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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	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 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.

<u>RESPONSE</u>

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.

<u>RESPONSE</u>
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.

<u>RESPONSE</u>
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.

<u>RESPONSE</u>
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?

<u>RESPONSE</u>
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

NOTARY PUBLIC STATE OF FLORIDA
SHERRY ANN SANDSTROM
Commission # GG 125392
Expires August 7, 2021
Bonded Thru Budget Notary Services

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 2.8% [4] qualified rate of return 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]	- Previous calendar year
		$ 67,655,152 [6]	- 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.

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%						
Line	Rate Schedule	Type of Charge	2018 Units	Current Rates	Del. Volt. Cr. Proposed Increase (B) x % incr.	SSN Meters Proposed Increase (B) x % incr.	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)
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
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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%						
Line	Rate Schedule	Type of Charge	2018 Units	Current Rates	Del. Volt. Cr. Proposed Increase (B) x % incr.	SSN Meters Proposed Increase (B) x % incr.	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)
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													

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%**						
Line	Rate Schedule	Type of Charge	2018 Units	Current Rates	Del. Volt. Cr. Proposed Increase (B) x % incr.	SSN Meters Proposed Increase (B) x % incr.	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)
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

			(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)
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

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%						
Line	Rate Schedule	Type of Charge	2018 Units	Current Rates	Del. Volt. Cr. Proposed Increase (B) x % incr.	SSN Meters Proposed Increase (B) x % incr.	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

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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%						
Line	Rate Schedule	Type of Charge	2018 Units	Current Rates	Del. Volt. Cr. Proposed Increase (B) x % incr.	SSN Meters Proposed Increase (B) x % incr.	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
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			UNITS	**RATES**					**BASE REVENUE ($000s)**				
					0.655%	0.170%	7.500%						
Line	Rate Schedule	Type of Charge	2018 Units	Current Rates	Del. Volt. Cr. Proposed Increase (B) x % incr.	SSN Meters Proposed Increase (B) x % incr.	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)
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)				
					0.655%	0.170%	7.500%						
Line	Rate Schedule	Type of Charge	2018 Units	Current Rates	Del. Volt. Cr. Proposed Increase (B) x % incr.	SSN Meters Proposed Increase (B) x % incr.	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

	DEF Tariff Base Rates	effective
1	Customer Chrg - Seasonal (Mar-Oct)	$/mo
2	Customer Chrg - Unmetered	$/mo
3	Customer Chrg - Secondary	$/mo
4	Customer Chrg - Primary	$/mo
5	Customer Chrg - Transmission	$/mo
6	Customer Chrg - Secondary - CIAC Pd	$/mo
7	Customer Chrg - Primary - CIAC Pd	$/mo
8	Customer Chrg - Transmission - CIAC Pd	$/mo
9	CIAC for Metering Cost	$
10	Energy Chrg - Standard	¢/kWh
11	Energy Chrg - Standard <= 1,000 kWh	¢/kWh
12	Energy Chrg - Standard > 1,000 kWh	¢/kWh
13	Energy Chrg - TOU - On Peak	¢/kWh
14	Energy Chrg - TOU - Off Peak	¢/kWh
15	Energy Chrg - Prem Distrib	¢/kWh
16	Demand Chrg - Standard	$/kW
17	Demand Chrg - TOU - Base	$/kW
18	Demand Chrg - TOU - On Peak	$/kW
19	Demand Chrg - Prem Distrib Chrg	$/kW
20	Demand Chrg - Primary Voltage Cr	$/kW
21	Demand Chrg - Transmission Voltage Cr	$/kW
22	Capacity Chrg - Distrib Capacity	$/kW
23	Capacity Chrg - G&T-greater of SB cap or	$/kW
24	Capacity Chrg - G&T-greater of daily max	$/kW
25	IS/CS Cr	$/kW
26	IS/CS Cr - greater of SB capacity or	$/kW
27	IS/CS Cr - greater of daily max demands	$/kW
28	Meter Voltage Adj - Primary	%
29	Meter Voltage Adj - Transmission	%
30	Power Factor	$/kVar
31	Equip Rental Chrg	%
32	Other Fixture Chrg	%
33	Other Pole Chrg	%

			SSN Meters						0.17%														
	DEF Tariff Base Rates	effective	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18	Jan-18
			RS-1	RSS-1	RST-1	GS-1	GST-1	GS-2	GSD-1	GSDT-1	CS-1	CS-2	CS-3	CST-1	CST-2	CST-3	IS-1	IS-2	IST-1	IST-2	SS-1	SS-2	SS-3
					(closed)			100% LF	24 mWh	24 mwh	(closed)	500 kW	2000 kW	(closed)	500 kW	2000 kW		500 kW	(closed)	500 kW	Firm	IS	CS
1	Customer Chrg - Seasonal (Mar-Oct)	$/mo	-	4.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Customer Chrg - Unmetered	$/mo	-	-	-	6.58	-	6.58	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Customer Chrg - Secondary	$/mo	8.82	8.82	16.30	11.67	19.13	11.67	11.67	19.13	76.46	76.46	76.46	76.46	76.46	76.46	280.78	280.78	280.78	280.78	101.37	305.70	101.37
4	Customer Chrg - Primary	$/mo	-	-	-	147.52	155.00	-	147.52	155.00	212.31	212.31	212.31	212.31	212.31	212.31	416.65	416.65	416.65	416.65	237.23	441.55	237.23
5	Customer Chrg - Transmission	$/mo	-	-	-	727.63	735.10	-	727.63	735.10	792.41	792.41	792.41	792.41	792.41	792.41	996.74	996.74	996.74	996.74	817.33	1,021.66	817.33
6	Customer Chrg - Secondary - CIAC Pd	$/mo	-	-	8.82	-	11.67	-	-	11.67	-	-	-	-	-	-	-	-	-	-	81.74	286.06	81.74
7	Customer Chrg - Primary - CIAC Pd	$/mo	-	-	-	-	147.52	-	-	147.52	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Customer Chrg - Transmission - CIAC Pd	$/mo	-	-	-	-	727.63	-	-	727.63	-	-	-	-	-	-	-	-	-	-	-	-	-
9	CIAC for Metering Cost	$	-	-	90.00	-	132.00	-	-	n/a	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Energy Chrg - Standard	¢/kWh	-	-	-	5.663	-	2.147	2.365	-	1.554	1.554	1.554	-	-	-	1.041	1.041	-	-	1.029	1.016	1.020
11	Energy Chrg - Standard <= 1,000 kWh	¢/kWh	5.214	5.214	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Energy Chrg - Standard > 1,000 kWh	¢/kWh	6.641	6.641	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Energy Chrg - TOU - On Peak	¢/kWh	-	-	16.101	-	16.074	-	-	5.148	-	-	-	2.852	2.852	2.852	-	-	1.458	1.458	-	-	-
14	Energy Chrg - TOU - Off Peak	¢/kWh	-	-	0.894	-	0.871	-	-	0.863	-	-	-	0.857	0.857	0.857	-	-	0.851	0.851	-	-	-
15	Energy Chrg - Prem Distrib	¢/kWh	-	-	-	0.773	0.773	0.156	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Demand Chrg - Standard	$/kW	-	-	-	-	-	-	5.30	-	8.51	8.51	8.51	-	-	-	7.20	7.20	-	-	-	-	-
17	Demand Chrg - TOU - Base	$/kW	-	-	-	-	-	-	-	1.30	-	-	-	1.26	1.26	1.26	-	-	1.14	1.14	-	-	-
18	Demand Chrg - TOU - On Peak	$/kW	-	-	-	-	-	-	-	3.94	-	-	-	7.18	7.18	7.18	-	-	6.30	6.30	-	-	-
19	Demand Chrg - Prem Distrib Chrg	$/kW	-	-	-	-	-	-	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.06	1.06	1.06
20	Demand Chrg - Primary Voltage Cr	$/kW	-	-	-	-	-	-	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19
21	Demand Chrg - Transmission Voltage Cr	$/kW	-	-	-	-	-	-	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	-	-	-
22	Capacity Chrg - Distrib Capacity	$/kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.09	2.08	2.08
23	Capacity Chrg - G&T-greater of SB cap or	$/kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.163	1.161	1.161
24	Capacity Chrg - G&T-greater of daily max	$/kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.554	0.553	0.553
25	IS/CS Cr	$/kW	-	-	-	-	-	-	-	-	5.03	8.77	8.77	5.03	8.77	8.77	6.71	11.70	6.71	11.70	-	-	-
26	IS/CS Cr - greater of SB capacity or	$/kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.170	0.877
27	IS/CS Cr - greater of daily max demands	$/kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.557	0.418
28	Meter Voltage Adj - Primary	%				1.0%	1.0%		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
29	Meter Voltage Adj - Transmission	%				2.0%	2.0%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
30	Power Factor	$/kVar							0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30			
31	Equip Rental Chrg	%				1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%			
32	Other Fixture Chrg	%																					
33	Other Pole Chrg	%																					

	DEF Tariff Base Rates	effective	Jan-18 LS-1
1	Customer Chrg - Seasonal (Mar-Oct)	$/mo	-
2	Customer Chrg - Unmetered	$/mo	1.20
3	Customer Chrg - Secondary	$/mo	3.44
4	Customer Chrg - Primary	$/mo	-
5	Customer Chrg - Transmission	$/mo	-
6	Customer Chrg - Secondary - CIAC Pd	$/mo	-
7	Customer Chrg - Primary - CIAC Pd	$/mo	-
8	Customer Chrg - Transmission - CIAC Pd	$/mo	-
9	CIAC for Metering Cost	$	-
10	Energy Chrg - Standard	¢/kWh	2.234
11	Energy Chrg - Standard <= 1,000 kWh	¢/kWh	-
12	Energy Chrg - Standard > 1,000 kWh	¢/kWh	-
13	Energy Chrg - TOU - On Peak	¢/kWh	-
14	Energy Chrg - TOU - Off Peak	¢/kWh	-
15	Energy Chrg - Prem Distrib	¢/kWh	-
16	Demand Chrg - Standard	$/kW	-
17	Demand Chrg - TOU - Base	$/kW	-
18	Demand Chrg - TOU - On Peak	$/kW	-
19	Demand Chrg - Prem Distrib Chrg	$/kW	-
20	Demand Chrg - Primary Voltage Cr	$/kW	-
21	Demand Chrg - Transmission Voltage Cr	$/kW	-
22	Capacity Chrg - Distrib Capacity	$/kW	-
23	Capacity Chrg - G&T-greater of SB cap or	$/kW	-
24	Capacity Chrg - G&T-greater of daily max	$/kW	-
25	IS/CS Cr	$/kW	-
26	IS/CS Cr - greater of SB capacity or	$/kW	-
27	IS/CS Cr - greater of daily max demands	$/kW	-
28	Meter Voltage Adj - Primary	%	
29	Meter Voltage Adj - Transmission	%	
30	Power Factor	$/kVar	
31	Equip Rental Chrg	%	
32	Other Fixture Chrg	%	1.59%
33	Other Pole Chrg	%	1.82%

		DVC						0.65%							IS/CS/GSLM2 Credit increase %:			7.50%				
DEF Tariff Base Rates	effective	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18	Jan 18
		RS-1	RSS-1	RST-1	GS-1	GST-1	GS-2	GSD-1	GSDT-1	CS-1	CS-2	CS-3	CST-1	CST-2	CST-3	IS-1	IS-2	IST-1	IST-2	SS-1	SS-2	SS-3
				(closed)			100% LF	24 mWh	24 mwh	(closed)	500 kW	2000 kW	(closed)	500 kW	2000 kW		500 kW	(closed)	500 kW	Firm	IS	CS
1 Customer Chrg - Seasonal (Mar-Oct)	$/mo	-	4.61	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2 Customer Chrg - Unmetered	$/mo	-	-	-	6.58	-	6.58	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Customer Chrg - Secondary	$/mo	8.82	8.82	16.30	11.67	19.13	11.67	11.67	19.13	76.46	76.46	76.46	76.46	76.46	76.46	280.78	280.78	280.78	280.78	101.37	305.70	101.37
4 Customer Chrg - Primary	$/mo	-	-	-	147.52	155.00	-	147.52	155.00	212.31	212.31	212.31	212.31	212.31	212.31	416.65	416.65	416.65	416.65	237.23	441.55	237.23
5 Customer Chrg - Transmission	$/mo	-	-	-	727.63	735.10	-	727.63	735.10	792.41	792.41	792.41	792.41	792.41	792.41	996.74	996.74	996.74	996.74	817.33	1,021.66	817.33
6 Customer Chrg - Secondary - CIAC Pd	$/mo	-	-	8.82	-	11.67	-	-	11.67	-	-	-	-	-	-	-	-	-	-	81.74	286.06	81.74
7 Customer Chrg - Primary - CIAC Pd	$/mo	-	-	-	-	147.52	-	-	147.52	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Customer Chrg - Transmission - CIAC Pd	$/mo	-	-	-	-	727.63	-	-	727.63	-	-	-	-	-	-	-	-	-	-	-	-	-
9 CIAC for Metering Cost	$			90.00		132.00			n/a													
10 Energy Chrg - Standard	¢/kWh	-	-	-	5.654	-	2.143	2.361	-	1.554	1.554	1.554	-	-	-	1.041	1.041	-	-	1.028	1.016	1.020
11 Energy Chrg - Standard <= 1,000 kWh	¢/kWh	5.205	5.205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 Energy Chrg - Standard > 1,000 kWh	¢/kWh	6.630	6.630	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13 Energy Chrg - TOU - On Peak	¢/kWh	-	-	16.074	-	16.046	-	-	5.139	-	-	-	2.852	2.852	2.852	-	-	1.458	1.458	-	-	-
14 Energy Chrg - TOU - Off Peak	¢/kWh	-	-	0.893	-	0.870	-	-	0.862	-	-	-	0.857	0.857	0.857	-	-	0.851	0.851	-	-	-
15 Energy Chrg - Prem Distrib	¢/kWh	-	-	-	0.772	0.772	0.156	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16 Demand Chrg - Standard	$/kW	-	-	-	-	-	-	5.29	-	8.51	8.51	8.51	-	-	-	7.20	7.20	-	-	-	-	-
17 Demand Chrg - TOU - Base	$/kW	-	-	-	-	-	-	-	1.30	-	-	-	1.26	1.26	1.26	-	-	1.14	1.14	-	-	-
18 Demand Chrg - TOU - On Peak	$/kW	-	-	-	-	-	-	-	3.94	-	-	-	7.18	7.18	7.18	-	-	6.30	6.30	-	-	-
19 Demand Chrg - Prem Distrib Chrg	$/kW	-	-	-	-	-	-	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.06	1.06	1.06
20 Demand Chrg - Primary Voltage Cr	$/kW			-	-	-	-	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19
21 Demand Chrg - Transmission Voltage Cr	$/kW			-	-	-	-	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	5.95	-	-	-
22 Capacity Chrg - Distrib Capacity	$/kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.08	2.08	2.08
23 Capacity Chrg - G&T-greater of SB cap or	$/kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.161	1.161	1.161
24 Capacity Chrg - G&T-greater of daily max	$/kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.553	0.553	0.553
25 IS/CS Cr	$/kW	-	-	-	-	-	-	-	-	5.03	8.77	8.77	5.03	8.77	8.77	6.71	11.70	6.71	11.70	-	-	-
26 IS/CS Cr - greater of SB capacity or	$/kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.170	0.877
27 IS/CS Cr - greater of daily max demands	$/kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.557	0.418
28 Meter Voltage Adj - Primary	%				1.0%	1.0%		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
29 Meter Voltage Adj - Transmission	%				2.0%	2.0%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
30 Power Factor	$/kVar							0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30			
31 Equip Rental Chrg	%				1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%			
32 Other Fixture Chrg	%																					
33 Other Pole Chrg	%																					

	DEF Tariff Base Rates	effective	Jan 18 LS-1
1	Customer Chrg - Seasonal (Mar-Oct)	$/mo	-
2	Customer Chrg - Unmetered	$/mo	1.20
3	Customer Chrg - Secondary	$/mo	3.44
4	Customer Chrg - Primary	$/mo	-
5	Customer Chrg - Transmission	$/mo	-
6	Customer Chrg - Secondary - CIAC Pd	$/mo	-
7	Customer Chrg - Primary - CIAC Pd	$/mo	-
8	Customer Chrg - Transmission - CIAC Pd	$/mo	-
9	CIAC for Metering Cost	$	
10	Energy Chrg - Standard	¢/kWh	2.231
11	Energy Chrg - Standard <= 1,000 kWh	¢/kWh	-
12	Energy Chrg - Standard > 1,000 kWh	¢/kWh	-
13	Energy Chrg - TOU - On Peak	¢/kWh	-
14	Energy Chrg - TOU - Off Peak	¢/kWh	-
15	Energy Chrg - Prem Distrib	¢/kWh	-
16	Demand Chrg - Standard	$/kW	-
17	Demand Chrg - TOU - Base	$/kW	-
18	Demand Chrg - TOU - On Peak	$/kW	-
19	Demand Chrg - Prem Distrib Chrg	$/kW	-
20	Demand Chrg - Primary Voltage Cr	$/kW	-
21	Demand Chrg - Transmission Voltage Cr	$/kW	-
22	Capacity Chrg - Distrib Capacity	$/kW	-
23	Capacity Chrg - G&T-greater of SB cap or	$/kW	-
24	Capacity Chrg - G&T-greater of daily max	$/kW	-
25	IS/CS Cr	$/kW	-
26	IS/CS Cr - greater of SB capacity or	$/kW	-
27	IS/CS Cr - greater of daily max demands	$/kW	-
28	Meter Voltage Adj - Primary	%	
29	Meter Voltage Adj - Transmission	%	
30	Power Factor	$/kVar	
31	Equip Rental Chrg	%	
32	Other Fixture Chrg	%	1.59%
33	Other Pole Chrg	%	1.82%

	DEF Tariff Base Rates	effective	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17	Apr-17
			RS-1	RSS-1	RST-1	GS-1	GST-1	GS-2	GSD-1	GSDT-1	CS-1	CS-2	CS-3	CST-1	CST-2	CST-3	IS-1	IS-2	IST-1	IST-2	SS-1	SS-2	SS-3
					(closed)			100% LF	24 mWh	24 mwh	(closed)	500 kW	2000 kW	(closed)	500 kW	2000 kW		500 kW	(closed)	500 kW	Firm	IS	CS
1	Customer Chrg - Seasonal (Mar-Oct)	$/mo		4.58																			
2	Customer Chrg - Unmetered	$/mo				6.54		6.54															
3	Customer Chrg - Secondary	$/mo	8.76	8.76	16.19	11.59	19.01	11.59	11.59	19.01	75.96	75.96	75.96	75.96	75.96	75.96	278.95	278.95	278.95	278.95	100.71	303.71	100.71
4	Customer Chrg - Primary	$/mo				146.56	153.99		146.56	153.99	210.93	210.93	210.93	210.93	210.93	210.93	413.94	413.94	413.94	413.94	235.69	438.68	235.69
5	Customer Chrg - Transmission	$/mo				722.90	730.32		722.90	730.32	787.26	787.26	787.26	787.26	787.26	787.26	990.26	990.26	990.26	990.26	812.02	1,015.02	812.02
6	Customer Chrg - Secondary - CIAC Pd	$/mo			8.76		11.59			11.59											81.21	284.20	81.21
7	Customer Chrg - Primary - CIAC Pd	$/mo					146.56			146.56													
8	Customer Chrg - Transmission - CIAC Pd	$/mo					722.90			722.90													
9	CIAC for Metering Cost	$			90.00		132.00			n/a													
10	Energy Chrg - Standard	¢/kWh				5.617		2.129	2.346		1.544	1.544	1.544				1.034	1.034			1.021	1.009	1.013
11	Energy Chrg - Standard <= 1,000 kWh	¢/kWh	5.171	5.171																			
12	Energy Chrg - Standard > 1,000 kWh	¢/kWh	6.587	6.587																			
13	Energy Chrg - TOU - On Peak	¢/kWh			15.969		15.942			5.106				2.833	2.833	2.833			1.449	1.449			
14	Energy Chrg - TOU - Off Peak	¢/kWh			0.887		0.864			0.856				0.851	0.851	0.851			0.845	0.845			
15	Energy Chrg - Prem Distrib	¢/kWh				0.767	0.767	0.155															
16	Demand Chrg - Standard	$/kW							5.26		8.45	8.45	8.45				7.15	7.15					
17	Demand Chrg - TOU - Base	$/kW								1.29				1.25	1.25	1.25			1.13	1.13			
18	Demand Chrg - TOU - On Peak	$/kW								3.91				7.13	7.13	7.13			6.26	6.26			
19	Demand Chrg - Prem Distrib Chrg	$/kW							1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.05	1.05	1.05
20	Demand Chrg - Primary Voltage Cr	$/kW							0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.37	0.37	0.37
21	Demand Chrg - Transmission Voltage Cr	$/kW							1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55	1.55			
22	Capacity Chrg - Distrib Capacity	$/kW																			2.07	2.07	2.07
23	Capacity Chrg - G&T-greater of SB cap or	$/kW																			1.153	1.153	1.153
24	Capacity Chrg - G&T-greater of daily max	$/kW																			0.549	0.549	0.549
25	IS/CS Cr	$/kW									4.68	8.16	8.16	4.68	8.16	8.16	6.24	10.88	6.24	10.88			
26	IS/CS Cr - greater of SB capacity or	$/kW																				1.088	0.816
27	IS/CS Cr - greater of daily max demands	$/kW																				0.518	0.389
28	Meter Voltage Adj - Primary	%				1.0%	1.0%		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
29	Meter Voltage Adj - Transmission	%				2.0%	2.0%		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
30	Power Factor	$/kVar							0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30			
31	Equip Rental Chrg	%				1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%			
32	Other Fixture Chrg	%																					
33	Other Pole Chrg	%																					

	DEF Tariff Base Rates	effective	Apr-17 LS-1
1	Customer Chrg - Seasonal (Mar-Oct)	$/mo	
2	Customer Chrg - Unmetered	$/mo	1.19
3	Customer Chrg - Secondary	$/mo	3.42
4	Customer Chrg - Primary	$/mo	
5	Customer Chrg - Transmission	$/mo	
6	Customer Chrg - Secondary - CIAC Pd	$/mo	
7	Customer Chrg - Primary - CIAC Pd	$/mo	
8	Customer Chrg - Transmission - CIAC Pd	$/mo	
9	CIAC for Metering Cost	$	
10	Energy Chrg - Standard	¢/kWh	2.216
11	Energy Chrg - Standard <= 1,000 kWh	¢/kWh	
12	Energy Chrg - Standard > 1,000 kWh	¢/kWh	
13	Energy Chrg - TOU - On Peak	¢/kWh	
14	Energy Chrg - TOU - Off Peak	¢/kWh	
15	Energy Chrg - Prem Distrib	¢/kWh	
16	Demand Chrg - Standard	$/kW	
17	Demand Chrg - TOU - Base	$/kW	
18	Demand Chrg - TOU - On Peak	$/kW	
19	Demand Chrg - Prem Distrib Chrg	$/kW	
20	Demand Chrg - Primary Voltage Cr	$/kW	
21	Demand Chrg - Transmission Voltage Cr	$/kW	
22	Capacity Chrg - Distrib Capacity	$/kW	
23	Capacity Chrg - G&T-greater of SB cap or	$/kW	
24	Capacity Chrg - G&T-greater of daily max	$/kW	
25	IS/CS Cr	$/kW	
26	IS/CS Cr - greater of SB capacity or	$/kW	
27	IS/CS Cr - greater of daily max demands	$/kW	
28	Meter Voltage Adj - Primary	%	
29	Meter Voltage Adj - Transmission	%	
30	Power Factor	$/kVar	
31	Equip Rental Chrg	%	
32	Other Fixture Chrg	%	1.59%
33	Other Pole Chrg	%	1.82%

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: DUKE ENERGY FLORIDA

DOCKET NO: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule RS-1

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase
1												
2	**Customer Charge:**											
3	Standard											
4	Secondary Standard	18,523,521	Bills @	8.76	=	162,266,043	18,523,521	Bills @	8.82	=	163,328,081	
5	Seasonal											
6	Secondary Standard	482,227	Bills @	8.76	=	4,224,310	482,227	Bills @	8.82	=	4,251,958	
7	Secondary Seasonal	216,653	Bills @	4.58	=	992,270	216,653	Bills @	4.61	=	998,764	
8	Subtotal	698,880					698,880					
9	Time-of-Use											
10	Secondary (single & three phase)	194	Bills @	16.19	=	3,140	194	Bills @	16.30	=	3,161	
11	Customer CIAC Paid	156	Bills @	8.76	=	1,367	156	Bills @	8.82	=	1,376	
12	TOTAL	19,222,751	Bills			167,487,130	19,222,751	Bills			168,583,340	0.65%
13												
14	**Energy Charge:**											
15	Standard											
16	Secondary											
17	0-1000 KWH	14,248,311	MWH @	51.71	=	736,780,172	14,248,311	MWH @	52.14	=	742,866,322	
18	over 1000 KWH	5,749,357	MWH @	65.87	=	378,710,147	5,749,357	MWH @	66.41	=	381,838,471	
19	Subtotal	19,997,668					19,997,668					
20												
21	Time-of-Use											
22	Secondary											
23	On-Peak	142	MWH @	159.69	=	22,634	142	MWH @	161.01	=	22,821	
24	Off-Peak	413	MWH @	8.87	=	3,662	413	MWH @	8.94	=	3,692	
25	Subtotal	555					555					
26												
27	TOTAL	19,998,223	MWH	55.78		1,115,516,615	19,998,223	MWH	56.24		1,124,731,306	0.83%
28												
29	**Adjustments**											
30	n/a					-					-	
31												
32	**Total RS-1 Base Revenue**					1,283,003,745					1,293,314,646	0.80%
33												
34							Increase/ (Decrease) - $				10,310,901	
35												
36												
37												
38												
39												

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: DUKE ENERGY FLORIDA

DOCKET NO: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule GS-1

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase
1												
2	**Customer Charge:**											
3	Standard											
4	Unmetered	5,132	Bills @	6.54	=	33,561	5,132	Bills @	6.58	=	33,780	
5	Secondary	1,544,930	Bills @	11.59	=	17,905,743	1,544,930	Bills @	11.67	=	18,022,936	
6	Primary	461	Bills @	146.56	=	67,559	461	Bills @	147.52	=	68,002	
7	Transmission		Bills @	722.90	=	-	-	Bills @	727.63	=	-	
8	Time-of-Use											
9	Secondary (single & three phase)	10,714	Bills @	19.01	=	203,667	10,714	Bills @	19.13	=	205,000	
10												
11	Customer CIAC Paid	24	Bills @	11.59	=	278	24	Bills @	11.67	=	280	
12	Primary	68	Bills @	153.99	=	10,504	68	Bills @	155.00	=	10,573	
13	Transmission	12	Bills @	730.32	=	9,058	12	Bills @	735.10	=	9,117	
14	TOTAL	1,561,341	Bills			18,230,370	1,561,341	Bills			18,349,688	0.65%
15												
16	**Energy Charge:**											
17	Standard											
18	Secondary	1,821,592	MWH @	56.17	=	102,318,796	1,821,592	MWH @	56.63	=	103,163,997	
19	Primary	16,444	MWH @	56.17	=	923,632	16,444	MWH @	56.63	=	931,262	
20	Transmission	-	MWH @	56.17	=	-	-	MWH @	56.63	=	-	
21	Time-of-Use											
22	Secondary											
23	On-Peak	22,817	MWH @	159.42	=	3,637,476	22,817	MWH @	160.74	=	3,667,523	
24	Off-Peak	71,167	MWH @	8.64	=	614,884	71,167	MWH @	8.71	=	619,963	
25	Primary											
26	On-Peak	1,175	MWH @	159.42	=	187,373	1,175	MWH @	160.74	=	188,921	
27	Off-Peak	2,820	MWH @	8.64	=	24,367	2,820	MWH @	8.71	=	24,568	
28	Transmission											
29	On-Peak	213	MWH @	159.42	=	33,913	213	MWH @	160.74	=	34,193	
30	Off-Peak	2,263	MWH @	8.64	=	19,550	2,263	MWH @	8.71	=	19,711	
31	TOTAL	1,938,490	MWH			107,759,991	1,938,490	MWH			108,650,138	0.83%
32												
33	**Adjustments**											
34	Distribution Primary Metering	1%	OF	1,135,372	=	(11,354)	1%	OF	1,144,751	=	(11,448)	
35	Transmission Metering	2%	OF	53,463	=	(1,069)	2%	OF	53,904	=	(1,078)	
36	TOTAL					(12,423)					(12,526)	0.83%
37												
38	**Total GS-1 Base Revenue**					125,977,938					126,987,300	0.80%
39							Increase/ (Decrease) - $				$ 1,009,362	

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: DUKE ENERGY FLORIDA

DOCKET NO: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule GS-2

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase
1												
2	**Customer Charge:**											
3	Standard											
4	Unmetered	11,500	Bills @	6.54	=	75,208	11,500	Bills @	6.58	=	75,700	
5	Secondary	156,466	Bills @	11.59	=	1,813,443	156,466	Bills @	11.67		1,825,312	
6	TOTAL	167,966	Bills			1,888,651	167,966				1,901,012	0.65%
7												
8	**Energy Charge:**											
9	Standard											
10	Secondary	173,218	MWH @	21.29	=	3,687,803	173,218	MWH @	21.47	=	3,718,266	0.83%
11												
12	**Adjustments**											
13												
14	n/a					-					-	
15												
16	**Total GS-2 Base Revenue**					5,576,454					5,619,278	0.77%
17												
18							Increase/ (Decrease) - $				42,824	
19												
20												
21												
22												
23												
24												
25												
26												
27												
28												
29												
30												
31												
32												
33												
34												
35												
36												
37												
38												
39												

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: DUKE ENERGY FLORIDA

DOCKET NO: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule GSD

Line No.	Type of Charges	Present Units		Present Charge/Unit		Present $ Revenue	Proposed Units		Proposed Charge/Unit		Proposed $ Revenue	Percent Increase
1	**Customer Charge:**											
2	Standard											
3	Secondary	443,320	Bills @	11.59	=	5,138,079	443,320	Bills @	11.67	=	5,171,708	
4	Primary	1,043	Bills @	146.56	=	152,887	1,043	Bills @	147.52	=	153,888	
5	Transmission	-	Bills @	722.90	=	-	-	Bills @	727.63		-	
6	Time-of-Use											
7	Secondary	153,106	Bills @	19.01	=	2,910,554	153,106	Bills @	19.13	=	2,929,603	
8	Customer CIAC Paid	132	Bills @	11.59	=	1,530	132	Bills @	11.67	=	1,540	
9	Primary	2,695	Bills @	153.99	=	415,038	2,695	Bills @	155.00	=	417,754	
10	Customer CIAC Paid	48	Bills @	146.56	=	7,035	48	Bills @	147.52	=	7,081	
11	Transmission	6	Bills @	730.32	=	4,526	6	Bills @	735.10	=	4,555	
12	TOTAL	600,351	Bills			8,629,649	600,351	Bills			8,686,129	0.65%
13												
14	**Demand Charge:**											
15	Standard											
16	Secondary	13,224,002	kW @	5.26	=	69,558,253	13,224,002	kW @	5.30	=	70,132,837	
17	Primary	294,652	kW @	4.85	=	1,429,062	294,652	kW @	4.11	=	1,212,036	
18	Transmission	-	kW @	3.71	=	-	-	kW @	(0.65)	=	-	
19	Time-of-Use											
20	Secondary											
21	On-Peak	16,710,186	kW @	3.91	=	65,336,826	16,710,186	kW @	3.94	=	65,876,539	
22	Base	17,321,541	kW @	1.29	=	22,344,788	17,321,541	kW @	1.30	=	22,529,366	
23	Primary											
24	On-Peak	4,000,127	kW @	3.91	=	15,640,496	4,000,127	kW @	3.94	=	15,769,694	
25	Base	4,201,477	kW @	0.88	=	3,697,300	4,201,477	kW @	0.11	=	464,919	
26	Transm/Primary											
27	On-Peak	5,696	kW @	3.91	=	22,271	5,696	kW @	3.94	=	22,455	
28	Base	7,449	kW @	(0.26)	=	(1,937)	7,449	kW @	(4.65)	=	(34,631)	
29	Sec/Pri											
30	On-Peak	46,640	kW @	3.91	=	182,364	46,640	kW @	3.94	=	183,870	
31	Base	47,139	kW @	1.29	=	60,810	47,139	kW @	1.30	=	61,312	
32												
33	Premium Distrib. Charge	445,155	kW @	1.13	=	503,025	445,155	kW @	1.14	=	507,180	
34	TOTAL Billed/Base	35,096,260	kW	TOTAL		178,773,258	35,096,260	kW			176,725,577	-1.15%
35												
36												
37												
38												
39												

Supporting Schedules: | Recap Schedules:

Florida Public Service Commission

Company: Duke Energy Florida

Docket No.: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule GSD

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase
1												
2	**Energy Charge:**											
3	Standard											
4	Secondary	4,046,725	MWH @	23.46	=	94,936,162	4,046,725	MWH @	23.65	=	95,720,379	
5	Primary	91,298	MWH @	23.46	=	2,141,855	91,298	MWH @	23.65	=	2,159,548	
6	Transmission	-	MWH @	23.46	=	-	-	MWH @	23.65	=	-	
7	Time-of-Use											
8	Secondary											
9	On-Peak	2,206,620	MWH @	51.06	=	112,669,992	2,206,620	MWH @	51.48	=	113,600,699	
10	Off-Peak	5,605,329	MWH @	8.56	=	47,981,614	5,605,329	MWH @	8.63	=	48,377,965	
11	Primary											
12	On-Peak	556,074	MWH @	51.06	=	28,393,155	556,074	MWH @	51.48	=	28,627,696	
13	Off-Peak	1,522,141	MWH @	8.56	=	13,029,524	1,522,141	MWH @	8.63	=	13,137,154	
14	Transm/Primary											
15	On-Peak	487	MWH @	51.06	=	24,877	487	MWH @	51.48	=	25,083	
16	Off-Peak	1,421	MWH @	8.56	=	12,163	1,421	MWH @	8.63	=	12,263	
17	Sec/Pri											
18	On-Peak	7,450	MWH @	51.06	=	380,389	7,450	MWH @	51.48	=	383,531	
19	Off-Peak	21,085	MWH @	8.56	=	180,484	21,085	MWH @	8.63	=	181,975	
20	TOTAL	14,058,629	MWH			299,750,215	14,058,629	MWH			302,226,293	0.83%
21												
22	**Adjustments**											
23	Distribution Primary Metering	1%	OF	65,192,813	=	(651,928)	1%	OF	62,206,905		(622,069)	
24	Transmission Metering	2%	OF	-	=	-	2%	OF	-		-	
25	Power Factor	(698,631)	KVar	0.30		(209,589)	(698,631)	KVar	0.30		(209,589)	
26	TOTAL					(861,517)					(831,658)	-3.47%
27												
28	**Total GSD-1 Base Revenue**					486,291,605					486,806,341	0.11%
29												
30							Increase/ (Decrease) - $				514,736	
31												
32												
33												
34												
35												
36												
37												
38												
39												

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: DUKE ENERGY FLORIDA

DOCKET NO: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule CS

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase
1												
2	**Customer Charge:**											
3	Standard											
4	Secondary	-	Bills @	75.96	=	-	-	Bills @	76.46	=	-	
5	Primary	-	Bills @	210.93	=	-	-	Bills @	212.31		-	
6	Transmission	-	Bills @	787.26	=	-	-	Bills @	792.41	=	-	
7	Time-of-Use						-					
8	Secondary	-	Bills @	75.96	=	-	-	Bills @	76.46	=	-	
9	Primary	37	Bills @	210.93	=	7,837	37	Bills @	212.31	=	7,889	
10	Transmission	-	Bills @	787.26	=	-	-	Bills @	792.41	=	-	
11	TOTAL	37	Bills			7,837	37	Bills			7,889	0.66%
12												
13	**Demand Charge:**											
14	Standard											
15	Secondary	-	kW @	8.45	=	-	-	kW @	8.51	=	-	
16	Primary	-	kW @	8.04	=	-	-	kW @	7.32	=	-	
17	Transmission	-	kW @	6.90	=	-	-	kW @	2.56	=	-	
18	Time-of-Use											
19	Secondary											
20	On-Peak	-	kW @	7.13	=	-	-	kW @	7.18	=	-	
21	Base	-	kW @	1.25	=	-	-	kW @	1.26	=	-	
22	Primary											
23	On-Peak	250,209	kW @	7.13	=	1,783,991	250,209	kW @	7.18	=	1,795,667	
24	Base	294,392	kW @	0.84	=	247,289	294,392	kW @	0.07	=	20,072	
25	Transmission											
26	On-Peak	-	kW @	7.13	=	-	-	kW @	7.18	=	-	
27	Base	-	kW @	(0.30)	=	-	-	kW @	(4.69)	=	-	
28	TOTAL Billed/Base	294,392	kW	TOTAL		2,031,280	294,392	kW	TOTAL		1,815,739	-10.61%
29												
30												
31												
32												
33												
34												
35												
36												
37												
38												
39												

Supporting Schedules: Recap Schedules:

Florida Public Service Commission

Company: Duke Energy Florida

Docket No.: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule CS

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase
1												
2	**Energy Charge:**											
3	Standard											
4	Secondary	-	MWH @	15.44	=	-	-	MWH @	15.54	=	-	
5	Primary	-	MWH @	15.44	=	-	-	MWH @	15.54	=	-	
6	Transmission	-	MWH @	15.44	=	-	-	MWH @	15.54	=	-	
7	Time-of-Use											
8	Secondary											
9	On-Peak	-	MWH @	28.33	=	-	-	MWH @	28.52	=	-	
10	Off-Peak	-	MWH @	8.51	=	-	-	MWH @	8.57	=	-	
11	Primary											
12	On-Peak	17,327	MWH @	28.33	=	490,884	17,327	MWH @	28.52	=	494,097	
13	Off-Peak	53,822	MWH @	8.51	=	458,024	53,822	MWH @	8.57	=	461,022	
14	Transmission											
15	On-Peak	-	MWH @	28.33	=	-	-	MWH @	28.52	=	-	
16	Off-Peak	-	MWH @	8.51	=	-	-	MWH @	8.57	=	-	
17	TOTAL	71,149	MWH			948,908	71,149	MWH			955,119	0.65%
18												
19	**Adjustments**											
20												
21	Distribution Primary Metering	1%	OF	2,980,188	=	(29,802)	1%	OF	2,770,858	=	(27,709)	
22	Transmission Metering	2%	OF	-	=	-	2%	OF	-	=	-	
23	Power Factor	(2,225)	Kvar	0.30		-	(2,225)	Kvar	0.30		(668)	
24	TOTAL					(29,802)					(28,377)	-4.78%
25												
26	**Total CS-1, CS-2, CS-3 Base Revenue**					2,958,223					2,750,370	-7.03%
27												
28							Increase/ (Decrease) - $				(207,853)	
29												
30												
31												
32												
33												
34												
35												
36												
37												
38												
39												

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: DUKE ENERGY FLORIDA

DOCKET NO: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule IS

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase
1	**Customer Charge:**											
2	Standard											
3	Secondary	225	Bills @	278.95	=	62,836	225	Bills @	280.78	=	63,247	
4	Primary	316	Bills @	413.94	=	130,869	316	Bills @	416.65		131,725	
5	Transmission	-	Bills @	990.26	=	-	-	Bills @	996.74	=	-	
6	Time-of-Use						-					
7	Secondary	156	Bills @	278.95	=	43,544	156	Bills @	280.78	=	43,829	
8	Primary	718	Bills @	413.94	=	297,318	718	Bills @	416.65	=	299,264	
9	Transmission	71	Bills @	990.26	=	70,442	71	Bills @	996.74	=	70,903	
10	TOTAL	1,487	Bills			605,009	1,487	Bills			608,968	0.65%
11												
12	**Demand Charge:**											
13	Standard											
14	Secondary	92,510	kW @	7.15	=	661,448	92,510	kW @	7.20	=	665,777	
15	Primary	471,248	kW @	6.74	=	3,176,213	471,248	kW @	6.01	=	2,830,692	
16	Transmission	-	kW @	5.60	=	-	-	kW @	1.25	=	-	
17	Sec/Pri	4,034	kW @	7.15	=	28,846	4,034	kW @	7.20	=	29,035	
18	Transm/Pri	-	kW @	5.60	=	-	-	kW @	1.25	=	-	
19	Time-of-Use											
20	Secondary											
21	On-Peak	119,739	kW @	6.26	=	749,568	119,739	kW @	6.30	=	754,474	
22	Base	125,194	kW @	1.13	=	141,469	125,194	kW @	1.14	=	142,395	
23	Primary											
24	On-Peak	2,438,056	kW @	6.26	=	15,262,234	2,438,056	kW @	6.30	=	15,362,125	
25	Base	2,598,805	kW @	0.72	=	1,871,140	2,598,805	kW @	(0.05)	=	(136,708)	
26	Transmission											
27	On-Peak	623,662	kW @	6.26	=	3,904,125	623,662	kW @	6.30	=	3,929,677	
28	Base	634,587	kW @	(0.42)	=	(266,527)	634,587	kW @	(4.81)	=	(3,054,016)	
29	Sec/Pri											
30	On-Peak	6,351	kW @	6.26	=	39,757	6,351	kW @	6.30	=	40,017	
31	Base	6,428	kW @	1.13	=	7,264	6,428	kW @	1.14	=	7,312	
32	Pri/Transm											
33	On-Peak	477	kW @	6.26	=	2,983	477	kW @	6.30	=	3,003	
34	Base	488	kW @	0.72	=	351	488	kW @	(0.05)	=	(26)	
35	Transm/Pri											
36	On-Peak	830,772	kW @	6.26	=	5,200,633	830,772	kW @	6.30	=	5,234,672	
37	Base	847,282	kW @	(0.42)	=	(355,858)	847,282	kW @	(4.81)	=	(4,077,633)	
38	TOTAL Billed/Base	4,780,577	kW	TOTAL		30,423,646	4,780,577	kW	TOTAL		21,730,796	-28.57%
39												

Supporting Schedules: Recap Schedules:

Schedule E-13c | BASE REVENUE BY RATE SCHEDULE - CALCULATIONS |

Florida Public Service Commission

Company: Duke Energy Florida

Docket No.: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule IS

Line No.	Type of Charges	Present Units		Present Charge/Unit		Present $ Revenue	Proposed Units		Proposed Charge/Unit		Proposed $ Revenue	Percent Increase
1	**Energy Charge:**											
2	Standard											
3	Secondary	23,497	MWH @	10.34	=	242,959	23,497	MWH @	10.41	=	244,550	
4	Primary	139,731	MWH @	10.34	=	1,444,814	139,731	MWH @	10.41	=	1,454,270	
5	Transmission	-	MWH @	10.34	=	-	-	MWH @	10.41	=	-	
6	Sec/Pri	1,111	MWH @	10.34	=	11,486	1,111	MWH @	10.41	=	11,561	
7	Tran/Prim	-	MWH @	10.34	=	-	-	MWH @	10.41	=	-	
8	Time-of-Use											
9	Secondary											
10	On-Peak	17,617	MWH @	14.49	=	255,266	17,617	MWH @	14.58	=	256,936	
11	Off-Peak	47,930	MWH @	8.45	=	405,008	47,930	MWH @	8.51	=	407,658	
12	Primary											
13	On-Peak	285,701	MWH @	14.49	=	4,139,802	285,701	MWH @	14.58	=	4,166,897	
14	Off-Peak	838,245	MWH @	8.45	=	7,083,174	838,245	MWH @	8.51	=	7,129,533	
15	Transmission											
16	On-Peak	75,715	MWH @	14.49	=	1,097,108	75,715	MWH @	14.58	=	1,104,289	
17	Off-Peak	238,447	MWH @	8.45	=	2,014,877	238,447	MWH @	8.51	=	2,028,064	
18	Sec/Pri											
19	On-Peak	904	MWH @	14.49	=	13,097	904	MWH @	14.58	=	13,183	
20	Off-Peak	2,665	MWH @	8.45	=	22,519	2,665	MWH @	8.51	=	22,667	
21	Pri/Transm											
22	On-Peak	68	MWH @	14.49	=	986	68	MWH @	14.58	=	993	
23	Off-Peak	197	MWH @	8.45	=	1,668	197	MWH @	8.51	=	1,679	
24	Transm/Pri											
25	On-Peak	70,643	MWH @	14.49	=	1,023,618	70,643	MWH @	14.58	=	1,030,318	
26	Off-Peak	151,057	MWH @	8.45	=	1,276,433	151,057	MWH @	8.51	=	1,284,787	
27	TOTAL	1,893,527	MWH			19,032,815	1,893,527	MWH			19,157,385	0.65%
28												
29	**Adjustments**											
30	Distribution Primary Metering	1%	OF	40,245,172	=	(402,452)	1%	OF	34,402,728	=	(344,027)	
31	Transmission Metering	2%	OF	6,755,571	=	(135,111)	2%	OF	4,013,663	=	(80,273)	
32	Power Factor	(98,482)	Kvar	0.30		(29,545)	(98,482)	Kvar	0.30		(29,545)	
33	TOTAL					(567,108)					(453,845)	-19.97%
34												
35	**Total CS-1, CS-2, CS-3 Base Revenue**					49,494,362					41,043,304	-17.07%
36												
37							Increase/ (Decrease) - $				(8,451,058)	

Supporting Schedules: | Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: DUKE ENERGY FLORIDA

DOCKET NO: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule LS

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase
1	**Customer Charge:**											
2	Standard											
3	Unmetered	750,056	Bills @	1.19	=	892,567	750,056	Bills @	1.20	=	898,409	
4	Secondary	12,568	Bills @	3.42	=	42,984	12,568	Bills @	3.44	=	43,265	
5	TOTAL	762,625	Bills			935,551	762,625	Bills			941,674	0.65%
6												
7	**Energy & Demand Charge:**											
8	Standard											
9	Secondary	378,883	MWH @	22.16	=	8,396,056	378,883	MWH @	22.34	=	8,465,412	0.83%
10												
11	**Adjustments**											
12												
13	n/a					-					-	
14												
15	**Total LS-1 Base Revenue**					9,331,607					9,407,086	0.81%
16												
17							Increase/ (Decrease) - $				75,479	
18												
19												
20												
21												
22												
23												
24												
25												
26												
27												
28												
29												
30												
31												
32												
33												
34												
35												
36												
37												
38												
39												

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: DUKE ENERGY FLORIDA

DOCKET NO: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule SS-1

Line No.	Type of Charges	Present Units		Present Charge/Unit		Present $ Revenue	Proposed Units		Proposed Charge/Unit		Proposed $ Revenue	Percent Increase
1												
2	**Customer Charge:**											
3	Primary	50	Bills @	235.69	=	11,776	50	Bills @	237.23	=	11,853	
4	Transmission	10	Bills @	812.02	=	8,070	10	Bills @	817.33	=	8,123	
5	Pri/Transm (Customer Owned - CIAC)	72	Bills @	81.21	=	5,847	72	Bills @	81.74	=	5,885	
6	Total	132	Bills			25,693	132	Bills			25,861	0.65%
7												
8	**Demand Charge:**											
9	Distribution Charge											
10	Primary	111,036	kW @	2.07	=	229,845	111,036	kW @	2.09	=	231,743	
11	Transmission	306,900	kW @		=	-	306,900	kW @		=	-	
12												
13	(Greater of SB Cap or DD)											
14	Primary											
15	Specified SB Cap	17,760	kW @	1.153	=	20,477	17,760	kW @	1.163	=	20,646	
16	Daily Demand	1,537,910	kW @	0.549	=	844,313	1,537,910	kW @	0.554	=	851,287	
17	Transmission											
18	Specified SB Cap	235,008	kW @	1.153	=	270,964	235,008	kW @	1.163	=	273,203	
19	Daily Demand	342,840	kW @	0.549	=	188,219	342,840	kW @	0.554	=	189,774	
20	Total Specified SB Cap	417,936		Total		1,553,818	417,936		Total		1,566,653	0.83%
21												
22	**Energy Charge:**											
23	Standard											
24	Primary	41,438	MWH @	10.21	=	423,082	41,438	MWH @	10.29	=	426,577	
25	Transmission	7,627	MWH @	10.21	=	77,876	7,627	MWH @	10.29	=	78,519	
26	Total	49,065	MWH			500,958	49,065	MWH			505,096	
27	**Adjustments**											
28	Delivery Voltage Credit	111,036		(0.37)		(41,083)	111,036		(1.19)		(132,133)	
29	Distribution Primary Metering	1%	OF	1,517,717	=	(15,177)	1%	OF	1,530,253	=	(15,303)	
30	Transmission Metering	2%	OF	537,059	=	(10,741)	2%	OF	541,496	=	(10,830)	
31	Total					(67,002)					(158,265)	136.21%
32												
33	**Total SS-1 Base Revenue**					2,013,467					1,939,345	-3.68%
34												
35											(74,123)	
36												
37												
38												
39												

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: DUKE ENERGY FLORIDA

DOCKET NO: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule SS-2

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase
1												
2	**Customer Charge:**											
3	Primary	26	Bills @	438.68	=	11,389	26	Bills @	441.55	=	11,463	
4	Transmission	(0)	Bills @	1,015.02	=	(273)	(0)	Bills @	1,021.66	=	(275)	
5	Transmission (Customer Owned)	7	Bills @	284.20	=	1,989	7	Bills @	286.06	=	2,002	
6	Total	33	Bills			13,105	33	Bills			13,190	0.65%
7												
8	**Demand Charge:**											
9	Distribution Charge											
10	Primary	114,000	kW @	2.07	=	235,980	114,000	kW @	2.08	=	237,524	
11	Transmission	323,592	kW @		=	-	323,592	kW @		=	-	
12	Generation & Transm											
13	(Greater of SB Cap/DD)											
14	Primary											
15	Specified SB Cap	47,500	kW @	1.153	=	54,768	47,500	kW @	1.161	=	55,126	
16	Daily Demand	3,602,101	kW @	0.549	=	1,977,553	3,602,101	kW @	0.553	=	1,990,497	
17	Transmission											
18	Specified SB Cap	8,196	kW @	1.153	=	9,450	8,196	kW @	1.161	=	9,512	
19	Daily Demand	267,570	kW @	0.549	=	146,896	267,570	kW @	0.553	=	147,857	
20	Total Specified SB Cap	437,592		Total		2,424,647	437,592		Total		2,440,516	0.65%
21												
22	**Energy Charge:**											
23	Standard											
24	Primary	8,991	MWH @	10.09	=	90,723	8,991	MWH @	10.16	=	91,317	
25	Transmission	97,196	MWH @	10.09	=	980,705	97,196	MWH @	10.16	=	987,124	
26	Total	106,187	MWH			1,071,428	106,187	MWH			1,078,441	0.65%
27	**Adjustments**											
28	Delivery Voltage Credit	114,000		(0.37)		(42,180)	114,000		(1.19)		(135,660)	
29	Distribution Primary Metering	1%	OF	2,359,024	=	(23,590)	1%	OF	2,374,464	=	(23,745)	
30	Transmission Metering	2%	OF	1,137,051	=	(22,741)	2%	OF	1,144,493	=	(22,890)	
31	Total					(88,511)					(182,295)	105.96%
32												
33	**Total SS-2 Base Revenue**					3,420,669					3,349,852	-2.07%
34												
35											(70,817)	
36												
37												
38												
39												

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: DUKE ENERGY FLORIDA

DOCKET NO: xxxxxx-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15.

PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
__X__ Projected Test Year Ended 12/31/18
_____ Prior Year Ended 12/31/xx
_____ Historical Year Ended 12/31/xx
Witness: _________

Rate Schedule SS-3

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase
1												
2	**Customer Charge:**											
3	Primary	13	Bills @	235.69		3,176	13	Bills @	237.23		3,197	
4	Primary (Customer Owned)	-	Bills @	81.21	=	-	-	Bills @	81.74	=	-	
5	Transmission	-	Bills @	812.02	=	-	-	Bills @	817.33	=	-	
6	Total	13	Bills			3,176	13	Bills			3,197	0.66%
7												
8	**Demand Charge:**											
9	Distribution Charge											
10	Primary	266,652	kW @	2.070	=	551,970	266,652	kW @	2.084	=	555,582	
11	Transmission	-	kW @		=	-	-	kW @		=	-	
12	Generation & Transm											
13	(Greater of SB Cap/DD)											
14	Primary											
15	Specified SB Cap	133,326	kW @	1.153	=	153,725	133,326	kW @	1.161	=	154,731	
16	Daily Demand	1,614,827	kW @	0.549	=	886,540	1,614,827	kW @	0.553	=	892,342	
17	Transmission											
18	Specified SB Cap	-	kW @	1.153	=	-	-	kW @	1.161	=	-	
19	Daily Demand	-	kW @	0.549	=	-	-	kW @	0.553	=	-	
20	Total Specified SB Cap	266,652	kW	Total		1,592,235	2,014,805	kW	Total		1,602,655	0.65%
21												
22	**Energy Charge:**											
23	Standard											
24	Primary	55,813	MWH @	10.13	=	565,384	55,813	MWH @	10.20	=	569,084	
25	Transmission	-	MWH @	10.13	=	-	-	MWH @	10.20	=	-	
26	Total	55,813	MWH			565,384	55,813	MWH			569,084	0.65%
27	**Adjustments:**											
28	Delivery Voltage Credit	266,652		(0.37)		(98,661)	266,652		(1.19)		(317,316)	
29	Distribution Primary Metering	1%	OF	2,157,619	=	(21,576)	1%	OF	2,171,739	=	(21,717)	
30	Transmission Metering	2%	OF	-	=	-	2%	OF	-	=	-	
31	Total					(120,237)					(339,033)	181.97%
32												
33	**Total SS-3 Base Revenue**					2,040,558					1,835,903	-10.03%
34												
35											(204,655)	
36												
37												

Supporting Schedules:

Recap Schedules:

Unit Charge / Unit Cost Data

Line	Rate Schedule	Type of Charge	4/1/17 Current Rate	1/1/18 Proposed Rate
1	**RS-1**	Customer Charge - $ per Line of Billing		
2	**RST-1**	Standard	$8.76	$8.82
3	**RSS-1**	Seasonal (RSS-1)	$4.58	$4.61
4	**(RST closed**	Time of Use		
5	**2/10/2010)**	Single Phase	$16.19	$16.30
6		Three Phase	$16.19	$16.30
7		Customer CIAC Paid	$8.76	$8.82
8				
9		TOU Metering CIAC - One Time Charge	$90.00	$90.00
10				
11		Energy and Demand Charge - cents per KWH		
12		Standard		
13		0 - 1,000 KWH	5.171	5.214
14		Over 1,000 KWH	6.587	6.641
15		Time of Use - On Peak	15.969	16.101
16		Time of Use - Off Peak	0.887	0.894

Unit Charge / Unit Cost Data

17	**GS-1,**	Customer Charge - $ per Line of Billing		
18	**GST-1**	Standard		
19		Unmetered	$6.54	$6.58
20		Secondary	$11.59	$11.67
21		Primary	$146.56	$147.52
22		Transmission	$722.90	$727.63
23		Time of Use		
24		Single Phase	$19.01	$19.13
25		Three Phase	$19.01	$19.13
26		Customer CIAC Paid	$11.59	$11.67
27		Primary	$153.99	$155.00
28		Transmission	$730.32	$735.10
29				
30		TOU Metering CIAC - One Time Charge	$132.00	$132.00
31				
32		Energy and Demand Charge - cents per KWH		
33		Standard	5.617	5.663
34		Time of Use - On Peak	15.942	16.074
35		Time of Use - Off Peak	0.864	0.871
36		Premium Distribution Charge - cents per KWH	0.767	0.773
37				
38		Meter Voltage Adjustment - % of Demand & Energy Charges		
39		Primary	1.0%	1.0%
40		Transmission	2.0%	2.0%
41		Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%
42	**GS-2**	Customer Charge - $ per Line of Billing		
43		Standard		
44		Unmetered	$6.54	$6.58
45		Metered	$11.59	$11.67
46				
47		Energy and Demand Charge - cents per KWH		
48		Standard	2.129	2.147
49				
50		Premium Distribution Charge - cents per KWH	0.155	0.156

Unit Charge / Unit Cost Data

51	**GSD-1**	Customer Charge - $ per Line of Billing		
52	**GSDT-1**	Standard		
53		Secondary	$11.59	$11.67
54		Primary	$146.56	$147.52
55		Transmission	$722.90	$727.63
56		Time of Use		
57		Secondary	$19.01	$19.13
58		Secondary - Customer CIAC paid	$11.59	$11.67
59		Primary	$153.99	$155.00
60		Primary - Customer CIAC paid	$146.56	$147.52
61		Transmission	$730.32	$735.10
62		Transmission Customer CIAC paid	$722.90	$727.63
63				
64		Demand Charge - $ per KW		
65		Standard	$5.26	$5.30
66				
67		Time of Use		
68		Base	$1.29	$1.30
69		On Peak	$3.91	$3.94
70				
71		Delivery Voltage Credits - $ per KW		
72		Primary	$0.41	$1.19
73		Transmission	$1.55	$5.95
74				
75		Premium Distribution Charge - $ per KW	$1.13	$1.14
76				
77		Energy Charge - cents per KWH		
78		Standard	2.346	2.365
79		Time of Use - On Peak	5.106	5.148
80		Time of Use - Off Peak	0.856	0.863
81				
82		Meter Voltage Adjustment - % of Demand & Energy Charges		
83		Primary	1.0%	1.0%
84		Transmission	2.0%	2.0%
85		Power Factor - $ per KVar	0.30	0.30
86		Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%

Unit Charge / Unit Cost Data

87	**CS-1**	Customer Charge - $ per Line of Billing		
88	**CS-2**	Secondary	$75.96	$76.46
89	**CS-3**	Primary	$210.93	$212.31
90	**CST-1**	Transmission	$787.26	$792.41
91	**CST-2**			
92		Demand Charge - $ per KW		
93		Standard	$8.45	$8.51
94				
95		Time of Use		
96		Base	$1.25	$1.26
97		On Peak	$7.13	$7.18
98				
99		Curtailable Demand Credit		
100		CS-2, CST-2 - $ per KW LF adjusted Demand	$8.16	$8.77
101		CS-3, CST-3 - $ per KW of Contract Demand	$8.16	$8.77
102				
103		Delivery Voltage Credits - $ per KW		
104		Primary	$0.41	$1.19
105		Transmission	$1.55	$5.95
106				
107		Premium Distribution Charge - $ per KW	$1.13	$1.14
108				
109		Energy Charge - cents per KWH		
110		Standard	1.544	1.554
111		Time of Use - On Peak	2.833	2.852
112		Time of Use - Off Peak	0.851	0.857
113				
114		Meter Voltage Adjustment - % of Demand & Energy Charges		
115		Primary	1.0%	1.0%
116		Transmission	2.0%	2.0%
117		Power Factor - $ per KVar	0.30	0.30
118		Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%

Unit Charge / Unit Cost Data

119	**IS-1**	Customer Charge - $ per Line of Billing		
120	**IS-2**	Secondary	$278.95	$280.78
121	**IST-1**	Primary	$413.94	$416.65
122	**IST-2**	Transmission	$990.26	$996.74
123				
124		Demand Charge - $ per KW		
125		Standard	$7.15	$7.20
126				
127		Time of Use		
128		Base	$1.13	$1.14
129		On Peak	$6.26	$6.30
130				
131		Interruptible Demand Credit		
132		IS-2, IST-2 - $ per KW LF Adjusted Demand	$6.24	$6.71
133				
134		Delivery Voltage Credits - $ per KW		
135		Primary	$0.41	$1.19
136		Transmission	$1.55	$5.95
137				
138		Premium Distribution Charge - $ per KW	$1.13	$1.14
139				
140		Energy Charge - cents per KWH		
141		Standard	1.034	1.041
142		Time of Use - On Peak	1.449	1.458
143		Time of Use - Off Peak	0.845	0.851
144				
145		Meter Voltage Adjustment - % of Demand & Energy Charges		
146		Primary	1.0%	1.0%
147		Transmission	2.0%	2.0%
148		Power Factor - $ per KVar	0.30	0.30
149		Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%
150	**LS-1**	Customer Charge - $ per Line of Billing		
151		Standard		
152		Unmetered	$1.19	$1.20
153		Metered	$3.42	$3.44
154				
155		Energy and Demand Charge - cents per KWH		
156		Standard	2.216	2.234
157				
158		Fixture & Maintenance Charges - $ per fixture	various	various
159				
160		Pole Charges - $ per pole	various	various
161				

162	Other Fixture Charge Rate - % of Installed Fixture Cost	1.59%	1.59%
163	Other Pole Charge Rate - % of Installed Pole Cost	1.82%	1.82%

Unit Charge / Unit Cost Data

164	**SS-1**	Customer Charge - $ per Line of Billing		
165		Secondary	$100.71	$101.37
166		Primary	$235.69	$237.23
167		Transmission	$812.02	$817.33
168		Customer Owned	$81.21	$81.74
169				
170		Base Rate Energy Customer Charge - cents per KWH	1.021	1.029
171				
172		Distribution Charge - $ per KW		
173		Applicable to Specified SB Capacity	$2.07	$2.09
174				
175		Generation and Transmission Capacity Charge		
176		Greater of : - $ per KW		
177		Monthly Reservation Charge		
178		Applicable to Specified SB Capacity	$1.153	$1.163
179		Peak Day Utilized SB Power Charge of:	$0.549	$0.554
180				
181		Delivery Voltage Credits - $ per KW		
182		Primary	$0.37	$1.19
183		Transmission	n/a	n/a
184		Premium Distribution Charge - $ per KW	1.05	1.06
185	**SS-2**	Customer Charge - $ per Line of Billing		
186		Secondary	$303.71	$305.70
187		Primary	$438.68	$441.55
188		Transmission	$1,015.02	$1,021.66
189		Customer Owned	$284.20	$286.06
190				
191		Base Rate Energy Customer Charge - cents per KWH	1.009	1.016
192				
193		Distribution Charge - $ per KW		
194		Applicable to Specified SB Capacity	$2.07	$2.08
195				
196		Generation and Transmission Capacity Charge		
197		Greater of : - $ per KW		
198		Monthly Reservation Charge		
199		Applicable to Specified SB Capacity	$1.153	$1.161
200		Peak Day Utilized SB Power Charge of:	$0.549	$0.553
201				
202		Effective 1/1/06		
203		Monthly Reservation Credit	$1.088	$1.170
204		Daily Demand Credit	$0.518	$0.557
205				
206		Delivery Voltage Credits - $ per KW		

207	Primary	$0.37	$1.19
208	Transmission	n/a	n/a
209	Premium Distribution Charge - $ per KW	$1.05	$1.06

Unit Charge / Unit Cost Data

210	**SS-3**	Customer Charge - $ per Line of Billing		
211		Secondary	$100.71	$101.37
212		Primary	$235.69	$237.23
213		Transmission	$812.02	$817.33
214		Customer Owned	$81.21	$81.74
215				
216		Base Rate Energy Customer Charge - cents per KWH	1.013	1.020
217				
218		Distribution Charge - $ per KW		
219		Applicable to Specified SB Capacity	$2.07	$2.08
220				
221		Generation and Transmission Capacity Charge		
222		Greater of : - $ per KW		
223		Monthly Reservation Charge		
224		Applicable to Specified SB Capacity	$1.153	$1.161
225		Peak Day Utilized SB Power Charge of:	$0.549	$0.553
226				
227		Effective 1/1/06		
228		Monthly Reservation Credit	$0.816	$0.877
229		Daily Demand Credit	$0.389	$0.418
230				
231		Delivery Voltage Credits - $ per KW		
232		Primary	$0.37	$1.19
233		Transmission	n/a	n/a
234		Premium Distribution Charge - $ per KW	$1.05	$1.06
235		Gross Receipts Tax	2.5641%	2.5641%