Matthew R. Bernier
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May 16, 2017

VIA ELECTRONIC FILING

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

Re: *Docket 170069-EI – DEF's Response to Staff's First Data Request*

Dear Ms. Stauffer:

Please find enclosed for filing on behalf of Duke Energy Florida, LLC ("DEF"), DEF's Response to Staff's First Data Request propounded by Staff on May 1, 2017 that concerns DEF's revised underground residential distribution tariffs.

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
Sr. Counsel

MRB/at
Enclosure

Duke Energy Florida, LLC
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail this 16th day of May, 2017 as indicated below.

s/Matthew R. Bernier
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Duke Energy Florida, LLC's Response to Staff's First Data Request
Docket No. 170069-EI – Petition for approval of revised underground residential distribution tariffs, by Duke Energy Florida, LLC

1. Please refer to section 11.03 – Summary of cost changes for residential subdivision designs (last page of the filing) for the following questions.

    a. The first paragraph states that some 50 kva padmounted transformers were upgraded to 75 kva in the underground design. The sentence continues with "based the lower loading capacities of the newer energy efficient transformers." Please explain what that means.

    <u>Response:</u>

    Transformer efficiency improvements have been mandated by the DOE (Department of Energy) with effective dates of 2010 and 2016. In the past Duke Energy loaded transformers to 140% of nameplate rating for subdivision designs. Current design tools provide for a standard maximum of 120% of nameplate rating which is an industry standard for summer loading. The underground designs were adjusted to reflect this value.

    b. The second paragraph states that overhead hourly rates remained relatively flat, while associated burdens decreased. Please describe the burdens that decreased (e.g., benefits, pension, etc.) and explain why they decreased.

    <u>Response:</u>

    The decrease in benefit burden rate is attributable to the harmonization of the legacy Progress OPEB plan with the legacy Duke plan. The harmonization resulted in an OPEB plan amendment that reduced OPEB benefits beginning in Q4 2014, over a four year period

    c. According to the second paragraph, underground labor costs have decreased due to the transition from hourly pricing to unit based pricing for contractors. Please describe the differences between unit based pricing and hourly pricing and explain why unit based pricing is less costly (second paragraph).

Response:

Contractors compensated under an "hourly" pricing structure are compensated for the duration to complete the work. This includes any inefficiencies and unforeseen delays.

Contractors compensated under a "Unit" cost structure are compensated based on fixed prices associated with specific work. Any inefficiencies and unforeseen delays would be absorbed by the contractor.

When comparing the labor for an underground service from the 2014 filing to our 2017 filing, the per lot cost for the sample subdivisions decreased by 36%.

d. Does Duke use employees or contractors for overhead and underground labor in the residential subdivision cost analysis? Is this a change from 2014?

Response:

Yes, the OH and UG subdivisions design analysis include both Duke Energy employees and contractors. Duke Energy continues to use the same labor crews for the same labor functions in the 2017 filing as was used in the 2014 filing for both estimation and actual construction purposes.

e. Please explain why material costs have "fluctuated marginally" (third paragraph).

Response:

All the percentage variations fluctuated a maximum of plus or minus 5% annually when purchasing materials, which is why it was described as "fluctuated marginally".

2. The following questions refer to the loading factors (please also see Duke's response to staff's first data request in Docket No. 140067-EI, No. 3).

a. Does the 2017 filing use historical data provided by the work management system to determine current loading factors? If yes, what time period is used?

Response:

Duke Energy applied actual material and labor charging to the jobs in our work management system to determine the appropriate loading factor in 2017. The date range used was January 1, 2016 to December 31, 2016.

b. Has the list of material items classified as benchstock changed since the 2014 filing? If so, please explain any effect on the Stores loading factor.

Response:

No, the list of items classified as benchstock has not changed since the 2014 filing.

c. Does the Management & Supervision loading factor still include additional non-direct field personnel? If no, please explain.

Response:

Yes, this is consistent with our loading factor included in the 2014 filing.

d. Please explain why the Management and Supervision loading factor decreased from 35.67 percent in 2014 to 28.86 percent in 2017.

Response:

The rate is calculated comparing the previous year amount of management and supervision costs divided by the amount of costs (CWIP, RWIP and O&M) overseen for that same year. The proportion of investment in the distribution system has increased greater than the management and supervision costs, causing the loader rate to decrease.

e. Please explain why the Stores loading factor decreased from 21.25 percent in 2014 to 19.71 percent in 2017.

Response:

Process improvements and reduction of storekeepers has helped lower the stores loading rate.

f. Please explain why the Fleet loading factor decreased from 22.49 percent in 2014 to 21.41 percent in 2017.

Response:

The drop in fuel costs from 2014 to 2017 is the main driver. Fuel costs averaged in the state of Florida $3.42 in 2014 versus the average in 2016 of $2.22.

g. Please explain why the Design and Project Management loading factor decreased from 17.9 percent in 2014 to 13.9 percent in 2017.

Response:

Similar to DEF’s response to part d, the Design and Project management costs have not increased in the same proportion as the investment in the distribution system. This has resulted in a reduction in the Design and Project management loader rate.

3. Please refer to WR #1449870 (rev 2), WR #1449872 (rev 3), WR #1451310 (rev 1), WR #145308 (rev 1), WR #1452463 (rev 1), and WR #1452464 (rev 1) in the filing. It appears as if the 2017 Stores loading factor used is about 18.5 percent (19.71 percent Stores loading factor less 6.5 percent sales tax rate). Is this correct? If yes, please explain why sales tax is not included. If not correct, please explain why the factor used is described as the Stores loading factor but does not equal to 19.71 percent.

Response:

Yes, the sales tax is included. The Benchstock, Corporate Stores and Local Stores in the current 2017 filing are 19.71% of material. The Sub-Total (1) includes 6.5 % sales tax. The Stores Handling (3) can be derived by dividing the Sub-Total (1) by 1.065 (removing the sales tax) and multiplying by the Stores Handling percentage outlined in footnote (3) .

4. Referring to proposed Tariff Sheet No. 4.113, legislative version, please explain why the rate for 2 inch conduit has increased while the rates for 4 and 6 inch conduit have decreased.

Response:

The material costs have decreased by 9% for 2” conduit and 13% for 4” and 6” conduit over the last 3 years. However, the majority of the change in referenced rates are due to new labor pricing for our contractors. In the 2017 filing, the labor associated with handling 2”, 4”, or 6” conduit is a flat rate for the various sizes. As a result, when combining the material and labor costs, the referenced rates reflect the increase for 2” and the decrease for 4” and 6” conduits.

5. Referring to proposed Tariff Sheet No. 4.122, legislative version, please explain why the phrase was deleted at the end of (2).

Response:

The deleted phrase, which included specific cost information, was deleted for a couple of reasons. The first is for consistency with the remainder of the items listed under (2), as none of the other items included specific cost information (DEF also notes that the proposed treatment aligns with the other Florida utilities’ tariffs). The second reason is the specific amounts at issue are actually “baked into” the remainder of the items listed under (2); that is, the equation presented is illustrative of the components of the Facility Charge, but does not show a hard calculation thereof.

6. Please refer to the page immediately following Schedule No. 10; this page is titled "Summary of NPV Life Cycle Costs per mile for Overhead and Underground Distribution Including Storm Costs and Pole Attachment Revenues." Please see the table below which summarizes the changes in Duke's NPV Life Cycle Costs between 2014 and the present. (Also see Duke's response to staff's first data request in Docket No. 140067-EI, No. 4)

NPV Parameter Description	Docket No. 140067-EI	Docket No. 170069-EI
5 yr avg ann OH cost w/o storm	$3,812	$5,098
5 yr avg ann OH cost – storm	$674	$652
5 yr avg ann UG cost w/o storm	$4,310	$5,320
5 yr avg ann UG cost – storm	$189	$182
OH 34 yr life cycle w/o storm	$72,499	$92,225
OH 34 yr life cycle – storm	$12,819	$11,795
UG 34 yr life cycle w/o storm	$81,970	$96,241
UG 34 yr life cycle – storm	$3,595	$3,292

a. For each of the 2017 amounts listed above, please explain in detail how the amounts were developed. Please discuss the discount rate(s) used and provide the rationale regarding why the discount rates are appropriate.

<u>Response:</u>

The process for developing the Net Present Value of the lifecycle operational costs including storm damage (NPV Lifecycle costs) was the same for each subdivision type and is described below. The company identified all the specific work activities associated with overhead (OH) and underground (UG) distribution work. Where activities might be associated with both OH and UG, determination of each was made based on specific materials. This included both capital and O&M activity (certain activities such as work for the public were excluded). Actual annual pole attachment revenues were subtracted from the OH costs assuming that most OH poles would have attachments. Expected annual storm damage from the Company's latest storm damage study was allocated to both the OH and UG costs based on our storm damage experience from the 2004 & 2005 storms. Unit costs for OH and UG costs were then calculated on a per mile basis using circuit miles of OH and UG distribution lines. These annual unit costs for 2012-2016 were then escalated to 2016 dollars per circuit mile. A 5-year average was then calculated on the 2016 unit costs for both OH and UG. This 5-year average was then escalated out for 34 years (the average service life for UG per currently approved depreciation study). These escalated values were then discounted back to 2016 dollars using an appropriate discount rate to get the NPV Lifecycle unit cost per mile of both OH and UG.

The discount rate is the financial weighted average cost of capital "WACC" used for investments at Duke Energy Florida. For the equity component the allowed

ROE of 10.50% is used. For the debt component the marginal cost of debt of 4.2% (2.58% after tax).

The following calculation derives the WACC:
10.50% * 53% = 5.57% (Equity)
2.58% * 47% = 1.21% (Debt)
5.57% + 1.21% = 6.78% rounded to 6.80% (Total WACC)

The discount rate is appropriate because it represents the cost to finance DEF's investments.

b. Please compare the 2014 and 2017 amounts in the table above and describe the reasons why costs have increased or decreased between 2014 and the present. In particular please discuss why the values for overhead are increasing at a greater rate than the values for underground for costs without storm and why the reverse is occurring, to a lesser extent, for the storm values.

Response:

During the historical 5-year average spending cycle that supported the 2014 filing, there was increased program focus on UG maintenance and repairs, such as cable replacement versus cable repairs, UG network systems and transformer replacement. The 5-year cycle that supports the 2017 filing included more of an OH spending strategy such as pole replacement, hardening and grid automation.

With respect to the decrease in storm values, the current filing reflects storm costs from the 2014 storm study and adjusts those costs (for the time value of money) to the 5-year average of 2012-2016 dollars while the prior filing reflects storm costs from the 2009 storm study and adjusts those costs to the 5-year average of 2009-2013 dollars. Storm costs per circuit mile in current dollars at the time of each of these filings have decreased, and because a larger portion of storm costs is associated with overhead lines, this results in a larger decrease in overhead storm costs than underground.