sale, trading or other use upon the Customer's payment of the Monthly Subscription Fee.

9. In the event that the Shared Solar Pilot Program is discontinued or modified by the Florida Public Service Commission, the Company reserves the right to discontinue service under this Rider. In such case, the customer shall be released from any obligation to pay DEF for Subscription Fees which have yet to be billed to the customer. The customer or the Company shall not be entitled to a refund for Subscription Fees but will receive corresponding Bill Credits which have already been billed.

10. Participation in this program does not convey to the customer any right, title or interest in or to any portion of the property comprising of any Duke Energy owned solar facilities or any solar facilities constructed pursuant to the Shared Solar Program.

Methodology of Income Tax Change (Illustrative)

Line	Description	Source	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 federal & 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	-	200	-	-
8						
9	**PARAGRAPH 12 - MULTIYEAR INCREASE**					
10	Base rate revenue increase	Given	67	67	67	67
11	Income tax at current statutory tax rate	Line 6 x Line 10	26	26	26	26
12	FPSC Adjusted NOI impact	Line 10 - Line 11	41	41	41	41
13	Gross up factor at new statutory tax rate	1 - Line 5	61.4%	66.2%	66.2%	75.6%
14	Revenue requirement at new statutory tax rate	Line 12 / Line 13	67	62	62	54
15						
16	**PARAGRAPH 16 - TAX REFORM SHARING**					
17	<u>**Step 1 - Calculate income tax expense BEFORE tax reform**</u>					
18	FPSC adjusted NOI before tax (per Forecasted Surveillance)	Input	1,200	1,200	1,200	1,200
19	Less interest expense	Input	(200)	(200)	(200)	(200)
20	Permanent differences	Input	(50)	(50)	(50)	(50)
21	FPSC adjusted taxable income	Sum of Lines 18 through 20	950	950	950	950
22	Current combined statutory tax rate	Line 6	38.6%	38.6%	38.6%	38.6%
23	Income tax expense	Line 21 x Line 22	366	366	366	366
24						
25	<u>**Step 2 - Calculate income tax expense AFTER tax reform**</u>					
26	FPSC adjusted NOI before tax (per Forecasted Surveillance)	Input	1,200	1,200	1,200	1,200
27	Less interest expense	Input	(200)	-	(200)	(200)
28	Permanent differences	Input	(50)	(50)	(50)	(50)
29	FPSC adjusted taxable income	Sum of Lines 26 through 28	950	1,150	950	950
30	New combined statutory tax rate	Line 5	38.6%	33.9%	33.9%	24.4%
31	Income tax expense	Line 29 x Line 30	366	389	322	232
32						
33	<u>**Step 3 - Calculate impact on FPSC Adjusted NOI**</u>					
34	Income tax expense BEFORE tax reform - Step 1	Line 23	366	366	366	366
35	Income tax expense AFTER tax reform - Step 2	Line 31	366	389	322	232
36	Difference - FPSC Adusted NOI increase/(decrease) from tax reform	Line 34 - Line 35	-	(23)	45	135
37						
38	<u>**Step 4 - Calculate adjustment for base rate increases implemented at new combined statutory tax rate**</u>					
39	Multi-year increase	Line 14	67	62	62	54
40	Solar base rate adjustment	Input	tbd	tbd	tbd	tbd
41	GBRA	Input	tbd	tbd	tbd	tbd
42	Subtotal	Sum Lines 39 through 41	67	62	62	54
43	Change in combined statutory tax rate	Line 5 - Line 6	0.0%	-4.7%	-4.7%	-14.2%
44	Adj. for base rate increases at new combined statutory tax rate	Line 42 x Line 43	-	(3)	(3)	(8)
45						
46	<u>**Step 5 - Calculate net favorable/(unfavorable) FPSC adjusted NOI impact**</u>					
47	Impact on NOI - Step 3	Line 36	-	(23)	45	135
48	Impact on NOI - Step 4	Line 44	-	(3)	(3)	(8)
49	Net favorable/(unfavorable) FPSC adjusted NOI impact - after tax	Line 47 + Line 48	-	(26)	42	127
50	Divide by one minus new combined statutory tax rate	1 - Line 5	61%	66%	66%	76%
51	Net favorable/(unfavorable) FPSC adjusted NOI impact - pretax	Line 49 / Line 50	-	(39)	63	168
52						
53	<u>**Step 6 - Calculate annual pretax impacts**</u>					
54	Annual CR4&5 accelerated depreciation	If Line 51 > 0, then Line 51 x 40%, up to $50m	-	-	25	50
55	Annual flowback to customers	If Line 51 > 0, then Line 51 - Line 54	-	-	38	118
56	Annual deferral to Regulatory Asset	If Line 51 < 0, then Line 51	-	(39)	-	-
57	Total	Sum Lines 54 through 56, ties to Line 51	-	(39)	63	168

EVSE Chart

Segment	Multi-unit dwellings (MUD)	Workplaces	"Long dwell time" public locations	DC Fast Charging Depots
EVSE Technology	Level 2	Level 2	Level 2	DC Fast Charging
Minimum EVSE to be deployed (number of plugs or ports)	325	100	75	30
Explanation	Home charging is necessity for EV ownership; MUDs are demonstrably underserved market	Increases EV value proposition; increases EV miles traveled	Address range anxiety	Necessary for distance travel

3

DEF's Response to Staff's First Set of Data Requests, No. 3A

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170183-EI EXHIBIT: 3
PARTY: STAFF– (DIRECT)
DESCRIPTION: DEF's Response to Staff's First Set of Data Requests, No. 3A[Bates No.

Dianne M. Triplett
Deputy General Counsel
Duke Energy Florida, LLC

September 14, 2017

VIA ELECTRONIC FILING

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

Re: *Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC; Docket No. 20170183-EI*

Dear Ms. Stauffer:

Please find enclosed for electronic filing, Duke Energy Florida, LLC's (DEF) redacted Response to Staff's First Data Request.

Thank you for your assistance in this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Respectfully,

s/Dianne M. Triplett

Dianne M. Triplett

DMT/mw
Enclosure

Duke Energy Florida, LLC
Docket No.: 20170183-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 14th day of September, 2017.

s/Dianne M. Triplett

Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Kelly Corbari Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us kcorbari@psc.state.fl.us ltan@psc.state.fl.us rgervasi@psc.state.fl.us scuello@psc.state.fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com

kevin.donaldson@fpl.com
Jon C. Moyle, Jr.
Moyle Law Firm, P.A.
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com

George Cavros
120 E. Oakland Park Blvd, Suite 105
Fort Lauderdale, FL 33334
george@cavros-law.com

Mike Cassel, Director
Regulatory Affairs
Florida Public Utilities Company
1750 S 14th Street, Suite 200
Fernandina Beach, FL 32034
mcassel@fpuc.com

Rhonda J. Alexander
Regulatory and Pricing Manager
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
rjalexad@southernco.com

Jeffrey A. Stone, General Counsel
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
jastone@southernco.com

Joseph Fichera
Saber Partners, LLC
44 Wall Street
New York, NY 10005
jfichera@saberpartners.com

Russell A. Badders / Steven R. Griffin
Beggs & Lane
P.O. Box 12950
Pensacola, FL 32591
rab@beggslane.com
srg@beggslane.com

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe Street, Suite 601
Tallahassee, FL 32301
bkeating@gunster.com

Ms. Paula K. Brown
Manager, Regulatory Coordination
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601
regdept@tecoenergy.com

John T. Butler / Maria Jose Moncada
Florida Power & Light Company
700 Universe Boulevard (LAW/JB)
Juno Beach, FL 33408-0420
john.butler@fpl.com
maria.moncada@fpl.com

Kenneth Hoffman, Vice President
Regulatory Affairs
Florida Power & Light Company
215 S. Monroe Street, Suite 810
Tallahassee, FL 32301-1858
ken.hoffman@fpl.com

Dean E. Criddle
Orrick, Herrington & Sutcliffe
405 Howard Street, #11
San Francisco, CA 94105
dcriddle@orrick.com

3. Please refer to paragraph 11 of the 2017 Settlement Agreement.

   a. In the last sentence of this paragraph it is stated, in part, that "there will never be any LNP-related costs of any type or nature whatsoever recovered from DEF's retail ratepayers." Is it the intent of the parties that if there are any on-going activities or costs (such as environmental testing, monitoring, or reporting) that are a condition of the State's Levy Site Certification, these types of cost would be included in the above-quoted statement?

   RESPONSE
   Yes, it is the intent of the parties that "there will never be any LNP-related costs of any type or nature whatsoever recovered from DEF's retail ratepayers," which would include any further costs associated with the Site Certification, which are not expected.

4. Please refer to paragraph 22 of the 2017 Settlement Agreement, addressing that DEF will not enter into new financial natural gas hedging contracts through the term of this agreement.

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

   REDACTED

   RESPONSE
   As of September 8, 2017, DEF previously financially hedged approximately [redacted] for periods that settle in 2018.

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

   REDACTED

   RESPONSE
   As of September 8, 2017, DEF previously financially hedged approximately [redacted] for periods that settle in 2019.

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

   REDACTED

   RESPONSE
   As of September 8, 2017, DEF [redacted] for periods that settle in 2020.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Application for Limited Proceeding to Approve 2017 Second Revised and Restated Settlement Agreement including certain rate Adjustments by Duke Energy Florida, LLC.	Docket No. 20170183-EI Filed: September 18, 2017

DUKE ENERGY FLORIDA, LLC'S NOTICE OF FILING VERIFIED AFFIDAVITS

Duke Energy Florida, LLC ("DEF") hereby gives notice of filing the verified Affidavits of Javier Portuondo and Joseph McCallister in support of its Response to Staff's First Data Request (Nos. 1-4) this 18th day of September, 2017.

s/Matthew R. Bernier

DIANNE M. TRIPLETT
Deputy General Counsel
Duke Energy Florida, LLC.
299 First Avenue North
St. Petersburg, FL 33701
T: 727.820.4692
F: 727.820.5041
E: Dianne.Triplett@duke-energy.com

MATTHEW R. BERNIER
Associate General Counsel
Duke Energy Florida, LLC
106 East College Avenue
Suite 800
Tallahassee, Florida 32301
T: 850.521.1428
F: 727.820.5041
E: Matthew.Bernier@duke-energy.com

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 18th day of September, 2017.

s/Matthew R. Bernier

Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Kelly Corbari Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us kcorbari@psc.state.fl.us ltan@psc.state.fl.us rgervasi@psc.state.fl.us scuello@psc.state.fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com kevin.donaldson@fpl.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com Russell A. Badders / Steven R. Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591 rab@beggslane.com srg@beggslane.com

jmoyle@moylelaw.com	
George Cavros 120 E. Oakland Park Blvd, Suite 105 Fort Lauderdale, FL 33334 george@cavros-law.com	Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com
Mike Cassel, Director Regulatory Affairs Florida Public Utilities Company 1750 S 14th Street, Suite 200 Fernandina Beach, FL 32034 mcassel@fpuc.com	Ms. Paula K. Brown Manager, Regulatory Coordination Tampa Electric Company P.O. Box 111 Tampa, FL 33601 regdept@tecoenergy.com
Rhonda J. Alexander Regulatory and Pricing Manager Gulf Power Company One Energy Place Pensacola, FL 32520-0780 rjalexad@southernco.com	John T. Butler / Maria Jose Moncada Florida Power & Light Company 700 Universe Boulevard (LAW/JB) Juno Beach, FL 33408-0420 john.butler@fpl.com maria.moncada@fpl.com
Jeffrey A. Stone, General Counsel Gulf Power Company One Energy Place Pensacola, FL 32520-0780 jastone@southernco.com	Kenneth Hoffman, Vice President Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com
Joseph Fichera Saber Partners, LLC 44 Wall Street New York, NY 10005 jfichera@saberpartners.com	Dean E. Criddle Orrick, Herrington & Sutcliffe 405 Howard Street, #11 San Francisco, CA 94105 dcriddle@orrick.com

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 18 day of September, 2017, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JAVIER J. PORTUONDO, who is personally known to me, and he acknowledged before me that he provided the responses to questions 1 through 3, from STAFF'S FIRST DATA REQUEST (NOS. 1-4) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20170183-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18 day of September, 2017.

Javier J. Portuondo

Sarah Hirschman Libes
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF106231
Expires 3/23/2018

Notary Public
State of Florida

My Commission Expires:
3/23/2018

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 18 day of September, 2017, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JOSEPH MCCALLISTER, who is personally known to me, and he acknowledged before me that he provided the response to question 4, from STAFF'S FIRST DATA REQUEST (NOS. 1-4) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20170183-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18 day of September, 2017.

KATIE JAMIESON
Notary Public, North Carolina
Gaston County
My Commission Expires

Joseph McCallister

Katie Jamieson
Notary Public
State of North Carolina

My Commission Expires:

June 14, 2021

4

DEF's Response to Staff's Second Data Request, Nos. 6, 7, 8

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170183-EI EXHIBIT: 4
PARTY: STAFF– (DIRECT)
DESCRIPTION: DEF's Response to Staff's Second Data Request, Nos. 6, 7, 8[Bates No.

DUKE ENERGY.
FLORIDA

Dianne M. Triplett
DEPUTY GENERAL COUNSEL
Duke Energy Florida, LLC

September 15, 2017

Via ELECTRONIC DELIVERY

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

Re: Docket 20170183-EI; *Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC*

Dear Ms. Stauffer:

Please find enclosed for electronic filing, DEF's Response to Staff's Second Data Request.

Thank you for your assistance in this matter. If you have any questions concerning this filing, please feel free to contact me at (727) 820-4692.

Sincerely,

/s/ Dianne M. Triplett

Dianne M. Triplett

DMT/at
Attachments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 15th day of September, 2017.

/s/ Dianne M. Triplett
Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Kelly Corbari Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us kcorbari@psc.state.fl.us ltan@psc.state.fl.us rgervasi@psc.state.fl.us scuello@psc.state.fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com kevin.donaldson@fpl.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com Russell A. Badders / Steven R. Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591 rab@beggslane.com srg@beggslane.com

George Cavros 120 E. Oakland Park Blvd, Suite 105 Fort Lauderdale, FL 33334 george@cavros-law.com Mike Cassel, Director Regulatory Affairs Florida Public Utilities Company 1750 S 14th Street, Suite 200 Fernandina Beach, FL 32034 mcassel@fpuc.com Rhonda J. Alexander Regulatory and Pricing Manager Gulf Power Company One Energy Place Pensacola, FL 32520-0780 rjalexad@southernco.com Jeffrey A. Stone, General Counsel Gulf Power Company One Energy Place Pensacola, FL 32520-0780 jastone@southernco.com Joseph Fichera Saber Partners, LLC 44 Wall Street New York, NY 10005 jfichera@saberpartners.com	Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com Ms. Paula K. Brown Manager, Regulatory Coordination Tampa Electric Company P.O. Box 111 Tampa, FL 33601 regdept@tecoenergy.com John T. Butler / Maria Jose Moncada Florida Power & Light Company 700 Universe Boulevard (LAW/JB) Juno Beach, FL 33408-0420 john.butler@fpl.com maria.moncada@fpl.com Kenneth Hoffman, Vice President Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Dean E. Criddle Orrick, Herrington & Sutcliffe 405 Howard Street, #11 San Francisco, CA 94105 dcriddle@orrick.com

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S SECOND DATA REQUEST (NOS. 5-8) REGARDING DEF'S APPLICATION FOR LIMITED PROCEEDING TO APPROVE 2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT, INCLUDING CERTAIN RATE ADJUSTMENTS
DOCKET NO. 20170183-EI

For the following question and subparts, please refer to the August 29, 2017 Petition DEF filed in this docket, and the specific page and paragraph references identified below.

5. Please refer to page 40, Paragraph 22, addressing that DEF will not enter into new financial natural gas hedging contracts through the term of this agreement.

    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.

    RESPONSE
    Please see DEF's Response to Staff's First Data Request, question 4, filed on September 14, 2017 in the referenced docket.

6. Please verify that DEF would only implement a storm damage surcharge for its customers only if the storm reserve was depleted.

    RESPONSE
    Yes, the storm damage surcharge will only be implemented upon the depletion of the storm reserve.

7. Please explain what is meant by "an estimate of incremental costs above the level of storm reserve prior to the storm event."

    RESPONSE

The reference to "an estimate of the incremental cost above the level of the storm reserve prior to that storm event" is intended to capture the estimate of the amount which exceeded the balance in the storm reserve just prior to the storm event. To illustrate, if the storm reserve had $50 million prior to the storm but the estimate of the total storm restoration cost was $200 million (retail), then the amount being referenced by that passage would be $150 million ($200M - $50M = $150M).

8. Please refer to this hypothetical scenario: A named tropical storm hits DEF's service area on February 1, 2018, lasted for two days, caused $400,000,000 worth of damage, and DEF's has $120,500,000 in its storm reserve.

   a. How much would DEF petition the Commission for storm cost recovery?

   RESPONSE
   Assuming the dollars in this example are all retail, DEF would seek to recover $411.5M ($400M - $120.5M = $279.5 + 132M = $411.5M). This represents the incremental amount above the storm reserve balance just prior to the storm plus the replenishment of the reserve to $132M (the storm reserve balance as of the February 2012 implementation date of the 2012 Settlement Agreement).

   b. When would DEF petition the Commission for storm cost recovery?

   RESPONSE
   DEF would petition the Commission for storm cost recovery once it had a fairly reasonable estimate of the total cost of restoration, possibly within a couple of months following the event. Once all storm restoration costs have been tabulated and finalized, those costs would be subject to true-up, consistent with the language in paragraph 38c. of the Settlement Agreement.

   c. How much DEF charge its customers per 1,000 kWh?

   RESPONSE
   Assuming the example from (a) above, the impact of $411.5 million would be approximately $10.64 per 1,000 kWh.

d. When would DEF start charging its customer for storm recovery?

RESPONSE

DEF would begin to charge customers with the first billing cycle 60 days following the filing of its petition with the Commission.

e. When would DEF stop charging its customers for storm recovery?

RESPONSE

DEF would stop charging customers upon the conclusion of the 12-month recovery period, subject to a final true-up of any over/under recovery. The amount to be recovered would be subject to any adjustments that have been made by the Commission as a result of a formal proceeding, if any such proceeding were held.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Application for Limited Proceeding to Approve 2017 Second Revised and Restated Settlement Agreement including certain rate Adjustments by Duke Energy Florida, LLC.	Docket No. 20170183-EI Filed: September 18, 2017

DUKE ENERGY FLORIDA, LLC'S NOTICE OF FILING VERIFIED AFFIDAVIT

Duke Energy Florida, LLC ("DEF") hereby gives notice of filing the verified Affidavit of Javier Portuondo in support of its Response to Staff's Second Data Request (Nos. 5-8), this 18th day of September, 2017.

s/Matthew R. Bernier

DIANNE M. TRIPLETT
Deputy General Counsel
Duke Energy Florida, LLC.
299 First Avenue North
St. Petersburg, FL 33701
T: 727.820.4692
F: 727.820.5041
E: Dianne.Triplett@duke-energy.com

MATTHEW R. BERNIER
Associate General Counsel
Duke Energy Florida, LLC
106 East College Avenue
Suite 800
Tallahassee, Florida 32301
T: 850.521.1428
F: 727.820.5041
E: Matthew.Bernier@duke-energy.com

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 18th day of September, 2017.

s/Matthew R. Bernier

Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Kelly Corbari Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us kcorbari@psc.state.fl.us ltan@psc.state.fl.us rgervasi@psc.state.fl.us scuello@psc.state.fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com kevin.donaldson@fpl.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com Russell A. Badders / Steven R. Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591 rab@beggslane.com srg@beggslane.com

jmoyle@moylelaw.com	
George Cavros 120 E. Oakland Park Blvd, Suite 105 Fort Lauderdale, FL 33334 george@cavros-law.com	Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com
Mike Cassel, Director Regulatory Affairs Florida Public Utilities Company 1750 S 14th Street, Suite 200 Fernandina Beach, FL 32034 mcassel@fpuc.com	Ms. Paula K. Brown Manager, Regulatory Coordination Tampa Electric Company P.O. Box 111 Tampa, FL 33601 regdept@tecoenergy.com
Rhonda J. Alexander Regulatory and Pricing Manager Gulf Power Company One Energy Place Pensacola, FL 32520-0780 rjalexad@southernco.com	John T. Butler / Maria Jose Moncada Florida Power & Light Company 700 Universe Boulevard (LAW/JB) Juno Beach, FL 33408-0420 john.butler@fpl.com maria.moncada@fpl.com
Jeffrey A. Stone, General Counsel Gulf Power Company One Energy Place Pensacola, FL 32520-0780 jastone@southernco.com	Kenneth Hoffman, Vice President Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com
Joseph Fichera Saber Partners, LLC 44 Wall Street New York, NY 10005 jfichera@saberpartners.com	Dean E. Criddle Orrick, Herrington & Sutcliffe 405 Howard Street, #11 San Francisco, CA 94105 dcriddle@orrick.com

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 18 day of September, 2017, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JAVIER J. PORTUONDO, who is personally known to me, and he acknowledged before me that he provided the responses to questions 6 through 8, from STAFF'S SECOND DATA REQUEST (NOS. 5-8) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20170183-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18 day of September, 2017.

Javier J. Portuondo

Sarah Hirschman Libes
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF105231
Expires 3/23/2018

Notary Public
State of Florida

My Commission Expires:
3/23/2018

5

DEF's Response to Staff's Third Data, No. Request 9

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170183-EI EXHIBIT: 5
PARTY: STAFF– (DIRECT)
DESCRIPTION: DEF's Response to Staff's Third Data, No. Request 9[Bates No.

DUKE ENERGY
FLORIDA

Dianne M. Triplett
Deputy General Counsel
Duke Energy Florida, LLC

September 20, 2017

VIA ELECTRONIC FILING

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

Re: *Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC; Docket No. 20170183-EI*

Dear Ms. Stauffer:

Please find enclosed for electronic filing, Duke Energy Florida, LLC's (DEF) Response to Staff's Third Data Request (No. 9).

Thank you for your assistance in this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Respectfully,

s/Dianne M. Triplett

Dianne M. Triplett

DMT/mw
Enclosure

Duke Energy Florida, LLC
Docket No.: 20170183-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 20th day of September, 2017.

s/Dianne M. Triplett

Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Kelly Corbari Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us kcorbari@psc.state.fl.us ltan@psc.state.fl.us rgervasi@psc.state.fl.us scuello@psc.state.fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com

kevin.donaldson@fpl.com
Jon C. Moyle, Jr.
Moyle Law Firm, P.A.
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com

George Cavros
120 E. Oakland Park Blvd, Suite 105
Fort Lauderdale, FL 33334
george@cavros-law.com

Mike Cassel, Director
Regulatory Affairs
Florida Public Utilities Company
1750 S 14th Street, Suite 200
Fernandina Beach, FL 32034
mcassel@fpuc.com

Rhonda J. Alexander
Regulatory and Pricing Manager
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
rjalexad@southernco.com

Jeffrey A. Stone, General Counsel
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
jastone@southernco.com

Joseph Fichera
Saber Partners, LLC
44 Wall Street
New York, NY 10005
jfichera@saberpartners.com

Russell A. Badders / Steven R. Griffin
Beggs & Lane
P.O. Box 12950
Pensacola, FL 32591
rab@beggslane.com
srg@beggslane.com

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe Street, Suite 601
Tallahassee, FL 32301
bkeating@gunster.com

Ms. Paula K. Brown
Manager, Regulatory Coordination
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601
regdept@tecoenergy.com

John T. Butler / Maria Jose Moncada
Florida Power & Light Company
700 Universe Boulevard (LAW/JB)
Juno Beach, FL 33408-0420
john.butler@fpl.com
maria.moncada@fpl.com

Kenneth Hoffman, Vice President
Regulatory Affairs
Florida Power & Light Company
215 S. Monroe Street, Suite 810
Tallahassee, FL 32301-1858
ken.hoffman@fpl.com

Dean E. Criddle
Orrick, Herrington & Sutcliffe
405 Howard Street, #11
San Francisco, CA 94105
dcriddle@orrick.com

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S THIRD DATA REQUEST (NO. 9) REGARDING DEF'S APPLICATION FOR LIMITED PROCEEDING TO APPROVE 2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT, INCLUDING CERTAIN RATE ADJUSTMENTS
DOCKET NO. 20170183-EI

9. Please refer to paragraph 19, page 38. Please provide an example of the calculation of the specific adjustment to DEF's common equity balance and rate base working capital balance based on the methodology employed by Standard and Poor's Rating Service in its determination of imputed off balance sheet obligations related to future capacity payments to qualifying facilities and other entities under long-term purchase power agreements. For simplicity, please use the Citrus County Combined Cycle Units GBRA in the example.

<u>**RESPONSE**</u>

Please see that attached document bearing bates number DEF-20170183-00001 through DEF-20170183-00009. The following is an explanation of each page:

- Page 1 supports the rate base FPSC adjustments in Surveillance Schedule 2 page 1 and Schedule 3 page 1, as well as the capital structure specific adjustments in Schedule 4. The amounts are input from Page 2.
- Page 2 provides the calculation of the net present value of the annual contractual obligations shown on Page 3, using the discount rate on Page 4.
- Page 3 provides the annual contractual obligations for each agreement.
- Page 4 provides the calculation of the discount rate.
- Page 5 is the July 2017 surveillance schedule 2 page 1. The highlighted "Imputed Off Balance Sheet Obligations" amount ties to the amount on Page 1.
- Page 6 shows the same data as Page 5, except the "Imputed Off Balance Sheet Obligations" amount has been removed.
- Page 7 is the July 2017 surveillance capital structure schedule 4 page 3. It shows the specific adjustment to common equity, which is made up of the "Imputed Off Balance Sheet Obligations" amount, partially offset by the specific adjustment to remove non-utility property directly from common equity, both shown on Page 1.
- Page 8 shows the same data as Page 7, except the "Imputed Off Balance Sheet Obligations" amount has been removed. (Note, the remaining adjustment to common equity is the non-utility property.)
- Page 9 shows a hypothetical illustration of the difference in return requirements based on a capital structure that includes and excludes the "Imputed Off Balance Sheet Obligations" adjustment. The Citrus CC GBRA has not yet been filed, and the rate base and weighted average cost of capital will be different at the time of filing.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 19TH day of September, 2017, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JAVIER J. PORTUONDO, who is personally known to me, and he acknowledged before me that he provided the response to question 9, from STAFF'S THIRD DATA REQUEST (NO. 9) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20170183-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 19 day of September, 2017.

Javier J. Portuondo

Javier J. Portuondo

Helen M Kyriakou

Notary Public
State of Florida

HELEN M. KYRIAKOU
Commission # FF 038690
Expires October 24, 2017
Bonded Thru Troy Fain Insurance 800-385-7019

My Commission Expires:

10/24/2017

Duke Energy Florida
Off Balance Sheet Debt Adjustment

	WORKING CAPITAL ADJUSTMENT		CAPITAL STRUCTURE ADJUSTMENT				
Sep Factor:		0.92885		Adjustment to Remove Non-Utility Plant	Adjusted System	Sep Factor	Specific Adjustment
	System	Retail	System				
2016 July	818,680,306	760,431,202	818,680,306	16,345,191	802,335,115	0.97113	779,171,513
2016 August	818,680,306	760,431,202	818,680,306	16,309,649	802,370,657	0.96818	776,840,456
2016 September	818,680,306	760,431,202	818,680,306	16,275,394	802,404,912	0.95427	765,714,415
2016 October	818,680,306	760,431,202	818,680,306	16,241,039	802,439,267	0.94810	760,790,768
2016 November	818,680,306	760,431,202	818,680,306	16,424,425	802,255,881	0.93621	751,083,554
2016 December	818,680,306	760,431,202	818,680,306	16,392,762	802,287,544	0.92743	744,068,741
2017 January	750,446,259	697,052,007	750,446,259	16,363,955	734,082,304	0.91015	668,125,360
2017 February	750,446,259	697,052,007	750,446,259	15,516,842	734,929,417	0.91439	672,015,529
2017 March	750,446,259	697,052,007	750,446,259	15,527,934	734,918,325	0.90941	668,338,711
2017 April	750,446,259	697,052,007	750,446,259	15,499,469	734,946,790	0.90242	663,230,650
2017 May	750,446,259	697,052,007	750,446,259	15,549,599	734,896,660	0.89354	656,662,435
2017 June	750,446,259	697,052,007	750,446,259	15,717,493	734,728,766	0.88940	653,467,358
2017 July	750,446,259	697,052,007	750,446,259	12,601,350	737,844,909	0.89277	658,723,070
13 Mo. Avg.	781,938,896	$\boxed{726,303,944}$	781,938,896	15,751,162	766,187,734	0.90178	$\boxed{690,929,088}$
						OBS portion only	705,133,094

Duke Energy Florida, LLC
Preliminary Purchase Power and Operating Lease Debt and Interest Expense Adjustments
Based on 2016 10-K Support
(in millions)

DE Florida Discount Factor	3.54%
DE Florida Risk Factor	25%

Purchased Power Agreements

	NPV 2017	NPV 2018	NPV 2019	NPV 2020	NPV 2021	NPV 2022	NPV 2023	NPV 2024	NPV 2025	NPV 2026	NPV 2027	NPV 2028	NPV 2029	NPV 2030	NPV 2031	NPV 2032	NPV 2033	NPV 2034	NPV 2035	NPV 2036	NPV 2037	NPV 2038	NPV 2039	NPV 2040	NPV 2041	NPV 2042	NPV 2043
Southern Company Services-Scherer Unit 3 - Capacity	61.15	48.05	34.48	20.44	5.90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Southern Company Services-Franklin Unit - Capacity	154.82	121.64	87.27	50.67	12.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shady Hills (treated as a PPA at the DE Florida level and a capital lease at the Consolidated Duke Energy level)	92.20	83.83	74.22	63.26	50.80	36.70	28.30	19.60	10.59	1.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Purchased Power	308.17	253.51	195.98	134.37	69.48	36.70	28.30	19.60	10.59	1.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Purchased Power Agreements treated as Operating Leases

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Vandolah Power Company (Northern Star)	335.02	307.55	279.10	249.64	219.13	187.55	154.85	120.99	85.93	49.62	12.04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal PPA Operating Leases	335.02	307.55	279.10	249.64	219.13	187.55	154.85	120.99	85.93	49.62	12.04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Cogeneration Agreements

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Mulberry/Royster-Capacity	659.79	597.67	529.29	454.41	371.80	281.16	182.23	74.70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Orange Cogen-Capacity	572.04	530.23	483.88	432.83	375.91	313.92	245.66	170.91	89.44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Orlando Cogen-Capacity	439.74	393.24	343.06	286.01	223.88	155.49	80.60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pasco County-Capacity	184.68	169.85	152.46	133.44	111.71	88.18	61.80	32.44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pinellas County-Capacity	441.01	404.73	364.12	317.99	267.18	210.49	147.73	77.65	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ridge Generating Station-Capacity	61.33	53.33	45.04	36.46	27.57	18.37	8.85	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Ecogen	-	64.80	65.06	63.30	61.47	59.58	57.61	55.59	53.48	51.31	49.05	46.72	44.31	41.81	39.22	36.53	33.76	30.88	27.91	24.82	21.63	18.33	14.91	11.36	7.70	3.90	0.98
Subtotal Cogeneration	2,358.59	2,213.86	1,982.91	1,724.44	1,439.51	1,127.19	784.47	411.28	142.93	51.31	49.05	46.72	44.31	41.81	39.22	36.53	33.76	30.88	27.91	24.82	21.63	18.33	14.91	11.36	7.70	3.90	0.98
Total Purchased Power, Transmission and Operating L	3,001.79	2,774.91	2,457.98	2,108.45	1,728.13	1,351.44	967.61	551.86	239.44	102.19	61.09	46.72	44.31	41.81	39.22	36.53	33.76	30.88	27.91	24.82	21.63	18.33	14.91	11.36	7.70	3.90	0.98
DE Florida Imputed Debt based on PPA's (25% risk fac	750.446259	693.73	614.50	527.11	432.03	337.86	241.90	137.97	59.86	25.55	15.27	11.68	11.08	10.45	9.80	9.13	8.44	7.72	6.98	6.21	5.41	4.58	3.73	2.84	1.92	0.97	0.25

20170183-EI Staff Hearing Exhibits 00211

Duke Energy Florida, Inc.
Purchase Power and Operating Lease Schedule
(in millions)

Purchased Power Agreements

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Southern Company Services-Scherer Unit 3 - Capacity	15.00	15.00	15.00	15.00	6.00																						
Southern Company Services-Franklin Unit - Capacity	38.00	38.00	39.00	39.00	13.00																						
Subtotal Purchased Power	53.00	53.00	54.00	54.00	19.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Purchased Power Agreements treated as Operating Leases

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Vandolah Power Company and Osprey-Calpine	38.66	38.66	38.66	38.66	38.66	38.66	38.66	38.66	38.66	38.66	12 25																
Subtotal PPA Operating Leases	38.66	38.66	38.66	38.66	38.66	38.66	38.66	38.66	38.66	38.66	12 25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Purchased Power Agreements treated as Capital Leases

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Shady Hills (treated as a PPA at the DE Florida level and a capital lease at the Consolidated Duke Energy level)	11.44	12.36	13.36	14.44	15.63	9 54	9 54	9 54	9 54	1 28																	
Subtotal PPA Capital Leases	11.44	12.36	13.36	14.44	15.63	9 54	9 54	9 54	9 54	1 28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Cogeneration Agreements

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Mulberry/Royster-Capacity	84.00	88.00	92.00	97.00	102.00	107.00	112.00	76.00																			
Orange Cogen-Capacity	61.00	64.00	67.00	71.00	74.00	78.00	82.00	86.00	91.00																		
Orlando Cogen-Capacity	61.00	63.00	68.00	71.00	75.00	79.00	82.00																				
Pasco County-Capacity	21.00	23.00	24.00	26.00	27.00	29.00	31.00	33.00																			
Pinellas County-Capacity	51.00	54.00	58.00	61.00	65.00	69.00	74.00	79.00																			
Ridge Generating Station-Capacity	10.00	10.00	10.00	10.00	10.00	10.00	9.00																				
U.S. Ecogen		2.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	3.00	1.00
Subtotal Cogeneration	288.00	304.00	323.00	340.00	357.00	376.00	394.00	278.00	95.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	3.00	1.00

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Total Purchased Power, Operating & Capital Leases and Cogeneration	391.10	408.02	429.02	447.11	430.29	424.20	442.20	326 20	143 20	43 94	16 25	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	3.00	1.00

Methodology is similar to that used in forecast updates

Tenor	As of 2/23/2017 UST rate	 Indicative Spread	Indicative rate	Weighting	Extended
10-yr	2.373%	0.75%	3.123%	50%	1.562%
30-yr	3.013%	0.95%	3.963%	50%	1.982%
Calculated discount rate				→	3.543%

DUKE ENERGY FLORIDA
Average Rate of Return - Rate Base
Jul 2017

	Plant in Service	Accum Depr & Amort	Net Plant in Service	Future Use & Appd Unrecov Plant	Const Work in Progress	Net Utility Plant	Working Capital	Total Average Rate Base
System Per Books	**$15,235,494,136**	**$5,413,781,682**	**$9,821,712,454**	**$127,965,424**	**$1,364,804,350**	**$11,314,482,228**	**$1,430,902,282**	**$12,745,384,510**
Regulatory Base - Retail	**$13,843,512,169**	**$5,010,492,209**	**$8,833,019,960**	**$110,928,108**	**$1,222,408,343**	**$10,166,356,411**	**$1,348,004,521**	**$11,514,360,932**
FPSC Adjustments								
ARO	(20,637,665)	(18,884,172)	(1,753,493)			(1,753,493)	2,375,065	621,572
ECCR	(51,282,656)	(16,453,548)	(34,829,108)			(34,829,108)	(13,694,886)	(48,523,994)
ECRC	(174,354,486)	(16,007,006)	(158,347,480)		(256,974)	(158,604,454)	(8,522,233)	(167,126,687)
FUEL	(26,840,201)	(26,305,404)	(534,797)			(534,797)	(66,499,535)	(67,034,332)
CCR							(152,877,125)	(152,877,125)
NUCLEAR					(632,972)	(632,972)	(232,078,126)	(232,711,098)
CR3 Removal							0	0
Derivatives							(862,030)	(862,030)
Employee Related							268	268
Investments Earning a Return							(182,243,893)	(182,243,893)
Jobbing Accounts							(702,774)	(702,774)
Non-Regulated and Miscellaneous	(47,374,889)	(36,824,589)	(10,550,300)		(495,307)	(11,045,607)	107,798,469	96,752,862
Retention Accounts							1,426,908	1,426,908
CWIP - AFUDC					(842,588,690)	(842,588,690)		(842,588,690)
Imputed Off Balance Sheet Obligations							726,303,944	726,303,944
Capital Lease	(135,347,326)		(135,347,326)			(135,347,326)	132,086,044	(3,261,282)
Total FPSC Adjustments	**(455,837,223)**	**(114,474,719)**	**(341,362,504)**		**(843,973,943)**	**(1,185,336,447)**	**312,510,096**	**(872,826,351)**
FPSC Adjusted	**$13,387,674,946**	**$4,896,017,490**	**$8,491,657,456**	**$110,928,108**	**$378,434,400**	**$8,981,019,964**	**$1,660,514,617**	**$10,641,534,581**

20170183-EI Staff Hearing Exhibits 00214

DUKE ENERGY FLORIDA
Average Rate of Return - Rate Base
Jul 2017

EXCLUDING ADJUSTMENT FOR IMPUTED OFF BALANCE SHEET OBLIGATIONS

	Plant in Service	Accum Depr & Amort	Net Plant in Service	Future Use & Appd Unrecov Plant	Const Work in Progress	Net Utility Plant	Working Capital	Total Average Rate Base
System Per Books	**$15,235,494,136**	**$5,413,781,682**	**$9,821,712,454**	**$127,965,424**	**$1,364,804,350**	**$11,314,482,228**	**$1,430,902,282**	**$12,745,384,510**
Regulatory Base - Retail	**$13,843,512,169**	**$5,010,492,209**	**$8,833,019,960**	**$110,928,108**	**$1,222,408,343**	**$10,166,356,411**	**$1,348,004,521**	**$11,514,360,932**
FPSC Adjustments								
ARO	(20,637,665)	(18,884,172)	(1,753,493)			(1,753,493)	2,375,065	621,572
ECCR	(51,282,656)	(16,453,548)	(34,829,108)			(34,829,108)	(13,694,886)	(48,523,994)
ECRC	(174,354,486)	(16,007,006)	(158,347,480)		(256,974)	(158,604,454)	(8,522,233)	(167,126,687)
FUEL	(26,840,201)	(26,305,404)	(534,797)			(534,797)	(66,499,535)	(67,034,332)
CCR							(152,877,125)	(152,877,125)
NUCLEAR					(632,972)	(632,972)	(232,078,126)	(232,711,098)
CR3 Removal							0	0
Derivatives							(862,030)	(862,030)
Employee Related							268	268
Investments Earning a Return							(182,243,893)	(182,243,893)
Jobbing Accounts							(702,774)	(702,774)
Non-Regulated and Miscellaneous	(47,374,889)	(36,824,589)	(10,550,300)		(495,307)	(11,045,607)	107,798,469	96,752,862
Retention Accounts							1,426,908	1,426,908
CWIP - AFUDC					(842,588,690)	(842,588,690)		(842,588,690)
Imputed Off Balance Sheet Obligations								0
Capital Lease	(135,347,326)		(135,347,326)			(135,347,326)	132,086,044	(3,261,282)
Total FPSC Adjustments	**(455,837,223)**	**(114,474,719)**	**(341,362,504)**		**(843,973,943)**	**(1,185,336,447)**	**(413,793,848)**	**(1,599,130,295)**
FPSC Adjusted	**$13,387,674,946**	**$4,896,017,490**	**$8,491,657,456**	**$110,928,108**	**$378,434,400**	**$8,981,019,964**	**$934,210,673**	**$9,915,230,637**

DUKE ENERGY FLORIDA
Average - Capital Structure
FPSC Adjusted Basis
Jul 2017

Schedule 4
Page 3 of 4

	System Per	Retail Per	Pro Rata	Specific	Adjusted	Cap	Low-Point		Mid-Point		High-Point	
	Books	**Books**	**Adjustments**	**Adjustments**	**Retail**	**Ratio**	**Cost Rate**	**Weighted Cost**	**Cost Rate**	**Weighted Cost**	**Cost Rate**	**Weighted Cost**
Common Equity	$4,967,817,707	$4,479,854,744	($427,631,336)	$690,929,088	$4,743,152,495	44.57%	9.50%	4.23%	10.50%	4.68%	11.50%	5.13%
Long Term Debt	5,078,551,009	4,579,711,288	(437,163,294)		4,142,547,994	38.93%	5.22%	2.03%	5.22%	2.03%	5.22%	2.03%
Short Term Debt	(22,203,004)	(20,022,118)	1,911,242	(25,251,432)	(43,362,308)	(0.41%)	0.66%	(0.00%)	0.66%	(0.00%)	0.66%	(0.00%)
Customer Deposits												
Active	211,052,756	211,052,756	(20,146,361)		190,906,395	1.79%	2.28%	0.04%	2.28%	0.04%	2.28%	0.04%
Inactive	1,616,797	1,616,797	(154,334)		1,462,463	0.01%						
Investment Tax Credits	2,596,326	2,341,302	(223,493)		2,117,810	0.02%						
Deferred Income Taxes	2,731,781,093	2,463,452,407	(235,152,590)	(439,383,202)	1,788,916,615	16.81%						
FAS 109 DIT - Net	(225,828,174)	(203,646,244)	19,439,361		(184,206,883)	-1.73%						
Total	**$12,745,384,510**	**$11,514,360,932**	**($1,099,120,805)**	**$226,294,454**	**$10,641,534,581**	**100.00%**		**6.30%**		**6.75%**		**7.20%**

*** Daily Weighted Average**

**** Cost Rates Calculated Per IRS Ruling**

DUKE ENERGY FLORIDA
Average - Capital Structure
FPSC Adjusted Basis
Jul 2017

EXCLUDING ADJUSTMENT FOR IMPUTED OFF BALANCE SHEET OBLIGATIONS

Schedule 4
Page 3 of 4

	System Per	Retail Per	Pro Rata	Specific	Adjusted	Cap	Low-Point		Mid-Point		High-Point	
	Books	Books	Adjustments	Adjustments	Retail	Ratio	Cost Rate	Weighted Cost	Cost Rate	Weighted Cost	Cost Rate	Weighted Cost
Common Equity	$4,967,817,707	$4,479,854,744	($435,868,210)	($14,204,006)	$4,029,782,528	40.65%	9.50%	3.86%	10.50%	4.27%	11.50%	4.67%
Long Term Debt	5,078,551,009	4,579,711,288	($445,583,769)		4,134,127,519	41.69%	5.22%	2.18%	5.22%	2.18%	5.22%	2.18%
Short Term Debt	(22,203,004)	(20,022,118)	$1,948,055	(25,251,432)	(43,325,495)	(0.44%)	0.66%	(0.00%)	0.66%	(0.00%)	0.66%	(0.00%)
Customer Deposits			$0									
Active	211,052,756	211,052,756	($20,534,413)		190,518,343	1.92%	2.28%	0.04%	2.28%	0.04%	2.28%	0.04%
Inactive	1,616,797	1,616,797	($157,307)		1,459,490	0.01%						
Investment Tax Credits	2,596,326	2,341,302	($227,797)		2,113,505	0.02%						
Deferred Income Taxes	2,731,781,093	2,463,452,407	($239,682,010)	(439,383,202)	1,784,387,195	18.00%						
FAS 109 DIT - Net	(225,828,174)	(203,646,244)	$19,813,795		(183,832,449)	-1.85%						
Total	**$12,745,384,510**	**$11,514,360,932**	**($1,120,291,655)**	**($478,838,640)**	**$9,915,230,637**	**100.00%**		**6.08%**		**6.49%**		**6.89%**

* **Daily Weighted Average**

** **Cost Rates Calculated Per IRS Ruling**

20170183-EI Staff Hearing Exhibits 00217

Duke Energy Florida
Impact of Adjustment for Imputed Off Balance Sheet Obligations
All Amounts are Hypothetical and Illustrative

	With Adjustment Page 7 of 9	Without Adjustment Page 8 of 9	Difference
Citrus CC Rate Base (retail)	$1,400,000,000	$1,400,000,000	$0
Based on July Surveillance Sch. 4 page 3:			
Weighted Average Cost of Equity (After Tax)	4.68%	4.27%	0.41%
Gross up for Federal & State Income Tax	38.58%	38.58%	0.00%
Weighted Average Cost of Equity (Pre Tax)	7.62%	6.95%	0.67%
Weighted Average Cost of Debt	2.07%	2.22%	-0.15%
Weighted Average Cost of Capital (Pre Tax)	9.69%	9.17%	0.52%
Return on Rate Base (Rate Base x Pre Tax WACC)	$135,651,853	$128,321,311	$7,330,542

6

DEF's Response to Staff's Fourth Data Request, Nos. 10-15

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170183-EI EXHIBIT: 6
PARTY: STAFF– (DIRECT)
DESCRIPTION: DEF's Response to Staff's Fourth Data Request, Nos. 10-15[Bates No.

FILED 9/25/2017
DOCUMENT NO. 07885-2017
FPSC - COMMISSION CLERK

DUKE ENERGY
FLORIDA

Matthew R. Bernier
Associate General Counsel
Duke Energy Florida, LLC.

September 25, 2017

VIA ELECTRONIC FILING

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

Re: *Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC; Docket No. 20170183-EI*

Dear Ms. Stauffer:

Please find enclosed for electronic filing, Duke Energy Florida, LLC's (DEF) Response to Staff's Fourth Data Request.

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this filing.

Respectfully,

s/Matthew R. Bernier

Matthew R. Bernier
Matthew.Bernier@duke-energy.com

MRB/mw
Enclosures

Duke Energy Florida, LLC
Docket No.: 20170183-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 25th day of September, 2017.

s/Matthew R. Bernier

Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Kelly Corbari Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us kcorbari@psc.state.fl.us ltan@psc.state.fl.us rgervasi@psc.state.fl.us scuello@psc.state.fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com

kevin.donaldson@fpl.com
Jon C. Moyle, Jr.
Moyle Law Firm, P.A.
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com

George Cavros
120 E. Oakland Park Blvd, Suite 105
Fort Lauderdale, FL 33334
george@cavros-law.com

Mike Cassel, Director
Regulatory Affairs
Florida Public Utilities Company
1750 S 14th Street, Suite 200
Fernandina Beach, FL 32034
mcassel@fpuc.com

Rhonda J. Alexander
Regulatory and Pricing Manager
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
rjalexad@southernco.com

Jeffrey A. Stone, General Counsel
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
jastone@southernco.com

Joseph Fichera
Saber Partners, LLC
44 Wall Street
New York, NY 10005
jfichera@saberpartners.com

Russell A. Badders / Steven R. Griffin
Beggs & Lane
P.O. Box 12950
Pensacola, FL 32591
rab@beggslane.com
srg@beggslane.com

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe Street, Suite 601
Tallahassee, FL 32301
bkeating@gunster.com

Ms. Paula K. Brown
Manager, Regulatory Coordination
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601
regdept@tecoenergy.com

John T. Butler / Maria Jose Moncada
Florida Power & Light Company
700 Universe Boulevard (LAW/JB)
Juno Beach, FL 33408-0420
john.butler@fpl.com
maria.moncada@fpl.com

Kenneth Hoffman, Vice President
Regulatory Affairs
Florida Power & Light Company
215 S. Monroe Street, Suite 810
Tallahassee, FL 32301-1858
ken.hoffman@fpl.com

Dean E. Criddle
Orrick, Herrington & Sutcliffe
405 Howard Street, #11
San Francisco, CA 94105
dcriddle@orrick.com

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S FOURTH DATA REQUEST (NOS. 10-15) REGARDING DEF'S APPLICATION FOR LIMITED PROCEEDING TO APPROVE 2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT, INCLUDING CERTAIN RATE ADJUSTMENTS
DOCKET NO. 20170183-EI

10. With regard to paragraph provision 10 on pages 17 and 18 of the 2017 Second Revised and Restated Settlement Agreement (2017 Second RRSA), what are the respective retail jurisdictional amounts of the Lybasse parcel and the Rayonier/Lybasse parcel?

RESPONSE

Lybasse parcel $25,699,375, Rayonier/Lybasse parcel $61,679,702.

11. With regard to paragraph provision 11 on pages 18 and 19 of the 2017 Second RRSA, what is the current status of Case Nos. 17-1087 and 17-1151?

RESPONSE

The appeals are still pending. On August 23, 2017, DEF filed its opening brief. On September 22, WEC's response brief will be due, and on October 20, DEF's final reply brief will be due. The court has not indicated whether or when it will schedule oral arguments (it does not do so until after briefs have been submitted). DEF does not know when the court will issue a final decision in the appeal.

12. At the September 15, 2017 Informal Meeting for Docket No. 20170183-EI, regarding paragraph provision 17 on pages 33 through 37 of the 2017 Second RRSA, DEF represented it had the option to sell its Electric Vehicle Service Equipment (EVSE) to a third party after the end of the 5-year pilot program. If such a sale to a third party were to occur in the future, how would the benefit of any resulting net gain on sale of the EVSE be treated?

RESPONSE

Assuming that upon filing with the Commission in accordance with paragraph 17(f)(iii) the Commission determines that the program should not continue, DEF would endeavor to disposition the assets as cost effectively as possible. If the EVSE is sold at the end of the five year pilot program, any proceeds received on the EVSE would serve to reduce the ESVE regulatory asset balance. DEF cannot predict whether there would be a net gain or loss on the sale, if any, at the end of the five year pilot program.

13. With regard to paragraph provision 23 on pages 40 and 41 of the 2017 Second RRSA, please provide a detailed narrative explaining what the new Customer Information System is, as well as the estimated unamortized system and retail jurisdictional amounts. In the response, please state all sources and bases used to derive the estimated unamortized system and retail jurisdictional amounts.

RESPONSE

The new Customer Information System ("CIS" aka Customer Connect) is a companywide initiative to replace decades-old CIS platforms in order to transform the customer experience. DEF's existing CIS is more than twenty years old and has limited technological capability. It does not possess the ability or sufficient upgradability to meet growing customer needs or their increasingly desired levels of service. Key customer benefits of Customer Connect include the following:

- Enables new and comprehensive ways to understand customers and better serve their unique needs; today we only understand our meters
- Creates an intuitive and personalized experience for customers
- Enables improvements to bill formats, helping customers more easily view and understand their bills
- Improves efficiency in managing billing and payments for net metering and other complex billing customers
- Reduces the complexity and the number of systematic changes required when introducing new rates, riders and programs to better serve customer's unique needs
- Further enables flexibility and scale in leveraging AMI and providing customers alternative rates and enhanced basic services (pick your own due date, prepaid advantage, etc.)

Customer Connect is currently estimated to cost approximately $95 million in capital and $102 million in O&M for DEF and is 100% retail. These are estimates and will be refined as the program progresses.

DEF based the estimated total program cost for Duke Energy on the Best and Final Offer (BAFO) from the software provider and systems integrator request for proposal. DEF then added the estimated incremental labor and other program costs using standard project estimation methodologies. The amount assigned to DEF is based on the number of DEF customers as a percentage of the total Duke Energy customer base.

14. What is the specific Accounting Standards Codification associated with the Generally Accepted Accounting Principles (GAAP) required and referenced in paragraph provision 26 on page 42 of the 2017 Second RRSA?

RESPONSE

Pension settlement accounting falls under ASC 715.

15. As a result of Hurricane Irma, does DEF anticipate in the foreseeable future filing a petition under paragraph provision 38c of the 2017 Second RRSA or under paragraph provision 24c of the 2013 Revised and Restated Stipulation and Settlement Agreement? If so, when does DEF anticipate filing said petition?

RESPONSE

Given the magnitude of Hurricane Irma, and the amount of damage caused, DEF does anticipate a future filing under either paragraph 24c of the 2013 RRSSA (if the 2017 Settlement Agreement is not approved) or 38c of the 2017 Settlement Agreement (if it is approved). DEF estimates that it will not be able to file a petition until a reasonable estimate of restoration costs can be developed, which is likely to take at least 2-3 months after storm restoration is complete.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 22nd day of September, 2017, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JAVIER J. PORTUONDO, who is personally known to me, and he acknowledged before me that he provided the responses to question 10 through 15, from STAFF'S FOURTH DATA REQUEST (NOS. 10-15) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20170183-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 22nd day of September, 2017.

Sarah Hirschman Libes
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF105231
Expires 3/23/2018

Javier J. Portuondo

Notary Public
State of Florida

My Commission Expires:
3/23/2018

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DEF's Response to Staff's Fifth Data Request, No. 16

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170183-EI EXHIBIT: 7
PARTY: STAFF– (DIRECT)
DESCRIPTION: DEF's Response to Staff's
Fifth Data Request, No. 16[Bates No.

DUKE ENERGY
FLORIDA

Matthew R. Bernier
Associate General Counsel
Duke Energy Florida, LLC.

September 26, 2017

VIA ELECTRONIC FILING

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

Re: *Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC; Docket No. 20170183-EI*

Dear Ms. Stauffer:

Please find enclosed for electronic filing, Duke Energy Florida, LLC's (DEF) Response to Staff's Fifth Data Request.

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this filing.

Respectfully,

s/Matthew R. Bernier

Matthew R. Bernier
Matthew.Bernier@duke-energy.com

MRB/mw
Enclosures

Duke Energy Florida, LLC
Docket No.: 20170183-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 26th day of September, 2017.

s/Matthew R. Bernier

Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us ltan@psc.state.fl.us rgervasi@psc.state.fl.us scuello@psc.state.fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com kevin.donaldson@fpl.com Jon C. Moyle, Jr.	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com

Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com	Russell A. Badders / Steven R. Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591 rab@beggslane.com srg@beggslane.com
George Cavros 120 E. Oakland Park Blvd, Suite 105 Fort Lauderdale, FL 33334 george@cavros-law.com	Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com
Mike Cassel, Director Regulatory Affairs Florida Public Utilities Company 1750 S 14th Street, Suite 200 Fernandina Beach, FL 32034 mcassel@fpuc.com	Ms. Paula K. Brown Manager, Regulatory Coordination Tampa Electric Company P.O. Box 111 Tampa, FL 33601 regdept@tecoenergy.com
Rhonda J. Alexander Regulatory and Pricing Manager Gulf Power Company One Energy Place Pensacola, FL 32520-0780 rjalexad@southernco.com	John T. Butler / Maria Jose Moncada Florida Power & Light Company 700 Universe Boulevard (LAW/JB) Juno Beach, FL 33408-0420 john.butler@fpl.com maria.moncada@fpl.com
Jeffrey A. Stone, General Counsel Gulf Power Company One Energy Place Pensacola, FL 32520-0780 jastone@southernco.com	Dean E. Criddle Orrick, Herrington & Sutcliffe 405 Howard Street, #11 San Francisco, CA 94105 dcriddle@orrick.com
Joseph Fichera Saber Partners, LLC 44 Wall Street New York, NY 10005 jfichera@saberpartners.com	

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S FIFTH DATA REQUEST (NO.16) REGARDING DEF'S APPLICATION FOR LIMITED PROCEEDING TO APPROVE 2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT, INCLUDING CERTAIN RATE ADJUSTMENTS
DOCKET NO. 20170183-EI

16. At the September 15, 2017 Informal Meeting to discuss issues related to Docket No. 20170183-EI, DEF represented that Federal Emergency Management Agency (FEMA) funding has historically been unavailable to the company.

    a. Notwithstanding the aforementioned historical unavailability, in light of Hurricane Irma, please describe DEF's efforts to contact FEMA regarding the company's eligibility for financial recovery options. If no efforts to contact FEMA have been made thus far, please state when such efforts will occur.

    b. Please describe what options for recovery are available to DEF through FEMA under the pertinent law. If no options are available to DEF through FEMA, please explain why.

    c. Please describe any other efforts to solicit funding or other alternatives through any other means (e.g. local/state/federal programs) that could offset any storm recovery.

RESPONSE

Investor owned utilities are prohibited by federal law from accessing funds directly through FEMA for purposes of recovery under the Stafford Act (P.L. 100-707). However, given the spate of recent natural disasters and the significant damage incurred in Florida, Texas and Puerto Rico, Congress is expected to consider additional relief legislation that may provide support to our customers through tax incentives, additional Community Block Development Grant funds or other means. We intend to closely follow these activities and continue to advocate on behalf of Duke Energy Florida customers. We will pursue potential opportunities as appropriate to access federal resources to offset costs incurred during restoration efforts.

We cannot predict the outcome of this effort. However, we believe it is our responsibility to work with the FPSC and Governor Scott to minimize the financial impacts on ratepayers.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 22nd day of September, 2017, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JAVIER J PORTUONDO, who is personally known to me, and he acknowledged before me that he provided the response to question 16, from STAFF'S FIFTH DATA REQUEST (NO. 16) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20170183-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 22nd day of September, 2017.

Javier J. Portuondo

HELEN M. KYRIAKOU
Commission # FF 038690
Expires October 24, 2017
Bonded Thru Troy Fain Insurance 800-385-7019

Helen M Kyriakou
Notary Public
State of Florida

My Commission Expires:

10-24-2017

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DEF's Response to Staff's Sixth Set of Data Request, Nos. 17-29, 31-42, 45, 46, 48-52

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170183-EI   EXHIBIT: 8
PARTY: STAFF– (DIRECT)
DESCRIPTION: DEF's Response to Staff's Sixth Set of Data Request, Nos. 17-29, 31-42,

DUKE ENERGY.
FLORIDA

Matthew R. Bernier
Associate General Counsel
Duke Energy Florida, LLC.

September 27, 2017

VIA ELECTRONIC FILING

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

Re: *Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC; Docket No. 20170183-EI*

Dear Ms. Stauffer:

Please find enclosed for electronic filing, Duke Energy Florida, LLC's (DEF) Response to Staff's Sixth Data Request (Nos. 17-53).

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this filing.

Respectfully,

s/Matthew R. Bernier

Matthew R. Bernier
Matthew.Bernier@duke-energy.com

MRB/mw
Enclosures

Duke Energy Florida, LLC
Docket No.: 20170183-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 27th day of September, 2017.

s/Matthew R. Bernier

Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us ltan@psc.state.fl.us rgervasi@psc.state.fl.us scuello@psc.state.fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com kevin.donaldson@fpl.com	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com

Jon C. Moyle, Jr.
Moyle Law Firm, P.A.
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com

George Cavros
120 E. Oakland Park Blvd, Suite 105
Fort Lauderdale, FL 33334
george@cavros-law.com

Mike Cassel, Director
Regulatory Affairs
Florida Public Utilities Company
1750 S 14th Street, Suite 200
Fernandina Beach, FL 32034
mcassel@fpuc.com

Rhonda J. Alexander
Regulatory and Pricing Manager
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
rjalexad@southernco.com

Jeffrey A. Stone, General Counsel
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
jastone@southernco.com

Joseph Fichera
Saber Partners, LLC
44 Wall Street
New York, NY 10005
jfichera@saberpartners.com

Russell A. Badders / Steven R. Griffin
Beggs & Lane
P.O. Box 12950
Pensacola, FL 32591
rab@beggslane.com
srg@beggslane.com

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe Street, Suite 601
Tallahassee, FL 32301
bkeating@gunster.com

Ms. Paula K. Brown
Manager, Regulatory Coordination
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601
regdept@tecoenergy.com

John T. Butler / Maria Jose Moncada
Florida Power & Light Company
700 Universe Boulevard (LAW/JB)
Juno Beach, FL 33408-0420
john.butler@fpl.com
maria.moncada@fpl.com

Dean E. Criddle
Orrick, Herrington & Sutcliffe
405 Howard Street, #11
San Francisco, CA 94105
dcriddle@orrick.com

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S SIXTH DATA REQUEST (NO. 17-53) REGARDING DEF'S APPLICATION FOR LIMITED PROCEEDING TO APPROVE 2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT, INCLUDING CERTAIN RATE ADJUSTMENTS
DOCKET NO. 20170183-EI

17. Refer to Paragraph 17a.i. Regarding EVSE installations located behind the customer meter, please identify, by customer class and technology type as available, the target customers, anticipated types of expenses incurred, approved tariff pages containing all service and rates provisions inclusive of EVSE, methods of recovering each type of expense incurred not otherwise contained in currently-approved rates (if any), accounting provisions (with sample entries by FERC account), the services DEF expects to contract out in order to provide EVSE service, and the associated types of vendors to perform each such service.

RESPONSE

DEF is in the preliminary stage of developing action plans with regard to EVSE. Therefore, the following answer is based on DEF's current understanding and expectation, which are subject to change as plans become finalized in the upcoming months.

EVSE installations will generally be separated into two groups: AC Level 2 installations (located at multi-unit dwelling, workplace, and long-dwell public segments) and DC Fast Charge installations (where EV drivers expect a significant charge in a short period of time). Any of the two types of installations can be at any of the three types of customer locations.

Target customers can generally include, among others, owners of apartment complexes, retail establishments and office buildings. Installations can be 1) behind a customer's existing meter (which measures all electricity usage by the customer), 2) behind a customer's newly installed meter (which measures only the EVSE electricity usage), or 3) at a standalone facility metered directly by DEF.

There will not be a separate tariff for EVSE. Rather, for installations behind a customer's existing meter, the existing applicable tariff rates will apply, and for newly metered customers and standalone facilities, the general service time of use tariff will generally apply. The base rate portion of the existing tariff will be credited to the regulatory asset as discussed in provision 17(g)(i) of the settlement. All clause related revenues will flow to their respective clauses. DEF will report total revenue collected as part of its reporting requirement of provision 17(f)(ii).

Anticipated types of expenses include, but are not limited to, electric service delivery upgrades, "stub-out" infrastructure, hardware, installation costs, network operation fees, general operations and maintenance costs, billing agent fees, and overall project management. All of these costs and investments in EVSE will be recorded in a regulatory asset and later amortized beginning no earlier than 2022 per Paragraph 17.g.i.

DEF expects to contract out activities including, but not limited to, EVSE installation, networking, operating, maintaining, collection of data and billing. The types of vendors who will perform these activities include, but are not limited to, electrical contractors, EV service providers, and/or billing agents. The following table provides an illustration:

Type of Installation	Tariff	Illustration
1. Behind customer's existing meter	Existing Tariff	Scenario A: Host (e.g. office building owner) agrees to pay all electric costs of end user consumption (e.g. for office employees). EVSE telemetry measures kWh usage in order for DEF to track electric revenues received for EVSE. No billing agent is needed. Scenario B: Host does not agree to pay EVSE electricity costs of end user consumption. Therefore, DEF contracts a billing agent to bill and remit payments to DEF. EVSE telemetry provides kWh usage. Host pays total metered electric bill, and DEF reimburses host for EVSE revenues received from billing agent based on end user consumption. DEF pays administrative fees to billing agent.
2. Behind customer's newly installed meter	General Service Time of Use	The only difference from 1 above is that a new separate meter is installed to only measure EVSE electricity usage. All other aspects in this illustration are the same.
3. Standalone metered by DEF	General Service Time of Use	Host does not want to be responsible for metered usage. Therefore DEF installs EVSE and pays a billing agent to bill and remit payments to DEF for end user consumption. There is no reimbursement of electricity usage to the host since the host is not paying DEF for the metered usage in the first place.

18. Refer to Paragraph 17.c. Regarding EVSE installations in which electricity is sold directly to EV drivers, identify the target customers, anticipated types of expenses incurred, approved tariff pages containing all service and rates provisions inclusive of EVSE (including administrative and processing fees), methods of recovering each expense incurred not otherwise contained in currently-approved rates (if any), billing and collection arrangements, accounting provisions (with sample entries by FERC account),

the services DEF expects to contract out in order to provide EVSE service, and the associated types of vendors to perform each such service.

RESPONSE

Please see DEF's Response to Data Request No. 17.

19. Refer to Paragraph 17.g.i. As stated in the proposed Settlement, "Revenues generated through the EVSE shall offset the amount of the costs to be deferred to the Regulatory Asset."
    a. Please explain specifically which revenues generated from the EVSE Pilot Program (funds collected through approved rates) will be used to offset the amount of costs to be deferred to the Regulatory Asset, as opposed to recovering the other costs of production, distribution, transmission, etc. of electricity service.
    b. Please explain whether such revenues are expected to meaningfully offset the amount of costs to be deferred to the regulatory asset.

RESPONSE

a. Since DEF will defer the capital and operating costs associated with EVSE to a regulatory asset earning the AFUDC rate, DEF will credit all base revenues (kWh multiplied by the applicable tariffed base rate) against this regulatory asset.
b. We cannot predict the demand for electricity at this time, but our current working assumption is that revenues will not meaningfully offset the costs deferred to the regulatory asset.

20. Refer to Exhibit 7 of the proposed Settlement. Please indicate the expected proportion of "minimum EVSE" to be deployed for each segment in each of the two possible installation categories, including: 1. Behind the meter installations and 2. Direct sales to EV drivers installations.

RESPONSE

It has not yet been determined what proportion of EVSE will be located behind the meter and will depend on what type of host sites apply to the program and the layout of their existing parking and electrical service facilities.

21. Refer to Paragraph 17a.ii. What is meant by the term "reasonable" as relates to operating and maintenance expense?

RESPONSE

The term "reasonable" has the same meaning that is used in various proceedings before the FPSC with respect to costs that are incurred by the utility. Black's Law Dictionary defines reasonable as "fair, proper, or moderate under the circumstances." In this context, DEF will be permitted to incur operating and maintenance expenses related to operating and maintaining the EVSE that it installs during the term of this Pilot. Part of the O&M expense will include the consumer education costs referenced in Paragraph 17.e of the proposed Settlement.

22. Refer to Paragraph 17a.ii. This section appears to state that the Pilot Program expenditures for any segment for which DEF cannot find willing host sites for the number of installations identified in Exhibit 7 can be shifted to new segments proposed by DEF, approved in advance by the Commission or segments identified in Paragraph 17.a.iii as "low income communities." Please further elaborate on the segments known as "low income communities" to more definitively explain the location and types of installations, similar to the more precise locations included in the Exhibit 7 EVSE Chart and the EVSE technology to be deployed, and how such segments are distinct from those appearing in Exhibit 7.

RESPONSE

The intention of the inclusion of a carve-out for "low income communities" is to provide access to EV charging infrastructure to communities which may not otherwise be served in the short term by the EV charging infrastructure market. Therefore, the 10% carve-out for "low income communities" as defined in Section 288.9913(3), F.S. applies to any and/or all segments in Exhibit 7 yet to be determined.

23. What is the expected schedule for the EVSE Pilot Program Request for Proposals, market education and outreach, initiation and completion of the EVSE installations identified in Exhibit 7 of the proposed Settlement, and the filing of various reports and all other DEF filings with the Commission associated with the EVSE Pilot Program referenced in Paragraph 17?

RESPONSE

The RFP is tentatively scheduled for release on Oct. 31, 2017 with a deadline of Nov. 30, 2017 and the winner(s) announced by Dec. 31, 2017. Initiation of EVSE installation will begin in Q1 of 2018 with a target completion by the end of Q4 2018. DEF will file annual reports starting in Q1 of 2019 summarizing program data for the previous calendar year and continuing every year following until the end of the program. Market education and outreach efforts will commence in Q1 of 2018 and continue evenly throughout the program.

24. Refer to Paragraph 17e. At this time, does DEF have a general plan for market education and outreach to promote the EVSE Pilot Program? If so, please explain in as much detail as may be available.

RESPONSE

DEF does not have a market education and outreach plan at this time. DEF anticipates working with its selected vendors (see response to Q 23) to develop this plan later in 2017.

25. Refer to Paragraph 17f.iv. Please explain whether the cost of DEF's efforts to coordinate with transit agencies to expand awareness of Zero Emission Buses is funded by the consumer education funding discussed in Par. 17e., and if not, how it will otherwise be funded.

RESPONSE

DEF's efforts to coordinate with transit agencies to expand awareness of Zero Emission Buses is funded by the consumer education funding discussed in Par. 17e.

26. How will DEF's implementation of the EVSE Pilot Program be reflected in DEF's Annual Depreciation Status Reports as referenced in Rule 25-6.0436(6), F.A.C.?

RESPONSE

The EVSE Pilot Program will not be reflected in DEF's Annual Depreciation Status Reports during the 5-year term of the pilot. Per Paragraph 17.g.i., capital and operating costs will be recorded in a regulatory asset that will earn DEF's AFUDC rate. DEF will begin amortizing this regulatory asset no sooner than the expiration of the settlement.

27. Refer to Paragraph 17.f.i. Does DEF intend to include in the annual comprehensive data related to the EVSE Pilot Program reported annually the financial data associated with the program, such as revenues collected, expenses incurred, achieved return, and net income?

RESPONSE

Yes.

Refer to Paragraph 5a.(1) for questions 28-30.

28. Does DEF have a current estimate of the total in-service capital cost associated with the dry cask storage (DCS) facility? If so, please provide.

RESPONSE

The total in-service capital cost of the DCS facility is approximately $115 million. This includes capital spend and carrying charges as well as the reduction made in 2014 of $17.7 million (retail) for a payment received from the Department of Energy related to DEF's 2006-2010 claim (as further explained in DEF's response to Q29).

29. To date, has DEF received any awards/compensation from the Department of Energy regarding onsite spent nuclear fuel storage? If so, please provide a dated listing of all award/compensation amounts.

RESPONSE

DEF was awarded $21.1 million in damages from the DOE related to 2006-2010 costs of spent nuclear fuel storage by an order dated March 10, 2014. DEF received that award in September 2014, and used the retail portion of the proceeds (approximately $17.7 million) to reduce the balance of the ISFSI or DCS portion of the CR3 Regulatory Asset. DEF is currently seeking $24.5 million in damages associated with DCS design and initial construction costs incurred from 2011-2013. The trial was held in June 2017 and briefings concluded in August 2017. DEF does not know when the court will issue a decision, but it may not be until first quarter 2018.

30. Does DEF have an estimated timeframe of when it will make its initial filing for recovery of DCS facility costs?

RESPONSE

Assuming the question refers to recovery from the Department of Energy, as explained in the response to Q 29, DEF already has pending a lawsuit involving some of the DCS facility costs. DEF currently plans to file another lawsuit, for damages incurred 2014-2018, sometime in late 2018 or early 2019 (once all DCS facility construction-related costs have been incurred).

Refer to Paragraph 7 for questions 31-36.

31. Please specify the current balance of the Crystal River Unit 3 (CR3) Nuclear Decommissioning Trust Fund (NDT).

RESPONSE

The CR3 NDTF Market Value as of July 31, 2017 is $724,468,430.83.

32. Please discuss how/what factors would lead DEF to determine "that additional funds are necessary in order to fund the CR3 Nuclear Decommissioning Trust" in the near-term or prior to the filing of DEF's next decommissioning study.

RESPONSE

Two main drivers impact whether the trust is adequately funded: (1) a change in the cost estimate for decommissioning; and/or (2) a change in the expected market performance of the trust fund. DEF will not avail itself of Paragraph 7 of the proposed Settlement without updating and filing its decommissioning cost study with the FPSC.

33. How does DEF contemplate the Commission will ascertain the amount of any possible base rate surcharge as discussed in Paragraph 7 of the proposed Settlement? Please specify the type of proceeding, nature of Company filings, requested surcharge formulation support etc.

RESPONSE

DEF will not request a base rate surcharge as discussed in Paragraph 7 of the Proposed Settlement without updating its decommissioning cost study pursuant to Rule 25-6.04365, F.A.C. Accordingly, the Commission will ascertain the amount of any possible base rate surcharge using the information and process described in Rule 25-6.04365, F.A.C.

34. To date, has DEF withdrawn any funds from the CR3 NDT? If so, please provide the dated withdrawal amount(s) and discuss the associated actions/expenditures.

RESPONSE

The cost elements are assigned to one of three subcategories **License Termination, Spent Fuel Management, and Site Restoration**

License Termination is used to accumulate costs that are consistent with "decommissioning" as defined by the NRC in its financial assurance regulations (i.e., 10 CFR Part 50.75). The cost in this subcategory is associated with and sufficient to terminate the unit's operating license.

Spent Fuel Management contains costs associated with the containerization and transfer of spent fuel from the wet storage pool to the ISFSI. Costs are included for the security, operation, and maintenance of the storage pool and management of the ISFSI until such time as the spent fuel transfer to the Department of Energy is complete. It does not include any cost to construct the ISFSI, or the purchase of Dry Storage Canisters (DSCs) or Horizontal Storage Modules (HSMs).

Site Restoration is used to capture costs associated with the operation, maintenance, or the dismantlement and demolition of facilities, systems or components demonstrated to be free from contamination.

It should be noted that the costs assigned to these subcategories are guided by controls established by DEF Accounting and decommissioning management. Please note that there can be interaction between the activities in the three subcategories. For example, DEF could, and has at times, decided to remove non-contaminated facilities to improve access to contaminated plant components. In these instances, the non-contaminated removal costs could be assigned from Site Restoration to License Termination. However, in general, the charges represent a reasonable accounting of those costs incurred for the specific subcategories as described.

Withdrawals are made only after the costs have been submitted by Finance to site management for review. Subsequently the reviewed costs are submitted to representatives from Tax, Legal, Nuclear Policy, and Asset Accounting departments for a reasonableness and completeness review. When all documented reviews are completed the request is routed to Duke Energy Treasury department and submitted for reimbursement from the Trustee of the Nuclear Decommissioning Trust Fund.

	Date Received	LICENSE TERMINATION	SPENT FUEL MANAGEMENT	SITE RESTORATION	TOTAL
	Jan-14	3,159,121.02	819,106.55	180,009.30	4,158,236.87
Total Received in 2014		**3,159,121.02**	**819,106.55**	**180,009.30**	**4,158,236.87**
Total 2013 requested		9,755,876.35	1,801,825.87	727,781.74	12,285,483.96
Deduct Jan 14 Receipt		(3,159,121.02)	(819,106.55)	(180,009.30)	(4,158,236.87)
Total 2013 received in 2015	Mar-15	6,596,755.33	982,719.32	547,772.44	8,127,247.09
Total 2014 requested		36,511,271.50	30,503,585.13	2,221,621.62	69,236,478.25
Exclude Tallahasee Request		(6,900,000.00)			(6,900,000.00)
Total 2014 received in 2015	Mar-15	29,611,271.50	30,503,585.13	2,221,621.62	62,336,478.25
Jan 2015 Request received 2015	Mar-15	1,123,225.38	3,349,711.00	334,779.94	4,807,716.32
February 2015 Request	Jun-15	1,150,645.36	3,634,869.66	332,944.95	5,118,459.97
March 2015 Request	Sep-15	791,513.72	4,393,886.52	397,486.48	5,582,886.72
April 2015 Request	Sep-15	1,571,943.77	3,724,714.79	92,907.35	5,389,565.91
Total 2015 Received in 2015		4,637,328.23	15,103,181.97	1,158,118.72	20,898,628.92
Total received in 2015		**40,845,355.06**	**46,589,486.42**	**3,927,512.78**	**91,362,354.26**
May 2015 Request	Jan-16	516,996.00	4,095,674.85	297,830.20	4,910,501.05
June 2015 Request	Jan-16	(4,321.20)	3,746,513.60	277,091.18	4,019,283.58
July 2015 Request	Mar-16	(408,510.77)	3,799,191.43	103,546.66	3,494,227.32
August 2015 Request	Mar-16	334,318.47	3,381,992.99	162,488.31	3,878,799.77
Sept 2015 Request	Apr-16	(378,037.89)	2,435,754.72	(107,466.76)	1,950,250.07
Oct 2015 Request	Apr-16	350,937.88	3,049,139.50	(203,338.64)	3,196,738.74
Nov 2015 Request	Apr-16	427,337.48	2,513,222.70	670,847.61	3,611,407.79
Dec 2015 Request	Apr-16	959,762.02	2,729,052.56	29,177.24	3,717,991.82
Jan 2016 Request	May-16	345,470.48	2,670,440.48	15,569.00	3,031,479.96
FMPA Request	May-16	1,994,357.82	6,025,487.48	344,353.92	8,364,199.22
Feb 2016 Request	Jul-16	1,214,132.00	4,637,398.19	498,855.24	6,350,385.43
Mar 2016 Request	Jul-16	873,740.62	2,095,738.54	71,742.69	3,041,221.85
Apr 2016 Request	Aug-16	3,178,609.96	2,439,946.92	30,429.00	5,648,985.88
May 2016 Request	Aug-16	653,730.06	3,337,497.64	844,982.88	4,836,210.58
Jun 2016 Request	Sep-16	596,094.72	3,331,396.11	116,687.65	4,044,178.48
Jul 2016 Request	Sep-16	5,059,474.45	1,496,962.27	(22,501.24)	6,533,935.48
Aug 2016 Request	Oct-16	1,163,008.76	4,232,028.91	22,580.64	5,417,618.31
Sept 2016 Request	Nov-16	752,860.46	2,622,278.78	28,468.00	3,403,607.24
Oct 2016 Request	Dec-16	3,968,863.27	2,478,014.24	31,915.98	6,478,793.49
Total received in 2016		**21,598,824.59**	**61,117,731.91**	**3,213,259.56**	**85,929,816.06**
Nov 2016 Request	Jan-17	1,050,662.06	4,436,794.35	56,506.57	5,543,962.98
SECI thru Nov 2016	Mar-17	463,469.12	1,400,263.96	80,024.46	1,943,757.54
Dec 2016 Request	Mar-17	2,171,021.65	2,647,273.23	5,321.70	4,823,616.58
Jan 2017 Request	Apr-17	630,911.50	1,810,344.89	10,172.12	2,451,428.51
Feb 2017 Request	May-17	584,340.39	2,292,343.78	55,615.12	2,932,299.29
Mar 2017 Request	May-17	1,833,504.01	6,412,357.45	51,235.57	8,297,097.03
APR 2017 Request	Jun-17	694,325.43	2,643,802.45	34,294.52	3,372,422.40
May 2017 Request	Jul-17	641,973.38	6,122,471.58	42,542.06	6,806,987.02
JUN 2017 Request	Sep-17	673,739.77	2,703,247.40	12,285.59	3,389,272.76
Total received in 2017		**8,743,947.31**	**30,468,899.09**	**347,997.71**	**39,560,844.11**
Total received to date		**74,347,247.98**	**138,995,223.97**	**7,668,779.35**	**221,011,251.30**

35. Are the cost projections found in DEF's 2014 Decommissioning Cost Study of CR3 the most current estimates known to the Company? If not, please specify the most current total projected decommissioning cost figure available in both nominal and current dollars.

RESPONSE

Yes.

36. Are there any current interests/parties (i.e. financial contributors to the CR3 NDT) other than DEF who bear cost responsibility for the cost of decommissioning CR3?

   a. If the response to Data Request 36 is negative, how and by what means were all previous co-owners of CR3 discharged of their responsibilities for funding decommissioning activities?
   b. Does Paragraph 7 of the proposed Settlement affect in any way current (if any) or prior co-owners of CR3?
   c. If the response to Data Request 36 is null/no effect, is it possible that DEF's customers may directly fund (exclusive of any fund earnings) the decommissioning cost of CR3 in excess of 91.7806 percent? [1]

RESPONSE

DEF is the sole owner of CR3, so there are no other financial contributors to the CR3 NDT.

a. DEF bought back the interests of the City of Alachua, the City of Bushnell, the City of Gainesville d/b/a Gainesville Regional Utilities, the City of Kissimmee, the City of Leesburg, the City of New Smyrna Beach, the City of Ocala, and the Orlando Utilities Commission pursuant to an agreement executed in September 2014 and closed in October 2015. Pursuant to that agreement, the parties transferred the value of their individual nuclear decommissioning trust funds for use by DEF during decommissioning. DEF also purchased Seminole Electric Cooperative's interest in CR3 pursuant to an agreement executed April 2015 and closed November 2016. Pursuant to that agreement, Seminole transferred its nuclear decommissioning trust fund to DEF.
b. No. DEF's obligations to its prior co-owners are governed by the agreements referenced in section a above.
c. No. DEF's customers will not fund any decommissioning costs in excess of 91.7806 percent. DEF is tracking the percentage of costs incurred and the portion of the trust funds that were obtained from the co-owners to ensure that customers are only funding the 91.7806 percent.

[1] DEF's ownership share of CR3 per the Company's most recent decommissioning study, filed in Docket No. 140057-EI (Section 1, Page 4 of 8).

Refer to Paragraph 8 for questions 37 and 38:

37. The agreement reads "DEF shall be permitted to continue the annual depreciation expense and depreciation rate associated with CRS based on the last Commission-approved depreciation study which assumed a 2020 CRS retirement date" Please specify the month (and year if different than 2020) depreciation expense would cease under this compliance measure/early retirement scenario.

RESPONSE

Depreciation expense would continue through December 31, 2020 and cease on January 1, 2021.

38. Is it correct that the terms of Paragraph 8 of the proposed Settlement imply a 1-year amortization of the remaining Crystal River South net book value and such amortization will occur in 2021 (subject to minor deviation due to billing cycles) unless a different period is agreed on by the signatories to the proposed Settlement?

RESPONSE

Yes.

Refer to Paragraph 24 for questions 39-44.

39. What is the currently-approved depreciation rate (or rates) and authorizing Commission Order No. associated with both the meter reading (MMR) assets and the commercial Silver Springs Network (SSN) meter assets?

RESPONSE

The current approved depreciation rate for the MMR and SSN meter assets is 5.97% which is shown as a rounded 6.0% in Order No. PSC-20100131-FOF-EI, page 44.

40. Please specify the current net book value of the Company's MMR and SSN assets.

RESPONSE

The estimated net book value as of June 30, 2017 for SSN assets is: $16.7 million.
The estimated net book value as of June 30, 2017 for MMR assets is: $57.3 million.
Note that these amounts exclude the accumulated COR for these assets as the actual costs to remove these meters will be charged against the COR reserve.

41. Regarding the new advanced metering infrastructure (AMI) assets, what is the proposed rate of net salvage associated with these investments?

RESPONSE

The Settlement Agreement proposes a 15 year depreciable life for the new AMI meters which equals a 6.67% annual rate with no negative net salvage included. The net salvage percentage for these assets will be re-evaluated as the Company has more experience with these assets and will be updated as part of the next depreciation study.

42. Does DEF have a total in-service cost estimate associated with its planned AMI campaign? If so, please provide.

RESPONSE

The current in-service cost estimate of DEF's AMI campaign is $336 million.

43. If Paragraph 24 of the Petition is approved, what is the estimated dollar impact on the 2018 projections provided in Docket No. 20170002-EG, Schedule C-2, page 2? Please explain.

RESPONSE

The following response is also being provided in response to Staff's Interrogatory No. 47 in Docket No. 20170002-EG. If the Commission approves Paragraph 24 of Duke's Settlement, the estimated dollar impact on the 2018 projections provided in Schedule C-2, Page 2 is a decrease in expenses for the Energy Management Program of $2,812,348.

44. If Paragraph 24 of the Petition is approved, what impact will this have on the 2018 factors requested by the Company in Docket No. 20170002-EG? Please explain.

RESPONSE

The following response is also being provided in response to Staff's Interrogatory No. 48 in Docket No. 20170002-EG. There are no impacts on DEF's 2018 factors as filed on August 18, 2017 in Docket No. 21070002-EG, as the decrease to the Energy Management Program will be substantially offset by increases in incentives for the commercial Interruptible, Curtailable, and the Stand-by Service Program, per Exhibit 1 of the Settlement, resulting in a net increase in estimated program costs of $120,399.

45. Refer to Paragraph 25. Please specify the current net book value of the UF Cogeneration Plant.

RESPONSE

The net book value of the UF Cogeneration Plant as of June 30, 2017 is approximately $30 million.

Refer to Paragraph 32 for requests 44 and 45.

46. Please specify the current balance of the cost of removal regulatory asset.

RESPONSE

The current balance is $480,833,943.

47. For illustrative purposes, please provide a hypothetical example of how the Company intends to recover the cost of removal regulatory asset (i.e. will the recovery be incorporated into (or outside of) plant remaining life depreciation rates etc.) pursuant to the terms of this paragraph.

RESPONSE

The cost of removal regulatory asset will be recovered outside of plant remaining life depreciation rates. The cost of removal regulatory asset was established by crediting Account 407.4 (Regulatory credits) and debiting Account 182.3 (Other regulatory assets). Account 403 (Depreciation Expense) and Account 108 (Accumulated Depreciation Reserve) were not impacted. The cost of removal regulatory asset will be amortized over the remaining life of assets as determined by the updated depreciation study. When recovery begins, the amortization will be recorded as a debit to Account 407.3 (Regulatory debits) per FERC accounting guidelines.

48. Referring to the Shared Solar Rider (Rate Schedule SOL-1), please respond to the following questions:

a. What costs is the monthly subscription fee of $7.75 designed to recover?

RESPONSE

The monthly subscription fee is designed to provide a low cost clean energy participation option to recover the Shared Solar Program costs in alignment with our market research data on the Shared Solar concept. The Program costs include the levelized revenue requirements on a pro rata share of the costs of the local Florida DEF-owned solar facilities dedicated to the Program in addition to reasonable Program administrative costs.

b. Is a residential customer who purchases an individual block of 50 kWh expected to save on the bill (i.e., will the monthly bill credit for one block offset the monthly subscription fee?) If not, please state how many blocks a residential customer needs to purchase to offset the subscription fee based on estimated as available energy prices for 2018.

RESPONSE

Currently, the monthly bill credit is not expected to offset the monthly subscription fee. The Shared Solar Program is an offer to DEF's customers that want to participate in solar and lower their carbon footprint in a measurable way as found in our focus group surveys. Solar supporters and environmental advocates find personal value in claiming their retired environmental or renewable attributes measured in kilowatt-hours associated with their solar block purchase. Please find example monthly calculations for both minimum and maximum residential Program participation in 2018 with comments below:

Residential Participation			
Per Month	**Minimum Participation**	**Maximum Participation**	*Comments*
Block Subscription	1	25	
Clean Energy Kilowatt-hours	50	1,250	*An average residential customer has the ability to achieve a net-zero carbon footprint.*
Subscription Fee	$7.75	$193.75	*Wide range available for any budget.*
Example Bill Credit	$1.25	$31.25	*Bill Credit is based on a solar weighted avoided cost annual average that varies each year and recovered through the Fuel and Purchased Power Clause.*
Net Customer Charge	$6.50	$162.50	*The net charge associated with minimum participation is an affordable Program that will maintain adequate interest with a wide range of optionality for any customer's request and budget.*

49. Referring to Paragraph 12.b of the proposed Settlement, please state the projected residential 1,000 kwh bill for January 2019, January 2020, and January 2021 based on the base rate increases shown in that paragraph. Please show base rates and recovery clauses separate.

RESPONSE

The following table provides a very early and high level estimate of the residential 1,000 kWh bill. Actual fuel and other pass-through clause rates will be different from these estimates, and the base rate increases for solar generation and the Citrus combined cycle generation will become more refined as they get closer to their in-service dates.

	2019	2020	2021
Base Rates	$71	$74	$78
Clauses	$60	$56	$57
Total	$131	$130	$135

50. Referring to the proposed FixedBill Program (Rate Schedule FB-1), please respond to the following questions:

a. The Risk Adder is designed to compensate DEF for "non- weather related impacts." The Usage adder is used to compensate DEF in the first year for "increased usage not associated with the weather." Please discuss in more detail the difference between the two adders applied in the customer's first year on the FixedBill Program.

RESPONSE

The Risk Adder is used to mitigate the following risks:

- Weather Risk – fluctuations in weather over time that drive increased customer energy usage.
- Price Risk – price model risk or unforeseen price risk that is not accounted for in projected rates used to calculate FixedBill amounts.
- Model Risk – over and under predictions of customer energy usage.
- Implementation Risk – using model inputs such as estimated bills and cancel re-bills.

The Usage Adder is used to mitigate the below risks:

- Increased Consumption Risk – behavioral risk due to no price signal.
- Self-Selection Bias – customers who make changes that increase energy usage are more likely to enroll in FixedBill.

b. Provision 3C of the tariff allows DEF to terminate the customer's FixedBill agreement. Please discuss how DEF will monitor a customer's consumption and at what point DEF will notify the customer that they are at risk of being removed from the program.

RESPONSE

For each customer enrolled in the FixedBill program, DEF will create a regression model used to predict the customer's energy usage based on 12 – 48 months of their historical energy usage. DEF will then use the regression model to calculate the customer's Predicted Weather Adjusted Total kWh on a monthly basis. This is the customer's predicted energy usage based on actual weather. Each month, DEF will identify customer accounts where their total actual energy usage exceeds their total predicted energy usage by 25%. These accounts will be further reviewed to determine if other non-related factors may be causing the increased usage (e.g. a bad meter read). If the customer's total actual energy usage exceeds their total predicted energy usage by at least 30% for at least two months during months 3 through 9 of their enrollment period, the customer will be notified that they are at risk of being removed from the FixedBill program.

51. Refer to the proposed Settlement's Rate Schedule FB-1, Page 2 of 3, Definition "Predicted Weather Normalized Monthly kWh Usage." Please explain the calculations used to determine this weather input to this metric (normal weather), including the number of years of heating-degree and cooling degree-days data, any weightings which may be applied to the data (e.g. perhaps recognizing population density by weather station, climate change, etc.), base temperatures, etc..

RESPONSE

The "Predicted Weather Normalized Monthly kWh Usage" is calculated by using regression models (see response to Question 50b above) based on actual parameters around each customer's historical monthly bills including heating degree-days, cooling degree-days and actual kWhs. DEF will use between 12 - 48 months of historical data to create a customer's regression model. If the customer does not have 12 contiguous months of historical data, then DEF will not model the customer's usage and they will not eligible to participate in the FixedBill program. Once a regression model is created, DEF will simulate it through weather patterns that go back to January 1984. DEF prefers to use the 30+ years of weather to calculate highs and the lows, but will ultimately pull out the customer's 50th percentile usage for the normalized kWh usage. Each customer is mapped to one of four major weather stations that include Tampa, Orlando, Gainesville, and Tallahassee.

52. Please provide the most recent documentation filed with the Nuclear Regulatory Commission concerning the status/level of the CR3 NDT (associated with Paragraph 7 of the proposed Settlement).

RESPONSE
Please find attached document bearing bates number DEF-20170183-00010 through DEF-20170183-00018.

53. Please provide Exhibit 2 of the proposed Settlement in spreadsheet form, including all formulas embedded in the spreadsheet.

RESPONSE
Please see the attached Excel file bearing bates number DEF-20170183-00019 through DEF-20170183-00056.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 26th day of September, 2017, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JAVIER J. PORTUONDO, who is personally known to me, and he acknowledged before me that he provided the responses to questions 17 through 53, from STAFF'S SIXTH DATA REQUEST (NOS. 17-53) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20170183-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 26th day of September, 2017.

Javier J. Portuondo

Sherry Ann Sandstrom
Notary Public
State of Florida

My Commission Expires:
August 7, 2021

SHERRY ANN SANDSTROM
Commission # GG 125392
Expires August 7, 2021
Bonded Thru Budget Notary Services

DUKE ENERGY.

Crystal River Nuclear Plant
15760 W. Power Line Street
Crystal River, FL 34428
Docket 50-302
Docket 72-1035
Operating License No. DPR-72

10 CFR 50.82
10 CFR 50.75

March 28, 2017
3F0317-03

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

Subject: Crystal River Unit 3 – Annual Decommissioning and Irradiated Fuel Management Financial Status Report for 2016

References:

1. NRC to CR-3 letter dated March 13, 2013, "Crystal River Unit 3 Nuclear Generating Plant Certification of Permanent Cessation of Operation and Permanent Removal of Fuel From the Reactor" (ADAMS Accession No. ML13058A380)
2. CR-3 to NRC letter dated December 2, 2013, "Crystal River Unit 3 – Post-Shutdown Decommissioning Activities Report" (ADAMS Accession No. ML13340A009)
3. NRC to CR-3 letter dated January 26, 2015, "Crystal River Unit 3 Nuclear Generating Plant – Exemptions from the Requirements of 10 CFR Part 50, Sections 50.82(a)(8)(i)(A) and 50.75(h)(2)" (ADAMS Accession No. ML14247A545)
4. NRC to CR-3 letter dated March 11, 2015, "Crystal River Unit 3 Nuclear Generating Plant Post-Shutdown Decommissioning Activities Report" (ADAMS Accession No. ML14321A751)
5. NRC to CR-3 letter dated August 10, 2016, "Crystal River Unit 3 Nuclear Generating Plant - Order Approving Transfer and Conforming Amendment" (ADAMS Accession No. ML16173A019)

Dear Sir:

In accordance with 10 CFR 50.75(f)(1), 10 CFR 50.82(a)(8)(v), 10 CFR 50.82(a)(8)(vi), and 10 CFR 50.82(a)(8)(vii), Duke Energy Florida, LLC, (DEF) is submitting the annual status of decommissioning funding, status of funding for managing irradiated fuel, and the financial assurance status report for 2016. In Reference 1, the NRC acknowledged Crystal River Unit 3 Nuclear Generating Plant (CR-3) certification of permanent cessation of power operation and permanent removal of fuel from the reactor vessel. In Reference 2, DEF submitted its Post-Shutdown Decommissioning Activities Report (PSDAR) containing a site-specific Decommissioning Cost Estimate (DCE) pursuant to 10 CFR 50.82(a)(4)(i) and 10 CFR 50.82(a)(8)(iii). Accordingly, a status of decommissioning funding pursuant to 10 CFR 50.75(f)(1), a financial assurance status report pursuant to 10 CFR 50.82(a)(8)(v) and 10 CFR 50.82(a)(8)(vi), and a report on the status of the funding for managing irradiated fuel pursuant to 10 CFR 50.82(a)(8)(vii) are required to be submitted by March 31 of each year.

In Reference 3, the NRC provided its approval of the CR-3 exemption request to use the funds from the CR-3 Decommissioning Trust Funds for Irradiated Fuel Management and Site Restoration Costs. The financial assurance demonstration performed in this submittal has been prepared consistent with that exemption request. In Reference 4, the NRC found that the PSDAR contained the necessary information required by 10 CFR 50.82(a)(4)(i) and was consistent with the guidance of Regulatory Guide 1.185.

In Reference 5, the NRC approved a license transfer of the 1.6994 percent combined ownership share in CR-3 held by Seminole Electric Cooperative, Inc. co-owner to DEF. This leaves DEF as the sole owner of CR-3.

The attachments to this letter contain the information required by the above regulations for DEF. The report contains the following required information:

(1) The amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c), (While DEF is identifying this amount because it is specified in 10 CFR 50.75(f)(1), it does not appear applicable to a plant that has permanently ceased operation, has submitted a site specific cost estimate, and is engaged in decommissioning).
(2) The amount of decommissioning funds accumulated to the end of the calendar year preceding the date of this report,
(3) A schedule of annual amounts remaining to be collected,
(4) The assumptions used regarding rates of escalation in decommissioning costs, rates of earnings on decommissioning funds, and rates of other factors used in funding projections,
(5) Any contracts upon which the licensee is relying pursuant to 10 CFR 50.75(e)(1)(v),
(6) Any modifications occurring to a licensee's current method of providing financial assurance since the last submitted report,
(7) Any material changes to trust agreements or financial assurance contracts,
(8) The amount spent on decommissioning, both cumulative and over the previous calendar year,
(9) The remaining balance of any decommissioning funds,
(10) The amount provided by other financial assurance methods being relied upon,
(11) An estimate of the costs to complete decommissioning, reflecting any difference between actual and estimated costs for work performed during the year,
(12) The decommissioning criteria upon which the estimate is based,
(13) If the sum of the balance of any remaining decommissioning funds, plus earnings on such funds calculated are not greater than a 2 percent real rate of return, together with the amount provided by other financial assurance methods being relied upon, does not cover the estimated costs to complete the decommissioning, the financial assurance status report must include additional financial assurance to cover the estimated cost of completion,
(14) The amount of funds accumulated to cover the cost of managing the irradiated fuel,
(15) The projected cost of managing irradiated fuel until title to the fuel and possession of the fuel is transferred to the Secretary of Energy, and
(16) If the funds accumulated do not cover the projected cost (of irradiated fuel), a plan to obtain additional funds to cover the cost.

The adjustment factors for labor rates and energy costs used in Item (1) for the calculation in 10 CFR 50.75(c)(2) are determined using the December 2016 indices from the U.S. Department of Labor, Bureau of Labor Statistics. The adjustment factor for the cost of low-level waste burial charges used in Item (1) for the calculation in 10 CFR 50.75(c)(2) is determined using NUREG-1307, Revision 16, "Report on Waste Burial Charges."

There are no new regulatory commitments associated with this letter.

If you have any questions regarding this submittal, please contact Mr. Mark Van Sicklen, Licensing Lead, Nuclear Regulatory Affairs, at (352) 563-4795.

Sincerely,

Terry Hobbs
General Manager, Decommissioning

TDH/mvs

Attachments:

Attachment 1 – Duke Energy Florida, Crystal River Unit 3 Funding Status Report
Attachment 2 – Crystal River Unit 3, Estimate of Costs to Complete Decommissioning and Financial Assurance Demonstration

xc: NMSS Project Manager
Regional Administrator, Region I

DUKE ENERGY FLORIDA, LLC

DOCKET NUMBER 50 - 302 / LICENSE NUMBER DPR - 72

ATTACHMENT 1

DUKE ENERGY FLORIDA,
CRYSTAL RIVER UNIT 3 FUNDING STATUS REPORT

NRC Decommissioning Funding Status Report
Report Dated as of December 31, 2016
Duke Energy Florida
Crystal River Unit 3
100% Ownership

Item #		Crystal River Unit 3	
	10 CFR 50.75(f)(1) - Status of decommissioning funding		
1	1a. The amount of decommissioning funds estimated to be required pursuant to 10 CFR 50.75(b) and (c);	$ 451,687,566	
	1b. The amount of decommissioning funds estimated to be required for remaining License Termination costs.	$ 821,185,432 [1]	
2	The amount of decommissioning funds accumulated to the end of the calendar year preceding the date of the report;	$ 722,083,733 [2,3]	
3	A schedule of the annual amounts remaining to be collected;	None	
4	The assumptions used regarding rates of escalation in decommissioning costs, rates of earnings on decommissioning funds, and rates of other factors used in funding projections;	inflation qualified rate of return	2.8% [4] 5.10% [4]
5	Any contracts upon which the licensee is relying pursuant to paragraph 10 CFR 50.75(e)(1)(v);	None	
6	Any modifications occurring to a licensee's current method of providing financial assurance since the last submitted report; and	None	
7	Any material changes to trust agreements.	None	
	10 CFR 50.82(a)(8)(v) - Financial assurance status report		
8	(A) The amount spent on decommissioning, both cumulative and over the previous calendar year,	$ 23,650,676 [5] $ 67,655,152 [6]	- Previous calendar year - Cumulative
9	The remaining balance of any decommissioning funds, and	$ 722,083,733 [2,3]	
10	The amount provided by other financial assurance methods being relied upon;	None	
11	(B) An estimate of the costs to complete decommissioning, reflecting any difference between actual and estimated costs for work performed during the year, and	See Attachment 2	
12	The decommissioning criteria upon which the estimate is based;	Unrestricted Release	
13	(C) Any modifications occurring to a licensee's current method of providing financial assurance since the last submitted report; and	None	
14	(D) Any material changes to trust agreements or financial assurance contracts.	None	
	10 CFR 50.82(a)(8)(vi)		
15	If the sum of the balance of any remaining decommissioning funds, plus earnings on such funds calculated at not greater than a 2 percent real rate of return, together with the amount provided by other financial assurance methods being relied upon, does not cover the estimated cost to complete the decommissioning, the financial assurance status report must include additional financial assurance to cover the estimated cost of completion.	As demonstrated in Attachment 2, funds accumulated cover estimated cost of completion.	
	10 CFR 50.82(a)(8)(vii) - Report on the status of funding for managing irradiated fuel		
16	(A) The amount of funds accumulated to cover the cost of managing the irradiated fuel;	As demonstrated in Attachment 2, funds accumulated cover estimated cost of completion.	
17	(B) The projected cost of managing irradiated fuel until title to the fuel and possession of the fuel is transferred to the Secretary of Energy; and	See Attachment 2	
18	(C) If the funds accumulated do not cover the projected cost, a plan to obtain additional funds to cover the cost.	As demonstrated in Attachment 2, funds accumulated cover projected cost of managing irradiated fuel, with the noted exception of DEF's portion of ISFSI capital construction costs as described in the update to Irradiated Fuel Management Program pursuant to 10CFR50.54(bb) (ADAMS Accession No. ML13440A008).	

Footnotes next page

Attachment 1 Footnotes:

[1] Total amount of License Termination costs (Column A) in Attachment 2.

[2] Amount is net of 2016 tax obligations.

[3] Represents (a) the full fund balance of DEF's qualified and non-qualified decommissioning funds, which, in accordance with the NRC exemption request approval (ADAMS Accession No. 14247A545), can also be used for Spent Fuel Management and Site Restoration costs, and (b) 100% of the funds held by the City of Tallahassee on behalf of DEF, which pursuant to NRC order (ADAMS Accession No. ML020670117) will only be used for NRC radiological decommissioning.

[4] Represents values approved by the Florida Public Service Commission in Order No. PSC-14-0702-PAA-EI, issued December 22, 2014, which became effective and final pursuant to Order No. PSC-15-0067-CO-EI, issued on January 23, 2015.

[5] Represents the amount actually disbursed from the fund in calendar year 2016 for License Termination costs, not the costs incurred in calendar year 2016. The Note applicable to Column A in Attachment 2 identifies the total amount of 2016 License Termination costs that have not been disbursed from the funds as of December 31, 2016.

[6] Represents the cumulative amount actually disbursed from the fund as of December 31, 2016 for License Termination costs, not the cumulative costs incurred as of December 31, 2016. The Note applicable to Column A in Attachment 2 identifies the total amount of 2016 License Termination costs that have not been disbursed from the funds as of December 31, 2016.

DUKE ENERGY FLORIDA, LLC

DOCKET NUMBER 50 - 302 / LICENSE NUMBER DPR - 72

ATTACHMENT 2

CRYSTAL RIVER UNIT 3, ESTIMATE OF COSTS TO COMPLETE DECOMMISSIONING AND FINANCIAL ASSURANCE DEMONSTRATION

Crystal River Unit 3
Attachment 2 - Financial Assurance Demonstration
December 31, 2016

	Column A	Column B	Column C	Column D	Column E	Column F
	Annual Expenses	Annual expenses	Annual expenses	Total Expenses	Projected Earnings	End-of-year Fund Balances
	License Termination Cost (in thousands)	Spent Fuel Cost (in thousands)	Site Restoration Cost (in thousands)	Total Cost (in thousands)	Annual Earnings on Decommissioning Trust Fund at 2% (in thousands)	All Owners Decommissioning Trust Fund Year-End Balance (in thousands)
2016						722,084
2017	100,160	27,255	0	127,415	13,168	607,836
2018	7,025	37,045	0	44,070	11,716	575,482
2019	6,471	24,415	0	30,886	11,201	555,797
2020	5,607	4,755	0	10,362	11,012	556,447
2021	5,591	4,742	0	10,333	11,026	557,140
2022	5,591	4,742	0	10,333	11,039	557,846
2023	5,591	4,742	0	10,333	11,054	558,567
2024	5,607	4,755	0	10,362	11,068	559,272
2025	5,591	4,742	0	10,333	11,082	560,021
2026	5,591	4,742	0	10,333	11,097	560,785
2027	5,591	4,742	0	10,333	11,112	561,565
2028	5,607	4,755	0	10,362	11,128	562,330
2029	5,591	4,742	0	10,333	11,143	563,140
2030	5,591	4,742	0	10,333	11,159	563,967
2031	5,591	4,742	0	10,333	11,176	564,810
2032	5,607	4,755	0	10,362	11,193	565,640
2033	5,591	4,742	0	10,333	11,209	566,516
2034	5,591	4,742	0	10,333	11,227	567,410
2035	5,591	7,588	0	13,179	11,216	565,447
2036	5,607	6,890	0	12,497	11,184	564,135
2037	5,558	0	0	5,558	11,227	569,803
2038	5,558	0	0	5,558	11,340	575,585
2039	5,558	0	0	5,558	11,456	581,483
2040	5,573	0	0	5,573	11,574	587,484
2041	5,558	0	0	5,558	11,694	593,620
2042	5,558	0	0	5,558	11,817	599,878
2043	5,558	0	0	5,558	11,942	606,262
2044	5,573	0	0	5,573	12,070	612,758
2045	5,558	0	0	5,558	12,200	619,399
2046	5,558	0	0	5,558	12,332	626,173
2047	5,558	0	0	5,558	12,468	633,083
2048	5,573	0	0	5,573	12,606	640,116
2049	5,558	0	0	5,558	12,747	647,304
2050	5,558	0	0	5,558	12,890	654,636
2051	5,558	0	0	5,558	13,037	662,115
2052	5,573	0	0	5,573	13,187	669,728
2053	5,558	0	0	5,558	13,339	677,509
2054	5,558	0	0	5,558	13,495	685,445
2055	5,558	0	0	5,558	13,653	693,540
2056	5,573	0	0	5,573	13,815	701,782
2057	5,558	0	0	5,558	13,980	710,204
2058	5,558	0	0	5,558	14,148	718,794
2059	5,558	0	0	5,558	14,320	727,556
2060	5,573	0	0	5,573	14,495	736,478
2061	5,558	0	0	5,558	14,674	745,594
2062	5,558	0	0	5,558	14,856	754,892
2063	5,558	0	0	5,558	15,042	764,375
2064	5,573	0	0	5,573	15,232	774,034
2065	5,558	0	0	5,558	15,425	783,901
2066	5,558	0	0	5,558	15,622	793,965
2067	29,350	0	421	29,771	15,582	779,775
2068	66,698	0	1,360	68,058	14,915	726,632
2069	121,761	0	1,680	123,441	13,298	616,489
2070	92,562	0	1,028	93,590	11,394	534,293
2071	77,902	0	701	78,603	9,900	465,590
2072	52,165	0	273	52,438	8,787	421,939
2073	5,009	0	28,112	33,121	8,108	396,926
2074	96	0	18,654	18,750	7,751	385,927
Total[1]	$821,185	$174,371	$52,230	$1,047,787		

Footnotes next page

Attachment 2 Footnotes:

Column A - Annual Expenses - License Termination Cost - Reflects the License Termination cost portion of the Decommissioning Cost Estimate (DCE) escalated to 2016 dollars at the Consumer Price Index escalation rate of 1.7% for 2014, 0.1% for 2015 and 1.3% for 2016. The 2017 costs represent the sum of 2013 through 2017 costs from the DCE, less $67,655,152 of License Termination costs disbursed from the funds through December 31, 2016. Outstanding License Termination costs of $10,614,556 were not reimbursed as of December 31, 2016 due to outstanding joint owner reimbursements and November and December 2016 reimbursements. Reimbursement of these outstanding costs is expected after December 31, 2016.

Column B - Annual Expenses - Spent Fuel Management Cost - Reflects the Spent Fuel Management cost portion of the Decommissioning Cost Estimate (DCE) escalated to 2016 dollars at the Consumer Price Index escalation rate of 1.7% for 2014, 0.1% for 2015 and 1.3% for 2016. The 2017 costs represent the sum of 2013 through 2017 costs from the DCE, less $107,852,441 of Spent Fuel Management costs disbursed from the funds through December 31, 2016. Outstanding Spent Fuel Management costs of $8,459,278 were not reimbursed as of December 31, 2016 due to outstanding joint owner reimbursements and November and December 2016 reimbursements. Reimbursement of these outstanding costs is expected after December 31, 2016. Notwithstanding the acquisition in 2015 and 2016 by DEF of co-owner ownership interests, the 2016 through 2018 costs continue to include ISFSI capital construction costs for the ownership interests of all co-owners (8.2194%) as of the submittal date of the Update to Irradiated Fuel Management Program pursuant to 10 CFR 50.54(bb) (ADAMS Accession No. ML13340A008). DEF will continue to fund the ISFSI capital construction costs for its ownership interest (91.7806%) as of the submittal date of the Update to Irradiated Fuel Management Program pursuant to 10 CFR 50.54(bb) (ADAMS Accession No. ML13340A008) in accordance therewith. Current projected ISFSI capital construction costs are now estimated to be $102M through 2018. Accordingly, these costs associated with the ownership interests of all co-owners (8.2194%) are included in the table above.

Column C - Annual Expenses - Site Restoration Cost - Reflects the Site Restoration cost portion of the Decommissioning Cost Estimate (DCE) escalated to 2016 dollars at the Consumer Price Index escalation rate of 1.7% for 2014, 0.1% for 2015 and 1.3% for 2016. Site Restoration costs of $7,494,563 were incurred in 2013 through 2016, of which $7,357,059 has been reimbursed as of December 31, 2016. Reimbursement of the outstanding costs is expected after December 31, 2016. $2,139,772 of the reimbursed amount was related to Site Restoration costs contemplated in the DCE for the year 2074 and was therefore deducted from the 2074 costs in the table above.

Column D - Annual Expenses - Total Cost - Reflects the sum of the License Termination, Spent Fuel Management and Site Restoration costs.

Column E - Projected Earnings - Reflects earnings on funds remaining in the trusts. Pursuant to 10 CFR 50.82(a)(8)(vi), a 2% real rate of return is used in this financial analysis. The earnings are calculated on the previous year's end-of-year fund balance (Column F) less 50% of the given year's annual expenses.

Column F - End-of-year Fund Balances - Reflects the end-of year fund balance of all funds after all projected earnings are added and projected expenditures are deducted. The 2016 end-of-year fund balance includes 100% of $6,891,614 in funds held by the City of Tallahassee on behalf of Duke Energy Florida, which pursuant to NRC order (ADAMS Accession No. ML020670117) will only be used for NRC radiological decommissioning.

For the purposes of demonstrating financial assurance in accordance with 10 CFR 50.82(a)(8)(vi), the methodology and assumptions in this analysis are consistent with the March 28, 2014, Request for Exemption from 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2) (ADAMS Accession No. ML14098A037), which was approved by NRC on January 26, 2015 (ADAMS Accession No. ML14247A545).

[1] Total may not add due to rounding.

9

DEF's Response to Staff's Seventh Data Request, Nos. 54-56

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170183-EI EXHIBIT: 9
PARTY: STAFF– (DIRECT)
DESCRIPTION: DEF's Response to Staff's Seventh Data Request, Nos. 54-56[Bates No.

DUKE ENERGY.
FLORIDA

Matthew R. Bernier
Associate General Counsel
Duke Energy Florida, LLC.

October 9, 2017

VIA ELECTRONIC FILING

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

Re: *Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC; Docket No. 20170183-EI*

Dear Ms. Stauffer:

Please find enclosed for electronic filing, Duke Energy Florida, LLC's (DEF) Response to Staff's Seventh Data Request (Nos. 54-56).

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this filing.

Respectfully,

s/Matthew R. Bernier

Matthew R. Bernier
Matthew.Bernier@duke-energy.com

MRB/mw
Enclosures

Duke Energy Florida, LLC
Docket No.: 20170183-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 9th day of October, 2017.

s/Matthew R. Bernier

Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us ltan@psc.state.fl.us rgervasi@psc.state.fl.us scuello@psc.state.fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com kevin.donaldson@fpl.com	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com

Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com	Russell A. Badders / Steven R. Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591 rab@beggslane.com srg@beggslane.com
George Cavros 120 E. Oakland Park Blvd, Suite 105 Fort Lauderdale, FL 33334 george@cavros-law.com	Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com
Mike Cassel, Director Regulatory Affairs Florida Public Utilities Company 1750 S 14th Street, Suite 200 Fernandina Beach, FL 32034 mcassel@fpuc.com	Ms. Paula K. Brown Manager, Regulatory Coordination Tampa Electric Company P.O. Box 111 Tampa, FL 33601 regdept@tecoenergy.com
Rhonda J. Alexander Regulatory and Pricing Manager Gulf Power Company One Energy Place Pensacola, FL 32520-0780 rjalexad@southernco.com	John T. Butler / Maria Jose Moncada Florida Power & Light Company 700 Universe Boulevard (LAW/JB) Juno Beach, FL 33408-0420 john.butler@fpl.com maria.moncada@fpl.com
Jeffrey A. Stone, General Counsel Gulf Power Company One Energy Place Pensacola, FL 32520-0780 jastone@southernco.com	Dean E. Criddle Orrick, Herrington & Sutcliffe 405 Howard Street, #11 San Francisco, CA 94105 dcriddle@orrick.com
Joseph Fichera Saber Partners, LLC 44 Wall Street New York, NY 10005 jfichera@saberpartners.com	

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S SEVENTH DATA REQUEST (NOS. 54-56) REGARDING DEF'S APPLICATION FOR LIMITED PROCEEDING TO APPROVE 2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT, INCLUDING CERTAIN RATE ADJUSTMENTS DOCKET NO. 20170183-EI

54. Please refer to DEF's Response to Staff's Sixth Data Request, No. 30. Does DEF have an estimated timeframe of when it will make its initial filing with the Florida Public Service Commission for cost recovery of the dry cask storage facility referenced in Paragraph 5.a.(1) of the 2017 Second Revised and Restated Settlement Agreement (Revised Settlement)?

RESPONSE

DEF will make its filing with the FPSC after the litigation with the Department of Energy associated with the construction of the dry cask storage facility has concluded, including the resolution of any appeals. At this time, DEF anticipates that the litigation will be fully concluded in approximately 2021.

55. Please refer to DEF's Response to Staff's Sixth Data Request, No. 42. Does the estimated $336 million figure include any costs associated with removal and the net book value recovery of DEF's meter reading and commercial Silver Springs Network meter assets? As in, is the estimated $336 million expenditure associated solely with new advanced metering infrastructure investment?

RESPONSE

The $336 million is solely associated with the new advanced metering infrastructure investment.

56. Please provide the results and all assumptions used in calculating the three cost-effectiveness tests for each Energy Conservation Cost Recovery program impacted by Paragraph 20 of the Revised Settlement.

RESPONSE

Please see the following table for the results of the three cost-effectiveness tests for the Energy Conservation Programs impacted by Paragraph 20 of the Revised Settlement. The assumptions that support the avoided cost calculations are provided in Attachment A, bearing bates numbers DEF-20170183-00057 through DEF-20170183-00058. The program incentives are based on the incentive levels included in Exhibit 1 of the Settlement Agreement from 2018-2021 and the Program Administrative costs are based on the costs included in 2015 Program Plan filing (Docket 201500083). The calculations extend through 2042.

Cost Effectiveness Test Results DEF 2017 Settlement Agreement - Par 20	Interruptible Program	Curtailable Program	Stand-by Generation
RIM	2.245	2.903	2.360
Participant	9999	9999	9999
TRC	21.349	67.671	7.331

AVOIDABLE GENERATION ASSUMPTIONS **PEF-ECCR**

CC3X1 P1 - COMBINED CYCLE		unit 1
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2018
(3) Winter Capacity	MW	1306.7
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$//KW	1,070.46
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	64.40
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	c/Kwh	0.5001
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		88% winter, 93.6% summer with CO2
(11) Avoided Generating Unit Fuel Cost	c/Kwh	4.05
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		unit 2
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2022
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$//KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	63.66
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	c/Kwh	0.1220
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer with CO2
(11) Avoided Generating Unit Fuel Cost	c/Kwh	7.86
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

CC2X1 P1 - COMBINED CYCLE		unit 3
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2024
(3) Winter Capacity	MW	865.8
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$//KW	1,145.43
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	67.37
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	c/Kwh	0.6782
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		46% winter 71% summer with CO2
(11) Avoided Generating Unit Fuel Cost	c/Kwh	5.22
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		unit 4
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2026
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$//KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	63.99
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	c/Kwh	0.1347
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer with CO2
(11) Avoided Generating Unit Fuel Cost	c/Kwh	8.75
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

CC2X1 P2 - COMBINED CYCLE		unit 5
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2027
(3) Winter Capacity	MW	865.8
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$//KW	749.45
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	63.10
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	c/Kwh	0.7303
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		46% winter 71% summer with CO2
(11) Avoided Generating Unit Fuel Cost	c/Kwh	5.82
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		unit 6
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2028
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	$//KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	$/kw-year	64.18

(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	c/Kwh	0.1415
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer with CO2
(11) Avoided Generating Unit Fuel Cost	c/Kwh	9.44
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

AVOIDABLE GENERATION ASSUMPTIONS **PEF-ECCR-0052**

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		**unit 7**
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2030
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	S//KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	S/kw-year	64.37
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	c/Kwh	0.1487
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer with CO2
(11) Avoided Generating Unit Fuel Cost	c/Kwh	10.08
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

CC2X1 P1 - COMBINED CYCLE		**unit 8**
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2031
(3) Winter Capacity	MW	865.8
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	S//KW	1,145.43
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	S/kw-year	68.83
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	c/Kwh	0.8061
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		46% winter 71% summer with CO2
(11) Avoided Generating Unit Fuel Cost	c/Kwh	6.63
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		**unit 9**
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2038
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	S//KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	S/kw-year	65.24
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	c/Kwh	0.1811
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer with CO2
(11) Avoided Generating Unit Fuel Cost	c/Kwh	13.05
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

AGT P2 Brown field- SIMPLE CYCLE COMBUSTION TURBINE		**unit 10**
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2039
(3) Winter Capacity	MW	214
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	S//KW	493.10
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	S/kw-year	65.36
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	c/Kwh	0.1856
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		1% winter 5% summer with CO2
(11) Avoided Generating Unit Fuel Cost	c/Kwh	13.39
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

CC2X1 P2 - COMBINED CYCLE		**unit 11**
(1) Base Year		2013
(2) In Service Year for Avoided Generation Unit		1-Jun-2041
(3) Winter Capacity	MW	865.8
(4) Base Year Avoided Generating Unit Cost (including transmission upgrade cost)	S//KW	749.45
(5) Generator Cost Escalation Rate		2.50%
(6) Generator Fixed O&M Cost (including non-escalating gas pipeline reservation cost)	S/kw-year	71.41
(7) Generator Fixed O&M Cost Escalation Rate		2.50%
(8) Avoided Gen Unit Variable O&M Cost	c/Kwh	1.0319
(9) Generator Variable O&M Cost Escalation Rate		2.50%
(10) Generator Capacity Factor		46% winter 71% summer with CO2
(11) Avoided Generating Unit Fuel Cost	c/Kwh	9.04
(12) Avoided Generating Unit Fuel Escalation Rate		3.00%

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 9th day of October, 2017, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JAVIER J PORTUONDO, who is personally known to me, and he acknowledged before me that he provided the responses to questions 54 through 56, from STAFF'S SEVENTH DATA REQUEST (NOS. 54-56) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20170183-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 9th day of October, 2017.

Javier J Portuondo

MONIQUE WEST
MY COMMISSION # FF 244727
EXPIRES: June 28, 2019
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida

My Commission Expires:

June 28, 2019

10

DEF's Response to Staff's Eighth's Data Request, Nos. 57-60

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170183-EI EXHIBIT: 10
PARTY: STAFF– (DIRECT)
DESCRIPTION: DEF's Response to Staff's Eighth's Data Request, Nos. 57-60[Bates No.

DUKE ENERGY.
FLORIDA

Dianne M. Triplett
Deputy General Counsel
Duke Energy Florida, LLC

October 13, 2017

VIA ELECTRONIC FILING

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

Re: *Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC; Docket No. 20170183-EI*

Dear Ms. Stauffer:

Please find enclosed for electronic filing, Duke Energy Florida, LLC's (DEF) Response to Staff's Eighth Data Request (Nos. 57-60).

Thank you for your assistance in this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Respectfully,

s/Dianne M. Triplett

Dianne M. Triplett

DMT/mw
Enclosure

Duke Energy Florida, LLC
Docket No.: 20170183-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 13th day of October, 2017.

s/Dianne M. Triplett
Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us ltan@psc.state.fl.us rgervasi@psc.state.fl.us scuello@psc.state.fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com kevin.donaldson@fpl.com Jeffrey A. Stone, General Counsel Gulf Power Company One Energy Place Pensacola, FL 32520-0780 jastone@southernco.com Joseph Fichera Saber Partners, LLC 44 Wall Street New York, NY 10005 jfichera@saberpartners.com	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com Russell A. Badders / Steven R. Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591 rab@beggslane.com srg@beggslane.com Rhonda J. Alexander Regulatory and Pricing Manager Gulf Power Company One Energy Place Pensacola, FL 32520-0780 rjalexad@southernco.com	Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com Ms. Paula K. Brown Manager, Regulatory Coordination Tampa Electric Company P.O. Box 111 Tampa, FL 33601 regdept@tecoenergy.com John T. Butler / Maria Jose Moncada Florida Power & Light Company 700 Universe Boulevard (LAW/JB) Juno Beach, FL 33408-0420 john.butler@fpl.com maria.moncada@fpl.com Dean E. Criddle Orrick, Herrington & Sutcliffe 405 Howard Street, #11 San Francisco, CA 94105 dcriddle@orrick.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com George Cavros 120 E. Oakland Park Blvd, Suite 105 Fort Lauderdale, FL 33334 george@cavros-law.com Mike Cassel, Director Regulatory Affairs Florida Public Utilities Company 1750 S 14th Street, Suite 200 Fernandina Beach, FL 32034 mcassel@fpuc.com

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S EIGHTH DATA REQUEST (NOS. 57-60) REGARDING DEF'S APPLICATION FOR LIMITED PROCEEDING TO APPROVE 2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT, INCLUDING CERTAIN RATE ADJUSTMENTS
DOCKET NO. 20170183-EI

Refer to Paragraph 17 for the following questions:

57. What are the objectives of the EV Charging Station Pilot Program?

RESPONSE

The objective of the EV Charging Station Pilot Program is to install a foundational level of EV infrastructure within the DEF service territory in order to gather information about DEF customer charging behavior and grid impacts of increasing EV adoption.

58. Please specify the specific existing DEF rate schedules (e.g. GST-1, GSDT-1) which are applicable to the EV Charging Station Pilot Program referenced in DEF's response to Staff Data Request No. 17.

RESPONSE

All non-demand DEF tariffs would be applicable to the EV charging station pilot program but we expect, given the types of locations being considered, that the majority of the facilities would be using GST-1.

59. Is it correct that customers of proposed Electric Vehicle Charging Station Pilot Program, under each of the types of program installations identified in response to Staff Data Request No. 17, will not pay any of the incremental expenses of the program (i.e. customers will pay only DEF's tariff rate of electricity) for the duration of the pilot program? If this is not correct, please explain.

RESPONSE

Partially correct. To the extent that the facilities are used, those customers will pay the tariffed rates for their consumption and the base rate component of those rates will be applied as a reduction in the regulatory asset associated with his pilot. In the absence of this pilot program there would be no revenues therefore any base rate revenues generated by this program are in fact contributing to address the incremental costs of the pilot. Per Paragraph 17.c., charges may also include nominal administrative or processing fees.

60. If the answer to Data Request No. 59 is affirmative, such that the program is fully subsidized, how is such subsidization expected to impact the objectives of the program?

RESPONSE

The degree to which the pilot is subsidized will have no impact on the objectives.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 13th day of October, 2017, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JAVIER J. PORTUONDO, who is personally known to me, and he acknowledged before me that he provided the responses to questions 57 through 60, from STAFF'S EIGHTH DATA REQUEST (NOS. 57-60) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20170183-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 13th day of October, 2017.

MONIQUE WEST
MY COMMISSION # FF 244727
EXPIRES: June 28, 2019
Bonded Thru Notary Public Underwriters

Javier J. Portuondo

Monique West
Notary Public
State of Florida

My Commission Expires:
June 28, 2019

11

DEF's Response to Staff's Ninth Data Request, Nos. 61, 63-67

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170183-EI EXHIBIT: 11
PARTY: STAFF– (DIRECT)
DESCRIPTION: DEF's Response to Staff's Ninth Data Request, Nos. 61, 63-67[Bates No.

DUKE ENERGY
FLORIDA

Dianne M. Triplett
Deputy General Counsel
Duke Energy Florida, LLC

October 16, 2017

VIA ELECTRONIC FILING

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

Re: *Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC; Docket No. 20170183-EI*

Dear Ms. Stauffer:

Please find enclosed for electronic filing, Duke Energy Florida, LLC's (DEF) Response to Staff's Ninth Data Request (Nos. 61-67).

Thank you for your assistance in this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Respectfully,

s/Dianne M. Triplett

Dianne M. Triplett

DMT/mw
Enclosure

Duke Energy Florida, LLC
Docket No.: 20170183-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 16th day of October, 2017.

s/Dianne M. Triplett
Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us ltan@psc.state fl.us rgervasi@psc.state.fl.us scuello@psc.state fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com kevin.donaldson@fpl.com Jeffrey A. Stone, General Counsel Gulf Power Company One Energy Place Pensacola, FL 32520-0780 jastone@southernco.com Joseph Fichera Saber Partners, LLC 44 Wall Street New York, NY 10005 jfichera@saberpartners.com	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com Russell A. Badders / Steven R. Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591 rab@beggslane.com srg@beggslane.com Rhonda J. Alexander Regulatory and Pricing Manager Gulf Power Company One Energy Place Pensacola, FL 32520-0780 rjalexad@southernco.com	Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com Ms. Paula K. Brown Manager, Regulatory Coordination Tampa Electric Company P.O. Box 111 Tampa, FL 33601 regdept@tecoenergy.com John T. Butler / Maria Jose Moncada Florida Power & Light Company 700 Universe Boulevard (LAW/JB) Juno Beach, FL 33408-0420 john.butler@fpl.com maria moncada@fpl.com Dean E. Criddle Orrick, Herrington & Sutcliffe 405 Howard Street, #11 San Francisco, CA 94105 dcriddle@orrick.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com George Cavros 120 E. Oakland Park Blvd, Suite 105 Fort Lauderdale, FL 33334 george@cavros-law.com Mike Cassel, Director Regulatory Affairs Florida Public Utilities Company 1750 S 14th Street, Suite 200 Fernandina Beach, FL 32034 mcassel@fpuc.com

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S NINTH DATA REQUEST (NOS. 61-67) REGARDING DEF'S APPLICATION FOR LIMITED PROCEEDING TO APPROVE 2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT, INCLUDING CERTAIN RATE ADJUSTMENTS
DOCKET NO. 20170183-EI

Please refer to Paragraph 15(a).

61. Please provide the estimated rate impact annually of the solar projects for a 1000/kwh-month residential customer using the $1,650 kWac cost cap.

RESPONSE

The residential rate impact using the cap of $1,650/kWac would be approximately $2.40 in 2019 assuming the maximum allowed MW of 350 and approximately $1.20 in 2020 and $1.20 in 2021 assuming the maximum allowed MW of 175 in each of these two years.

62. 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, Unit Type.

RESPONSE

DEF is unable to develop a new resource plan with the requested information in the timeframe provided. As part of its normal Ten Year Site Plan process, DEF intends to incorporate the impacts of the expected new solar units with the information requested. As required in paragraph 28 of the 2017 Settlement, DEF will also be assigning a capacity value to these solar units (see response to Data Request 66 below). Until this capacity value is determined, the impact of the new solar units on other future units cannot be known.

63. What benefits will rate payers realize from the construction of new solar projects as proposed within Paragraph 15?

RESPONSE

The specific benefits to customers associated with the construction of the new solar projects will be demonstrated in DEF's cost effectiveness analysis, which will accompany DEF's future filings for cost recovery of the solar units. DEF believes that its solar units will deliver cost effective energy from dependable clean energy sources, long-term fuel diversity, increased fuel price stability and energy security. If the construction of the new solar units is not cost effective for customers, DEF is not permitted to utilize the base rate adjustment mechanism set forth in Paragraph 15 of the 2017 Settlement.

Please refer to Paragraph 27.

64. Please describe the factors that will be considered when determining if the $2,300 kWac cost cap has been exceeded

RESPONSE

The average cost of the various projects that will make up the 50 MW total amount of battery storage will be used to calculate whether DEF has exceeded the $2,300 kWac cost. Costs will include the total installed capital cost, (e.g. batteries, battery management systems, balance of plant, engineering, construction, and interconnection) to install the battery facilities.

65. Paragraph 27 states that implementation of the Battery Storage Pilot will provide benefits for customers. What benefits, specifically, will the customers receive?

RESPONSE

Customers will benefit by DEF being able to gather the necessary data to discern how various battery storage projects benefit either the local or bulk power grid. DEF believes that battery storage may have different applications on its system and can assist with bulk power needs and power grid services. For example, battery storage may defer transmission or distribution upgrades, provide ancillary services such as voltage support and frequency regulation, improve reliability, and harden the electric grid. In addition, battery storage coupled with solar facilities may increase the capacity value of those solar facilities, which would also benefit customers. This pilot will allow DEF to prove out these value streams, and define the economic benefit for its customers.

Please refer to Paragraph 28.

66. Describe the methodology DEF plans to use to determine the capacity value for its solar facilities. As part of this response, explain how input from SACE or other parties would be utilized in the design of the data to be collected for this purpose.

RESPONSE:

DEF is gathering data and information from its currently installed solar facilities as well as the projected performance of specific project designs to determine the value of solar as compared to its summer peak. As it finalizes its methodology for incorporating this data into its model, DEF will reach out to SACE and the other parties for a meeting to solicit any feedback and determine whether that feedback can and should be included in the methodology.

Please refer to Paragraph 33.

67. Describe the methodology DEF plans to use to collect data on the benefits and costs of the use of demand-side solar on its system. As part of this response, explain how this project is different from its prior solar pilot program.

RESPONSE:

The primary of purpose of the Research and Demonstration pilot approved in Commission Order PSC-10-0605-PAA-EG was to research and test renewable technologies through field demonstration projects. The projects included in this pilot were focused on understanding the performance of various solar technologies, understanding the impacts of renewables on distribution circuits, and exploring the use of large-scale storage for mitigation of issues due to the integration of solar. Whereas, the purpose of the initiative included in the 2017 Second Revised and Restated Settlement Agreement is to reasonably identify the economic and operational benefits and costs of demand-side solar to support overall rate design. This will be a more widespread study to better analyze specific customer impacts and will involve gathering and analyzing data to assess the operational characteristics, contributions to system peak, solar production performance, and customer impacts of demand-side solar.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 16th day of October, 2017, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JAVIER J. PORTUONDO, who is personally known to me, and he acknowledged before me that he provided the responses to questions 61 through 67, from STAFF'S NINTH DATA REQUEST (NOS. 61-67) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20170183-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of October, 2017.

Javier J. Portuondo

MONIQUE WEST
MY COMMISSION # FF 244727
EXPIRES: June 28, 2019
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida

My Commission Expires:

June 28, 2019

12

DEF'S Response to Staff's Tenth Data Request, No. 68-72

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170183-EI EXHIBIT: 12
PARTY: STAFF– (DIRECT)
DESCRIPTION: DEF'S Response to Staff's Tenth Data Request, No. 68-72[Bates No.

DUKE ENERGY
FLORIDA

Dianne M. Triplett
Deputy General Counsel
Duke Energy Florida, LLC

October 18, 2017

<u>VIA ELECTRONIC FILING</u>

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

Re: *Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC; Docket No. 20170183-EI*

Dear Ms. Stauffer:

Please find enclosed for electronic filing, Duke Energy Florida, LLC's (DEF) Response to Staff's Tenth Data Request (Nos. 68-72).

Thank you for your assistance in this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Respectfully,

s/Dianne M. Triplett

Dianne M. Triplett

DMT/mw
Enclosure

Duke Energy Florida, LLC
Docket No.: 20170183-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 18th day of October, 2017.

s/Dianne M. Triplett
Attorney

Kyesha Mapp Margo DuVal Suzanne S. Brownless Danijela Janjic Lee Eng Tan Rosanne Gervasi Stephanie Cuello Office of the General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 kmapp@psc.state.fl.us mduval@psc.state.fl.us asoete@psc.state.fl.us sbrownle@psc.state.fl.us djanjic@psc.state.fl.us ltan@psc.state fl.us rgervasi@psc.state.fl.us scuello@psc.state fl.us Kenneth Hoffman Vice President, Regulatory Affairs Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken hoffman@fpl.com Jessica Cano / Kevin I.C. Donaldson Florida Power & Light Company 700 Universe Boulevard June Beach, FL 33408-0420 jessica.cano@fpl.com kevin.donaldson@fpl.com Jeffrey A. Stone, General Counsel Gulf Power Company One Energy Place Pensacola, FL 32520-0780 jastone@southernco.com Joseph Fichera Saber Partners, LLC 44 Wall Street New York, NY 10005 jfichera@saberpartners.com	J.R. Kelly Charles J. Rehwinkel Patty Christensen Office of Public Counsel c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 kelly.jr@leg.state.fl.us rehwinkel.charles@leg.state.fl.us christensen.patty@leg.state.fl.us Robert Scheffel Wright / John T. LaVia III Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com James W. Brew / Laura A. Wynn Stone Mattheis Xenopoulos & Brew, P.C. 1025 Thomas Jefferson Street, NW Eighth Floor, West Tower Washington, D.C. 20007 jbrew@smxblaw.com law@smxblaw.com James D. Beasley J. Jeffry Wahlen Ausley McMullen P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com Russell A. Badders / Steven R. Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591 rab@beggslane.com srg@beggslane.com Rhonda J. Alexander Regulatory and Pricing Manager Gulf Power Company One Energy Place Pensacola, FL 32520-0780 rjalexad@southernco.com	Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com Ms. Paula K. Brown Manager, Regulatory Coordination Tampa Electric Company P.O. Box 111 Tampa, FL 33601 regdept@tecoenergy.com John T. Butler / Maria Jose Moncada Florida Power & Light Company 700 Universe Boulevard (LAW/JB) Juno Beach, FL 33408-0420 john.butler@fpl.com maria moncada@fpl.com Dean E. Criddle Orrick, Herrington & Sutcliffe 405 Howard Street, #11 San Francisco, CA 94105 dcriddle@orrick.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com George Cavros 120 E. Oakland Park Blvd, Suite 105 Fort Lauderdale, FL 33334 george@cavros-law.com Mike Cassel, Director Regulatory Affairs Florida Public Utilities Company 1750 S 14th Street, Suite 200 Fernandina Beach, FL 32034 mcassel@fpuc.com

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S TENTH DATA REQUEST (NOS. 68-72) REGARDING DEF'S APPLICATION FOR LIMITED PROCEEDING TO APPROVE 2017 SECOND REVISED AND RESTATED SETTLEMENT AGREEMENT, INCLUDING CERTAIN RATE ADJUSTMENTS
DOCKET NO. 20170183-EI

68. Please refer to the entries in Exhibit 2, column (A) of the Second Revised and Restated Stipulation and Settlement Agreement. There appears to be a discrepancy of approximately 4% between the sum of units in Exhibit 2, column (A), lines 2-6, titled 'Customer Charge - $ per Line of Billing,' and the sum of units in Exhibit 2, column (A), lines 12-15, titled 'Energy Charge – cents per KWH.' Please clarify and reconcile this apparent discrepancy.

RESPONSE

The units in column (A) can be number of bills, kWh, kW, etc. Lines 2-6 represent customer bills multiplied by 12 months in order to determine the customer charge. Lines 12-15 represent kWh in order to determine the energy charge. It is a coincidence that the sum of these two sections are relatively close.

69. Please refer to DEF's response to Staff Data Request No. 23. For EVSE installed after Q1 2018, how does DEF proposes to fully depreciate, at a 20% depreciation rate, all such equipment during a period that is, cumulatively for any such installation, less than 5 years?

RESPONSE

Per Paragraph 17.g., the full revenue requirements, including capital expenditures for EVSE of up to $8 million and operating expenses, will be deferred to a regulatory asset earning DEF's AFUDC rate during the term of the Settlement, with base revenues generated through the EVSE assets serving to offset the amounts deferred. DEF will be authorized to begin recovering the regulatory asset via a base rate increase over a four year period after the December 2021 expiration of the settlement. Concomitantly with the rate increase to recover the regulatory asset, the capital expenditures for the portion of the regulatory asset associated with the equipment will begin to be amortized at the 20% depreciation rate and the remaining balance in the regulatory asset will be amortized over the four year recovery period.

Please refer to Paragraph 17a.-f. for question 70.

70. How does DEF's Electric Vehicle Charging Station Pilot Program differ from other electric vehicle charging options currently available to DEF customers?

RESPONSE

DEF's Electric Vehicle Charging Station Pilot Program will differ from other options available to customers in that DEF will purchase, install, own and support the EVSE at DEF's customers' locations. All other options remain available to customers, including the options to utilize third party owned EVSE and to own their own EVSE. This Pilot will allow DEF to collect comprehensive data related to the Pilot as outlined in Paragraph 17.f.

a. What benefits will DEF customers receive from the Electric Vehicle Charging Station Pilot Program?

RESPONSE

Benefits to customers will be more specifically determined based on the comprehensive data that will be collected during this Pilot. The collection of this data is expected to provide DEF with more detailed information on how EVSE impacts DEF's system, which allows DEF to better handle the impacts of increased EVSE, to evaluate customer use and responsiveness to EVSE availability, and to determine whether to deploy more DEF-owned EVSE installations.

71. Please refer to Paragraph 17.g.ii.

a. Does DEF have any electric vehicles in its fleet, and if so, how does the Company charge its vehicles?

RESPONSE

The following plug-in electric vehicles are currently in use by Duke Energy Florida in fleet applications:

VIA Pickup – 6

Odyne Step Van – 4

Chevrolet Volt – 8

Nissan Leaf – 1

Electric Forklift – 22

Electric ATV – 1

Total: 42

The on-road vehicles are charged using Level 2 EVSEs located at company facilities.

b. Please identify DEF's current plant balance of EVSE and the reserve balance of EVSE.

RESPONSE

Duke Energy Florida
Electric Vehicle Charging Station (in FERC account 394)
Balances as of September'17

			Data		
utility_account	vintage	retirement_unit	Book Cost	Allocated Reserve	Net Book Value
39400 - Tools, Shop & Garage Equip	2011	ELEC VEHICLE CHARGING STATION	14,575	14,817	(242)
	2012	ELEC VEHICLE CHARGING STATION	19,067	14,784	4,283
	2014	ELEC VEHICLE CHARGING STATION	16,424	8,271	8,153
	2015	ELEC VEHICLE CHARGING STATION	40,416	14,090	26,326
39400 - Tools, Shop & Garage Equipm Total			90,482	51,962	38,521

c. If the plant and reserve balances for EVSE are non-zero, please specify the FERC accounts in which such plant and reserve is recorded and the history of the approval of the associated depreciation rates.

RESPONSE

Company used electric vehicle charging stations are in FERC account 394-Tools, Shop & Garage Equipment. The depreciation rate for this account was approved by the Commission in Order No. PSC-2010-0131-FOF-EI.

d. If the plant and reserve balances are non-zero, please explain where such plant is deployed, the technical specifications of such plant, whether such plant is for company use, the recovery mechanism for such plant, and when such plant was put into service.

RESPONSE

See Vintage and Asset Location for the charging stations below:

Duke Energy Florida				
Electric Vehicle Charging Station (in FERC account 394)				
retirement	ELEC VEHICLE CHARGING STATION			
		Data		
vintage	asset_location	Book Cost	Allocated Reserve	Net Book Value
⊟2011	LAKE WALES DISTRICT OFF - Q19	-	-	-
	LAKE WALES OPERATING CENTER - LK W	5,247	5,081	166
	NORTHPOINT III OFFICE BUILDING 3501 Co	1,750	2,158	(408)
	ST PETERSBURG DIST OFF - A81	1,781	1,781	-
	WINTER GARDEN DIST OFF - U30	5,797	5,797	-
⊟2012	CLEARWATER DISTRICT OFF - E16	15	15	-
	HINES ENERGY COMPLEX COMMON ARO	4,557	(893)	5,450
	OCALA DIVISION OFFICE (L - I33	4,511	4,511	-
	SEVEN SPRINGS OPERATIONS CENTER	4,016	4,016	-
	ST. PETE OFFICE TOWER (NEW): FAAS C	2,015	2,409	(394)
	PEF GM GRANT - SOUTH REGION OFFICE	3,952	4,725	(773)
⊟2014	TARPON SPRNGS LINE-ENG B - E60	16,424	8,271	8,153
⊟2015	ST. PETERSBURG OPERATING CENTER -	40,416	14,090	26,326
Grand Total		90,482	51,962	38,521

e. If the plant and reserve balances are non-zero, what is the basis for DEF maintaining a depreciation rate for such plant at a rate that may be different from the depreciation rate proposed in the EVSE Charging Station Pilot Program as proposed in the 2017 Settlement?

RESPONSE

Company used electric vehicle charging stations are in FERC account 394-Tools, Shop & Garage Equipment. The assets are depreciating with the depreciation rates (for FERC account 394) from the last approved depreciation study. The Agreement establishes a depreciation rate of 20% on its EVSE due to this being a pilot program which may or may not become a permanent program.

Please refer to Paragraph 39.

72. DEF states that "[t]he parties further agree that this 2017 Second Revised and Restated Settlement Agreement is in the public interest." Please explain with particularity why the 2017 Second Revised and Restated Settlement Agreement is in the public interest.

RESPONSE

The 2017 Second Revised and Restated Settlement Agreement, when considered as a whole, is in the public interest because it determines, in a comprehensive, balanced, and fair manner, all remaining rate issues that may adversely affect DEF's customers. I in particular, the proposed agreement provides that, effective as of May 2015, there will never be any additional Levy Nuclear Project ("LNP")-related costs recovered from DEF's retail customers. It settles all remaining issues between the parties in the Nuclear Cost Recovery Clause ("NCRC") docket pertaining to the LNP and streamlines and continues the complete and final exit of DEF from the NCRC proceeding process by the end of 2019, with DEF participating in its last NCRC hearing in 2018. Approval of the 2017 Second Revised and Restated Settlement Agreement promotes administrative efficiency and avoids the time and expense associated with litigating the settled issues in the various existing and continuing Commission dockets and is further consistent with the Commission's long-standing practice of encouraging parties to settle contested proceedings whenever possible. This 2017 Second Revised and Restated Settlement Agreement also addresses numerous base rate, infrastructure and clean energy matters that all parties support as timely, appropriate, and reasonable. It presents a base rate plan that would establish rates through the end of the year 2021 and represents both a short-term and longer-term moderation of future rate impacts that would otherwise likely occur as a result of conventional base rate proceedings in and after 2018. It is a fair, reasonable, and comprehensive resolution of matters that is in the best interests of DEF and its customers.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 18th day of October, 2017, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JAVIER J. PORTUONDO, who is personally known to me, and he acknowledged before me that he provided the responses to questions 68 through 72, from STAFF'S TENTH DATA REQUEST (NOS. 68-72) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20170183-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 18th day of October, 2017.

Javier J. Portuondo

MONIQUE WEST
MY COMMISSION # FF 244727
EXPIRES: June 28, 2019
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida

My Commission Expires:

June 28, 2019